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April 21, 2020

Bryce Bird
Director
Utah Division of Air Quality
195 North 1950 West
P.O. Box 144820
Salt Lake City, UT 84114-4820

Subject: PacifiCorp – Utah Thermal Generation Facilities – Regional Haze Second Planning Period Reasonable Progress Analysis

Dear Mr. Bird:

In a letter dated October 21, 2019, the Utah Division of Air Quality (UDAQ) notified PacifiCorp that UDAQ had begun work on its State Implementation Plan (SIP) for the second planning period for regional haze. The letter stated that a four-factor reasonable progress analysis would need to be completed for PacifiCorp's Huntington and Hunter plants to be used by UDAQ for its development of the second planning period SIP.

In a follow-up meeting on December 10, 2019, UDAQ staff requested that PacifiCorp provide a notice identifying any pollution control measures that were implemented at PacifiCorp's Huntington, Hunter, and Carbon plants since 2014 which resulted in reductions of visibility-impairing pollutants (NO_X, SO_2 and PM_{10}). On January 31, 2020, PacifiCorp provided the requested notification and indicated its intent to provide the requested four-factor analysis for Huntington and Hunter by March 31, 2020. Due to unforeseen circumstances, including challenges and delays relating to addressing COVID-19 impacts, PacifiCorp subsequently determined that it would have difficulty in providing a complete four-factor analysis by that date. PacifiCorp therefore requested, and UDAQ approved, an extended submission deadline of April 21, 2020.

Attached are PacifiCorp's responses to UDAQ's requests for four-factor analyses at PacifiCorp's Huntington and Hunter plants.

Sincerely,

James Owen
Director, Environmental

cc: Jay Baker – Utah Division of Air Quality
Jim Doak – PacifiCorp
Marie Bradshaw Durrant – PacifiCorp
Dana Ralston – PacifiCorp
Blaine Rawson – Ray Quinney & Nebeker

PacifiCorp – Utah Coal Generation Facilities

REGIONAL HAZE - SECOND PLANNING PERIOD
REASONABLE PROGRESS ANALYSIS

APRIL 2020

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1.0 HISTORY OF THE REGIONAL HAZE RULE WITH RELEVANCE TO SECOND PLANNING PERIOD

The Clean Air Act ("CAA") requires the Environmental Protection Agency ("EPA") to monitor and address visibility in national parks and wilderness areas. Visibility impairment in national parks and wilderness areas is called "regional haze," and EPA's program to address the same is called the "regional haze program." The regional haze program requires the States, in coordination with EPA and other federal agencies, to develop and implement air quality protection plans (regional haze state implementation plans, or "RH SIPs") to reduce the pollution that causes visibility impairment.

These RH SIPs cover a ten-year (unless otherwise extended) period (called a "planning period"). The goal is to return the national parks and wilderness areas to "natural visibility" by 2064. The first RH SIPs for regional haze reduction for the first planning period were due in December 2007. States, tribes, and five multi-jurisdictional regional planning organizations worked together to develop the technical basis for these first planning period plans. The regional haze program requires comprehensive periodic revisions every ten years (unless otherwise extended) to the RH SIPs, with the next revision due in 2021 (for the second planning period), then 2028, and every 10 years thereafter (unless otherwise extended).

The CAA and EPA's regional haze rule provide a process for States to follow to determine what is necessary to make reasonable progress in Class I areas. The first step is to determine which sources will be reviewed and analyzed as part of the regional haze program. As a general matter, after determining which sources should be evaluated, the States evaluate what emission control measures are necessary for the selected sources (which can be individual sources, groups of sources, and/or source sectors) in light of the four statutory reasonable progress factors, five additional considerations specified in the regional haze rule, and possibly other considerations (e.g., visibility benefits of potential control measures, etc.). States have discretion to balance these factors and considerations in determining what control measures are necessary to make reasonable progress.

The States, including Utah, are currently in the process of identifying the sources that will be addressed in the second regional haze planning period, and determining what controls or emissions reductions will be required of these sources. Utah has notified particular sources it believes could be covered by its second planning period RH SIP, is receiving feedback on which of these sources should be included in the second planning period RH SIP, and, if included, what emissions controls and limits would be appropriate for the included sources.

Specifically, in a December 10, 2019, meeting, the Utah Division of Air Quality ("UDAQ") requested that PacifiCorp's Hunter and Huntington power plants conduct statutory four-factor analyses to be used by the state in UDAQ's development of the second decadal RH SIPs. PacifiCorp and UDAQ agreed that the statutory four-factor analyses for these two power plants should be submitted to UDAQ no later than April 21, 2020. This submission by PacifiCorp fulfills this requirement, and includes important information and analyses regarding the regional haze requirements for the second planning period for its two coal-fired power plants in Utah.

1.1 REASONABLE PROGRESS AND PLANTWIDE ANALYSIS

Among the issues relevant to the second planning period, one key issue is whether PacifiCorp's coal-fired power plants should be analyzed as a group, as individual power plants, or by each unit at each power plant. PacifiCorp believes it is appropriate under the regional haze rules for Utah to conduct its "reasonable progress" analyses for the second planning period on both a "group" and a "plantwide" basis for PacifiCorp's power plants in Utah.

The regional haze regulations governing the creation of RH SIPs for the second planning period provide the states with significant discretion in determining the sources covered, and how those sources are defined. For example, when making "reasonable progress" determinations for inclusion in long term strategies for the RH SIP, the regulations advise states "should consider evaluating *major and minor stationary sources or groups of sources*, mobile sources, and area sources. The State must include in its implementation plan a description of the criteria it used to determine *which sources or groups of sources* it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy." 40 CFR 51.308(f)(2)(i) (emphasis added).

Moreover, the regional haze regulations define "stationary source" broadly to mean "any building, structure, facility, or installation which emits or may emit any air pollutant." 40 CFR 51.301. The regulations then define "building, structure, or facility" to mean "all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person." *Id.* Because each unit at each of PacifiCorp's Utah power plants belong to the same industrial grouping, are located on the same property, and are under PacifiCorp's control, then these units can be grouped together to comprise a single "stationary source."[1] Therefore, Utah should review each power plant as a "stationary source," and each unit as different "pollutant emitting activity" at that single "stationary source."

And, in certain analyses, Utah may want to consider PacifiCorp's coal-fired power plants[2] as a "group of sources," or Utah may want to consider all coal-fired power plants in Utah as a "group

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[1] The 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" is very flexible on this point. In Appendix C of the 2019 Guidance, specifically page C-4, it states, "The Regional Haze Rule defines a stationary source as "any building, structure, facility or installation which emits or may emit any air pollutant. In this document, the *terms stationary source* and *source*, depending on context, may also refer to a single emission release point, process, or unit at a building, structure, facility, or installation. Group of sources and source category are used interchangeably in this guidance document. In addition, the use of source in a statement does not necessarily exclude the application of a concept or step to a group of sources or source category, nor exclude the application of a concept or step to only one unit or emissions process at a source."

[2] EPA has previously noted that because the Huntington and Hunter plants are located within close proximity to one another, the geographic distribution of emissions from the facilities are not considered substantially different for visibility analysis at impacted Class I Areas. *See* Approval and Promulgation of Air Quality Implementation Plans; Utah; Regional Haze State and Federal Implementation Plans**,** 85 Fed. Reg. 3558, 3566 (January 22, 2020).

of sources" that belong to the same industrial grouping, and balance the various reasonable progress requirements between the different sources in the group. For example, the closure of one large coal-fired power plant may result in sufficient modeled visibility improvement to represent reasonable progress for the entire coal-fired power plant group. The closure of PacifiCorp's Carbon power plant yielded significant visibility improvements during the first planning period, and the closure of a much larger coal-fired power plant during the second planning period may also yield very significant visibility improvements.

1.2 INSTANCES WHEN REASONABLE PROGRESS ANALYSIS IS NOT NEEDED

Under the current regional haze regulations and EPA's 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" ("2019 Guidance"), certain sources are not required to conduct a statutory four-factor "reasonable progress determination" in certain circumstances. One circumstance that justifies foregoing the four-factor analysis – effective emission control technology – is discussed below.

1.2.1 Effective Emission Control Technology in Place

Utah should consider the "anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy" in developing its second planning period RH SIP. 40 C.F.R. § 51.308(f)(2)(iv)(E). The 2019 Guidance explains that when selecting sources for the second planning period:

> *It may be reasonable for a state not to select an effectively controlled source. A source may already have effective controls in place as a result of a previous regional haze SIP or to meet another CAA requirement.* In general, if post-combustion controls were selected and installed fairly recently . . . to meet a CAA requirement, there will be only a low likelihood of a significant technological advancement that could provide further reasonable emission reductions having been made in the intervening period. If a source owner has recently made a significant expenditure that has resulted in significant reductions of visibility impairing pollutants at an emissions unit, it may be reasonable for the state to assume that additional controls for that unit are unlikely to be reasonable for the upcoming implementation period. A state that does not select a source or sources for the following or any similar reasons should explain why the decision is consistent with the requirement to make reasonable progress, i.e., why it is reasonable to assume for the purposes of efficiency and prioritization that a full four factor analysis would likely result in the conclusion that no further controls are necessary.

Id. at 22-23 (emphasis added).

The 2019 Guidance provides examples which illustrate, in a non-exhaustive fashion, scenarios that may provide reasonable grounds for a State not to select a source for analysis, including but not limited to:

- For the purpose of SO_2 control measures, an EGU that has add-on flue gas desulfurization ("FGD") and that meets the applicable alternative SO_2 emission limit of the 2012 Mercury Air Toxics Standards ("MATS") rule for power plants.

- For the purposes of SO_2 and NO_x control measures, a combustion source (e.g., an EGU or industrial boiler or process heater) that, during the first implementation period, installed a FGD system that operates year-round with an effectiveness of at least 90 percent or by the installation of a selective catalytic reduction system that operates year-round with an overall effectiveness of at least 90 percent (in both cases calculating the effectiveness as the total for the system, including any bypassed flue gas), on a pollutant-specific basis.

- BART-eligible units that installed and began operating controls to meet BART emission limits for the first implementation period, on a pollutant-specific basis. Although the Regional Haze Rule anticipates the re-assessment of BART-eligible sources under the reasonable progress rule provisions, if a source installed and is currently operating controls to meet BART emission limits, it may be unlikely that there will be further available reasonable controls for such sources. However, States may not categorically exclude all BART-eligible sources, or all sources that installed BART controls, as candidates for selection for analysis of control measures.[3]

2.0 HUNTINGTON REASONABLE PROGRESS ANALYSIS

As requested by Utah, PacifiCorp is providing a four-factor reasonable progress analysis for the Huntington plant for the State's review and consideration as it develops an implementation plan to achieve reasonable progress for the regional haze second planning period.

2.0.1 Huntington Unit 1 and Unit 2 Overview

PacifiCorp's Huntington facility currently has effective NO_x, SO_2, and PM emission control technologies in place, which align with the illustrative examples provided in the 2019 Guidance to exempt a source from second planning period analysis, including:

- Huntington Unit 1 – BART-eligible unit installed LNB and SOFA to meet BART limits (installed 2010);

[3] EPA 2019 Guidance at 23-24.

- Huntington Unit 1 – FGD (scrubber) system upgrade that meets the applicable alternative SO_2 emission limit of the 2012 MATS rule is installed and operates year-round (installed 2010);
- Huntington Unit 1 – Baghouse retrofit for PM control installed to meet BART (installed 2010);
- Huntington Unit 2 – BART-eligible unit installed LNB and SOFA to meet BART limits (installed 2005);
- Huntington Unit 2 – FGD (scrubber) system that meets the applicable alternative SO_2 emission limit of the 2012 MATS rule is installed and operates year-round (installed 2005);
- Huntington Unit 2 – Baghouse retrofit for PM control to meet BART (installed 2005).

Because the Huntington units already have the specific, effective control technologies in place for controlling SO_2 and PM emissions that EPA identified in its 2019 Guidance, PacifiCorp is not providing any analysis for additional equipment or retrofits to further control those pollutants. As anticipated by EPA's 2019 Guidance, because effective controls are in place, it is reasonable for Utah to determine that no additional controls are reasonable for these units for the upcoming implementation period. A full four-factor analysis is not necessary to reach the conclusion that no further reasonable controls for SO_2 and PM emissions are available.

While the units have effective NOx control equipment in place (LNB and SOFA), none of the units have selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) systems in place, which are the more stringent controls listed in the 2019 Guidance. Therefore, PacifiCorp is providing analysis of those NOx control technologies as part of a four-factor reasonable progress analysis for Huntington. Applying the required four factors, the initial analysis of the standard retrofit NOx pollution controls of SCR and SNCR shows that these options are not cost effective for the Huntington plant. Although the high costs for standard NOx controls make additional NOx controls unreasonable for the second planning period at the Huntington plant, rather than propose no action for the Huntington plant for the second planning period, PacifiCorp is proposing an alternative emissions limit (described in more detail in Section 2.0.2 below) that would reduce the Huntington plant's current plantwide applicability limits ("PALs") for NOx and SO_2 at the plant.[4] Reducing the permitted plantwide limits will provide a lower emissions ceiling for the Huntington plant, with the reduction from current permitted limits roughly equivalent to SNCR's reduction from baseline. This alternative proposal has the additional benefit of also lowering PM emissions compared to SCR and SNCR. PacifiCorp provides below an analysis of the proposed plantwide NOx and SO_2 emission limit alternative, along with the SCR and SNCR four-factor analyses.

[4] PacifiCorp's reasonable progress analysis for the proposed alternative plantwide emissions limit addresses the related NOx and SO2 control measures in detail. PacifiCorp's proposal will also have impacts on PM/PM_{10} emissions, which are demonstrated in Table A.3 below.

2.0.2 Huntington Reasonable Progress Emission Limit (RPEL)

As part of Huntington's four-factor reasonable progress analysis, PacifiCorp proposes and provides analysis of a NOx and SO_2 emission limit as a control measure (that has the additional benefit of lower PM emissions), which PacifiCorp asserts will help satisfy reasonable progress for the second planning period. Specifically, PacifiCorp proposes a plantwide combined NOx + SO_2 emission limit of 10,000 tons/year be implemented at Huntington as a control measure to achieve reasonable progress for NOx emissions. This limit will be referred to herein as the Huntington "Reasonable Progress Emission Limit" ("RPEL"). As discussed above, the Huntington Units do not require a four-factor analysis for SO_2 and PM. However, the RPEL has the added benefit of reducing both SO_2 and PM emissions in comparison with SCR and SNCR.

SO_2 reductions have been shown to produce greater visibility benefits than NOx for Class I areas on the Colorado plateau.[5] The SO_2 reductions proposed as part of the RPEL are new and surplus reductions that are not included in nor relied upon by the first planning period SO_2 backstop trading program; and if needed as a substitute for NOx emission reductions, they can be included in and validated by the state and regional modeling that will take place for the second planning period.

The Huntington RPEL was derived through a multi-step process. First, PacifiCorp identified the plant's most restrictive permit limit. This was done to set a benchmark and ensure that the RPEL was lower (more stringent) than the facility's most restrictive current permit limit. In this case, Huntington's most restrictive limits are its NOx and SO_2 plantwide applicability limits (PAL). Huntington's current NOx PAL is 7,971 tons/year and its SO_2 PAL is 3,105 tons/year, providing a combined annual NOx+SO_2 PAL of 11,076 tons/year.

Second, PacifiCorp re-calculated the PALs, theoretically assuming SNCR were installed on both units.[6] In this theoretical SNCR case, the Huntington plant's NOx+SO_2 PAL would be 10,491 tons/year. Detailed RPEL support calculations are provided in Attachment 1.

Third, PacifiCorp rounded the number down to the nearest thousand tons for simplification and to ensure that emissions under the RPEL were lower than the theoretical SNCR-installation scenario, which resulted in a RPEL NOx+SO_2 limit of 10,000 tons/year.

Fourth, and finally, PacifiCorp evaluated whether the RPEL was plausible for the plant to maintain, considering PacifiCorp's operation plans and projected dispatch expectations for the Huntington plant. Once the Huntington RPEL was established, it was compared against current equipment

[5] *See* Grand Canyon Visibility Transport Commission, Recommendations for Improving Western Vistas (June 10, 1996) at 32-33; *see also* WRAP Regional Haze Rule Reasonable Progress Report Support Document, State and Class I Area Summaries, at 6-11-6-16 (Doc. No. EPA-R08-OAR-2015-0463-0200) ("WRAP Report") (finding that ammonium sulfate (produced by SO_2 emissions combining with ammonia) accounted for higher visibility impacts on the most impaired days than ammonium nitrate (produced by NOx emissions combining with ammonia).
[6] If SNCR were implemented on Huntington Units 1 and 2, the units would likely be required to maintain a NOx rate of 0.17lb/MMBtu.

installation using the statutory four factor reasonable progress analysis. The Huntington four-factor analysis therefore compares three scenarios for implementing control measures:

(1) Current NOx, SO_2, and PM control measures +SNCR
(2) Current NOx, SO_2, and PM control measures +SCR
(3) Current NOx, SO_2, and PM control measures +RPEL

For this analysis, PacifiCorp analyzed the four statutory factors listed in Section 169A(g)(1) of the Clean Air Act: (1) the cost of compliance; (2) the time necessary to achieve compliance; (3) the energy and non-air quality related environmental impacts of compliance; and (4) the remaining useful life of any existing source subject to the requirements. *See* 42 U.S.C. 7491(g)(1). PacifiCorp understands that Utah will be analyzing visibility impacts for the second planning period through visibility modeling, including at the regional level. PacifiCorp anticipates that if the reductions from the RPEL are included in state and regional modeling they will help the state in demonstrating reasonable progress by reducing the Huntington plant's permitted potential to emit.

2.0.3 Cost of Compliance

The 2019 Guidance explains how the four statutory "reasonable progress" factors should be analyzed by the States, including the "cost of compliance" factor. Specifically, the 2019 Guidance encourages States to consider costs based on "complete cost data; that is, estimated values of capital costs, annual operating and maintenance costs, annualized costs, and cost per ton of emission reductions that have been prepared according to EPA's Control Cost Manual." *Id*. at 21. The 2019 Guidance states that EPA "recommends that a state express the costs of compliance in terms of a cost/ton of emissions reduction metric." *Id*. at 31.

Cost analyses for SNCR and SCR installation at Huntington were completed by Sargent & Lundy in March 2020. Sargent & Lundy's Huntington Power Station NOx Control Cost Development and Analysis is provided in Attachment 2. The 2019 Guidance states that when choosing a baseline control scenario for the analysis, "[t]he projected 2028 (or the current) scenario can be a reasonable and convenient choice for use as the baseline control scenario for measuring the incremental effects of potential reasonable progress control measures on emissions, costs . . . ." 2019 Guidance at 29. For the cost-effectiveness evaluation of SNCR and SCR, the average baseline NOx emissions and the average baseline heat input for Units 1-2 were calculated based on the average of the most recent five years (2015-2019), which PacifiCorp considers a reasonable "current" scenario. The average values were used to provide a cost-effectiveness evaluation that was not overly conservative.

The 2019 Guidance also explains that "[a] state may choose a different emission control scenario as the analytical baseline scenario". *Id* at 29. PacifiCorp completed a cost analysis for the Huntington RPEL using the facility's current PAL as the baseline because it is a compatible control measure to the RPEL, and it is an already implemented restriction that has been agreed upon by PacifiCorp and the State. Using the PAL as the baseline for the RPEL, which is lower, allows the

State to consider a viable alternative which tightens a current emission restriction. Considering the RPEL is proper as the 2019 Guidance specifically includes "operating restrictions … to reduce emissions" as an example of an emission control measure that states may consider. 2019 Guidance at 29-30. The costs associated with the Huntington RPEL are the estimated amounts of capital upgrades and operating and maintenance (O&M) costs that would be required to meet the limit. Specifically, PacifiCorp assumed it would incur some costs associated with additional scrubbing of SO_2 to ensure the RPEL is met.

Huntington Unit 1 has a lowest achievable NO_x emission rate of 0.20 lb/MMBtu (with the existing LNB/SOFA control equipment), and an SO_2 emission limit of 0.12 lb/MMBtu. Based on these rates, the achievable NO_x+SO_2 emissions would be 6,952 tons/year without additional scrubbing. If 5,000 tons/year of the Huntington RPEL's 10,000 tons/year of NO_x+SO_2 was attributed to Unit 1, the Unit would need to scrub to an SO_2 emission rate of 0.030 lb/MMBtu to achieve the RPEL. Scrubbing to an SO_2 emission rate of 0.030 lb/MMBtu on Unit 1 would require $207,000/year in capital upgrades and $253,000/year in O&M costs for a total annualized cost of $460,000/year.

Table A.1 below summarizes the cost of compliance (on a dollar per ton of pollutant basis) for the installation of SNCR and SCR at Huntington Unit 1 and the implementation of the RPEL. As shown in the table, the dollar-per-ton cost effectiveness of SNCR installed on Huntington Unit 1 is $6,545/ton with the SCR cost effectiveness at $5,841/ton and the RPEL cost effectiveness at $855/ton.

Table A.1: Huntington Unit 1 SNCR, SCR and RPEL Cost Effectiveness

COST EFFECTIVENESS	SNCR	SCR	RPEL
Baseline Emissions			
Annual Baseline Heat Input (MMBtu)	28,063,728	28,063,728	N/A
Baseline NOx Emission (lb/MMBtu)	0.212	0.221	N/A
Baseline NOx Emission (tons/year)	2,968	2,968	N/A
Current PAL (NOx + SO_2) (tons/year)	N/A	N/A	5,538[7]
Emissions with Controls			
Controlled NOx Emission (lb/MMBtu)	0.17	0.05	N/A
Controlled NOx Emission (tons/year)	2,385	702	N/A
Controlled NOx+SO_2 (tons/year)	N/A	N/A	5,000[8]
Control Cost Effectiveness			
Annualized Capital Costs (NOx Control)	$1,525,000	$11,439,000	$0
Total Annual O&M Costs (NOx Control)	$2,287,000	$1,797,000	$0
Annualized Capital Costs (SO_2 Control)	N/A	N/A	$207,000
Total Annual O&M Costs (SO_2 Control)	N/A	N/A	$253,000
Total Annual Cost (NOx+SO_2)	**$3,812,000**	**$13,263,000**	**$460,000**
COST EFFECTIVNESS (NOX+SO_2) ($/TON)	**$6,545**	**$5,841**	**$855**

Huntington Unit 2 also has a lowest achievable NOx emission rate of 0.20 lb/MMBtu (with the existing LNB/SOFA control equipment), and an SO_2 emission limit of 0.12 lb/MMBtu. Based on these rates, the achievable NOx+SO_2 emissions would be 6,952 tons/year without additional scrubbing. If 5,000 tons/year of the Huntington RPEL's 10,000 tons/year of NOx+SO_2 was attributed to Unit 2, the Unit would need to scrub to an SO_2 emission rate of 0.030 lb/MMBtu to achieve the RPEL. Scrubbing to an SO_2 emission rate of 0.030 lb/MMBtu on Unit 2 would require $256,000/year in capital upgrades and $615,000/year in O&M costs for a total annualized cost of $871,000/year[9].

[7] 5,538 tons/year is the Unit 1 attribution of the Huntington PAL.
[8] 5,000 tons/year NOx+SO2 Unit 1 RPEL attribution with lowest achievable NOx rate (0.20 lb/MMBtu) and 0.030 lb/MMBtu SO2 emission rate.
[9] The Unit 2 scrubbing costs are projected higher that the Unit 1 scrubbing costs because Unit 1 was originally constructed with a four-vessel scrubber while the Unit 2 single-vessel scrubber

Table A.2 below summarizes the cost of compliance for the installation of SNCR and SCR at Huntington Unit 2 and the implementation of the RPEL. As shown in the table, the dollar-per-ton cost effectiveness of SNCR installed on Huntington Unit 2 is $7,040/ton, with the SCR cost effectiveness at $6,119/ton and the RPEL cost effectiveness at $1,619/ton.

Table A.2: Huntington Unit 2 SNCR, SCR and RPEL Cost Effectiveness

COST EFFECTIVENESS	SNCR	SCR	RPEL
Baseline Emissions			
Annual Baseline Heat Input (MMBtu)	27,150,145	27,150,145	N/A
Baseline NOx Emission (lb/MMBtu)	0.209	0.209	N/A
Baseline NOx Emission (tons/year)	2,835	2,835	N/A
Current PAL (NOx + SO_2) (tons/year)	N/A	N/A	5,538[10]
Emissions with Controls			
Controlled NOx Emission (lb/MMBtu)	0.17	0.05	N/A
Controlled NOx Emission (tons/year)	2,308	679	N/A
Controlled NOx+SO_2 (tons/year)	N/A	N/A	5,000[11]
Control Cost Effectiveness			
Annualized Capital Costs (NOx Control)	$1,525,000	$11,439,000	$0
Total Annual O&M Costs (NOx Control)	$2,186,000	$1,754,000	$0
Annualized Capital Costs (SO_2 Control)	N/A	N/A	$256,000
Total Annual O&M Costs (SO_2 Control)	N/A	N/A	$615,000
Total Annual Cost (NOx+SO_2)	**$3,711,000**	**$13,193,000**	**$871,000**
COST EFFECTIVNESS (NOX+SO_2) ($/TON)	**$7,040**	**$6,119**	**$1,619**

was retrofit in 2005. The increased annualized Unit 2 SO2 costs as compared to the Unit 1 costs are due to the scrubber design differences.

[10] 5,538 tons/year is the Unit 2 attribution of the Huntington PAL.

[11] 5,000 tons/year NOx+SO2 Unit 2 RPEL attribution with lowest achievable NOx rate (0.20 lb/MMBtu) and 0.030 lb/MMBtu SO2 emission rate.

2.0.4 Time Necessary for Compliance

The second factor of the statutory four-factor reasonable progress analysis is the timeframe for compliance. The installation of either SNCR or SCR at Huntington Unit 1 or 2 would require PacifiCorp to permit the installation of new pollution control equipment through the UDAQ New Source Review permitting process. The installation of SNCR on the units would be less intensive than would SCR, but both would require significant permitting, engineering, and procurement lead times for installation. It is anticipated that SNCR or SCR NO_X control technologies, if required, could be installed at Huntington Units 1 and 2 by the end of the second planning period in 2028.[12]

Implementation of the Huntington RPEL would also require permitting through UDAQ. However, the RPEL could be implemented as soon as the State's implementation plan is finalized and achieves federal approval. This means the RPEL would result in much earlier implementation of regional haze emission limits than the imposition of SNCR or SCR.

2.0.5 Energy and Non-Air Environmental Impacts

The third factor of the statutory four-factor reasonable progress analysis requires that the "energy and non-air quality environmental impacts" be considered. The 2019 Guidance explains that as part of analyzing "energy" impacts, "*states consider energy impacts by accounting for any increase or decrease in energy use at the source as part of the costs of compliance*." 2019 Guidance at 41. The following sub-sections provide several analyses of "energy" and "environmental" impacts covered by this factor, including comparisons of energy use; environmental impacts; consumption of natural resources; greenhouse gas ("GHG") emissions; coal combustion residuals ("CCR") impacts (including fly ash and bottom ash disposal); and additional benefits that would result from implementing the Huntington RPEL as compared to either the installation of SNCR or SCR. Supporting calculations for these analyses are included as Attachment 3.

2.0.5.1 Energy Impacts

The installation of SCR on Huntington Units 1 and 2 would require significant electrical energy to operate, with the two SCRs having a total electric power requirement of approximately 8.6 MW.[13] Adoption of either SNCR or the Huntington RPEL would avoid the significant auxiliary load demand of the two SCR installations, allowing the electrical energy which would have been

[12] This assumption does not account for the additional time that could potentially be consumed with challenges, requests for reconsideration, etc., that have historically occurred when such installations are required.
[13] The calculated SCR electric power requirement for the Huntington Unit 1 and Unit 2 boilers were scaled from the power requirements of the SCRs at PacifiCorp's Jim Bridger Units 3 and 4 in Wyoming.

required by the SCRs to instead be directed to the power grid. The 8.6 MW is enough energy to power approximately 6,864 average homes.[14] *See* Attachment 3.

2.0.5.2 Non-Air Environmental Impacts

The 2019 Guidance indicates that *"non-air impacts can include the generation of wastes for disposal,"* and that States may consider "*water usage or waste disposal of spent catalyst or reagent*". 2019 Guidance at 33, 42. Overall, the Huntington RPEL would result in fewer non-air environmental impacts than either SNCR or SCR.

First, the SCR "parasitic load" of 8.6 MW means a greater consumption of natural resources, increases in GHGs, and the creation and disposal of more CCR than either the Huntington RPEL or SNCR. To quantify these impacts, 32,607,019 gallons of water are required just to produce the electricity needed for the SCR parasitic load; 79,734 more tons of CO_2 would be emitted; and 3,834 more tons of CCR would be generated and disposed of to produce the electricity needed for the SCR.

It should also be noted that the installation of SCR would result in the storage and use of ammonia (a hazardous substance) and a periodic requirement to dispose of SCR catalyst. Likewise, the installation of SNCR at Huntington would require the storage and use of urea (also a hazardous substance). All calculations for non-air environmental impacts can be found in Attachment 3. An analysis of the energy and environmental impacts favors the RPEL as the best choice of reasonable progress control, with both SNCR and SCR having distinct, negative impacts.

2.0.5.3 Consumption of Natural Resources

In addition to SCR's parasitic load impacts on natural resources, if either SCR or SNCR are installed on Huntington Units 1 and 2, the facility has a potential to combust 2,538,709 tons of coal per year based on operating up to its most restrictive limit (the current PALs). With implementation of the Huntington RPEL, the facility would have the potential to combust a maximum of 2,292,081 tons of coal per year, providing a potential annual coal combustion decrease of 246,628 tons per year.

The Huntington plant utilizes raw water supplied by Huntington Creek in its plant processes. This water is primarily used for equipment cooling as well as to provide make-up for losses through evaporative cooling from the cooling towers. Huntington has a design make-up water requirement of approximately 7,069 gallons per minute. If either SCR or SNCR are installed on Huntington Units 1 and 2, the facility would maintain a water make-up demand of 2,492,452,589 gallons per year (7,649 acre-feet/year) based on operating up to its most restrictive limit (the current PALs). With implementation of the Huntington RPEL, the facility would have water make-up demand of 2,250,318,336 gallons per year (6,906 acre-feet/year). Thus, the RPEL provides a potential decrease in water make-up of 242,134,253 gallons per year (743 acre-feet/year).

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[14] In 2018, the U.S. Energy Information Administration estimated an average annual electricity consumption for a U.S. residential utility customer of 10,972 KWh. https://www.eia.gov/tools/faqs/faq.php?id=97&t=3

2.0.5.4 Greenhouse Gas Emissions

A byproduct of the coal combustion process is the generation of carbon dioxide (CO_2) which is a greenhouse gas. If either SCR or SNCR are installed on Huntington Units 1 and 2, the facility has a potential to emit 5,981,040 tons of CO_2 per year based on operating up to its most restrictive limit (the current PALs).[15] With implementation of the Huntington RPEL, the facility would have the potential to emit a maximum of 5,400,000 tons of CO_2 per year. Thus, the RPEL provides a potential annual CO_2 emission decrease of 581,040 tons per year compared with SCR and SNCR.

2.0.5.5 CCR Impacts

As a coal fired plant with fabric filter baghouses and scrubber pollution control equipment, the Huntington coal combustion process and pollution control equipment generate waste materials which the EPA has classified as CCR. At Huntington, CCR consists of fly ash, bottom ash and spent scrubber reagent. Fly ash, bottom ash and scrubber waste are coal combustion byproducts which are collected in the boilers, fabric filter baghouses and scrubbers and disposed at the facility's ash disposal site. At Huntington, coal ash is categorized as fly ash (approximately 75 percent of total ash production) and bottom ash (approximately 25 percent of total ash production). Huntington's current and projected coal ash content is 11.3 percent. Under the Huntington RPEL, due to reduced coal combustion and the resultant reduced generation of CCR waste materials, the generation of CCR would be reduced as compared to operation with SCR or SNCR.[16] If either SCR or SNCR are installed on Huntington Units 1 and 2, the facility has a potential to generate 285,861 tons of CCR per year based on operating up to its most restrictive limit (the current PALs). With implementation of the Huntington RPEL, the facility would have the potential to generate a maximum of 258,091 tons of CCR per year, providing a potential annual CCR generation decrease of 27,771 tons per year.

The Huntington plant is engaged in ongoing efforts to makes its CCR available for beneficial use. However, currently, all of the facility-generated bottom ash and fly ash is transported to the Huntington plant's CCR landfill for final disposal. The potential for reduced CCR under the RPEL would mean less waste going to the landfill, potentially extending the life of the landfill compared to SCR and SNCR.

In summary, adoption of the Huntington RPEL will provide the following potential CCR-related benefits:

- A reduction in the amount of coal combusted in the two facility boilers;
- A commensurate reduction of the volume of fly ash and bottom ash generated by the boilers;

[15] This is an aggregate GHG analysis and would include the parasitic load of SCR discussed above.
[16] This is an aggregate CCR analysis and would include the parasitic load of SCR discussed above.

- A reduction of ash transported[17] to and disposed in the Huntington CCR landfill;
- A potential increase in the operational life of the CCR landfill, lessening the future need for another permitted disposal site, and;
- A reduced coal demand and a corresponding reduction of coal mining activities, raw material usage, and transportation requirements as compared to operation with SCR or SNCR installed on the two Huntington boilers.

2.0.5.6 Additional Environmental Benefits from RPEL

In addition to the benefits described above, implementing the RPEL as compared to operation with SCR or SNCR also provides reductions in consumables and waste products associated with the coal combustion process. This includes a potential reduction in consumption of the following materials:

- Boiler and circulating water treatment chemicals
- Water treatment acids and bases
- SCR anhydrous ammonia reagent
- SNCR urea reagent
- Mercury control system reagent (powdered activated carbon and halogenated compounds)
- Diesel fuel consumed in heavy equipment used to manage the Huntington coal inventory

Lastly, the installation of SCR at Huntington will adversely affect the units' heat rates – essentially the thermal efficiency of the facility – due to increased boiler draft restrictions created by the installation of SCR equipment in the boiler flue gas streams.

Table A.3 below summarizes these additional relevant annual potential benefits provided by implementation of the RPEL as compared to installation of SCR or SNCR at Huntington.

Table A.3: Comparison of Energy and Non-Air Quality Environmental Impacts

Potential Energy and Non-Air Quality Related Impacts	**SNCR**	**SCR**	**RPEL**
Hg (lb/year)	38	38	34
CO (tons/year)	7,505	7,505	6,776
CO_2 (tons/year)	5,981,040	5,981,040	5,400,000
PM/PM_{10} (tons/year)	423	423	362
Coal Consumption (tons/year)	2,538,709	2,538,709	2,292,081
Fly Ash Production (tons/year)	214,396	214,396	193,568
Bottom Ash Production (tons/year)	71,465	71,465	64,523
Raw Water Consumption (acre-feet/year)	7,649	7,649	6,906

[17] A complete analysis of all associated upstream and downstream CCR transportation costs is not provided, but would represent additional reductions of environmental impacts beyond what is included in this reasonable progress determination.

Overall, proper analysis of the energy and non-air quality environmental benefits factor favors the RPEL.

2.0.6 Remaining Useful Life

The fourth statutory reasonable progress factor requires consideration of the remaining useful life of the emissions source. The remaining useful life of Huntington Units 1 and 2 is currently planned by PacifiCorp to be 2036.[18] If PacifiCorp were required to install SNCR or SCR on either unit, it would need to re-evaluate the expected remaining useful life of both units to determine whether such a requirement would increase or decrease the facility's remaining useful life. It should be noted that the cost-effectiveness estimates cited herein were calculated using the EPA-mandated 20-year depreciable life for SNCR and 30-year depreciable life for SCR, which is obviously much too long and likely causes the true cost-effectiveness numbers to be greatly skewed (meaning the cost effectiveness numbers should be higher). Implementing the Huntington RPEL is not expected to either increase or decrease the remaining useful life of the facility. Proper analysis of this factor favors the RPEL.

2.0.7 Balancing the Four Factors

When balanced for Huntington Units 1 and 2, the four factors demonstrate that the RPEL is the best option for making reasonable progress during the second planning period. First, installation of SNCR or SCR are not cost effective (even with the skewed depreciable life assumptions) and would result in hundreds of millions of dollars in costs for PacifiCorp customers, and tens of millions in additional operating costs for PacifiCorp. Implementation of the Huntington RPEL would not result in any significant additional costs for customers and would result in minimal additional operating costs. Second, installation of SNCR or SCR would involve long-lead times for permitting, design, procurement, and installation before reductions and compliance can be achieved. The Huntington RPEL requires negligible time for compliance, and could be implemented as soon as the State's implementation plan is finalized and achieves federal approval. Third, SCR requires more energy to implement, and SNCR and SCR result in additional non-air environmental impacts over the Huntington RPEL. As documented, the Huntington RPEL has less potential consumption of natural resources, less GHG emissions, and less generation of CCR. Fourth and finally, a requirement to install SCR or SNCR on Huntington Units 1 and 2 would create uncertainty about the facility's remaining useful life. Many coal-fired power plants across the country have been forced to shut down due to the increased costs associated with SNCR and SCR. Implementing the Huntington RPEL would not be expected to either increase or decrease the remaining useful life of the facility. Based on this analysis, Utah should determine that the Huntington RPEL is the best option for achieving reasonable progress during the second planning period.

The Utah Division of Air Quality has indicated that photochemical grid modeling and analysis of visibility impacts will be performed by the Western Regional Air Partnership ("WRAP") as part of the state's second planning period analysis. PacifiCorp anticipates that visibility modeling

[18] *See* PacifiCorp IRP at 252.

which incorporates the Huntington RPEL (and is compared to modeling of Huntington's current, permitted potential to emit) would assist the state in demonstrating reasonable progress at the Class I Areas impacted by emissions from the Huntington plant, supporting a conclusion that no additional installation of retrofit pollution control equipment is required at Huntington. However, if the State were to determine that the Huntington RPEL, as proposed, would not contribute to reasonable progress, PacifiCorp respectfully requests that the State propose an alternative RPEL (NO_x+SO_2 limit) for Huntington (allowing time for PacifiCorp to analyze the feasibility of the alternative RPEL proposal) as opposed to pursuing a requirement to install SNCR or SCR retrofits. This reasonable progress analysis demonstrates that implementing a RPEL is a better option than installing SNCR or SCR retrofits under each of the four statutory factors.

3.0 HUNTER REASONABLE PROGRESS ANALYSIS

As requested by Utah, PacifiCorp is providing a four-factor reasonable progress analysis for the Hunter plant for the State's review and consideration as it develops an implementation plan to achieve reasonable progress for the regional haze second planning period.

3.0.1 Hunter Unit 1, Unit 2, and Unit 3 Overview

PacifiCorp's Hunter facility currently has effective NO_x, SO_2, and PM emission control technologies in place, which align with the illustrative examples provided in the 2019 Guidance to exempt a source from second planning period analysis, including:

- Hunter Unit 1 – BART-eligible unit installed LNB and SOFA to meet BART limits (installed 2014);
- Hunter Unit 1 – FGD (scrubber) system upgrade that meets the applicable alternative SO_2 emission limit of the 2012 MATS rule is installed and operates year-round (installed 2014);
- Hunter Unit 1 – Baghouse retrofit for PM control installed to meet BART (installed 2014);
- Hunter Unit 2 – BART eligible unit installed LNB and SOFA to meet BART limits (installed 2011);
- Hunter Unit 2 – FGD (scrubber) system that meets the applicable alternative SO_2 emission limit of the 2012 MATS rule is installed and operates year-round (installed 2011);
- Hunter Unit 2 – Baghouse retrofit for PM control to meet BART (installed 2011).
- Hunter Unit 3 – Installed LNB and SOFA that meet BART limits (installed 2007);
- Hunter Unit 3 – Constructed with: FGD (scrubber) system upgrade that meets the applicable alternative SO_2 emission limit of the 2012 MATS rule is installed and operates year-round; and baghouse for PM control, which are considered Best Available Control Technology ("BACT") (installed 1983).

Because the Hunter units already have the specific, effective control technologies in place for controlling SO_2 and PM emissions that EPA identified in its 2019 Guidance, PacifiCorp is not providing any analysis for additional equipment or retrofits to further control those pollutants. As anticipated by EPA's 2019 Guidance, because effective controls are in place, it is reasonable for Utah to determine that no additional controls are reasonable for these units for the upcoming implementation period. A full four-factor analysis is not necessary to reach the conclusion that no further reasonable controls for SO_2 and PM emissions are available.

While the units have effective NOx control equipment in place (LNB and SOFA), none of the units have selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) systems in place, which are the more stringent controls listed in the 2019 Guidance. Therefore, PacifiCorp is providing analysis of those NOx control technologies as part of a four-factor reasonable progress analysis for Hunter. Applying the required four factors, the initial analysis of the standard retrofit NOx pollution controls of SCR and SNCR shows that these options are not cost effective options for the Hunter plant. Although the high costs for standard NOx controls make additional NOx controls unreasonable for the second planning period at the Hunter plant, rather than propose no action for the Hunter plant for the second planning period, PacifiCorp is proposing an alternative emissions limit (described in more detail in Section 3.0.2 below) that would reduce the Hunter plant's current PALs for NOx and SO_2 at the plant. Reducing the permitted plantwide limits will provide a lower emissions ceiling for the Hunter plant, with the reduction from current permitted limits roughly equivalent to SNCR's reduction from baseline.

This alternative proposal has the additional benefit of also lowering PM emissions compared to SCR and SNCR.[19] PacifiCorp provides below an analysis of the proposed plantwide NOx and SO_2 emission limit alternative along with the SCR and SNCR four-factor analyses.

3.0.2 Hunter Reasonable Progress Emission Limit (RPEL)

As part of Hunter's four-factor reasonable progress analysis, PacifiCorp proposes and provides analysis of a NOx and SO_2 emission limit as a control measure (that has the additional benefit of lower PM emissions), which PacifiCorp asserts will provide reasonable progress for the second planning period. Specifically, PacifiCorp proposes a plantwide combined NOx + SO_2 emission limit of 17,000 tons/year be implemented at Hunter as a control measure to achieve reasonable progress for NOx emissions. This limit will be referred to herein as the Hunter Reasonable Progress Emission Limit or RPEL. As discussed above, the Hunter Units do not require a four-factor analysis for SO_2 and PM. However, the RPEL has the added benefit of reducing both SO_2 and PM emissions in comparison with SCR and SNCR.

SO_2 reductions have been shown to produce greater visibility benefits than NOx for Class I areas on the Colorado plateau.[20] The SO_2 reductions proposed as part of the RPEL are new and surplus

[19] PacifiCorp's reasonable progress analysis for the emissions limit addresses NOx and SO2 control measures in detail. PacifiCorp's proposal will also have impacts on PM/PM_{10} emissions, which are demonstrated in Table B.4 below.
[20] *See* Grand Canyon Visibility Transport Commission, Recommendations for Improving Western Vistas (June 10, 1996) at 32-33; *see also* WRAP Regional Haze Rule Reasonable

reductions that are not included in nor relied upon by the first planning period SO_2 backstop trading program; and if needed as a substitute for NOx emission reductions, they can be included in and validated by the state and regional modeling that will take place for the second planning period.

The Hunter RPEL was derived through a multi-step process. First, PacifiCorp identified the plant's most restrictive permit limit. This was done to set a benchmark and ensure that the RPEL was lower (more stringent) than the facility's most restrictive current permit limit. In this case, Hunter's most restrictive limits are its NOx and SO_2 PALs. Hunter's current NOx PAL is 15,095 tons/year and its SO_2 PAL is 5,537.5 tons/year, providing a combined annual NOx+SO_2 PAL of 20,632.5 tons/year.

Second, PacifiCorp re-calculated the PALs, theoretically assuming SNCR were installed on all three units.[21] In this theoretical SNCR case, the Hunter plant's NOx+SO_2 PAL would be 17,773 tons/year. Detailed RPEL support calculations are provided in Attachment 4.

Third, PacifiCorp rounded the number down to the nearest thousand tons for simplification and to ensure that emissions under the RPEL were lower than the theoretical SNCR-installation scenario, which resulted in a RPEL NOx+SO_2 limit of 17,000 tons/year.

Fourth, and finally, PacifiCorp evaluated whether the RPEL was plausible for the plant to maintain, considering PacifiCorp's operation plans and projected dispatch expectations for the Hunter plant. Once the Hunter RPEL was established, it was compared against equipment installation using the statutory four-factor reasonable progress analysis. The Hunter four-factor analysis therefore compares three scenarios for implementing control measures:

(1) Current NOx, SO_2, and PM control measures +SNCR
(2) Current NOx, SO_2, and PM control measures +SCR
(3) Current NOx, SO_2, and PM control measures +RPEL

For this analysis, PacifiCorp analyzed the four statutory factors listed in Section 169A(g)(1) of the Clean Air Act: (1) the cost of compliance; (2) the time necessary to achieve compliance; (3) the energy and non-air quality related environmental impact of compliance; and (4) the remaining useful life of any existing source subject to the requirements. *See* 42 U.S.C. 7491(g)(1). PacifiCorp understands that Utah will be analyzing visibility impacts for the second planning period through visibility modeling, including at the regional level. PacifiCorp anticipates that if the reductions

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Progress Report Support Document, State and Class I Area Summaries, at 6-11-6-16 (Doc. No. EPA-R08-OAR-2015-0463-0200) ("WRAP Report") (finding that ammonium sulfate (produced by SO_2 emissions combining with ammonia) accounted for higher visibility impacts on the most impaired days than ammonium nitrate (produced by NOx emissions combining with ammonia).

[21] If SNCR were implemented on Hunter Units 1, 2, and 3, the units would likely be required to maintain a NOx rate of 0.17lb/MMBtu. Hunter 3 would likely be required to maintain a NOx rate 0.24lb/MMBtu.

from the RPEL are included in state and regional modeling they will help the state in demonstrating reasonable progress by reducing the Hunter plant's permitted potential to emit.

3.0.3 Cost of Compliance

As stated above, the 2019 Guidance explains how the four statutory reasonable progress factors should be analyzed by the States, including the cost of compliance factor. Specifically, the 2019 Guidance encourages States to consider costs based on "complete cost data; that is, estimated values of capital costs, annual operating and maintenance costs, annualized costs, and cost per ton of emission reductions that have been prepared according to EPA's Control Cost Manual." *Id*. at 21. The 2019 Guidance states that EPA "recommends that a state express the costs of compliance in terms of a cost/ton of emissions reduction metric." *Id*. at 31.

Cost analyses for SNCR and SCR installation at Hunter were completed by Sargent & Lundy in March 2020. Sargent & Lundy's Hunter Power Station NOx Control Cost Development and Analysis is provided in Attachment 5. The 2019 Guidance states that when choosing a baseline control scenario for the analysis, "[t]he projected 2028 (or the current) scenario can be a reasonable and convenient choice for use as the baseline control scenario for measuring the incremental effects of potential reasonable progress control measures on emissions, costs …" 2019 Guidance at 29. For the cost-effectiveness evaluation of SNCR and SCR, the average baseline NOx emissions and the average baseline heat input for Units 1, 2, and 3 were calculated based on the average of the most recent five years (2015-2019), which PacifiCorp considers a reasonable "current" scenario. The average values were used to provide a cost-effectiveness evaluation that was not overly conservative.

The 2019 Guidance also explains that "[a] state may choose a different emission control scenario as the analytical baseline scenario". *Id* at 29. PacifiCorp completed a cost analysis for the Hunter RPEL using the facility's current PAL as the baseline because it is a compatible control measure to the RPEL, and it is an already implemented restriction that has been agreed upon by PacifiCorp and the State. Using the PAL as the baseline for the RPEL, which is lower, allows the State to consider a viable alternative which tightens a current emission restriction. Considering the RPEL is proper as the 2019 Guidance specifically includes "operating restrictions … to reduce emissions" as an example of an emission control measure that states may consider. 2019 Guidance at 29-30. The costs associated with the RPEL are the estimated amounts of capital upgrades and operating and maintenance (O&M) costs that would be required to meet the limit. Specifically, PacifiCorp assumed it would incur some costs associated with additional scrubbing of SO_2 to ensure the RPEL is met.

Hunter Unit 1 has a lowest achievable NOx emission rate of 0.20 lb/MMBtu (with the existing LNB/SOFA control equipment), and an SO_2 emission limit of 0.12 lb/MMBtu. Based on these rates, the achievable NOx+SO_2 emissions would be 6,658 tons/year without additional scrubbing. If 4,824 tons/year of the Hunter RPEL's 17,000 tons/year of NOx+SO_2 was attributed to Unit 1, the Unit would need to scrub to an SO_2 emission rate of 0.032 lb/MMBtu to achieve the RPEL.

Scrubbing to an SO_2 emission rate of 0.032 lb/MMBtu on Unit 1 would require $301,000/year in O&M costs for a total annualized cost of $301,000/year.

Table B.1 below summarizes the cost of compliance (on a dollar per ton of pollutant basis) for the installation of SNCR and SCR at Hunter Unit 1 and the implementation of the RPEL. As shown in the table, the dollar-per-ton cost effectiveness of SNCR installed on Hunter Unit 1 is $8,816/ton, with the SCR cost effectiveness at $6,364/ton and the RPEL cost effectiveness at $198/ton.

Table B.1: Hunter Unit 1 SNCR, SCR and RPEL Cost Effectiveness

COST EFFECTIVENESS	SNCR	SCR	RPEL
Baseline Emissions			
Annual Baseline Heat Input (MMBtu)	28,482,643	28,482,643	N/A
Baseline NOx Emission (lb/MMBtu)	0.200	0.200	N/A
Baseline NOx Emission (tons/year)	2,842	2,842	N/A
Current PAL (NOx + SO_2) (tons/year)	N/A	N/A	6,346[22]
Emissions with Controls			
Controlled NOx Emission (lb/MMBtu)	0.17	0.05	N/A
Controlled NOx Emission (tons/year)	2,421	712	N/A
Controlled NOx+SO_2 (tons/year)	N/A	N/A	4,824[23]
Control Cost Effectiveness			
Annualized Capital Costs (NOx Control)	$1,511,000	$11,783,000	$0
Total Annual O&M Costs (NOx Control)	$2,198,000	$1,771,000	$0
Annualized Capital Costs (SO_2 Control)	N/A	N/A	$0
Total Annual O&M Costs (SO_2 Control)	N/A	N/A	$301,000
Total Annual Cost (NOx+SO_2)	**$3,709,000**	**$13,554,000**	**$301,000**
COST EFFECTIVNESS (NOX+SO_2) ($/TON)	**$8,816**	**$6,364**	**$198**

Hunter Unit 2 also has a lowest achievable NOx emission rate of 0.20 lb/MMBtu (with the existing LNB/SOFA control equipment), and an SO_2 emission limit of 0.12 lb/MMBtu. Based on these rates, the achievable NOx+SO_2 emissions would be 6,658 tons/year without additional scrubbing. If 4,824 tons/year of the Hunter RPEL's 17,000 tons/year of NOx+SO_2 was attributed to Unit 2,

[22] 6,346 tons/year is the Unit 1 attribution of the Hunter PAL.
[23] 4,824 tons/year NOx+SO2 Unit 1 RPEL attribution with lowest achievable NOx rate (0.20 lb/MMBtu) and 0.032 lb/MMBtu SO2 emission rate.

the Unit would need to scrub to an SO_2 emission rate of 0.032 lb/MMBtu to achieve the RPEL. Scrubbing to an SO_2 emission rate of 0.032 lb/MMBtu on Unit 2 would require would require $301,000/year in O&M costs for a total annualized cost of $301,000/year.

Table B.2 below summarizes the cost of compliance for the installation of SNCR and SCR at Hunter Unit 2 and the implementation of the RPEL. As shown in the table, the dollar-per-ton cost effectiveness of SNCR installed on Hunter Unit 2 is $10,913/ton, with the SCR cost effectiveness at $6,322/ton and the RPEL cost effectiveness at $198/ton.

Table B.2: Hunter Unit 2 SNCR, SCR and RPEL Cost Effectiveness

COST EFFECTIVENESS	SNCR	SCR	RPEL
Baseline Emissions			
Annual Baseline Heat Input (MMBtu)	30,101,030	30,101,030	N/A
Baseline NOx Emission (lb/MMBtu)	0.193	0.193	N/A
Baseline NOx Emission (tons/year)	2,902	2,902	N/A
Current PAL (NOx + SO_2) (tons/year)	N/A	N/A	6,346[24]
Emissions with Controls			
Controlled NOx Emission (lb/MMBtu)	0.17	0.05	N/A
Controlled NOx Emission (tons/year)	2,559	753	N/A
Controlled NOx+SO_2 (tons/year)	N/A	N/A	4,824[25]
Control Cost Effectiveness			
Annualized Capital Costs (NOx Control)	$1,511,000	$11,783,000	$0
Total Annual O&M Costs (NOx Control)	$2,240,000	$1,807,000	$0
Annualized Capital Costs (SO_2 Control)	N/A	N/A	$0
Total Annual O&M Costs (SO_2 Control)	N/A	N/A	$301,000
Total Annual Cost (NOx+SO_2)	**$3,751,000**	**$13,590,000**	**$301,000**
COST EFFECTIVNESS (NOX+SO_2) ($/TON)	**$10,913**	**$6,322**	**$198**

Hunter Unit 3 has a lowest achievable NOx emission rate of 0.31 lb/MMBtu (with the existing LNB/SOFA control equipment), and an SO_2 emission limit of 0.12 lb/MMBtu. Based on these rates, the achievable NOx+SO_2 emissions would be 9,247 tons/year without additional scrubbing.

[24] 6,346 tons/year is the Unit 2 attribution of the Hunter PAL.
[25] 4,824 tons/year NOx+SO2 Unit 2 RPEL attribution with lowest achievable NOx rate (0.20 lb/MMBtu) and 0.032 lb/MMBtu SO2 emission rate.

If 7,352 tons/year of the Hunter RPEL's 17,000 tons/year of NOx+SO_2 was attributed to Unit 3, the Unit would need to scrub to an SO_2 emission rate of 0.032 lb/MMBtu to achieve the RPEL. Scrubbing to an SO_2 emission rate of 0.032 lb/MMBtu on Unit 3 would require $311,000/year in O&M costs for a total annualized cost of $311,000/year.

Table B.3 below summarizes the cost of compliance for the installation of SNCR and SCR at Hunter Unit 3 and the implementation of the RPEL. As shown in the table, the dollar-per-ton cost effectiveness of SNCR installed on Hunter Unit 3 is $7,646/ton, with the SCR cost effectiveness at $4,290/ton and the RPEL cost effectiveness at $529/ton.

Table B.3: Hunter Unit 3 SNCR, SCR and RPEL Cost Effectiveness

COST EFFECTIVENESS	SNCR	SCR	RPEL
Baseline Emissions			
Annual Baseline Heat Input (MMBtu)	31,182,279	31,182,279	N/A
Baseline NOx Emission (lb/MMBtu)	0.280	0.280	N/A
Baseline NOx Emission (tons/year)	4,359	4,359	N/A
Current PAL (NOx + SO_2) (tons/year)	N/A	N/A	7,940[26]
Emissions with Controls			
Controlled NOx Emission (lb/MMBtu)	0.24	0.05	N/A
Controlled NOx Emission (tons/year)	3,742	780	N/A
Controlled NOx+SO_2 (tons/year)	N/A	N/A	7,352[27]
Control Cost Effectiveness			
Annualized Capital Costs (NOx Control)	$1,511,000	$13,092,000	$0
Total Annual O&M Costs (NOx Control)	$3,209,000	$2,264,000	$0
Annualized Capital Costs (SO_2 Control)	N/A	N/A	$0
Total Annual O&M Costs (SO_2 Control)	N/A	N/A	$311,000
Total Annual Cost (NOx+SO_2)	**$4,720,000**	**$15,356,000**	**$311,000**
COST EFFECTIVNESS (NOX+SO_2) ($/TON)	**$7,646**	**$4,290**	**$529**

[26] 7,940 tons/year is the Unit 3 attribution of the Hunter PAL.
[27] 7,352 tons/year NOx+SO2 Unit 3 RPEL attribution with lowest achievable NOx rate (0.31 lb/MMBtu) and 0.032 lb/MMBtu SO2 emission rate.

3.0.4 Time Necessary for Compliance

The second factor of the statutory four-factor reasonable progress analysis is the timeframe for compliance. The installation of either SNCR or SCR at Hunter Unit 1, 2 or 3 would require PacifiCorp to permit the installation of new pollution control equipment through the UDAQ New Source Review permitting process. The installation of SNCR on the units would be less intensive than would SCR, but both would require significant permitting, engineering, and procurement lead times for installation. It is anticipated that SNCR or SCR NO_X control technologies, if required, could be installed at Hunter Units 1, 2, and 3 by the end of the second planning period in 2028.[28]

Implementation of the Hunter RPEL would also require permitting through UDAQ. However, the RPEL could be implemented as soon as the State's implementation plan is finalized and achieves federal approval. This means the RPEL would result in much earlier implementation of regional haze emission limits than the imposition of SNCR or SCR.

3.0.5 Energy and Non-Air Environmental Impacts

The third factor of the statutory four-factor reasonable progress analysis requires that the energy and non-air quality environmental impacts be considered. The 2019 Guidance explains that as part of analyzing energy impacts, "*states consider energy impacts by accounting for any increase or decrease in energy use at the source as part of the costs of compliance*." 2019 Guidance at 41. The following sub-sections provide analyses of the energy and environmental impacts for this factor, including comparisons of energy use; environmental impacts; consumption of natural resources; GHG emissions; CCR impacts (including fly ash and bottom ash disposal); and additional benefits that would result from implementing the RPEL as compared to either the installation of SNCR or SCR. Supporting calculations for these analyses are included as Attachment 6.

3.0.5.1 Energy Impacts

The installation of SCR on Hunter Units 1, 2, and 3 would require significant electrical energy to operate, with the three SCRs having a total electric power requirement of approximately 12.5 MW.[29] Adoption of either SNCR or the Hunter RPEL would avoid the significant auxiliary load demand of the three SCR installations, allowing the electrical energy which would have been required by the SCRs to instead be directed to the power grid. The 12.5 MW is enough energy to power approximately 9,971 average homes.[30] *See* Attachment 6.

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[28] This assumption does not account for the additional time that could potentially be consumed with challenges, requests for reconsideration, etc., that have historically occurred when such installations are required.
[29] The calculated SCR electric power requirement for the Hunter Unit 1, Unit 2 and Unit 3 boilers were scaled from the power requirements of the SCRs at PacifiCorp's Jim Bridger Units 3 and 4 in Wyoming.
[30] In 2018, the U.S. Energy Information Administration estimated an average annual electricity consumption for a U.S. residential utility customer of 10,972 KWh. https://www.eia.gov/tools/faqs/faq.php?id=97&t=3

3.0.5.2 Non-Air Environmental Impacts

The 2019 Guidance indicates that *"non-air impacts can include the generation of wastes for disposal,"* and that States may consider "*water usage or waste disposal of spent catalyst or reagent.*" 2019 Guidance at 33, 42. Overall, the Hunter RPEL would result in fewer non-air environmental impacts than either SNCR or SCR.

First, the SCR "parasitic load" of 12.5 MW means a greater consumption of natural resources, increases in GHGs, and the creation and disposal of more CCR than either the Hunter RPEL or SNCR. To quantify these impacts, 47,309,999 gallons of water are required just to produce the electricity needed for the SCR parasitic load; 115,687 more tons of CO_2 would be emitted; and 5,487 more tons of CCR would be generated and disposed of to produce the electricity needed for the SCR.

It should also be noted that the installation of SCR would result in the storage and use of ammonia (a hazardous substance) and a periodic requirement to dispose of SCR catalyst. Likewise, the installation of SNCR at Hunter would require the storage and use of urea (also a hazardous substance). All calculations for non-air environmental impacts can be found in Attachment 6. An analysis of the energy and environmental impacts favors the RPEL as the best choice of reasonable progress control, with both SNCR and SCR having distinct, negative impacts.

3.0.5.3 Consumption of Natural Resources

In addition to SCR's parasitic load impacts on natural resources, if either SCR or SNCR are installed on Hunter Units 1, 2, and 3, the facility has a potential to combust 4,443,880 tons of coal per year based on operating up to its most restrictive limit (the current PALs). With implementation of the Hunter RPEL, the facility would have the potential to combust a maximum of 3,661,503 tons of coal per year, providing a potential annual coal combustion decrease of 782,377 tons per year.

The Hunter plant utilizes raw water supplied by Cottonwood Creek and Ferron Creek in its plant processes. This water is primarily used for equipment cooling as well as to provide make-up for losses through evaporative cooling from the cooling towers. Hunter has a design make-up water requirement of approximately 10,088 gallons per minute. If either SCR or SNCR are installed on Hunter Units 1, 2, and 3, the facility would maintain a water make-up demand of 4,256,020,039 gallons per year (13,061) acre-feet/year) based on operating up to its most restrictive limit (the current PALs). With implementation of the Hunter RPEL, the facility would have a potential water make-up demand of 3,506,717,105 gallons per year (10,762 acre-feet/year). Thus, the RPEL provides a potential decrease in water make-up of 749,302,934 gallons per year (2,300 acre-feet/year).

3.0.5.4 Greenhouse Gas Emissions

A byproduct of the coal combustion process is the generation of carbon dioxide (CO_2) which is a greenhouse gas. If either SCR or SNCR are installed on Hunter Units 1, 2, and 3, the facility has a potential to emit 10,407,223 tons of CO_2 per year based on operating up to its most restrictive limit (the current PALs).[31] With implementation of the Hunter RPEL, the facility would have the potential to emit a maximum of 8,574,957 tons of CO_2 per year. Thus, the RPEL provides a potential annual CO_2 emission decrease of 1,832,266 tons per year compared with SCR and SNCR.

3.0.5.5 CCR Impacts

As a coal-fired plant with fabric filter baghouses and scrubber pollution control equipment, the Hunter coal combustion process and pollution control equipment generate waste materials which the EPA has classified as CCR. At Hunter, CCR consists of fly ash, bottom ash and spent scrubber reagent. Fly ash, bottom ash and scrubber waste are coal combustion byproducts which are collected in the boilers, fabric filter baghouses and scrubbers and disposed at the facility's ash disposal site. At Hunter, coal ash is categorized as fly ash (approximately 75 percent of total ash production) and bottom ash (approximately 25 percent of total ash production). Hunter's current and projected coal ash content is 11.1 percent. Under the Hunter RPEL, due to reduced coal combustion and the resultant reduced generation of CCR waste materials, the generation of CCR would be reduced as compared to operation with SCR or SNCR.[32] If either SCR or SNCR are installed on Hunter Units 1, 2, and 3, the facility has a potential to generate 493,657 tons of CCR per year based on operating up to its most restrictive limit (the current PALs). With implementation of the Hunter RPEL, the facility would have the potential to generate a maximum of 406,745 tons of CCR per year, providing a potential annual CCR generation decrease of 86,912 tons per year.

The Hunter plant is engaged in ongoing efforts to makes its CCR available for beneficial use. However, currently, all of the facility-generated bottom ash and fly ash is transported to the Hunter plant's CCR landfill for final disposal. The potential for reduced CCR under the RPEL would mean less waste going to the landfill, potentially extending the life of the landfill compared to SCR and SNCR.

In summary, adoption of the Hunter RPEL will provide the following potential CCR-related benefits:

- A reduction in the amount of coal combusted in the three facility boilers;
- A commensurate reduction of the volume of fly ash and bottom ash generated by the boilers;
- A reduction of ash transported[33] to and disposed in the Hunter CCR landfill;

[31] This is an aggregate GHG analysis and would include the parasitic load of SCR discussed above.
[32] This is an aggregate CCR analysis and would include the parasitic load of SCR discussed above.
[33] A complete analysis of all associated upstream and downstream CCR transportation costs is not provided, but would represent additional reductions of environmental impacts beyond what is included in this reasonable progress determination.

- A potential increase in the operational life of the CCR landfill, lessening the future need for another permitted disposal site, and;
- A reduced coal demand and a corresponding reduction of coal mining activities, raw material usage, and transportation requirements as compared to operation with SCR or SNCR installed on the three Hunter boilers.

3.0.5.6 Additional Environmental Benefits from RPEL

In addition to the benefits described above, implementing the RPEL as compared to operation with SCR or SNCR also provides reductions in consumables and waste products associated with the coal combustion process. This includes a potential reduction in consumption of the following materials:

- Boiler and circulating water treatment chemicals
- Water treatment acids and bases
- SCR anhydrous ammonia reagent
- SNCR urea reagent
- Mercury control system reagent (powdered activated carbon and halogenated compounds)
- Diesel fuel consumed in heavy equipment used to manage the Hunter coal inventory

Lastly, the installation of SCR at Hunter will adversely affect the units' heat rates – essentially the thermal efficiency of the facility – due to increased boiler draft restrictions created by the installation of SCR equipment in the boiler flue gas streams.

Table B.4 below summarizes these additional relevant annual potential benefits provided by implementation of the RPEL as compared to installation of SCR or SNCR at Hunter.

Table B.4: Comparison of Energy and Non-Air Quality Environmental Impacts

Potential Energy and Non-Air Quality Related Impacts	**SNCR**	**SCR**	**RPEL**
Hg (lb/year)	66	66	54
CO (tons/year)	14,808	14,808	12,201
CO_2 (tons/year)	10,407,223	10,407,223	8,574,957
PM/PM_{10} (tons/year)	846	846	697
Potential Coal Consumption (tons/year)	4,443,880	4,443,880	3,661,503
Fly Ash Production (tons/year)	370,242	370,242	305,059
Bottom Ash Production (tons/year)	123,414	123,414	101686
Raw Water Consumption (acre-feet/year)	13,061	13,061	10,762

Overall, proper analysis of the energy and non-air quality environmental benefits factor favors the RPEL.

3.0.6 Remaining Useful Life

The fourth statutory reasonable progress factor requires consideration of the remaining useful life of the emissions source. The remaining useful life of Hunter Units 1, 2, and 3 is currently planned by PacifiCorp to be 2042.[34] If PacifiCorp were required to install SNCR or SCR on any of the three units, it would need to re-evaluate the expected remaining useful life of the impacted units to determine whether such a requirement would increase or decrease the facility's remaining useful life. It should be noted that the cost-effectiveness estimates cited herein were calculated using the EPA-mandated 20-year depreciable life for SNCR and 30-year depreciable life for SCR, which is obviously much too long and likely causes the true cost-effectiveness numbers to be greatly skewed (meaning the cost-effectiveness numbers should be higher). Implementing the Hunter RPEL is not expected to either increase or decrease the remaining useful life of the facility. Proper analysis of this factor favors the RPEL.

3.0.7 Balancing the Four Factors

When balanced for Hunter Units 1, 2, and 3 the four factors demonstrate that the RPEL is the best option for making reasonable progress during the second planning period. First, installation of SNCR or SCR are not cost effective (even with the skewed depreciable life assumptions) and would result in hundreds of millions of dollars in costs for PacifiCorp customers, and tens of millions in additional operating costs for PacifiCorp. Implementation of the Hunter RPEL would not result in any significant additional costs for customers and would result in minimal additional operating costs. Second, installation of SNCR or SCR would involve long-lead times for permitting, design, procurement, and installation before reductions and compliance can be achieved. The Hunter RPEL requires negligible time for compliance, and could be implemented as soon as the State's implementation plan is finalized and achieves federal approval. Third, SCR requires more energy to implement, and SNCR and SCR result in additional non-air environmental impacts over the Hunter RPEL. As documented, the Hunter RPEL has less potential consumption of natural resources, less GHG emissions, and less generation of CCR. Fourth and finally, a requirement to install SCR or SNCR on Hunter Units 1, 2, and 3 would create uncertainty about the facility's remaining useful life. Many coal-fired power plants across the country have been forced to shut down due to the increased costs associated with SNCR and SCR. Implementing the Hunter RPEL would not be expected to either increase or decrease the remaining useful life of the facility. Based on this analysis, Utah should determine that the Hunter RPEL is the best option for achieving reasonable progress during the second planning period.

The Utah Division of Air Quality has indicated that photochemical grid modeling and analysis of visibility impacts will be performed by the Western Regional Air Partnership ("WRAP") as part of the state's second planning period analysis. PacifiCorp anticipates that visibility modeling which incorporates the Hunter RPEL (and is compared to modeling of Hunter's current, permitted potential to emit) would assist the state in demonstrating reasonable progress at the Class I Areas impacted by emissions from the Hunter plant, supporting a conclusion that no additional installation of retrofit pollution control equipment is required at Hunter. However, if the State were

[34] *See* PacifiCorp IRP at 98.

to determine that the Hunter RPEL, as proposed, would not contribute to reasonable progress, PacifiCorp respectfully requests that the State propose an alternative RPEL (NO_x+SO_2 limit) for Hunter (allowing time for PacifiCorp to analyze the feasibility of the alternative RPEL proposal) as opposed to pursuing a requirement to install SNCR or SCR retrofits. This reasonable progress analysis demonstrates that implementing a RPEL is a better option than installing SNCR or SCR retrofits under each of the four statutory factors.

Attachment 1

RPEL Determination

Huntington Existing PALs

NOx	7,971	tons/year
SO2	3,105	tons/year
NOx+SO2	11,076	tons/year

NOx PAL Adjustment for SNCR-Equivalent NOx Rate

	Heat Input (MMBtu/hour)	SNCR NOx Rate (lb/MMBtu)	NOx Emissions (tons/year)
Unit 1	4,960	0.17	3,693
Unit 2	4,960	0.17	3,693
Total			7,386

NOx PAL	7,386	tons/year	(NOx PAL upon implementation of SNCR NOx rates)
SO2 PAL	3,105	tons/year	
NOx+SO2 PAL	10,491	tons/year	(NOx+SO2 PAL upon implementation of SNCR NOx rates)

RPEL

10,000	tons/year*

*The RPEL was determined by rounding-down the SNCR-equivalent NOx+SO2 PAL to the next 1,000 tons/year value.

Attachment 2

HUNTINGTON POWER STATION

NO_X CONTROL COST DEVELOPMENT AND ANALYSIS

Prepared for:

PACIFICORP

April 9, 2020
Project 11792-028

Prepared by:

Sargent & Lundy LLC

55 East Monroe Street
Chicago, IL 60603

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1. BACKGROUND

On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the Clean Air Act (CAA), establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).[1] The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. The Regional Haze Rule established a schedule setting forth deadlines by which the states must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter, unless otherwise extended.[2]

During the initial planning period, the Utah Department of Environmental Quality (DEQ) proposed to impose a NO_X emission limit of 0.26 lb/MMBtu (30-day rolling average) on PacifiCorp's Huntington units 1 and 2, which was proposed to be approved by the EPA on January 22, 2020. No additional NO_X control technologies were required to meet the limits for the initial planning period.

As part of the Regional Haze Rule second planning period, it is anticipated that additional NO_X control technologies will need to be evaluated at the Huntington station. PacifiCorp engaged Sargent & Lundy LLC (S&L) to develop study level, order-of-magnitude capital and annual operating and maintenance (O&M) costs for both SNCR and SCR for their Huntington Units 1-2. The capital and O&M costs for SCR and SNCR technology were estimated by S&L based on recent similarly sized projects.

2. INTRODUCTION

S&L is a leading global engineering, design, and consulting company, focused exclusively on the power generating industry. Since its inception in 1891, S&L has remained an independent evaluator of power generating technologies, power generating technology subsystems, and air pollution control systems.

S&L has considerable experience with the specification, evaluation, selection and implementation of emission control technologies for fossil fuel-fired power plants. With respect to the control of NO_X emissions from coal-fired power plants, S&L has completed, or is currently in the process of completing, more than 150 SCR and SNCR projects, representing more than 54,000 MW of generation.

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[1] 64 FR 35713

[2] On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).

Our NO_X control experience includes conceptual studies and preparing control system specifications, as well as the engineering, procurement, and installation of various control systems. S&L has participated in the design and installation of more than 30 SNCR control systems and more than 125 SCR control systems for coal and gas units. In addition, S&L has performed considerable work with respect to Best Available Retrofit Technology (BART) controls for coal-fired power plants. Our BART work includes control technology feasibility evaluations, cost estimating, and cost-effectiveness evaluations.

S&L was retained by PacifiCorp to prepare study level, order-of-magnitude capital and annual O&M costs for each unit affected for their Huntington Units 1-2 for both SCR and SNCR technologies. This report provides a summary of the capital and O&M cost estimates prepared for PacifiCorp, and includes an overview of the approach, design parameters, and assumptions.

3. COST ESTIMATING METHODOLOGY

To support states in their efforts to develop the regional haze state implementation plans for the second planning period, EPA adopted the "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" on August 20, 2019 ("2019 Guidance"). The 2019 Guidance, page 21, explains how the four statutory "reasonable progress" factors should be analyzed by the states, including the "cost of compliance" factor. Specifically, the 2019 Guidance encourages states to consider costs based on "complete cost data; that is, estimated values of capital costs, annual operating and maintenance costs, annualized costs, and cost per ton of emission reductions that have been prepared according to EPA's Control Cost Manual."[3]

Section 2.3 of the Control Cost Manual (Section 1, Chapter 2) describes the cost categories generally used to calculate the total capital cost of a retrofit control technology. Cost categories include total capital investment (TCI), which is defined to "include all costs required to purchase equipment needed for the control systems (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings, and certain other costs (indirect installation costs). TCI also includes costs for land, working capital, and off-site facilities." Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. Indirect installation costs include costs such as engineering costs; construction and field expenses (i.e., cost for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies.

The Control Cost Manual is intended to provide guidance to regulatory authorities and industry for the development of capital costs, operating and maintenance expenses, and others costs, for air pollution control devices.[4] The introduction to the Control Cost Manual states that it "does not directly address the controls needed to control air pollution at electrical generating units (EGUs) because of the differences in accounting for utility sources," and explains that while the cost methodology in the Manual may be helpful, it differs from the methodology generally used by the utility industry.[5]

The Control Cost Manual mandates a study-level cost estimate. When an industrial user has site-specific information available, inputs to the cost estimating methodology may differ from the broad assumptions made by the Cost Control Manual, but will produce more accurate results for the site in question. Under these circumstances, the Manual expressly provides flexibility for users, stating that "the user has to be able to exercise 'engineering judgment' on those occasions when the procedures [described in the Manual] may need to be modified or disregarded."[6]

The total annual cost (TAC) of a control option includes the annualized capital recovery cost plus the total annual O&M costs. The Control Cost Manual recommends using an equivalent uniform annual cash flow method to annualize the total capital investment by multiplying the total capital investment by a capital recovery factor (CRF).[7] The product of the total capital investment and CRF gives a uniform end-of-year payment necessary to repay the initial capital investment in "n" years at an interest rate of "i". The CRF is calculated using the following equation:

$$CRF = \frac{i * (1+i)^n}{(1+i)^n - 1}$$

Where:
i = interest rate; and
n = economic life of the emission control svstem

The 2019 Guidance, page 32, allows states to use generic cost estimates or estimating algorithms for estimating control system costs "for a streamlined approach or when site-specific cost estimates are not available." The 2019 Guidance strongly favors the use of source-specific cost estimates. Every "source-specific cost estimate used to support an analysis of control measures must be documented in the SIP." *Id.*

[4] Control Cost Manual, Section 1, Chapter 1, page 1-4.
[5] *Id.,* at page 1-3.
[6] Cost Manual, Section 1, Chapter 1, page 1-7.
[7] Id., at pg 2-21.

The total annual cost of each control option ($/yr) is divided by the total annual emissions reduction (tons/yr) to determine the control option's average cost-effectiveness on a $/ton basis. Emissions reductions are calculated based on the difference between baseline annual emissions and post-control annual emissions. The 2019 Guidance generally recommends calculating baseline emissions based on projected 2028 emissions assuming source compliance with emission limits that have been adopted and are enforceable. As an alternative, baseline emissions may be based on representative data of past actual emissions, assuming there is no evident basis for using a different emissions rate. As such, the cost of compliance is based on historical baseline as well as future projected capacity factors and fuels.

3.1 Overnight Cost

For purposes of the second implementation period, EPA recommends that states follow the source type-relevant recommendations in the EPA Air Pollution Control Cost Manual which recommends using the "overnight method" for accounting for capital investments.

The U.S. Energy Information Administration (EIA) defines overnight cost as an estimate of the cost at which a plant could be constructed assuming that the entire process from planning through construction could be completed in a single day[8]. However, in the same document cited by EPA, the EIA notes that overnight capital costs "serve as a starting point for developing the total cost of new generating capacity" and that "other parameters also play a key role in determining the total capital costs."[9] Lead time is identified by the EIA as one of the most notable parameters affecting total capital costs, as "[p]rojects with longer lead times increase financing costs."[10] Although the EIA starts with overnight cost estimates, other parameters, including financing, lead time, and inflation of material and construction costs play a key role in determining total capital costs, and are included in cost estimates relied upon by the EIA.

In order to be consistent with an "overnight cost" methodology, allowance for funds used during construction (AFUDC) has been excluded from these cost estimates. However, AFUDC represents real costs that will be incurred as part of the project. AFUDC accounts for the time value of money associated with the distribution of construction cash flows over the construction period. AFUDC can represent a significant cost on large construction projects with long project construction durations, and can be calculated based on a typical construction project cash flow and real interest rate (which excludes the effects of inflation).

[8] EIA, "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants," April 2013
[9] *Id*, pg. 3
[10] *Id*.

3.2 Contingency

Project contingency is included in the estimate to cover unknown risks associated with a project; these risks include for example additional scope not previously identified. The project contingency was estimated at 20% of the total project cost based on the project definition and cost estimate accuracy.

3.3 Owner's Costs

Owner's Costs are costs that the Owner incurs during the project; specifically including the cost of the Owner's staff required to oversee the project and interface with the EPC Contractor, Owner's Engineer, and other contractors, as applicable. The following list of items are covered by Owner's costs and are real costs PacifiCorp would incur based on the scope and schedule of these projects:

- Internal Labor
- Internal Travel Expenses
- Internal Indirects
- Legal Services
- Insurance
- Initial Reagent Fills

4. CAPITAL AND O&M COST ESTIMATES

S&L generally followed the approach described in the 2019 Guidance, and the methodology described in EPA's Control Cost Manual, to the greatest extent possible, to develop NO_X control system cost estimates for the Huntington Station.

4.1 Design Parameters

The Huntington Power Plant is located near Deer Creek Rd, Utah and is comprised of a total of two identical boilers. Unit 1 has a nominal 440 MW gross capacity while Unit 2 has a 455 MW gross capacity. The two units are Combustion Engineering tangentially fired boilers which fire bituminous coal as its primary fuel. Both units consist of low-NO_X burners (LNB) and Separated Over-Fire Air (SOFA) to control NO_X emissions. The two identical units are also equipped with fabric filter baghouses for particulate matter (PM) control and wet flue gas desulfurization (WFGD) control systems for sulfur dioxide (SO_2) control.

Design and operating parameters affecting the design of SCR systems include, but are not limited to, boiler heat input, flue gas volume, flue gas temperature, inlet NO_X, and the design target NO_X emission rate. Operating and design parameters for the control systems were developed based on input and data provided by the station for recent projects completed by S&L at the Huntington station, as well as experience with similar projects. Design and operating parameters used as the design basis of the Huntington units are summarized in Table 1.

Table 1: Huntington Design & Operating Parameters (from 2011 Design Basis)

PLANT DATA		UNIT 1	UNIT 2	SOURCE
Design Heat Input	MMBtu/hr	4,960	4,960	PacifiCorp
Design Full Load	MW (gross)	440	455	PacifiCorp
Fuel(s)	---	Bituminous	Bituminous	PacifiCorp
Air H_2O	lb/lb dry air	0.061	0.061	Design
Ash-Boiler	wt%	20.0	20.0	Assumption
Ambient Pressure	Psia	11.59	11.59	Calculated (Note 1)
Ambient Temperature	°F	80.0	80.0	PacifiCorp
Econ. Outlet Temp	°F	650	650	Design
Econ. Outlet Static Pressure	psia	11.25	11.25	Design
Econ. Outlet O_2	vol% wet	3.17	3.17	Design
Boiler SO_2 Oxidation	wt% SO_2	1.00	1.00	Engineering Judgement

Note 1: The ambient pressure is based on elevation of 6,400 ft. above sea level at Huntington.

4.2 SNCR Capital Cost Estimate Methodology & Assumptions

S&L used unit-specific operating data (e.g., fuel characteristics, boiler design data, temperature data, and NO_X emission rates), as well as experience from similar SNCR system installations, to develop capital and O&M costs specific to Huntington Station. Equipment costs were estimated for the SNCR system based on equipment costs provided by SNCR original equipment manufacturers (OEMs) for control systems on similar coal-fired boilers.

4.2.1 Factors Affecting the SNCR Design

Several site-specific factors affect the design and effectiveness of SNCR control systems. Operating conditions that have the most impact on SNCR system design and achievable performance include the temperature profile through the boiler, and the average concentration and distribution at the injection locations of O_2, CO, and NO_X. Industry experience has shown that temperatures in the range of 1,800 to 2,200°F and CO levels below 1,000 ppm at the boiler's bull nose are needed to obtain the highest SNCR NO_X removal efficiency. The achievable NO_X removal is dependent on the location of this temperature regime in conjunction with the injection locations, as well as the residence time of the flue gas within this range. If CO levels exceed 5,000 ppm at the bull nose, SNCR is not a feasible technology due to a number of factors, including low urea utilization, low removal efficiency and high ammonia slip.

The temperature profile and CO concentration at the injection levels are not currently known for the Huntington units, and boiler mapping would be required by any SNCR OEM to obtain performance guarantees[11]. SNCR equipment cost estimates will be based on the assumption that CO concentrations at the bull nose in each boiler can be controlled to a level that allows for effective NO_X removal. In addition, due to the size of the boilers it was assumed that achieving adequate injection and mixing within the required temperature profile will be challenging. Thus, the cost estimate includes a conservative equipment design with multiple levels and types of injection lances.

Based on control efficiencies achieved on other large coal-fired boilers, SNCR technology can typically achieve 15-25% reduction from a baseline average NO_X emission rate. Assuming CO concentrations and temperatures are within the design windows identified above, and assuming a conservative equipment design, S&L has assumed that a maximum NO_X reduction of 20% could be achieved on the Huntington units. The baseline average NO_X emission rate and design outlet NO_X emission rates and proposed permit limits are summarized in Table 2.

Table 2: Huntington SNCR Units 1-2 NO_X Control Summary

		UNIT 1	UNIT 2
Annual Average Inlet NO_X [12]	lb/MMBtu	0.199	0.194
NO_X Removal Efficiency	%	20	20
Design Average Outlet NO_X	lb/MMBtu	0.16	0.155
NO_X Permit Limit with SNCR	lb/MMBtu	0.17	0.17

4.2.2 SNCR Design

Based on a site-specific review of the NO_X reduction requirements and retrofit challenges for the installation of SNCR systems, the following project-specific issues were taken into consideration in the development of the SNCR cost estimates:

- Urea Delivery, Unloading, and Storage. The SNCR cost estimate is based on using urea as the reagent. The urea solution (50% aqueous urea by weight) would be delivered by truck and unloaded via onboard truck pumps into fiberglass reinforced plastic (FRP) storage tanks. The tanks are sized for a total storage capacity of 14 days of continuous operation at full load and would be heat traced and insulated in order to keep the 50% urea solution above 80°F to prevent precipitation of urea solids out of solution. One common storage area is included for the station.
- Urea Circulation. The urea storage tanks would be cross tied, providing a common storage area for Units 1&2. The urea solution would be transferred using stainless steel piping. A loop from the storage tanks to each unit's metering modules and back to the storage tanks would

[11] It is typical that the temperature profile and CO concentrations at the SNCR injection levels are unknown. Performance Guarantees provided by vendors are often indicative at the time of award and are finalized once boiler mapping is completed as part of initial detailed design. Therefore, the predicted performance is based on similar boilers (size, type, and fuel).
[12] The annual average inlet NO_X emission rate is calculated using the average of the annual heat input and NO_X emissions from 2015-2019.

continuously circulate the 50% urea solution. Process heat tracing would be required to keep the urea solution above 80°F.

- Urea Dilution and Metering. Dilution water would be pumped to the metering modules located in the unit, where it would mix with the 50% urea solution prior to injection into the boiler. Dilution of the urea solution to approximately 5 wt% urea is required prior to injection. Variable frequency drives would be utilized to maintain a constant pressure of dilution water in response to changing flow demands. The metering modules provide flow and pressure control of the fluids used in the SNCR process.
- Diluted Urea Distribution and Injection. The distribution modules would provide diluted urea solution and atomizing air to individual injectors. The modules are typically located near the injectors on the same elevation. Diluted urea solution is fed from the dilution/metering modules to the distribution modules. The distribution module distributes atomizing air and urea solution to each injector. The injectors are used for dispersion of diluted urea solution within targeted areas of the boiler. Design, quantity, type and placement of the injectors are critical to SNCR performance; furnace temperature, residence time, and droplet size are important design parameters controlled by injector placement. The exact locations of the injectors would be determined by the SNCR OEM based on computational fluid dynamics (CFD) modeling of the furnace. For the SNCR cost estimate, exact injector locations were not selected; however, it was assumed that the units would require a minimum of three injection levels to cover the entire load and temperature profile within the boiler.
- Raw Water & Water Treatment. It was assumed that raw water would be utilized for urea dilution water; therefore, no water treatment system was included in this cost estimate.
- Plant and Instrument Air System. The addition of the SNCR system adds a large air user to each unit. To meet the air consumption requirements for the atomizing air, compressors would be added per unit. These compressors would also provide compressed air to all new intermittent-users (e.g., valves, instruments, tools, etc.); therefore, no additional compressed air load would be added to the plant's existing compressed air systems. All air would be dried to -40°F dew point by implementing regenerative desiccant dryers. Instrument air piping would be stainless steel.
- Air Heater Evaluation. At the temperatures typically found in the air heater, excess ammonia from the SNCR can react with sulfur trioxide in the flue gas to form ammonium bisulfate in the intermediate section of the air heater. Based on operating experience with medium sulfur fuel, air heater plugging and corrosion may become an issue on these units. Therefore, an allowance for air heater modifications was included in the estimate.
- Fire Protection System. Fire protection for the new pre-engineered buildings would include alarm and detection, as well as fire extinguishers. It is anticipated no additional fire hydrants, or a dispersion system will be required for the urea unloading area.
- Furnace Modifications. Penetrations in the boiler water wall would be required at the injector locations. To support the injector penetrations, water wall tubes would need to be removed and replaced with tubes curved around the penetration location, a boot, and a flange, to which the injectors are mounted. In some instances, additional structural reinforcement may be required to support the injectors.

- Process and Freeze Protection Heat Tracing System. A freeze protection system would be provided for outdoor piping (8" and smaller), instruments, and other devices subject to freezing in cold weather. The freeze protection system would be designed to accommodate both normal plant operations and extended plant shutdowns during cold weather. All urea piping and tanks would be process heat traced to a minimum temperature of 80ºF to avoid crystallization.

4.2.3 SNCR Capital Cost Estimate

The following items are included in the scope of the SNCR cost estimate:

- Boiler wall modifications and injectors
- Dilution and metering skids
- Boiler mapping and CFD modeling for each unit
- Common urea unloading area storage tanks and tank equipment
- Circulating urea loop to each unit
- Foundations, buildings and support steel
- Piping and auxiliaries
- Electrical equipment
- Controls modifications

Based on the design parameters, costs, site constraints, and assumptions outlined above, capital cost estimates were developed for the Huntington units, assuming a common urea unloading and storage area for Units 1-2. The cost estimate represents a firm price Engineer-Procure-Construct (EPC) project similar to the SCR. The estimate includes all indirect capital costs such as engineering costs, construction and field expenses, contractor fees, start-up and performance test costs. PacifiCorp's Owner's Costs for Owner's Engineer, labor and permitting are included in the cost estimate.

Table 3 shows the estimated costs for the complete SNCR Units 1-2 Project at Huntington.

Table 3: Huntington SNCR Capital Costs for Units 1-2

Item	Unit 1-2 SNCR Cost Estimate	Single Unit SNCR Cost Estimate	Notes
Direct Costs			
SNCR Equipment Cost	$3,298,000	$1,649,000	Based on similar sized project costs.
Platforms and Support	$2,240,000	$1,120,000	Based on similar sized project costs.
Foundation and Buildings	$580,000	$290,000	Based on similar sized project costs.
Boiler Modifications	$800,000	$400,000	Based on similar sized project costs.
Piping and Auxiliaries	$4,300,000	$2,150,000	Based on similar sized project costs.
Electrical Equipment	$2,910,000	$1,455,000	Based on similar sized project costs.
Controls Modifications	$1,160,000	$580,000	Based on similar sized project costs.
Total Direct Costs	***$15,288,000***	***$7,644,000***	

Item	Unit 1-2 SNCR Cost Estimate	Single Unit SNCR Cost Estimate	Notes
Project Indirect Costs			
Construction Costs	$6,155,000	$3,057,500	Calculated based on 40% of Direct Costs
Engineering	$2,568,000	$1,284,000	Calculated based on 12% of Direct + Construction Costs
Permitting	$200,000	$100,000	Allowance for each unit
Construction Management Support	$1,070,000	$535,000	Calculated based on 5% of Direct + Construction Costs
Initial Fill	$214,000	$107,000	Calculated based on 1% of Direct + Construction Costs
Spare-Parts	$214,000	$107,000	Calculated based on 1% of Direct + Construction Costs
EPC Fee	$2,140,000	$1,070,000	Calculated based on 10% of Direct + Construction Costs
Owner's Costs	$214,000	$107,000	Calculated based on 1% of Direct + Construction Costs
Contingency	$4,281,000	$2,140,500	Calculated based on 20% of Direct + Construction Costs
Total Project Indirect Costs	***$17,016,000***	***$8,508,000***	
Total Capital Investment (TCI)	**$32,304,000**	**$16,152,000**	**Total Direct Costs + Total Indirect Costs**
Capital Recovery Factor $i(1+i)^n / (1+i)^n - 1$	0.0944	0.0944	Calculated using an interest rate of 7% and a control system life of 20 years.
Annualized Capital Cost	**$3,049,269**	**$1,524,635**	**Capital Recovery Factor x TCI**

4.3 SNCR Operating & Maintenance Cost Methodology & Assumptions

Annual O&M costs include both fixed and variable costs. Variable O&M costs are items that generally vary in proportion to the plant capacity factor. Variable costs associated with SNCR systems include: reagent costs (e.g., urea solution); dilution water costs; and auxiliary power costs associated with operating the new equipment. Fixed costs are independent of the level of production and would be incurred even if the control system were shut down, and include costs such as maintenance labor and materials, administrative charges, property taxes, and insurance. Both fixed and variable O&M costs were developed based on site specific design conditions for the Huntington units.

Variable O&M costs were calculated assuming a capacity factor of 71.0% for Unit 1 and 68.0% for Unit 2 (based on average operation from 2015-2019 to be consistent with equipment design basis). Annual O&M and total annual costs for the Huntington SNCR systems are summarized in Table 4.

Table 4: Huntington SNCR O&M Costs for Units 1-2

OPERATING & MAINTENANCE COSTS	UNIT 1	UNIT 2	Basis
Variable O&M Costs			
Urea Solution Cost	$1,940,000	$1,842,000	$300 per ton of solution.
Auxiliary Power Cost	$77,000	$75,000	$50/MWh.
Water Cost	$28,000	$27,000	$2/1,000 gallons
Total Variable O&M Cost	***$2,045,000***	***$1,944,000***	
Fixed O&M Costs			
Operating Labor	$0	$0	No additional operators required.
Supervisory Labor	$0	$0	Not included.
Maintenance Materials and Labor	$242,000	$242,000	1.5% of Total Capital Investment
Property Taxes	$0	$0	Not included.
Insurance	$0	$0	Not included.
Administration	$0	$0	Not included.
Total Fixed O&M Cost	***$242,000***	***$242,000***	
Total Annual O&M Cost	**$2,287,000**	**$2,186,000**	

4.4 SCR Capital Cost Estimate Methodology & Assumptions

S&L used unit-specific operating data (e.g., fuel characteristics, boiler design data, temperature data, and NO_X emission rates), as well as experience from similar SCR system installations, to develop capital and O&M costs specific to Huntington Station. Equipment costs were estimated for the SCR system based on equipment costs provided by SCR original equipment manufacturers (OEMs) for control systems on similar coal-fired boilers.

4.4.1 SCR Design

The following summarizes the major components of the SCR system design and project-specific issues that were taken into consideration in the development of the SCR cost estimates.

- <u>SCR Location</u>. The proposed SCR reactors will be located above the ESP inlet ductwork. The SCR structure will be supported on columns that avoid interferences with the ESP inlet ductwork and at grade. The SCR will be a high-dust configuration installed between the economizer outlet and the air heater inlet. Galleries were provided at each catalyst level and at the ammonia injection grid to allow for maintenance and inspection of the SCR system.

- <u>Boiler Building Reinforcement</u>. Due to the fact that the boiler building walls are load bearing walls, some of the existing boiler building steel columns and upper framing will have to be removed to make room for the new ductwork.

- <u>SCR Reactors and Catalyst</u>. The SCR system will consist of two reactors per unit. The SCRs will use anhydrous ammonia as the reagent. To achieve the required NO_X emission reductions on a consistent basis with low SO_2 to SO_3 conversion, three layers of catalyst are required for each of the SCRs. The SCRs would be designed to hold four layers of catalyst, with three layers being loaded initially.

- Economizer Modifications. At temperatures lower than 560-600°F (depending on the fuel sulfur content) extended operation of the SCR system with ammonia injection in-service would promote the generation of both ammonium sulfate and ammonium bisulfate deposits. The deposits accumulate over time, block catalyst sites, and reduce catalyst activity over the life of the catalyst. Based on historical operating data, an economizer bypass is required for both units to accommodate operation at low load 2.

- SCR Cleaning. The method of cleaning the fly ash that settles on the catalyst is extremely important to obtain the guaranteed life of the catalyst. For this reason, the use of steam sootblowers, in addition to sonic horns, is recommended. Steam sootblowers will remove fly ash that settles on the catalyst and the sonic horns will keep the fly ash moving through the catalyst. The conceptual design includes steam sootblowers for the top layer of catalyst, and sonic horns for the balance of the catalyst layer. The sonic horn system will require compressed air to operate. Separate compressors were assumed for each unit for the cost estimate.

- Large Particle Ash Screen. To collect large particle ash (LPA) upstream of the SCR, a large particle ash screen will be installed in each economizer outlet duct. Due to very high velocities at the economizer outlet, the LPA screens will be located at the base of each of the SCR riser ducts. New ash hoppers and handling equipment is included in the design to tie the LPA hoppers into the economizer ash system.

- Ammonia System. The anhydrous ammonia system will be located in a remote location from the units. A pipe rack is assumed to deliver the ammonia from the storage area to the SCR reactors. The scope of this system includes not only the storage tanks but also the foundation, feed pumps, feed piping, and necessary safety systems.

- Auxiliary Power Upgrades. Operation of the SCR control system will require larger ID fans and electrical systems to allow the plant to operate at full load with the additional pressure loss generated by the SCR. The estimate includes the cost to replace the ID fans and motors on all units. It is expected that the existing electrical systems are not capable of handling the new fan loads and SCR control systems, and that a new power line and related electrical equipment will be required.

- Structural Stiffening. Structural stiffening of the ductwork and equipment downstream of the boiler and upstream of the new ID fans will be required by NFPA regulations to operate at more negative pressures due to the installation of the SCR. Due to the similarity in ductwork design pressures of these units, the scope of structural stiffening is expected to be the same as the previous project.

- Control Systems. The existing distributed control system (DCS) will need to be expanded to accommodate the additional signals from the SCR system.

- <u>Construction Costs and Special Cranes</u>. Due to general site congestion, special cranes will be needed to provide the lifting capacity that is required to install SCRs and accommodate the associated demolition.

4.4.2 SCR Capital Cost Estimate

The following items are included in the scope of the SCR cost estimate:

- Economizer outlet / air heater inlet ductwork modifications
- Economizer bypass for low-load temperature control
- SCR equipment & ductwork (including catalyst, LPA screens, and cleaning equipment)
- Equipment and ductwork reinforcement for NFPA requirements
- Ammonia unloading area expansion consisting of two (2) storage tanks and tank equipment
- Ammonia delivery and vaporization equipment
- Foundations and support steel

Based on the design parameters, costs, site constraints, and assumptions outlined above, capital cost estimates were prepared for Unit 1-2 SCR systems. The cost estimates were estimated by S&L based on recent similarly sized projects and represents a firm price Engineer-Procure-Construct (EPC) project.

The cost estimate includes all indirect capital costs such as engineering costs, construction and field expenses, contractor fees, start-up and performance test costs, and contingencies are included. Also included in the cost estimate are PacifiCorp's actual Owner's Costs for Owner's Engineer, labor and permitting. Table 5 shows the estimated costs for the complete SCR Units 1-2 Project at Huntington.

Table 5: Huntington SCR Capital Costs for Units 1-2

Item	Unit 1	Unit 2	Notes
Direct Costs			
Equipment Costs	$19,602,565	$19,602,565	Scaled based on recent projects.
Material Costs	$23,176,464	$23,176,464	Scaled based on recent projects.
Labor Costs	$32,928,091	$32,928,091	Scaled based on recent projects.
Total Direct Costs	***$75,707,120***	***$75,707,120***	
Project Indirect Costs			
Construction Costs	$22,712,136	$22,712,136	30% of Total Direct Costs
Engineering	$9,842,000	$9,842,000	10% of Total Direct + Construction Costs
EPC Costs	$9,842,000	$9,842,000	10% of Total Direct + Construction Costs
Permitting	$200,000	$200,000	Scaled based on recent projects.
Construction Management Support	$1,968,000	$1,968,000	2% of Total Direct + Construction Costs
Initial Fill	$492,000	$492,000	0.5% of Total Direct + Construction Costs
Spare-Parts	$492,000	$492,000	0.5% of Total Direct + Construction Costs
Owner's Costs	$984,000	$984,000	1% of Total Direct + Construction
Contingency	$19,684,000	$19,684,000	20% of Total Direct + Construction
Total Indirect Costs	***$66,216,136***	***$66,216,136***	

Item	**Unit 1**	**Unit 2**	**Notes**
Total Capital Investment (TCI)	**$141,923,255**	**$141,923,255**	**Total Direct Costs + Total Indirect Costs**
Capital Recovery Factor $i(1+i)^n / (1+i)^n - 1$	0.0806	0.0806	Calculated using an interest rate of 7% and a control system life of 30 years.
Annualized Capital Cost	**$11,439,014**	**$11,439,014**	**Capital Recovery Factor x TCI**

4.5 SCR Operating & Maintenance Cost Methodology & Assumptions

Annual O&M costs include both fixed and variable costs. Variable O&M costs are items that generally vary in proportion to the plant capacity factor. Variable costs associated with SCR systems include: reagent costs (e.g., anhydrous ammonia); catalyst replacement costs; and auxiliary power costs associated with operating the new equipment. Fixed costs are independent of the level of production and would be incurred even if the control system were shut down, and include costs such as maintenance labor and materials, administrative charges, property taxes, and insurance. Both fixed and variable O&M costs were developed based on site specific design conditions for the Huntington units.

Variable O&M costs were calculated assuming a capacity factor of 71.0% for Unit 1 and 68.0% for Unit 2 (based on average operation from 2015-2019 to be consistent with SNCR). Annual O&M and total annual costs for the Huntington SCR systems are summarized in Table 6.

Table 6: Huntington SCR O&M Costs for Units 1-2

OPERATING & MAINTENANCE COSTS	**UNIT 1**	**UNIT 2**	**Basis**
Variable O&M Costs			
Anhydrous Ammonia Cost	$511,000	$492,000	$550 per ton of anhydrous ammonia
Auxiliary Power Cost	$613,000	$590,000	$30/MWh
Catalyst Replacement Cost	$288,000	$288,000	Note 1
Steam Cost	$26,000	$25,000	$5/MMBtu
Outage Penalty	$0	$0	Not included
Total Variable O&M Cost	***$1,438,000***	***$1,395,000***	
Fixed O&M Costs			
Operating Labor	$0	$0	No additional operators required.
Supervisory Labor	$0	$0	Not included.
Maintenance Materials and Labor	$325,000	$325,000	Note 2
Property Taxes	$0	$0	Not included.
Insurance	$0	$0	Not included.
Administration	$0	$0	Not included.
Total Fixed O&M Cost	***$325,000***	***$325,000***	
Total Annual O&M Cost	**$1,743,000**	**$1,700,000**	

Note 1. Annual catalyst replacement costs were calculated based on replacing one (1) layer of catalyst (approximately 155 m^3 per layer) once every two years. Catalyst costs were calculated by multiplying the volume of catalyst by the installed unit cost of $5,000/$m^3$ and using a future worth factor of 0.48 calculated as follows:

> FWF = i * [1 / $(1 + i)^y$ - 1]; where i = an assumed interest rate of 7.0% and y = 2 (i.e., replacing one layer every other year). See, Control Cost Manual, Section 4.2, Chapter 2, pg. 2-47

Note 2. The Control Cost Manual calculates SCR maintenance materials and labor at 1.5% of TCI (Control Cost Manual, Section 4.2, Chapter 2, page 2.45). This factor results in annual maintenance costs significantly higher than expected actual maintenance costs reported by industry. Therefore, for this evaluation, S&L revised the maintenance materials and labor cost downward to 0.25% of TCI.

5. COST EFFECTIVENESS

For the cost-effectiveness evaluation, the average baseline NO_X emissions and the average baseline heat input for Units 1-2 were calculated based on the average of the most recent five years (2015-2019). The average values were used in order to provide a cost-effectiveness evaluation that was not overly conservative. The heat input and NO_X emissions baseline for the cost-effectiveness calculations are provided in Table 7.

Table 7: Huntington Emission Baseline Summary

BASELINE INFORMATION	UNIT 1	UNIT 2
Heat Input Baseline		
Full Load Heat Input (MMBtu/hr)	4,960	4,960
2015-2019 Average Heat Input (MMBtu/year)	28,063,728	27,150,145
NO_X Emission Baseline (for Cost-Effectiveness)		
2015-2019 Average Annual NO_X Emission (tons/year)	2,968	2,825

Total annual costs were calculated as the sum of the annualized capital costs and total fixed and variable O&M costs. Capital costs were annualized using the capital recovery factor (CRF) approach described in Section 1, Chapter 2 of the Control Cost Manual. The total capital costs, capital recovery factor, and annualized capital costs for the SNCR and SCR technologies are provided in Section 5 of this report.

Total annual costs include the annualized cost of capital and the fixed and variable O&M costs. Variable O&M costs, which include the annual cost of reagents (anhydrous ammonia or urea solution), water, steam, auxiliary power, and catalyst replacement are provided in Section 5 of this report.

The cost-effectiveness of each control system was calculated on a dollar-per-ton-removed basis by dividing total annual costs by the reduction in annual emissions. Annual emissions using a particular control device were subtracted from baseline emissions to calculate tons removed per year.

5.1 SNCR Cost Effectiveness

Annual NO_X emissions with SNCR were calculated based on a NO_X reduction efficiency of 20%. Table 8 shows the total annual cost, average annual reduction in NO_X emissions, and average annual cost effectiveness, based on a 20-year life.

Table 8: SNCR Cost Effectiveness

COST EFFECTIVENESS	UNIT 1	UNIT 2
Baseline		
Baseline Heat Input (MMBtu/year)	28,063,728	27,150,145
Baseline NO_X Emission (lb/MMBtu)	0.212	0.209
Baseline NO_X Emission (tons/year)	**2,968**	**2,835**
NO_X Emissions with SNCR		
Controlled NO_X Permit Limit (lb/MMBtu)	0.17	0.17
Controlled NO_X Emission (tons/year)	**2,385**	**2,308**
SNCR Cost Effectiveness		
Annualized Capital Costs (20-year life)	$1,525,000	$1,525,000
Total Annual O&M Costs	$2,287,000	$2,186,000
Total Annual Cost ($/year)	**$3,812,000**	**$3,711,000**
COST EFFECTIVENESS ($/TON)	**$6,545**	**$7,040**

5.2 SCR Cost Effectiveness

Annual NO_X emissions with SCR were calculated based on a proposed NO_X emission permit limit of 0.07 lb/MMBtu. Table 9 shows the total annual cost, average annual reduction in NO_X emissions, and average annual cost effectiveness, based on a 30-year life.

Table 9: SCR Cost Effectiveness

COST EFFECTIVENESS	UNIT 1	UNIT 2
Baseline		
Baseline Heat Input (MMBtu/year)	28,063,728	27,150,145
Baseline NO_X Emission (lb/MMBtu)	0.212	0.209
Baseline NO_X Emission (tons/year)	**2,968**	**2,835**
NO_X Emissions with SCR		
Controlled NO_X Permit Limit (lb/MMBtu)	0.05	0.05
Controlled NO_X Emission (tons/year)	**702**	**679**
SCR Cost Effectiveness		
Annualized Capital Costs (30-year life)	$11,439,000	$11,439,000
Total Annual O&M Costs	$1,797,000	$1,754,000
Total Annual Cost ($/year)	**$13,263,000**	**$13,193,000**
COST EFFECTIVENESS ($/TON)	**$5,841**	**$6,119**

5.3 Cost Effectiveness Summary

Table 10 summarizes the cost-effectiveness of the two control options evaluated based on 20-year life for SNCR and 30-year life for SCR.

Table 10: Unit 1 Cost Effectiveness Summary

TECHNOLOGY / BASIS	UNIT 1 EMISSIONS	EVALUATION PERIOD (YEARS)	COST ($/TON)
Emission Baseline			
Annual Heat Input (MMBtu)	28,063,728	N/A	N/A
Baseline NO_X Emission (lb/MMBtu)	0.212		
Baseline NO_X Emission (tons/year)	**2,968**		
SNCR			
Controlled NO_X Permit Limit (lb/MMBtu)	0.17	20	$6,545
Controlled NO_X Emission (tons/year)	**2,385**		
SCR			
Controlled NO_X Permit Limit (lb/MMBtu)	0.05	30	$5,841
Controlled NO_X Emission (tons/year)	**702**		

Table 11: Unit 2 Cost Effectiveness Summary

TECHNOLOGY / BASIS	UNIT 2 EMISSIONS	EVALUATION PERIOD (YEARS)	COST ($/TON)
Emission Baseline			
Annual Heat Input (MMBtu)	27,150,145	N/A	N/A
Baseline NO_X Emission (lb/MMBtu)	0.209		
Baseline NO_X Emission (tons/year)	**2,835**		
SNCR			
Controlled NO_X Permit Limit (lb/MMBtu)	0.17	20	$7,040
Controlled NO_X Emission (tons/year)	**2,308**		
SCR			
Controlled NO_X Permit Limit (lb/MMBtu)	0.05	30	$6,119
Controlled NO_X Emission (tons/year)	**679**		

ATTACHMENTS

Attachments

Attachment 1: Cost Effectiveness Calculations

ATTACHMENT 1

COST EFFECTIVENESS CALCULATIONS

Huntington: Cost-Effectiveness Calculations

Unit 1 - Baseline (2015-2019)

	Emission Rate (2015-2019)	Annual Heat Input (2015-2019)	Annual Emissions
	lb/MMBtu	MMBtu	tpy
NO_X	0.212	28,063,728	2,968

Unit 1 - SNCR

	Emission Rate	Annual Heat Input (2015-2019)	Annual Emissions	Reduction from Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/MMBtu	MMBtu	tpy	tpy						
NO_X	0.170	28,063,728	2,385	582	$ 16,152,000	0.0944	$ 1,525,000	$ 2,287,000	$ 3,812,000	$ 6,545

Unit 1 - SCR

	Emission Rate	Annual Heat Input (2015-2019)	Annual Emissions	Reduction from Baseline	Incremental Reduction	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness	Incremental Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy	tpy							
NO_X	0.050	28,063,728	702	2,266	1684	$ 141,923,000	0.0806	$ 11,439,000	$ 1,797,000	$ 13,236,000	$ 5,841	$ 5,597

Unit 2 - Baseline (2015-2019)

	Emission Rate (2015-2019)	Annual Heat Input (2015-2019)	Annual Emissions
	lb/MMBtu	MMBtu	tpy
NO_X	0.209	27,150,145	2,835

Unit 2 - SNCR

	Emission Rate	Annual Heat Input (2015-2019)	Annual Emissions	Reduction from Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/MMBtu	MMBtu	tpy	tpy						
NO_X	0.170	27,150,145	2,308	527	$ 16,152,000	0.0944	$ 1,525,000	$ 2,186,000	$ 3,711,000	$ 7,040

Unit 2 - SCR

	Emission Rate	Annual Heat Input (2015-2019)	Annual Emissions	Reduction from Baseline	Incremental Reduction	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness	Incremental Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy	tpy							
NO_X	0.050	27,150,145	679	2,156	1629	$ 141,923,000	0.0806	$ 11,439,000	$ 1,754,000	$ 13,193,000	$ 6,119	$ 5,821

Attachment 2

PACIFICORP

Energy and Non-Air Quality Related Impacts Support Calculations

<u>Energy Impacts</u>

SCR Electrical Power Requirement

Huntington Unit 1 Boiler Heat Input:	4,960	MMBtu/hour
Huntington Unit 2 Boiler Heat Input	4,960	MMBtu/hour
Huntington Units 1-2 Boiler Heat Input:	9,920	MMBtu/hour
Jim Bridger Boiler Heat Input:	6,000	MMBtu/hour

Jim Bridger SCR Power Requirement:	5.2	MW	
Huntington SCR Power Requirement:	8.6	MW	(scaled from Jim Bridger)

Huntington Annual Power Requirement: (8.6 MW) x (8760 hours/year)
Huntington Annual Power Requirement: 75,313 MWh

Average Residential Customer Annual Power Usage: 10,972 kWh
Average Residential Customer Annual Power Usage: 10.972 MWh

Huntington SCR Annual Electrical Power Avoidance: (75,313 MWh) / (10.972 MWh/customer)
Huntington SCR Annual Electrical Power Avoidance: 6,864 customers

Avoiding Huntington SCR installation provides enough electrical energy of provide power to 6,864 residential customers

<u>Consumption of Natural Resources</u>

Determine Consumption of Natural Resources Under Three Operating Scenarios

1 Potential Capacity Operation with Implementation of SNCR or SCR on Both Units
2 Restricted Operation with Existing NOx and SO2 Plantwide Applicability Limits
3 Restricted Operation with Reasonable Progress Emission Limit (RPEL)

Annual Potential Heat Input Under Three Operating Scenarios

Potential Capacity

	Boiler Heat Input (MMBtu/hour)	NOx Emission Limit (lb/MMBtu)	SO2 Emission Limit (lb/MMBtu)	Potential NOx Emissions (tons/year)	Potential SO2 Emissions (tons/year)	Potential NOx+SO2 (tons/year)	Potential Annual Heat Input (MMBtu/year)
Unit 1	4,960	0.26	0.12	5,648	2,607	8,255	43,449,600
Unit 2	4,960	0.26	0.12	5,648	2,607	8,255	43,449,600
Total						16,511	86,899,200

Existing Plantwide Applicability Limits (PALs)

NOx PAL	7,971	tons/year
SO2 PAL	3,105	tons/year
NOx+SO2 PAL	11,076	tons/year

Existing PALs Provide a 32.7% Restriction Compared to SNCR/SCR Operation Based on Total NOx+SO2 Emissions

Restriction = 1 - [(NOx+SO2 PAL) / (Potential Capacity Operation NOx+SO2)]
Restriction = 1 - [(11,076 tons/year) / (16,511 tons/year)]
Restriction = 32.9%

Annual Heat Input Compensated for 32.7% NOx+SO2 PAL Reduction

	Potential Annual Heat Input (SNCR/SCR) (MMBtu/year)	PAL-Adjusted Potential Annual Heat Input (MMBtu/year)
Unit 1	43,449,600	29,147,368
Unit 2	43,449,600	29,147,368
Total	86,899,200	58,294,737

Reasonable Progress Emission Limit (RPEL)

RPEL NOx+SO2	10,000	tons/year

The RPEL Provides a 9.7% Restriction Compared to the Existing PALs Based on Total NOx+SO2 Emissions

Restriction = 1 - [(RPEL NOx+SO2) / (Existing NOx+SO2 PALs)]
Restriction = 1 - [(10,000 tons/year) / (11,076 tons/year)]
Restriction = 9.7%

Annual Heat Input Compensated for 9.7% NOx+SO2 RPEL Reduction

	PAL-Adjusted Annual Heat Input (MMBtu/year)	RPEL-Adjusted Potential Annual Heat Input (MMBtu/year)
Unit 1	29,147,368	26,315,789
Unit 2	29,147,368	26,315,789
Total	58,294,737	52,631,579

Non-Air Quality Huntington Parameters

Coal Heating Value	11,481	Btu/lb
Design Raw Water Make-up	7,069	gallons/minute
CO2 Emission Rate	205.2	lb/MMBtu
Coal Ash Concentration	11.3%	
Fraction Fly Ash	75%	
Fraction Bottom Ash	25%	
Unit 1 CO Emission Limit	0.34	lb/MMBtu
Unit 2 CO Emission Factor	0.175	lb/MMBtu
Unit 1 PM/PM10 Emission Limit	74	lb/hour
Unit 2 PM/PM10 Emission Limit	70	lb/MMBtu
Unit 1 Mercury Emission Limit	6.5E-07	lb/MMBtu
Unit 2 Mercury Emission Limit	6.5E-07	lb/MMBtu

Potential Coal Consumption

	Annual Heat Input (MMBtu/year)	Coal Heating Value (Btu/lb)	Annual Coal Combustion (tons/year)	Incremental Coal Combustion Reduction (tons/year)
Potential Capacity	86,899,200	11,481	3,784,420	
Existing PALs	58,294,737	11,481	2,538,709	1,245,711
RPEL	52,631,579	11,481	2,292,081	246,628

Potential Raw Water Consumption

	Raw Water Consumption (gallons/minute)	Annual Water Consumption (gallons/year)	Annual Water Consumption (acre-feet/year)	Incremental Water Consumption Reduction (gallons/year)	Incremental Water Consumption Reduction (acre-feet/year)
Potential Capacity	7,069	3,715,466,400	11,402		
Existing PALs	4,742	2,492,452,589	7,649	1,223,013,811	3,753
RPEL	4,281	2,250,318,336	6,906	242,134,253	743

Potential Greenhouse Gas Emissions

	Annual Heat Input (MMBtu/year)	Greenhouse Gas Emission Factor (lb/MMBtu)	Annual Greenhouse Gas Emissions (tons/year)	Incremental GHG Emissions Reduction (tons/year)
Potential Capacity	86,899,200	205.2	8,915,858	
Existing PALs	58,294,737	205.2	5,981,040	2,934,818
RPEL	52,631,579	205.2	5,400,000	581,040

Potential CCR Impacts

	Annual Coal Combustion (tons/year)	Coal Ash Concentration (percent)	Annual Total Ash Production (tons/year)	Annual Fly Ash Production (tons/year)	Annual Bottom Ash Production (tons/year)	Incremental Total Ash Reduction (tons/year)	Incremental Fly Ash Reduction (tons/year)	Incremental Bottom Ash Reduction (tons/year)
Potential Capacity	3,784,420	11.3%	426,130	319,597	106,532			
Existing PALs	2,538,709	11.3%	285,861	214,396	71,465	140,268	105,201	35,067
RPEL	2,292,081	11.3%	258,091	193,568	64,523	27,771	20,828	6,943

Potential Mercury Emissions

	Annual Heat Input (MMBtu/year)	Mercury Emission Limit (lb/MMBtu)	Annual Mercury Emissions (lb/year)	Incremental Hg Emissions Reduction (tons/year)
Potential Capacity	86,899,200	6.5E-07	56	
Existing PALs	58,294,737	6.5E-07	38	19
RPEL	52,631,579	6.5E-07	34	4

Potential Carbon Monoxide (CO) Emissions

	Annual Heat Input (MMBtu/year)	CO Emission Limit or Factor (lb/MMBtu)	Annual CO Emissions (tons/year)	Incremental CO Emissions Reduction (tons/year)
Unit 1 Potential Capacity	43,449,600	0.34	7,386	
Unit 2 Potential Capacity	43,449,600	0.175	3,802	
Total Potential Capacity			11,188	
Unit 1 Existing PALs	29,147,368	0.34	4,955	
Unit 2 Existing PALs	29,147,368	0.175	2,550	
Total Existing PALs			7,505	3,683
Unit 1 RPEL	26,315,789	0.34	4,474	
Unit 2 RPEL	26,315,789	0.175	2,303	
Total RPEL			6,776	729

Potential Particulate Matter (PM/PM_{10}) Emissions

	PM/PM10 Emission Limit (lb/hour)	Annual PM/PM_{10} Emissions (tons/year)	Incremental PM/PM_{10} Emissions Reduction (tons/year)
Unit 1 Potential Capacity	74	324	
Unit 2 Potential Capacity	70	307	
Total Potential Capacity		631	
Unit 1 Existing PALs	74	217	
Unit 2 Existing PALs	70	206	
Total Existing PALs		423	208
Unit 1 RPEL	74	186	
Unit 2 RPEL	70	176	
Total RPEL		362	61

Attachment 2

PACIFICORP

RPEL Determination

Hunter Existing PALs

NOx	15,095	tons/year
SO2	5,537.5	tons/year
NOx+SO2	20,632.5	tons/year

NOx PAL Adjustment for SNCR-Equivalent NOx Rate

	Heat Input (MMBtu/hour)	SNCR NOx Rate (lb/MMBtu)	NOx Emissions (tons/year)
Unit 1	4,750	0.17	3,537
Unit 2	4,750	0.17	3,537
Unit 3	4,910	0.24	5,161
Total			12,235

NOx PAL	12,235	tons/year	(NOx PAL upon implementation of SNCR NOx rates)
SO2 PAL	5,538	tons/year	
NOx+SO2 PAL	17,773	tons/year	(NOx+SO2 PAL upon implementation of SNCR NOx rates)

RPEL

17,000	tons/year*

*The RPEL was determined by rounding-down the SNCR-equivalent NOx+SO2 PAL to the next 1,000 tons/year value.

Attachment 2

HUNTER POWER STATION

NO_X CONTROL COST DEVELOPMENT AND ANALYSIS

Prepared for:

PACIFICORP

April 9, 2020
Project 11778-036

Prepared by:

Sargent & Lundy LLC

55 East Monroe Street
Chicago, IL 60603

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1. BACKGROUND

On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the Clean Air Act (CAA), establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).[1] The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. The Regional Haze Rule established a schedule setting forth deadlines by which the states must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter, unless otherwise extended.[2]

During the initial planning period, the Utah Department of Environmental Quality (DEQ) proposed to impose the following NO_X emission limits on PacifiCorp's Hunter plant, which was proposed to be approved by the EPA on January 22, 2020. No additional NO_X control technologies were required to meet the limits for the initial planning period.

- A NO_X emission limit of 0.26 lb/MMBtu (30-day rolling average) each for Hunter Units 1 and 2.
- A NO_X emission limit of 0.34 lb/MMBtu (30-day rolling average) for Hunter Unit 3.

As part of the Regional Haze Rule second planning period, it is anticipated that additional NO_X control technologies will need to be evaluated at Hunter station. PacifiCorp engaged Sargent & Lundy LLC (S&L) to develop study level, order-of-magnitude capital and annual operating and maintenance (O&M) costs for both SNCR and SCR for their Hunter Units 1-3. The capital and O&M costs for SCR and SNCR technology were estimated by S&L based on recent similarly sized projects.

2. INTRODUCTION

S&L is a leading global engineering, design, and consulting company, focused exclusively on the power generating industry. Since its inception in 1891, S&L has remained an independent evaluator of power generating technologies, power generating technology subsystems, and air pollution control systems.

S&L has considerable experience with the specification, evaluation, selection and implementation of emission control technologies for fossil fuel-fired power plants. With respect to the control of NO_X

[1] 64 FR 35713
[2] On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).

emissions from coal-fired power plants, S&L has completed, or is currently in the process of completing, more than 150 SCR and SNCR projects, representing more than 54,000 MW of generation.

Our NO_X control experience includes conceptual studies and preparing control system specifications, as well as the engineering, procurement, and installation of various control systems. S&L has participated in the design and installation of more than 30 SNCR control systems and more than 125 SCR control systems for coal and gas units. In addition, S&L has performed considerable work with respect to Best Available Retrofit Technology (BART) controls for coal-fired power plants. Our BART work includes control technology feasibility evaluations, cost estimating, and cost-effectiveness evaluations.

S&L was retained by PacifiCorp to prepare study level, order-of-magnitude capital and annual O&M costs for each unit affected for their Hunter Units 1-3 for both SCR and SNCR technologies. This report provides a summary of the capital and O&M cost estimates prepared for PacifiCorp, and includes an overview of the approach, design parameters, and assumptions.

3. COST ESTIMATING METHODOLOGY

To support states in their efforts to develop the regional haze state implementation plans for the second planning period, EPA adopted the "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" on August 20, 2019 ("2019 Guidance"). The 2019 Guidance, page 21, explains how the four statutory "reasonable progress" factors should be analyzed by the states, including the "cost of compliance" factor. Specifically, the 2019 Guidance encourages states to consider costs based on "complete cost data; that is, estimated values of capital costs, annual operating and maintenance costs, annualized costs, and cost per ton of emission reductions that have been prepared according to EPA's Control Cost Manual."[3]

Section 2.3 of the Control Cost Manual (Section 1, Chapter 2) describes the cost categories generally used to calculate the total capital cost of a retrofit control technology. Cost categories include total capital investment (TCI), which is defined to "include all costs required to purchase equipment needed for the control systems (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings, and certain other costs (indirect installation costs). TCI also includes costs for land, working capital, and off-site facilities." Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. Indirect installation costs include costs such as engineering costs; construction and field expenses (i.e., cost for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies.

The Control Cost Manual is intended to provide guidance to regulatory authorities and industry for the development of capital costs, operating and maintenance expenses, and others costs, for air pollution control devices.[4] The introduction to the Control Cost Manual states that it "does not directly address the controls needed to control air pollution at electrical generating units (EGUs) because of the differences in accounting for utility sources," and explains that while the cost methodology in the Manual may be helpful, it differs from the methodology generally used by the utility industry.[5]

The Control Cost Manual mandates a study-level cost estimate. When an industrial user has site-specific information available, inputs to the cost estimating methodology may differ from the broad assumptions made by the Cost Control Manual, but will produce more accurate results for the site in question. Under these circumstances, the Manual expressly provides flexibility for users, stating that "the user has to be able to exercise 'engineering judgment' on those occasions when the procedures [described in the Manual] may need to be modified or disregarded."[6]

The total annual cost (TAC) of a control option includes the annualized capital recovery cost plus the total annual O&M costs. The Control Cost Manual recommends using an equivalent uniform annual cash flow method to annualize the total capital investment by multiplying the total capital investment by a capital recovery factor (CRF).[7] The product of the total capital investment and CRF gives a uniform end-of-year payment necessary to repay the initial capital investment in "n" years at an interest rate of "i". The CRF is calculated using the following equation:

$$CRF = \frac{i * (1+i)^n}{(1+i)^n - 1}$$

Where:
i = interest rate; and
n = economic life of the emission control svstem

The 2019 Guidance, page 32, allows states to use generic cost estimates or estimating algorithms for estimating control system costs "for a streamlined approach or when site-specific cost estimates are not available." The 2019 Guidance strongly favors the use of source-specific cost estimates. Every "source-specific cost estimate used to support an analysis of control measures must be documented in the SIP." *Id.*

[4] Control Cost Manual, Section 1, Chapter 1, page 1-4.
[5] *Id.,* at page 1-3.
[6] Cost Manual, Section 1, Chapter 1, page 1-7.
[7] Id., at pg 2-21.

The total annual cost of each control option ($/yr) is divided by the total annual emissions reduction (tons/yr) to determine the control option's average cost-effectiveness on a $/ton basis. Emissions reductions are calculated based on the difference between baseline annual emissions and post-control annual emissions. The 2019 Guidance generally recommends calculating baseline emissions based on projected 2028 emissions assuming source compliance with emission limits that have been adopted and are enforceable. As an alternative, baseline emissions may be based on representative data of past actual emissions, assuming there is no evident basis for using a different emissions rate. As such, the cost of compliance is based on historical baseline as well as future projected capacity factors and fuels.

3.1 Overnight Cost

For purposes of the second implementation period, EPA recommends that states follow the source type-relevant recommendations in the EPA Air Pollution Control Cost Manual which recommends using the "overnight method" for accounting for capital investments.

The U.S. Energy Information Administration (EIA) defines overnight cost as an estimate of the cost at which a plant could be constructed assuming that the entire process from planning through construction could be completed in a single day[8]. However, in the same document cited by EPA, the EIA notes that overnight capital costs "serve as a starting point for developing the total cost of new generating capacity" and that "other parameters also play a key role in determining the total capital costs."[9] Lead time is identified by the EIA as one of the most notable parameters affecting total capital costs, as "[p]rojects with longer lead times increase financing costs."[10] Although the EIA starts with overnight cost estimates, other parameters, including financing, lead time, and inflation of material and construction costs play a key role in determining total capital costs, and are included in cost estimates relied upon by the EIA.

In order to be consistent with an "overnight cost" methodology, allowance for funds used during construction (AFUDC) has been excluded from these cost estimates. However, AFUDC represents real costs that will be incurred as part of the project. AFUDC accounts for the time value of money associated with the distribution of construction cash flows over the construction period. AFUDC can represent a significant cost on large construction projects with long project construction durations, and can be calculated based on a typical construction project cash flow and real interest rate (which excludes the effects of inflation).

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[8] EIA, "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants," April 2013
[9] *Id*, pg. 3
[10] *Id*.

3.2 Contingency

Project contingency is included in the estimate to cover unknown risks associated with a project; these risks include for example additional scope not previously identified. The project contingency was estimated at 20% of the total project cost based on the project definition and cost estimate accuracy.

3.3 Owner's Costs

Owner's Costs are costs that the Owner incurs during the project; specifically including the cost of the Owner's staff required to oversee the project and interface with the EPC Contractor, Owner's Engineer, and other contractors, as applicable. The following list of items are covered by Owner's costs and are real costs PacifiCorp would incur based on the scope and schedule of these projects:

- Internal Labor
- Internal Travel Expenses
- Internal Indirects
- Legal Services
- Insurance
- Initial Reagent Fills

4. CAPITAL AND O&M COST ESTIMATES

S&L generally followed the approach described in the 2019 Guidance, and the methodology described in EPA's Control Cost Manual, to the greatest extent possible, to develop NO_X control system cost estimates for the Hunter Station.

4.1 Design Parameters

The Hunter Power Plant is located near Castle Dale, Utah and is comprised of a total of three boilers, of which two are identical (nominally 430 MW gross each). The two identical units are Combustion Engineering tangentially fired boilers which fire bituminous coal as its primary fuel, while the third unit (nominally 510 MW) is Babcock and Wilcox opposed-fired boiler which fire bituminous coal as its primary fuel. All of the units consist of low-NO_X burners (LNB) and Separated Over-Fire Air (SOFA) to control NO_X emissions. Units 1, 2 and 3 are equipped with baghouses, reverse air for PM control and WFGD control systems for SO_2 control.

Design and operating parameters affecting the design of SCR and SNCR systems include, but are not limited to, boiler heat input, flue gas volume, flue gas temperature, inlet NO_X, and the design target NO_X emission rate. Operating and design parameters for the control systems were developed based on input and data provided by the station for recent projects completed by S&L at the Hunter station, as well as experience with similar projects. Design and operating parameters used as the design basis for the Hunter units are summarized in Table 1.

Table 1: Hunter Design & Operating Parameters (from 2011 Design Basis)

PLANT DATA		UNIT 1	UNIT 2	UNIT 3	SOURCE
Design Heat Input	MMBtu/hr	4,750	4,750	4,910	PacifiCorp
Design Full Load	MW (gross)	430	430	510	PacifiCorp
Fuel(s)	---	Bituminous	Bituminous	Bituminous	PacifiCorp
Air H_2O	lb/lb dry air	0.013	0.013	0.013	Design
Ash-Boiler	wt%	20.0	20.0	20.0	Assumption
Ambient Pressure	psia	11.92	11.92	11.92	Calculated (Note 1)
Ambient Temperature	°F	80.0	80.0	80.0	PacifiCorp
Econ. Outlet Temp	°F	718	718	645	Design / PI Data (Unit 3)
Econ. Outlet Static Pressure	psia	11.50	11.50	11.50	Design
Econ. Outlet O_2	vol% wet	4.7	5.0	4.4	Design / PI Data (Unit 3)
Boiler SO_2 Oxidation	wt% SO_2	1.00	1.00	1.00	Engineering Judgement

Note 1. The ambient pressure is based on elevation of 5,640 ft. above sea level at Hunter.

4.2 SNCR Capital Cost Estimate Methodology & Assumptions

S&L used unit-specific operating data (e.g., fuel characteristics, boiler design data, temperature data, and NO_X emission rates), as well as experience from similar SNCR system installations, to develop capital and O&M costs specific to the Hunter Station. Equipment costs were estimated for the SNCR system based on equipment costs provided by SNCR original equipment manufacturers (OEMs) for control systems on similar coal-fired boilers.

4.2.1 Factors Affecting the SNCR Design

Several site-specific factors affect the design and effectiveness of SNCR control systems. Operating conditions that have the most impact on SNCR system design and achievable performance include the temperature profile through the boiler, and the average concentration and distribution at the injection locations of O_2, CO, and NO_X. Industry experience has shown that temperatures in the range of 1,800 to 2,200°F and CO levels below 1,000 ppm at the boiler's bull nose are needed to obtain the highest SNCR NO_X removal efficiency. The achievable NO_X removal is dependent on the location of this temperature regime in conjunction with the injection locations, as well as the residence time of the flue gas within this range. If CO levels exceed 5,000 ppm at the bull nose, SNCR is not a feasible technology due to a number of factors, including low urea utilization, low removal efficiency and high ammonia slip.

The temperature profile and CO concentration at the injection levels are not currently known for the Hunter units, and boiler mapping would be required by any SNCR OEM to obtain performance guarantees[11]. SNCR equipment cost estimates will be based on the assumption that CO concentrations at the bull nose in each boiler can be controlled to a level that allows for effective NO_X removal. In addition, due to the size of the boilers it was assumed that achieving adequate injection and mixing within the required temperature profile will be challenging. Thus, the cost estimate includes a conservative equipment design with multiple levels and types of injection lances.

Based on control efficiencies achieved on other large coal-fired boilers, SNCR technology can typically achieve 15-25% reduction from a baseline average NO_X emission rate. Assuming CO concentrations and temperatures are within the design windows identified above, and assuming a conservative equipment design, S&L has assumed a maximum NO_X reduction of 20% could be achieved on the Hunter units. The baseline average NO_X emission rate and design outlet NO_X emission rates and proposed permit limits are summarized below in Table 2.

Table 2: Hunter SNCR Units 1-3 NO_X Control Summary

		UNIT 1	UNIT 2	UNIT 3
Annual Average Inlet NO_X [12]	lb/MMBtu	0.200	0.198	0.280
NO_X Removal Efficiency	%	20	20	20
Design Average Outlet NO_X	lb/MMBtu	0.16	0.16	0.23
NO_X Permit Limit with SNCR	lb/MMBtu	0.17	0.17	0.24

4.2.2 SNCR Design

Based on a site-specific review of the NO_X reduction requirements and retrofit challenges for the installation of SNCR systems, the following project-specific issues were taken into consideration in the development of the SNCR cost estimates:

- Urea Delivery, Unloading, and Storage. The SNCR cost estimate is based on using urea as the reagent. The urea solution (50% aqueous urea by weight) would be delivered by truck and unloaded via onboard truck pumps into fiberglass reinforced plastic (FRP) storage tanks. The tanks are sized for a total storage capacity of 14 days of continuous operation at full load and would be heat traced and insulated in order to keep the 50% urea solution above 80°F to prevent precipitation of urea solids out of solution. One common storage area is included for the station.
- Urea Circulation. The urea storage tanks would be cross tied, providing a common storage area for Units 1-3. The urea solution would be transferred using stainless steel piping. A loop from the storage tanks to each unit's metering modules and back to the storage tanks would continuously

[11] It is typical that the temperature profile and CO concentrations at the SNCR injection levels are unknown. Performance Guarantees provided by vendors are often indicative at the time of award and are finalized once boiler mapping is completed as part of initial detailed design. Therefore, the predicted performance is based on similar boilers (size, type, and fuel).
[12] The annual average inlet NO_X emission rate is calculated using the average of the annual heat input and NO_X emissions from 2015-2019.

circulate the 50% urea solution. Process heat tracing would be required to keep the urea solution above 80°F.

- Urea Dilution and Metering. Dilution water would be pumped to the metering modules located in the unit, where it would mix with the 50% urea solution prior to injection into the boiler. Dilution of the urea solution to approximately 5 wt% urea is required prior to injection. Variable frequency drives would be utilized to maintain a constant pressure of dilution water in response to changing flow demands. The metering modules provide flow and pressure control of the fluids used in the SNCR process.

- Diluted Urea Distribution and Injection. The distribution modules would provide diluted urea solution and atomizing air to individual injectors. The modules are typically located near the injectors on the same elevation. Diluted urea solution is fed from the dilution/metering modules to the distribution modules. The distribution module distributes atomizing air and urea solution to each injector. The injectors are used for dispersion of diluted urea solution within targeted areas of the boiler. Design, quantity, type and placement of the injectors are critical to SNCR performance; furnace temperature, residence time, and droplet size are important design parameters controlled by injector placement. The exact locations of the injectors would be determined by the SNCR OEM based on computational fluid dynamics (CFD) modeling of the furnace. For the SNCR cost estimate, exact injector locations were not selected; however, it was assumed that the units would require a minimum of three injection levels to cover the entire load and temperature profile within the boiler.

- Raw Water & Water Treatment. It was assumed that raw water would be utilized for urea dilution water; therefore, no water treatment system was included in this cost estimate.

- Plant and Instrument Air System. The addition of the SNCR system adds a large air user to each unit. To meet the air consumption requirements for the atomizing air, compressors would be added per unit. These compressors would also provide compressed air to all new intermittent-users (e.g., valves, instruments, tools, etc.); therefore, no additional compressed air load would be added to the plant's existing compressed air systems. All air would be dried to -40°F dew point by implementing regenerative desiccant dryers. Instrument air piping would be stainless steel.

- Air Heater Evaluation. At the temperatures typically found in the air heater, excess ammonia from the SNCR can react with sulfur trioxide in the flue gas to form ammonium bisulfate in the intermediate section of the air heater. Based on operating experience with medium sulfur fuel, air heater plugging and corrosion may become an issue on these units. Therefore, an allowance for air heater modifications was included in the estimate.

- Fire Protection System. Fire protection for the new pre-engineered buildings would include alarm and detection, as well as fire extinguishers. It is anticipated no additional fire hydrants, or a dispersion system will be required for the urea unloading area.

- Furnace Modifications. Penetrations in the boiler water wall would be required at the injector locations. To support the injector penetrations, water wall tubes would need to be removed and replaced with tubes curved around the penetration location, a boot, and a flange, to which the injectors are mounted. In some instances, additional structural reinforcement may be required to support the injectors.

- Process and Freeze Protection Heat Tracing System. A freeze protection system would be provided for outdoor piping (8" and smaller), instruments, and other devices subject to freezing in cold weather. The freeze protection system would be designed to accommodate both normal plant operations and extended plant shutdowns during cold weather. All urea piping and tanks would be process heat traced to a minimum temperature of 80ºF to avoid crystallization.

4.2.3 SNCR Capital Cost Estimate

The following items are included in the scope of the SNCR cost estimate:

- Boiler wall modifications and injectors
- Dilution and metering skids
- Boiler mapping and CFD modeling for each unit
- Common urea unloading area storage tanks and tank equipment
- Circulating urea loop to each unit
- Foundations, buildings and support steel
- Piping and auxiliaries
- Electrical equipment
- Controls modifications

Based on the design parameters, costs, site constraints, and assumptions outlined above, capital cost estimates were developed for the Hunter units, assuming a common urea unloading and storage area for Units 1-3. The cost estimate represents a firm price Engineer-Procure-Construct (EPC) project. The estimate includes all indirect capital costs such as engineering costs, construction and field expenses, contractor fees, start-up and performance test costs. PacifiCorp's Owner's Costs for Owner's Engineer, labor and permitting are included in the cost estimate.

Table 3 shows the estimated costs for the complete SNCR Units 1-3 Project at Hunter.

Table 3: Hunter SNCR Capital Costs for Units 1-3

Item	Unit 1-3 SNCR Cost Estimate	Single Unit SNCR Cost Estimate	Notes
Direct Costs			
SNCR Equipment Cost	$5,080,000	$1,693,000	Based on similar sized project costs.
Platforms and Support	$3,380,000	$1,127,000	Based on similar sized project costs.
Foundation and Buildings	$950,000	$317,000	Based on similar sized project costs.
Boiler Modifications	$1,250,000	$417,000	Based on similar sized project costs.
Piping and Auxiliaries	$6,550,000	$2,183,000	Based on similar sized project costs.
Electrical Equipment	$3,890,000	$1,297,000	Based on similar sized project costs.
Controls Modifications	$1,620,000	$540,000	Based on similar sized project costs.
Total Direct Costs	***$22,720,000***	***$7,574,000***	

Item	**Unit 1-3 SNCR Cost Estimate**	**Single Unit SNCR Cost Estimate**	**Notes**
Project Indirect Costs			
Construction Costs	$9,088,000	$3,029,000	Calculated based on 40% of Direct Costs
Engineering	$3,817,000	$1,272,000	Calculated based on 12% of Direct + Construction Costs
EPC Fee	$3,181,000	$1,060,000	Calculated based on 10% of Direct + Construction Costs
Permitting	$300,000	$100,000	Allowance for each unit
Construction Management Support	$1,590,000	$530,000	Calculated based on 5% of Direct + Construction Costs
Initial Fill	$318,000	$106,000	Calculated based on 1% of Direct + Construction Costs
Spare-Parts	$318,000	$106,000	Calculated based on 1% of Direct + Construction Costs
Owner's Costs	$318,000	$106,000	Calculated based on 1% of Direct + Construction Costs
Contingency	$6,362,000	$2,121,000	Calculated based on 20% of Direct + Construction Costs
Total Indirect Costs	***$25,292,000***	***$8,430,000***	
Total Capital Investment (TCI)	**$48,012,000**	**$16,004,000**	**Total Direct Costs + Total Indirect Costs**
Capital Recovery Factor $i(1+i)^n / (1+i)^n - 1$	0.0944	0.0944	Calculated using an interest rate of 7% and a control system life of 20 years.
Annualized Capital Cost	**$4,531,993**	**$1,510,644**	**Capital Recovery Factor x TCI**

4.3 SNCR Operating & Maintenance Cost Methodology & Assumptions

Annual O&M costs include both fixed and variable costs. Variable O&M costs are items that generally vary in proportion to the plant capacity factor. Variable costs associated with SNCR systems include: reagent costs (e.g., urea solution); dilution water costs; and auxiliary power costs associated with operating the new equipment. Fixed costs are independent of the level of production and would be incurred even if the control system were shut down, and include costs such as maintenance labor and materials, administrative charges, property taxes, and insurance. Both fixed and variable O&M costs were developed based on site specific design conditions for the Hunter units.

Variable O&M costs were calculated assuming a capacity factor of 68.0% for Unit 1, 72.0% for Unit 2, and 66.0 for Unit 3 (based on average operation from 2015-2019 to be consistent with equipment design basis).

Annual O&M and total annual costs for the Hunter SNCR systems are summarized in Table 4.

Table 4: Hunter SNCR O&M Costs for Units 1-3

OPERATING & MAINTENANCE COSTS	UNIT 1	UNIT 2	UNIT 3	Basis
Variable O&M Costs				
Urea Solution Cost	$1,857,000	$1,895,000	$2,847,000	$300 per ton of solution.
Auxiliary Power Cost	$74,000	$78,000	$81,000	$50/MWh.
Water Cost	$27,000	$27,000	$41,000	$2/1,000 gallons
Total Variable O&M Cost	***$1,958,000***	***$2,000,000***	***$2,969,000***	
Fixed O&M Costs				
Operating Labor	$0	$0	$0	No additional operators required.
Supervisory Labor	$0	$0	$0	Not included.
Maintenance Materials and Labor	$240,000	$240,000	$240,000	1.5% of Total Capital Investment
Property Taxes	$0	$0	$0	Not included.
Insurance	$0	$0	$0	Not included.
Administration	$0	$0	$0	Not included.
Total Fixed O&M Cost	***$240,000***	***$240,000***	***$240,000***	
Total Annual O&M Cost	**$2,198,000**	**$2,240,000**	**$3,209,000**	

4.4 SCR Capital Cost Estimate Methodology & Assumptions

S&L used unit-specific operating data (e.g., fuel characteristics, boiler design data, temperature data, and NO_X emission rates), as well as experience from similar SCR system installations, to develop capital and O&M costs specific to Hunter Station. Equipment costs were estimated for the SCR system based on equipment costs provided by SCR original equipment manufacturers (OEMs) for control systems on similar coal-fired boilers.

4.4.1 SCR Design

The following summarizes the major components of the SCR system design and project-specific issues that were taken into consideration in the development of the SCR cost estimates

- SCR Location. The proposed SCR reactors will be located above the ESP or baghouse inlet ductwork (depending on the unit). The SCR structure will be supported on columns that avoid interferences with the ESP or baghouse inlet ductwork and at grade. The SCR will be a high-dust configuration installed between the economizer outlet and the air heater inlet. Galleries were provided at each catalyst level and at the ammonia injection grid to allow for maintenance and inspection of the SCR system.

- Boiler Building Reinforcement. Due to the fact that the boiler building walls are load bearing walls, some of the existing boiler building steel columns and upper framing will have to be removed to make room for the new ductwork.

- SCR Reactors and Catalyst. The SCR system will consist of two reactors per unit. The SCRs will use anhydrous ammonia as the reagent. To achieve the required NO_X emission reductions on a consistent basis with low SO_2 to SO_3 conversion, three layers of catalyst are required for each of the SCRs. The SCRs would be designed to hold four layers of catalyst, with three layers being loaded initially.

- Economizer Modifications. At temperatures lower than 560-600°F (depending on the fuel sulfur content) extended operation of the SCR system with ammonia injection in-service would promote the generation of both ammonium sulfate and ammonium bisulfate deposits. The deposits accumulate over time, block catalyst sites, and reduce catalyst activity over the life of the catalyst. Based on historical operating data, an economizer bypass is required for all three units to accommodate operation at low load 2.

- SCR Cleaning. The method of cleaning the fly ash that settles on the catalyst is extremely important to obtain the guaranteed life of the catalyst. For this reason, the use of steam sootblowers, in addition to sonic horns, is recommended. Steam sootblowers will remove fly ash that settles on the catalyst and the sonic horns will keep the fly ash moving through the catalyst. The conceptual design includes steam sootblowers for the top layer of catalyst, and sonic horns for the balance of the catalyst layer. The sonic horn system will require compressed air to operate. Separate compressors were assumed for each unit for the cost estimate.

- Large Particle Ash Screen. To collect large particle ash (LPA) upstream of the SCR, a large particle ash screen will be installed in each economizer outlet duct. Due to very high velocities at the economizer outlet, the LPA screens will be located at the base of each of the SCR riser ducts. New ash hoppers and handling equipment is included in the design to tie the LPA hoppers into the economizer ash system.

- Ammonia System. The anhydrous ammonia system will be located in a remote location from the units. A pipe rack is assumed to deliver the ammonia from the storage area to the SCR reactors. The scope of this system includes not only the storage tanks but also the foundation, feed pumps, feed piping, and necessary safety systems.

- Auxiliary Power Upgrades. Operation of the SCR control system will require larger ID fans and electrical systems to allow the plant to operate at full load with the additional pressure loss generated by the SCR. The estimate includes the cost to replace the ID fans and motors on all units. It is expected that the existing electrical systems are not capable of handling the new fan loads and SCR control systems, and that a new power line and related electrical equipment will be required.

- Structural Stiffening. Structural stiffening of the ductwork and equipment downstream of the boiler and upstream of the new ID fans will be required by NFPA regulations to operate at more negative pressures due to the installation of the SCR. Due to the similarity in ductwork design pressures of these units, the scope of structural stiffening is expected to be the same as the previous project.

- Control Systems. The existing distributed control system (DCS) will need to be expanded to accommodate the additional signals from the SCR system.

- Construction Costs and Special Cranes. Due to general site congestion, special cranes will be needed to provide the lifting capacity that is required to install SCRs and accommodate the associated demolition.

4.4.2 SCR Capital Cost Estimate

The following items are included in the scope of the SCR cost estimate:

- Economizer outlet / air heater inlet ductwork modifications
- Economizer bypass for low-load temperature control
- SCR equipment & ductwork (including catalyst, LPA screens, and cleaning equipment)
- Equipment and ductwork reinforcement for NFPA requirements
- Ammonia unloading area expansion consisting of two (2) storage tanks and tank equipment
- Ammonia delivery and vaporization equipment
- Foundations and support steel

Based on the design parameters, costs, site constraints, and assumptions outlined above, capital cost estimates were prepared for Unit 1-3 SCR systems. The cost estimates were estimated by S&L based on recent similarly sized projects and represents a firm price Engineer-Procure-Construct (EPC) project.

The cost estimate includes all indirect capital costs such as engineering costs, construction and field expenses, contractor fees, start-up and performance test costs, and contingencies are included. Also included in the cost estimate are PacifiCorp's actual Owner's Costs for Owner's Engineer, labor and permitting.

Table 5 shows the estimated costs for the complete SCR Units 1-3 Project at Hunter.

Table 5: Hunter SCR Capital Costs for Units 1-3

Item	Unit 1	Unit 2	Unit 3	Notes
Direct Costs				
Equipment Costs	$24,614,000	$24,614,000	$27,465,000	Scaled based on recent projects.
Material Costs	$21,225,000	$21,225,000	$23,547,000	Scaled based on recent projects.
Labor Costs	$30,556,000	$30,556,000	$33,882,000	Scaled based on recent projects.
Total Direct Costs	***$76,395,000***	***$76,395,000***	***$84,894,000***	
Project Indirect Costs				
Construction Costs	$22,919,000	$22,919,000	$25,468,000	30% of Total Direct Costs
Engineering	$9,931,000	$9,931,000	$11,036,000	10% of Total Direct + Construction Costs
EPC Fee	$9,931,000	$9,931,000	$11,036,000	10% of Total Direct + Construction Costs
Permitting	$200,000	$200,000	$200,000	Scaled based on recent projects.
Construction Management Support	$4,966,000	$4,966,000	$5,518,000	5% of Total Direct + Construction Costs

Item	Unit 1	Unit 2	Unit 3	Notes
Initial Fill	$497,000	$497,000	$552,000	0.5% of Total Direct + Construction Costs
Spare-Parts	$497,000	$497,000	$552,000	0.5% of Total Direct + Construction Costs
Owner's Costs	$993,000	$993,000	$1,104,000	1% of Total Direct + Construction
Contingency	$19,863,000	$19,863,000	$22,072,000	20% of Total Direct + Construction
Total Indirect Costs	***$69,797,000***	***$69,797,000***	***$77,538,000***	
Total Capital Investment (TCI)	**$146,192,000**	**$146,192,000**	**$162,432,000**	**Total Direct Costs + Total Indirect Costs**
Capital Recovery Factor $i(1+i)^n / (1+i)^n - 1$	0.0806	0.0806	0.0806	Calculated using an interest rate of 7% and a control system life of 30 years.
Annualized Capital Cost	**$11,783,075**	**$11,783,075**	**$13,092,019**	**Capital Recovery Factor x TCI**

4.5 SCR Operating & Maintenance Cost Methodology & Assumptions

Annual O&M costs include both fixed and variable costs. Variable O&M costs are items that generally vary in proportion to the plant capacity factor. Variable costs associated with SCR systems include: reagent costs (e.g., anhydrous ammonia); catalyst replacement costs; and auxiliary power costs associated with operating the new equipment. Fixed costs are independent of the level of production and would be incurred even if the control system were shut down, and include costs such as maintenance labor and materials, administrative charges, property taxes, and insurance. Both fixed and variable O&M costs were developed based on site specific design conditions for the Hunter units.

Variable O&M costs were calculated assuming a capacity factor of 68.0% for Unit 1, 72.0% for Unit 2, and 66.0 for Unit 3 (based on average operation from 2015-2019 to be consistent with SNCR). Annual O&M and total annual costs for the Hunter SCR systems are summarized in Table 6.

Table 6: Hunter SCR O&M Costs for Units 1-3

OPERATING & MAINTENANCE COSTS	UNIT 1	UNIT 2	UNIT 3	Basis
Variable O&M Costs				
Anhydrous Ammonia Cost	$486,000	$492,000	$799,000	$550 per ton of anhydrous ammonia
Auxiliary Power Cost	$607,000	$636,000	$705,000	$30/MWh
Catalyst Replacement Cost	$288,000	$288,000	$320,000	Note 1
Steam Cost	$25,000	$26,000	$34,000	$5/MMBtu
Outage Penalty	$0	$0	$0	Not included
Total Variable O&M Cost	***$1,406,000***	***$1,442,000***	***$1,858,000***	
Fixed O&M Costs				
Operating Labor	$0	$0	$0	No additional operators required.
Supervisory Labor	$0	$0	$0	Not included.

OPERATING & MAINTENANCE COSTS	**UNIT 1**	**UNIT 2**	**UNIT 3**	**Basis**
Maintenance Materials and Labor	$365,000	$365,000	$406,000	Note 2
Property Taxes	$0	$0	$0	Not included.
Insurance	$0	$0	$0	Not included.
Administration	$0	$0	$0	Not included.
Total Fixed O&M Cost	***$365,000***	***$365,000***	***$406,000***	
Total Annual O&M Cost	**$1,771,000**	**$1,807,000**	**$2,264,000**	

Note 1. Annual catalyst replacement costs were calculated based on replacing one (1) layer of catalyst (approximately 155 m^3 per layer) once every two years. Catalyst costs were calculated by multiplying the volume of catalyst by the installed unit cost of $5,000/$m^3$ and using a future worth factor of 0.48 calculated as follows:

FWF = i * [1 / $(1 + i)^y$ - 1]; where i = an assumed interest rate of 7.0% and y = 2 (i.e., replacing one layer every other year). See, Control Cost Manual, Section 4.2, Chapter 2, pg. 2-47

Note 2. The Control Cost Manual calculates SCR maintenance materials and labor at 1.5% of TCI (Control Cost Manual, Section 4.2, Chapter 2, page 2.45). This factor results in annual maintenance costs significantly higher than expected actual maintenance costs reported by industry. Therefore, for this evaluation, S&L revised the maintenance materials and labor cost downward to 0.25% of TCI.

5. COST EFFECTIVENESS

For this evaluation, the average baseline NO_X emissions and the average baseline heat input for Units 1-3 were calculated based on the average of the most recent five years (2015-2019). The average values were used in order to provide a cost-effectiveness evaluation that was not overly conservative. The heat input and NO_X emissions baseline are summarized in Table 7.

Table 7: Hunter Emission Baseline Summary

BASELINE INFORMATION	UNIT 1	UNIT 2	UNIT 3
Heat Input Baseline			
Full Load Heat Input (MMBtu/hr)	4,750	4,750	4,910
2015-2019 Average Heat Input (MMBtu/year)	28,482,643	30,101,030	31,182,279
NO_X Emission Baseline (for Cost-Effectiveness)			
2015-2019 Average Annual NO_X Emission (tons/year)	2,842	2,902	4,359

Total annual costs were calculated as the sum of the annualized capital costs and total fixed and variable O&M costs. Capital costs were annualized using the capital recovery factor (CRF) approach described in Section 1, Chapter 2 of the Control Cost Manual. The total capital costs, capital recovery factor, and annualized capital costs for the SNCR and SCR technologies are provided in Section 5 of this report.

Total annual costs include the annualized cost of capital and the fixed and variable O&M costs. Variable O&M costs, which include the annual cost of reagents (anhydrous ammonia or urea solution), water, steam, auxiliary power, and catalyst replacement are provided in Section 5 of this report.

The cost-effectiveness of each control system was calculated on a dollar-per-ton-removed basis by dividing total annual costs by the reduction in annual emissions. Annual emissions using a particular control device were subtracted from baseline emissions to calculate tons removed per year.

5.1 SNCR Cost Effectiveness

Annual NO_X emissions with SNCR were calculated based on a NO_X reduction efficiency of 20%. Table 8 shows the total annual cost, average annual reduction in NO_X emissions, and average annual cost effectiveness, based on a 20-year life.

Table 8: SNCR Cost Effectiveness

COST EFFECTIVENESS	UNIT 1	UNIT 2	UNIT 3
Baseline			
Baseline Heat Input (MMBtu/year)	28,482,643	30,101,030	31,182,279
Baseline NO_X Emission (lb/MMBtu)	0.200	0.193	0.280
Baseline NO_X Emission (tons/year)	**2,842**	**2,902**	**4,359**
NO_X Emissions with SNCR			
Controlled NO_X Permit Limit (lb/MMBtu)	0.17	0.17	0.24
Controlled NO_X Emission (tons/year)	**2,421**	**2,559**	**3,742**
SNCR Cost Effectiveness			
Annualized Capital Costs (20-year life)	$1,511,000	$1,511,000	$1,511,000
Total Annual O&M Costs	$2,198,000	$2,240,000	$3,209,000
Total Annual Cost ($/year)	**$3,709,000**	**$3,751,000**	**$4,720,000**
COST EFFECVENESS ($/TON)	**$8,816**	**$10,913**	**$7,646**

5.2 SCR Cost Effectiveness

Annual NO_X emissions with SCR were calculated based on a design outlet NO_X emission of 0.05 lb/MMBtu. Table 9 shows the total annual cost, average annual reduction in NO_X emissions, and average annual cost effectiveness, based on a 30-year life.

Table 9: SCR Cost Effectiveness

COST EFFECTIVENESS	UNIT 1	UNIT 2	UNIT 3
Baseline			
Baseline Heat Input (MMBtu/year)	28,482,643	30,101,030	31,182,279
Baseline NO_X Emission (lb/MMBtu)	0.200	0.193	0.280
Baseline NO_X Emission (tons/year)	**2,842**	**2,902**	**4,359**
NO_X Emissions with SCR			
Controlled NO_X Permit Limit (lb/MMBtu)	0.05	0.05	0.05
Controlled NO_X Emission (tons/year)	**712**	**753**	**780**
SCR Cost Effectiveness			
Annualized Capital Costs (30-year life)	$11,783,000	$11,783,000	$13,092,000
Total Annual O&M Costs	$1,771,000	$1,807,000	$2,264,000
Total Annual Cost ($/year)	**$13,554,000**	**$13,590,000**	**$15,356,000**
COST EFFECVENESS ($/TON)	**$6,364**	**$6,322**	**$4,290**

5.3 Cost Effectiveness Summary

Tables 10-12 summarizes the cost-effectiveness of the two control options evaluated based on 20-year life for SNCR and 30-year life for SCR for each Unit.

Table 10: Unit 1 Cost Effectiveness Summary

TECHNOLOGY / BASIS	HUNTER UNIT 1 EMISSIONS	EVALUATION PERIOD (YEARS)	COST ($/TON)
Emission Baseline			
Annual Heat Input (MMBtu)	28,482,643	N/A	N/A
Baseline NO_X Emission (lb/MMBtu)	0.200		
Baseline NO_X Emission (tons/year)	**2,842**		
SNCR			
Controlled NO_X Permit Limit (lb/MMBtu)	0.17	20	$8,816
Controlled NO_X Emission (tons/year)	**2,421**		
SCR			
Controlled NO_X Permit Limit (lb/MMBtu)	0.05	30	$6,364
Controlled NO_X Emission (tons/year)	**712**		

Table 11: Unit 2 Cost Effectiveness Summary

TECHNOLOGY / BASIS	HUNTER UNIT 2 EMISSIONS	EVALUATION PERIOD (YEARS)	COST ($/TON)
Emission Baseline			
Annual Heat Input (MMBtu)	30,101,030	N/A	N/A
Baseline NO_X Emission (lb/MMBtu)	0.193		
Baseline NO_X Emission (tons/year)	**2,902**		
SNCR			
Controlled NO_X Permit Limit (lb/MMBtu)	0.17	20	$10,913
Controlled NO_X Emission (tons/year)	**2,559**		
SCR			
Controlled NO_X Permit Limit (lb/MMBtu)	0.05	30	$6,322
Controlled NO_X Emission (tons/year)	**780**		

Table 12: Unit 3 Cost Effectiveness Summary

TECHNOLOGY / BASIS	HUNTER UNIT 3 EMISSIONS	EVALUATION PERIOD (YEARS)	COST ($/TON)
Emission Baseline			
Annual Heat Input (MMBtu)	31,182,279	N/A	N/A
Baseline NO_X Emission (lb/MMBtu)	0.280		
Baseline NO_X Emission (tons/year)	**4,359**		
SNCR			
Controlled NO_X Permit Limit (lb/MMBtu)	0.24	20	$7,646
Controlled NO_X Emission (tons/year)	**3,742**		
SCR			
Controlled NO_X Permit Limit (lb/MMBtu)	0.05	30	$4,290
Controlled NO_X Emission (tons/year)	**780**		

ATTACHMENTS

Attachments

Attachment 1: Cost Effectiveness Calculations

ATTACHMENT 1

COST EFFECTIVENESS CALCULATIONS

Cost Effectiveness Calculation Worksheet

Hunter: Cost-Effectiveness Calculations

Unit 1 - Baseline (2015-2019)

	Emission Rate (2015-2019)	Annual Heat Input (2015-2019)	Annual Emissions
	lb/MMBtu	MMBtu	tpy
NO_X	0.200	28,482,643	2,842

Unit 1 - SNCR

	Emission Rate	Annual Heat Input (2015-2019)	Annual Emissions	Reduction from Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/MMBtu	MMBtu	tpy	tpy						
NO_X	0.170	28,482,643	2,421	421	$ 16,004,000	0.0944	$ 1,511,000	$ 2,198,000	$ 3,709,000	$ 8,816

Unit 1 - SCR

	Emission Rate	Annual Heat Input (2015-2019)	Annual Emissions	Reduction from Baseline	Incremental Reduction	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness	Incremental Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy	tpy							
NO_X	0.050	28,482,643	712	2,130	1709	$ 146,192,000	0.0806	$ 11,783,000	$ 1,771,000	$ 13,554,000	$ 6,364	$ 5,761

Unit 2 - Baseline (2015-2019)

	Emission Rate (2012-2014)	Annual Heat Input (2001-2003)	Annual Emissions
	lb/MMBtu	MMBtu	tpy
NO_X	0.193	30,101,030	2,902

Unit 2 - SNCR

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/MMBtu	MMBtu	tpy	tpy						
NO_X	0.170	30,101,030	2,559	344	$ 16,004,000	0.0944	$ 1,511,000	$ 2,240,000	$ 3,751,000	$ 10,913

Unit 2 - SCR

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Baseline	Incremental Reduction	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness	Incremental Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy	tpy							
NO_X	0.050	30,101,030	753	2,150	1806	$ 146,192,000	0.0806	$ 11,783,000	$ 1,807,000	$ 13,590,000	$ 6,322	$ 5,448

Cost Effectiveness
Calculation Worksheet

Unit 3 - Baseline (2015-2019)

	Emission Rate (2012-2014)	Annual Heat Input (2001-2003)	Annual Emissions
	lb/MMBtu	MMBtu	tpy
NO_X	0.280	31,182,279	4,359

Unit 3 - SNCR

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Baseline	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness
	lb/MMBtu	MMBtu	tpy	tpy						
NO_X	0.240	31,182,279	3,742	617	$ 16,004,000	0.0944	$ 1,511,000	$ 3,209,000	$ 4,720,000	$ 7,646

Unit 3 - SCR

	Emission Rate	Annual Heat Input (2001-2003)	Annual Emissions	Reduction from Baseline	Incremental Reduction	Total Capital	CRF	Annual Capital	Annual O&M	Total Annual Cost	Average Cost Effectiveness	Incremental Cost Effectiveness
	lb/hour	MMBtu	tpy	tpy	tpy							
NO_X	0.050	31,182,279	780	3,580	2962	$ 162,432,000	0.0806	$ 13,092,000	$ 2,264,000	$ 15,356,000	$ 4,290	$ 3,590

Attachment 2

PACIFICORP

Energy and Non-Air Quality Related Impacts Support Calculations

Energy Impacts

SCR Electrical Power Requirement

Hunter Unit 1 Boiler Heat Input:	4,750	MMBtu/hour
Hunter Unit 2 Boiler Heat Input:	4,750	MMBtu/hour
Hunter Unit 3 Boiler Heat Input:	4,910	
Hunter Units 1-3 Boiler Heat Input:	14,410	MMBtu/hour
Jim Bridger Boiler Heat Input:	6,000	MMBtu/hour
Jim Bridger SCR Power Requirement:	5.2	MW
Hunter SCR Power Requirement:	12.5	MW (scaled from Jim Bridger)
Hunter Annual Power Requirement:	(12.5 MW) x (8760 hours/year)	
Hunter Annual Power Requirement:	109,401	MWh
Average Residential Customer Annual Power Usage:	10,972	kWh
Average Residential Customer Annual Power Usage:	10.972	MWh
Hunter SCR Annual Electrical Power Avoidance:	(109,401 MWh) / (10.972 MWh/customer)	
Hunter SCR Annual Electrical Power Avoidance:	9,971	customers

Avoiding Hunter SCR installation provides enough electrical energy of provide power to 9,971 residential customers

Consumption of Natural Resources

Determine Consumption of Natural Resources Under Three Operating Scenarios

1 Potential Capacity Operation with Implementation of SNCR or SCR on All Three Units
2 Restricted Operation with Existing NOx and SO2 Plantwide Applicability Limits
3 Restricted Operation with Reasonable Progress Emission Limit (RPEL)

Annual Potential Heat Input Under Three Operating Scenarios

Potential Capacity

	Boiler Heat Input (MMBtu/hour)	NOx Emission Limit (lb/MMBtu)	SO2 Emission Limit (lb/MMBtu)	Potential NOx Emissions (tons/year)	Potential SO2 Emissions (tons/year)	Potential NOx+SO2 (tons/year)	Potential Annual Heat Input (MMBtu/year)
Unit 1	4,750	0.26	0.12	5,409	2,497	7,906	41,610,000
Unit 2	4,750	0.26	0.12	5,409	2,497	7,906	41,610,000
Unit 3	4,910	0.34	0.12	7,312	2,581	9,893	43,011,600
Total						25,704	126,231,600

Existing Plantwide Applicability Limits (PALs)

NOx PAL	15,095	tons/year
SO2 PAL	5,538	tons/year
NOx+SO2 PAL	20,633	tons/year

Existing PALs Provide a 19.7% Restriction Compared to SNCR/SCR Operation Based on Total NOx+SO2 Emissions

Restriction = 1 - [(NOx+SO2 PAL) / (Potential Capacity Operation NOx+SO2)]
Restriction = 1 - [(20,633 tons/year) / (25,704 tons/year)]
Restriction = 19.7%

Annual Heat Input Compensated for 19.7% NOx+SO2 PAL Reduction

	Potential Annual Heat Input (SNCR/SCR) (MMBtu/year)	PAL-Adjusted Potential Annual Heat Input (MMBtu/year)
Unit 1	41,610,000	33,399,576
Unit 2	41,610,000	33,399,576
Unit 3	43,011,600	34,524,614
Total	126,231,600	101,323,765

Reasonable Progress Emission Limit (RPEL)

RPEL NOx+SO2	17,000	tons/year

The RPEL Provides a 17.6% Restriction Compared to the Existing PALs Based on Total NOx+SO2 Emissions

Restriction = 1 - [(RPEL NOx+SO2) / (Existing NOx+SO2 PALs)]
Restriction = 1 - [(17,000 tons/year) / (20,633 tons/year)]
Restriction = 17.6%

Annual Heat Input Compensated for 17.6% NOx+SO2 RPEL Reduction

	PAL-Adjusted Annual Heat Input (MMBtu/year)	RPEL-Adjusted Potential Annual Heat Input (MMBtu/year)
Unit 1	33,399,576	27,519,340
Unit 2	33,399,576	27,519,340
Unit 3	34,524,614	28,446,307
Total	101,323,765	83,484,988

Non-Air Quality Hunter Parameters

Coal Heating Value	11,400	Btu/lb
Design Raw Water Make-up	10,088	gallons/minute
CO2 Emission Rate	205.4	lb/MMBtu
Coal Ash Concentration	11.1%	
Fraction Fly Ash	75%	
Fraction Bottom Ash	25%	
Unit 1 CO Emission Limit	0.34	lb/MMBtu
Unit 2 CO Emission Factor	0.34	lb/MMBtu
Unit 3 CO Emission Factor	0.2	lb/MMBtu
Unit 1 PM/PM10 Emission Limit	0.015	lb/MMBtu
Unit 2 PM/PM10 Emission Limit	0.015	lb/MMBtu
Unit 3 PM/PM10 Emission Limit	0.02	lb/MMBtu
Unit 1 Mercury Emission Limit	6.5E-07	lb/MMBtu
Unit 2 Mercury Emission Limit	6.5E-07	lb/MMBtu
Unit 3 Mercury Emission Limit	6.5E-07	lb/MMBtu

Potential Coal Consumption

	Annual Heat Input (MMBtu/year)	Coal Heating Value (Btu/lb)	Annual Coal Combustion (tons/year)	Incremental Coal Combustion Reduction (tons/year)
Potential Capacity	126,231,600	11,400	5,536,293	
Existing PALs	101,323,765	11,400	4,443,880	1,092,413
RPEL	83,484,988	11,400	3,661,503	782,377

Potential Raw Water Consumption

	Raw Water Consumption (gallons/minute)	Annual Water Consumption (gallons/year)	Annual Water Consumption (acre-feet/year)	Incremental Water Consumption Reduction (gallons/year)	Incremental Water Consumption Reduction (acre-feet/year)
Potential Capacity	10,088	5,302,252,800	16,272		
Existing PALs	8,097	4,256,020,039	13,061	1,046,232,761	3,211
RPEL	6,672	3,506,717,105	10,762	749,302,934	2,300

Potential Greenhouse Gas Emissions

	Annual Heat Input (MMBtu/year)	Greenhouse Gas Emission Factor (lb/MMBtu)	Annual Greenhouse Gas Emissions (tons/year)	Incremental GHG Emissions Reduction (tons/year)
Potential Capacity	126,231,600	205.4	12,965,571	
Existing PALs	101,323,765	205.4	10,407,223	2,558,347
RPEL	83,484,988	205.4	8,574,957	1,832,266

Potential CCR Impacts

	Annual Coal Combustion (tons/year)	Coal Ash Concentration (percent)	Annual Total Ash Production (tons/year)	Annual Fly Ash Production (tons/year)	Annual Bottom Ash Production (tons/year)	Incremental Total Ash Reduction (tons/year)	Incremental Fly Ash Reduction (tons/year)	Incremental Bottom Ash Reduction (tons/year)
Potential Capacity	5,536,293	11.1%	615,009	461,257	153,752			
Existing PALs	4,443,880	11.1%	493,657	370,242	123,414	121,353	91,015	30,338
RPEL	3,661,503	11.1%	406,745	305,059	101,686	86,912	65,184	21,728

Potential Mercury Emissions

	Annual Heat Input (MMBtu/year)	Mercury Emission Limit (lb/MMBtu)	Annual Mercury Emissions (lb/year)	Incremental Hg Emissions Reduction (tons/year)
Potential Capacity	126,231,600	6.5E-07	82	
Existing PALs	101,323,765	6.5E-07	66	16
RPEL	83,484,988	6.5E-07	54	12

Potential Carbon Monoxide (CO) Emissions

	Annual Heat Input (MMBtu/year)	CO Emission Limit or Factor (lb/MMBtu)	Annual CO Emissions (tons/year)	Incremental CO Emissions Reduction (tons/year)
Unit 1 Potential Capacity	41,610,000	0.34	7,074	
Unit 2 Potential Capacity	41,610,000	0.34	7,074	
Unit 3 Potential Capacity	43,011,600	0.2	4,301	
Total Potential Capacity			18,449	
Unit 1 Existing PALs	33,399,576	0.34	5,678	
Unit 2 Existing PALs	33,399,576	0.34	5,678	
Unit 3 Existing PALs	34,524,614	0.2	3,452	
Total Existing PALs			14,808	3,640
Unit 1 RPEL	27,519,340	0.34	4,678	
Unit 2 RPEL	27,519,340	0.34	4,678	
Unit 3 RPEL	28,446,307	0.2	2,845	
Total RPEL			12,201	2,607

Potential Particulate Matter (PM/PM_{10}) Emissions

	Annual Heat Input (MMBtu/year)	PM/PM_{10} Emission Limit (lb/hour)	Annual PM/PM_{10} Emissions (tons/year)	Incremental PM/PM_{10} Emissions Reduction (tons/year)
Unit 1 Potential Capacity	41,610,000	0.015	312	
Unit 2 Potential Capacity	41,610,000	0.015	312	
Unit 3 Potential Capacity	43,011,600	0.02	430	
Total Potential Capacity			1,054	
Unit 1 Existing PALs	33,399,576	0.015	250	
Unit 2 Existing PALs	33,399,576	0.015	250	
Unit 3 Existing PALs	34,524,614	0.02	345	
Total Existing PALs			846	208
Unit 1 RPEL	27,519,340	0.015	206	
Unit 2 RPEL	27,519,340	0.015	206	
Unit 3 RPEL	28,446,307	0.02	284	
Total RPEL			697	149