APPENDIX A – Part H Language for Enforcement of Reasonable Progress Determinations

H.21. General Requirements: Control Measures for Area and Point Sources, Emission Limits and Operating Practices, Regional Haze Requirements

a. Except as otherwise outlined in individual conditions of this Subsection IX.H.21 listed below, the terms and conditions of this Subsection IX.H.21 shall apply to all sources subsequently addressed in Subsection IX.H.22. Should any inconsistencies exist between these two subsections, the source specific conditions listed in IX.H.22 shall take precedence.

b. The definitions contained in R307-101-2, Definitions and R307-170-4, Definitions, apply to Section IX, Part H. In addition, the following definition also applies to Section IX, Part H.21 and 22:

   Boiler operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler. It is not necessary for fuel to be combusted for the entire 24-hour period.

c. The terms and conditions of R307-107-1 and R307-107-2 shall apply to all sources subsequently addressed in Subsection IX.H.22.

d. Any information used to determine compliance shall be recorded for all periods when the source is in operation, and such records shall be kept for a minimum of five years. All records required by IX.H.21.c shall be kept for a minimum of five years. Any or all of these records shall be made available to the Director upon request.

e. All emission limitations listed in Subsections IX.H.22 shall apply at all times, unless otherwise specified in the source specific conditions listed in IX.H.22. Each source shall submit a report of any deviation from the applicable requirements of Subsection IX.H, including those attributable to upset conditions, the probable cause of such deviations, and any corrective actions or preventive measures taken. The report shall be submitted in accordance with the requirements of R307-170, Continuous Emission Monitoring Program. Deviations due to breakdowns shall be reported according to the breakdown provisions of R307-107.

f. Stack Testing:

   i. As applicable, stack testing to show compliance with the emission limitations for the sources in Subsection IX.H.22 and IX.H.23 shall be performed in accordance with the following:

A. Sample Location: The testing point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or the most recent version of the EPA-approved test method if approved by the Director.

B. Volumetric Flow Rate: 40 CFR 60, Appendix A, Method 2, or ~~the most recent version of the~~ other EPA-approved testing methods ~~if approved by~~ acceptable to the Director.

C. Particulate (PM): 40 CFR 60, Appendix A, Method 5B, or the ~~most recent version of the~~ other EPA-approved testing methods ~~if approved by~~ acceptable to the Director. A test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. The back half condensables shall also be tested using Method 202. The back half condensables shall not be used for compliance demonstration but shall be used for inventory purposes.

D. Nitrogen Oxides (NOx): 40 CFR 60, Appendix A, Method 7E, or other EPA approved testing methods acceptable to the Director.

E. Calculations: To determine mass emission rates (lb/hr, etc.) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors to give the results in the specified units of the emission limitation.

F. ~~A stack test protocol shall be provided at least 30 days prior to the test. A pretest conference shall be held if directed by the Director.~~ Notification: The Director shall be notified at least 30 days prior to conducting any required emission testing. A source test protocol shall be submitted to DAQ when the testing notification is submitted to the Director.

G. The source test protocol shall be approved by the Director prior to performing the tests. The source test protocol shall outline the proposed test methodologies, stack to be tested, and procedures to be used. A pretest conference shall be held, if directed by the Director.

H. Source Operation and Testing Frequency: The production rate during all compliance testing shall be no less than 90% of the maximum production achieved in the previous three (3) years.

g. Continuous Emission and Opacity Monitoring.

i. For all continuous monitoring devices, the following shall apply:

A. Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of an affected source shall continuously operate all required continuous monitoring systems and shall meet minimum frequency of operation requirements as outlined in R307-170 and 40 CFR 60.13.

B. The monitoring system shall comply with all applicable sections of R307-170; 40 CFR 13; and 40 CFR 60, Appendix B – Performance Specifications.

C. For any hour in which fuel is combusted in the unit, the owner/operator of each unit shall calculate the hourly average NOx concentration in lb/MMBtu.

D. At the end of each boiler operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/MMBtu from the arithmetic average of all valid hourly emission rates from the CEMS for the current boiler operating day and the previous 29 successive boiler operating days.

E. An hourly average NOx emission rate in lb/MMBtu is valid only if the minimum number of data points, as specified in R307-170, is acquired by the owner/operator for both the pollutant concentration monitor (NOx) and the diluent monitor (O2 or CO2).

H.23. Source Specific Emission Limitations: Regional Haze Requirements, Reasonable Progress Controls

a. Intermountain Generation Station

i. Conditions on Units #1 and #2.

A. The owner/operator shall permanently close and cease operation of Intermountain Generation Station units #1 and #2 by December 31, 2027. The owner/operator shall notify the Director of the permanent closure of units #1 and #2 by no later than January 31, 2028.

b. PacifiCorp Hunter

i. The annual NO_x emissions for the entire Hunter Plant from all point and fugitive sources shall not exceed 10,514 tons/year based on a 12-month rolling total.

ii. As of January 1, 2025, the annual NOx emissions for the entire Hunter Plant from all point and fugitive sources shall not exceed 10,257 tons/year based on a 12-month rolling total.

iii. As of January 1, 2028, the annual NOx emissions for the entire Hunter Plant from all point and fugitive sources shall not exceed 10,001 tons/year based on a 12-month rolling total.

iv. The above NO_x limits shall be monitored in accordance with the procedures outlined in 40 CFR Part 52.21(aa)(12) and at a minimum shall be done by summing up emissions as follows:

A. For Units #1, #2 and #3 main boiler stacks, PacifiCorp's reporting to EPA's Acid Rain Emissions data base for NO_x in pounds per hour obtained from the boilers' CEM data shall be used to calculate NO_x emission rates.

B. For Units #1, #2 and #3 emergency diesel-fired equipment, emissions shall be calculated by multiplying the NO_x emission factor from the latest edition of EPA's emission factors compilation AP-42 and hours of operation. Records documenting equipment usage shall be kept in a log, and they shall show the date the equipment was used and the duration in hours of operation.

C. For the record keeping requirements of each limit, PacifiCorp shall comply with 40 CFR Subpart 52.21(aa)(13).

D. For record submittal, PacifiCorp shall comply with 40 CFR Subpart 52.21(aa)(14).

v. To determine compliance with the 12-month rolling NO_x limits, the owner/operator shall calculate new 12-month total NO_x emissions by the 20th day of each month using data from the previous 12 months. Records of emissions shall be kept for all periods when the plant is in operation.

vi. Emissions of SO_2 from Unit #1 and Unit #2 shall not exceed the following limits:

A. 1.2 lb/MMBtu heat input for any 3-hour period

B. 0.12 lb/MMBtu heat input based on a 30-day rolling average

vii. Emissions of SO_2 from Unit #3 shall not exceed 0.12 lb/MMBtu heat input based on a 30-day rolling period.

viii. The SO_2 emissions shall be determined by CEM as outlined in IX.H.21.g.

c. PacifiCorp Huntington

i. The annual NO_x emissions for the entire Huntington Plant from all point and fugitive sources shall not exceed 6,210 tons/year based on a 12-month rolling total.

ii. As of January 1, 2025, the annual NOx emissions for the entire Huntington Plant from all point and fugitive sources shall not exceed 6,151 tons/year based on a 12-month rolling total

iii. As of January 1, 2028, the annual NOx emissions for the entire Huntington Plant from all point and fugitive sources shall not exceed 6,091 tons/year based on a 12-month rolling total.

iv. The above NO_x limits shall be monitored in accordance with the procedures outlined in 40 CFR Part 52.21(aa)(12) and at a minimum shall be done by summing up emissions as follows:

A. For Units #1 and #2 main boiler stacks, PacifiCorp's reporting to EPA's Acid Rain Emissions data base for NO_x in pounds per hour obtained from the boilers' CEM data shall be used to calculate NO_x emission rates.

B. For Units #1 and #2 emergency diesel-fired equipment, emissions shall be calculated by multiplying the NO_x emission factor from the latest edition of EPA's emission factors compilation AP-42 and hours of operation. Records documenting equipment usage shall be kept in a log, and they shall show the date the equipment was used and the duration in hours of operation.

C. For the record keeping requirements of each limit, PacifiCorp shall comply with 40 CFR Subpart 52.21(aa)(13).

D. For record submittal, PacifiCorp shall comply with 40 CFR Subpart 52.21(aa)(14).

v. To determine compliance with the 12-month rolling NO_x limits, the owner/operator shall calculate new 12-month total NO_x emissions by the 20th day of each month using data from the previous 12 months. Records of emissions shall be kept for all periods when the plant is in operation.

vi. Emissions of SO_2 from Unit #1 shall not exceed 0.12 lb/MMBtu heat input (595 lb/hr) on a 30-day rolling average except during periods of startup, shutdown, maintenance/planned outage or malfunction.

vii. Emissions of SO_2 from Unit #2 shall not exceed 0.12 lb/MMBtu heat input for any 24-hour block average except during periods of startup, shutdown, maintenance/planned outage, or malfunction.

viii. The SO_2 emissions shall be determined by CEM as outlined in IX.H.21.g.

d. US Magnesium

i. The owner/operator shall install and operate a flue gas recirculation (FGR) system on the 60 MMBtu/hr (Riley) boiler no later than January 1, 2028.

ii. Following installation of the FGR system, total annual NO_x emissions from the Riley boiler shall not exceed 22.6 tons per rolling 12-month period.

iii. The emission rate from the Riley boiler shall be determined by stack test. Stack testing shall be performed at least once every three years.

iv. To determine compliance with the 12-month rolling NO_x limit, the owner/operator shall calculate new 12-month total NO_x emissions by the 20th day of each month using data from the previous 12 months. Records of emissions shall be kept for all periods when the plant is in operation. To calculate the monthly NO_x emissions, the owner/operator shall multiply the lb/hr NO_x emission rate from the most recent stack test by the hours of operation of the Riley boiler for each month.

APPENDIX B – Interstate Consultation Agreements

Chelsea Cancino <ccancino@utah.gov>

UT-AZ Interstate Regional Haze Consultation
2 messages

Chelsea Cancino <ccancino@utah.gov> Tue, Nov 16, 2021 at 9:57 AM
To: Elias Toon <toon.elias@azdeq.gov>, "Ryan C. Templeton" <templeton.ryan@azdeq.gov>
Cc: Glade Sowards <gladesowards@utah.gov>, Becky Close <bclose@utah.gov>

Hello Elias!

Thank you for your valuable consultation with us. We have decided to utilize your great consultation efforts documentation.

The Utah Division of Air Quality (UDAQ) is in the process of drafting its Regional Haze State Implementation Plan for the Second Implementation period. As part of our SIP narrative, we are fulfilling our interstate consultation obligations and seek confirmation from surrounding states that Utah has satisfied the requirements of the Regional Haze Rule.

During this implementation period, UDAQ has consulted with ADEQ in a two-prong approach. The first has been through our joint participation in the Western Regional Air Partnership Regional Haze planning efforts over the past 5 years. The second has been through the direct state-to-state discussions focused on Regional Haze planning. The following table summarizes the state-to-state regional haze consultation that has occurred to date between UDAQ and ADEQ:

Date	Meeting Type	Meeting Summary
4/13/2021	WESTAR/WRAP Regional Haze Region 8 State Coordination Call	States discussed RH modeling resources and gave progress updates. No parties identified, requested, or agreed to any measures during the meeting.
4/30/2021	Four Corners States Regional Haze Consultations	States gave regional haze updates and discussed interstate regional haze requirements No parties identified, requested, or agreed to any measures during the meeting.
5/6/2021, 6/3/2021, 7/1/2021, 8/5/2021, 9/2/2021, & 11/4/2021	WESTAR Planning Committee Call	States discussed regional haze updates and planning coordination. No parties identified, requested, or agreed to any measures during the meeting.
9/9/2021	UT-AZ RH Consultation	Consulted each other about interest rates and control costs. Neither party identified, requested, or agreed to any measures during the meeting.

To ensure that Utah has met its interstate consultation requirements for this planning period, UDAQ is requesting that ADEQ respond to this email and affirm that the following statements are correct:

1. Pursuant to 40 CFR 51.308(f)(2)(ii)(A), UDAQ and ADEQ have not agreed on any measures during our state-to-state consultation.
2. Pursuant to 40 CFR 51.308(f)(2)(ii)(B), the following statements are true:

a. ADEQ has shared the measures it has identified, to date, as being necessary to make reasonable progress in mandatory Class I Federal areas with UDAQ.

b. ADEQ has not requested that UDAQ consider any measures to achieve its apportionment of emission reduction obligations in mandatory Class I Federal areas.

3. Pursuant to 40 CFR 51.308(f)(2)(ii)(C), there are currently no disagreements between UDAQ and ADEQ on the emission reduction measures necessary to make reasonable progress in mandatory Class I Federal areas.

These responses will serve as documentation that Utah has met the state-to-state consultation requirements of the Regional Haze Rule, and a copy of the email responses will be included in Utah's SIP submission.

Please contact UDAQ if you have questions or concerns about this request.

Thank you,

Chelsea Cancino
Environmental Scientist
(614) 515-8235
195 North 1950 West, SLC UT 84116

Elias Toon <toon.elias@azdeq.gov> Wed, Nov 17, 2021 at 8:55 AM
To: Chelsea Cancino <ccancino@utah.gov>
Cc: "Ryan C. Templeton" <templeton.ryan@azdeq.gov>, Glade Sowards <gladesowards@utah.gov>, Becky Close <bclose@utah.gov>, Kelly Mackenzie <mackenzie.kelly@azdeq.gov>, Zachary Dorn <dorn.zachary@azdeq.gov>

Hello Chelsea,

I hope all is well. I can confirm that the following statements are correct:

1. Pursuant to 40 CFR 51.308(f)(2)(ii)(A), UDAQ and ADEQ have not agreed on any measures during our state-to-state consultation.
2. Pursuant to 40 CFR 51.308(f)(2)(ii)(B), the following statements are true:
    1. ADEQ has shared the measures it has identified, to date, as being necessary to make reasonable progress in mandatory Class I Federal areas with UDAQ.
    2. ADEQ has not requested that UDAQ consider any measures to achieve its apportionment of emission reduction obligations in mandatory Class I Federal areas.
3. Pursuant to 40 CFR 51.308(f)(2)(ii)(C), there are currently no disagreements between UDAQ and ADEQ on the emission reduction measures necessary to make reasonable progress in mandatory Class I Federal areas.

Please reach out if you have any further questions or concerns.

Best,

Elias

Elias Toon
Environmental Science Specialist III
Ph: 602-771-4665

azdeq.gov

Your feedback matters to ADEQ. Visit azdeq.gov/feedback

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Chelsea Cancino <ccancino@utah.gov>

UDAQ-NDEP Interstate Regional Haze Consultation

3 messages

Chelsea Cancino <ccancino@utah.gov> Mon, Nov 15, 2021 at 2:11 PM
To: Steven McNeece <smcneece@ndep.nv.gov>
Cc: Glade Sowards <gladesowards@utah.gov>, Becky Close <bclose@utah.gov>

Hello Steven,

The Utah Division of Air Quality (UDAQ) is in the process of drafting its Regional Haze State Implementation Plan for the Second Implementation period. As part of our SIP narrative, we are fulfilling our interstate consultation obligations and seek confirmation from surrounding states that Utah has satisfied the requirements of the Regional Haze Rule.

During this implementation period, UDAQ has consulted with NDEP in a two-prong approach. The first has been through our joint participation in the Western Regional Air Partnership Regional Haze planning efforts over the past 5 years. The second has been through the direct state-to-state discussions focused on Regional Haze planning. The following table summarizes the state-to-state regional haze consultation that has occurred to date between UDAQ and NDEP:

Date	Meeting Type	Meeting Summary
4/13/2021	Teleconference	WESTAR/WRAP Regional Haze Region 8 State Coordination Call No parties identified, requested, or agreed to any measures during the meeting.
5/6/2021, 6/3/2021, 7/1/2021, 8/5/2021, 9/2/2021, & 11/4/2021	Teleconference	WESTAR Planning Committee Call No parties identified, requested, or agreed to any measures during the meeting.

To ensure that Utah has met its interstate consultation requirements for this planning period, UDAQ is requesting that NDEP respond to this email and affirm that the following statements are correct:

1. Pursuant to 40 CFR 51.308(f)(2)(ii)(A), UDAQ and NDEP have not agreed on any measures during our state-to-state consultation.
2. Pursuant to 40 CFR 51.308(f)(2)(ii)(B), the following statements are true:
    a. NDEP has shared the measures it has identified, to date, as being necessary to make reasonable progress in mandatory Class I Federal areas with UDAQ.
    b. NDEP has not requested that UDAQ consider any measures to achieve its apportionment of emission reduction obligations in mandatory Class I Federal areas.
3. Pursuant to 40 CFR 51.308(f)(2)(ii)(C), there are currently no disagreements between UDAQ and NDEP on the emission reduction measures necessary to make reasonable progress in mandatory Class I Federal areas.

These responses will serve as documentation that Utah has met the state-to-state consultation requirements of the Regional Haze Rule, and a copy of the email responses will be included in Utah's SIP submission.

Please contact UDAQ if you have questions or concerns about this request.

Thank you!

Chelsea Cancino
Environmental Scientist
(614) 515-8235
195 North 1950 West, SLC UT 84116

Steven McNeece <smcneece@ndep.nv.gov> Mon, Nov 15, 2021 at 2:39 PM
To: Chelsea Cancino <ccancino@utah.gov>
Cc: Glade Sowards <gladesowards@utah.gov>, Becky Close <bclose@utah.gov>, Sigurd Jaunarajs <sjaunara@ndep.nv.gov>

Hi Chelsea,

All of the statements regarding NDEP/UDAQ consultations for Regional Haze listed in the previous email are correct. It has been a pleasure coordinating with you all throughout the second implementation period and we wish you good luck with the remainder of your SIP development!

Steven

From: Chelsea Cancino <ccancino@utah.gov>
Sent: Monday, November 15, 2021 1:11 PM
To: Steven McNeece <smcneece@ndep.nv.gov>
Cc: Glade Sowards <gladesowards@utah.gov>; Becky Close <bclose@utah.gov>
Subject: UDAQ-NDEP Interstate Regional Haze Consultation

[Quoted text hidden]

Chelsea Cancino <ccancino@utah.gov> Mon, Nov 15, 2021 at 2:45 PM
To: Steven McNeece <smcneece@ndep.nv.gov>
Cc: Glade Sowards <gladesowards@utah.gov>, Becky Close <bclose@utah.gov>, Sigurd Jaunarajs <sjaunara@ndep.nv.gov>

Thank you very much, Steven, and all the same to you!

Best,

Chelsea Cancino
Environmental Scientist
(614) 515-8235
195 North 1950 West, SLC UT 84116

[Quoted text hidden]

Chelsea Cancino <ccancino@utah.gov>

UDAQ-IDEQ Interstate Regional Haze Consultation

2 messages

Chelsea Cancino <ccancino@utah.gov> — Mon, Nov 15, 2021 at 2:03 PM
To: Aislinn.Johns@deq.idaho.gov, Pascale.Warren@deq.idaho.gov
Cc: Glade Sowards <gladesowards@utah.gov>, Becky Close <bclose@utah.gov>

Hello Aislinn,

Thank you for your consultation efforts email, we have a similar request below:

The Utah Division of Air Quality (UDAQ) is in the process of drafting its Regional Haze State Implementation Plan for the Second Implementation period. As part of our SIP narrative, we are fulfilling our interstate consultation obligations and seek confirmation from surrounding states that Utah has satisfied the requirements of the Regional Haze Rule.

During this implementation period, UDAQ has consulted with IDEQ in a two-prong approach. The first has been through our joint participation in the Western Regional Air Partnership Regional Haze planning efforts over the past 5 years. The second has been through the direct state-to-state discussions focused on Regional Haze planning. The following table summarizes the state-to-state regional haze consultation that has occurred to date between UDAQ and IDEQ:

Date	Meeting Type	Meeting Summary
04/13/2021	WESTAR/WRAP Regional Haze State Coordination Call	States discussed regional haze planning and modeling resources. No parties identified, requested, or agreed to any measures during the meeting.
5/6/2021, 6/3/2021, 7/1/2021, 8/5/2021, 9/2/2021, & 11/4/2021	WESTAR Planning Committee Call	States discussed regional haze updates and planning coordination. No parties identified, requested, or agreed to any measures during the meeting.

To ensure that Utah has met its interstate consultation requirements for this planning period, UDAQ is requesting that IDEQ respond to this email and affirm that the following statements are correct:

1. Pursuant to 40 CFR 51.308(f)(2)(ii)(A), UDAQ and IDEQ have not agreed on any measures during our state-to-state consultation.
2. Pursuant to 40 CFR 51.308(f)(2)(ii)(B), the following statements are true:
   a. IDEQ has shared the measures it has identified, to date, as being necessary to make reasonable progress in mandatory Class I Federal areas with UDAQ.
   b. IDEQ has not requested that UDAQ consider any measures to achieve its apportionment of emission reduction obligations in mandatory Class I Federal areas.
3. Pursuant to 40 CFR 51.308(f)(2)(ii)(C), there are currently no disagreements between UDAQ and IDEQ on the emission reduction measures necessary to make reasonable progress in mandatory Class I Federal areas.

These responses will serve as documentation that Utah has met the state-to-state consultation requirements of the Regional Haze Rule, and a copy of the email responses will be included in Utah's SIP submission.

Please contact UDAQ if you have questions or concerns about this request.

Thank you!

Chelsea Cancino

Environmental Scientist
(614) 515-8235
195 North 1950 West, SLC UT 84116

Aislinn Johns <Aislinn.Johns@deq.idaho.gov>
To: Chelsea Cancino <ccancino@utah.gov>, Pascale Warren <Pascale.Warren@deq.idaho.gov>
Cc: Glade Sowards <gladesowards@utah.gov>, Becky Close <bclose@utah.gov>

Fri, Nov 19, 2021 at 12:35 PM

IDEQ affirms that the following statements are correct:

1. Pursuant to 40 CFR 51.308(f)(2)(ii)(A), UDAQ and IDEQ have not agreed on any measures during our state-to-state consultation.

2. Pursuant to 40 CFR 51.308(f)(2)(ii)(B), the following statements are true:

   a. IDEQ has shared the measures it has identified, to date, as being necessary to make reasonable progress in mandatory Class I Federal areas with UDAQ.

   b. IDEQ has not requested that UDAQ consider any measures to achieve its apportionment of emission reduction obligations in mandatory Class I Federal areas.

3. Pursuant to 40 CFR 51.308(f)(2)(ii)(C), there are currently no disagreements between UDAQ and IDEQ on the emission reduction measures necessary to make reasonable progress in mandatory Class I Federal areas.

Thanks!

Aislinn Johns

Aislinn C. Johns, MS | Airshed Management Analyst
Idaho Department of Environmental Quality
1410 N Hilton St, Boise, ID 83706

Office: (208) 373-0185
http://www.deq.idaho.gov/

Our mission: Our mission is to protect human health and the quality of Idaho's air, land, and water.

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Chelsea Cancino <ccancino@utah.gov>

UDAQ-CDPHE Interstate Regional Haze Consultation

2 messages

Chelsea Cancino <ccancino@utah.gov> Mon, Nov 15, 2021 at 1:59 PM
To: Richard Coffin - CDPHE <richard.coffin@state.co.us>, "Heald - CDPHE, Sara" <sara.heald@state.co.us>, "Carloss - CDPHE, Weston" <weston.carloss@state.co.us>, Joshua Korth - CDPHE <joshua.korth@state.co.us>
Cc: Glade Sowards <gladesowards@utah.gov>, Becky Close <bclose@utah.gov>

Hello everyone,

The Utah Division of Air Quality (UDAQ) is in the process of drafting its Regional Haze State Implementation Plan for the Second Implementation period. As part of our SIP narrative, we are fulfilling our interstate consultation obligations and seek confirmation from surrounding states that Utah has satisfied the requirements of the Regional Haze Rule.

During this implementation period, UDAQ has consulted with CDPHE in a two-prong approach. The first has been through our joint participation in the Western Regional Air Partnership Regional Haze planning efforts over the past 5 years. The second has been through the direct state-to-state discussions focused on Regional Haze planning. The following table summarizes the state-to-state regional haze consultation that has occurred to date between UDAQ and CDPHE:

Date	Meeting Type	Meeting Summary
4/13/2021	WESTAR/WRAP Regional Haze Region 8 State Coordination Call	States discussed RH modeling resources. No parties identified, requested, or agreed to any measures during the meeting.
4/30/2021	Four Corners States Regional Haze Consultations	States gave regional haze updates and discussed interstate regional haze requirements No parties identified, requested, or agreed to any measures during the meeting.
5/6/2021, 6/3/2021, 7/1/2021, 8/5/2021, 9/2/2021, & 11/4/2021	WESTAR Planning Committee Call	States discussed regional haze updates and planning coordination. No parties identified, requested, or agreed to any measures during the meeting.
6/1/2021	UDAQ CDPHE Interstate Consultation Call	UDAQ and CDPHE gave regional haze planning updates and discussed interstate consultation requirements. Neither party identified, requested, or agreed to any measures during the meeting.
6/29/2021-6/30/2021	EPA Region 8 SIP Development Conference	States discussed regional haze SIP development with EPA. No parties identified, requested, or agreed to any measures during the meeting.

To ensure that Utah has met its interstate consultation requirements for this planning period, UDAQ is requesting that CDPHE respond to this email and affirm that the following statements are correct:

1. Pursuant to 40 CFR 51.308(f)(2)(ii)(A), UDAQ and CDPHE have not agreed on any measures during our state-to-state consultation.
2. Pursuant to 40 CFR 51.308(f)(2)(ii)(B), the following statements are true:
    a. CDPHE has shared the measures it has identified, to date, as being necessary to make reasonable progress in mandatory Class I Federal areas with UDAQ.
    b. CDPHE has not requested that UDAQ consider any measures to achieve its apportionment of emission reduction obligations in mandatory Class I Federal areas.
3. Pursuant to 40 CFR 51.308(f)(2)(ii)(C), there are currently no disagreements between UDAQ and CDPHE on the emission reduction measures necessary to make reasonable progress in mandatory Class I Federal areas.

These responses will serve as documentation that Utah has met the state-to-state consultation requirements of the Regional Haze Rule, and a copy of the email responses will be included in Utah's SIP submission.

Please contact UDAQ if you have questions or concerns about this request.

Thank you!

Chelsea Cancino
Environmental Scientist
(614) 515-8235
195 North 1950 West, SLC UT 84116

Korth - CDPHE, Joshua <joshua.korth@state.co.us> Wed, Dec 1, 2021 at 12:22 PM
To: Chelsea Cancino <ccancino@utah.gov>
Cc: Glade Sowards <gladesowards@utah.gov>, Becky Close <bclose@utah.gov>

Chelsea,

Colorado agrees with the listing of meetings and that the statements are accurate. We appreciate the ongoing communication and coordination with Utah in this process.

Thanks,

Josh
[Quoted text hidden]
--

Josh Korth
Unit Supervisor
Technical Support and SIP Unit
Planning and Policy Program
COLORADO
Air Pollution Control Division
Department of Public Health & Environment
P 303.692.3265
4300 Cherry Creek Drive South, Denver, CO 80246-1530
joshua.korth@state.co.us | www.colorado.gov/cdphe/apcd

APPENDIX C – Four-Factor Analysis Documents

APPENDIX C.1 - Ash Grove

Appendix C.1.A – Ash Grove Four Factor Analysis Submittal

ASH GROVE CEMENT COMPANY

ASH GROVE

A CRH COMPANY

WESTERN REGION
Hwy 132 6 Miles East of Leamington
LEAMINGTON, UTAH 84638
PHONE (435) 857-1200 FAX (435) 857-1288

March 16, 2020

To: Mr. Bryce Bird
Utah Department of Environmental Quality
195 North 1950 West
Salt Lake City, Utah 84114-4820

From: Ash Grove Cement Company

RE: **Regional Haze 2nd Implementation Period – Four-Factor Analysis**

Attached is the submission of Ash Grove Cement "four-factor analysis under the regional haze program" as requested by UTDEQ October 21, 2019 letter.

Any questions, please contact me at 435-857-1200 or paul.pederson@ashgrove.com.

3/16/2020

Paul Pederson
Plant Manager
Ash Grove Cement Company

Date

CC: Jay Baker
Mark Atkins

REGIONAL HAZE 2ND IMPLEMENTATION PERIOD FOUR-FACTOR ANALYSIS

Ash Grove Cement > Leamington, UT

Leamington Four-Factor Analysis

Prepared By:

Michael Hagerty - Consultant
Arron Heinerikson - Regional Director

TRINITY CONSULTANTS
3301 C St.
Suite 400
Sacramento, CA 95816
(916) 444-6666

March 2020

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LIST OF TABLES

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1. EXECUTIVE SUMMARY

This report documents the results of a four-factor analysis of a portland cement kiln and two (2) emergency generators at Ash Grove Cement Company's (AGC's) Leamington facility. This report is provided in response to the Utah Department of Air Quality (UDAQ) request letter dated October 21, 2019.

The Leamington facility was not identified as an eligible facility for the best available retrofit technology (BART) program during the first round of regional haze as it was built after August 7, 1977. UDAQ has identified the Leamington facility as an eligible source for the regional haze program reasonable progress analysis based on a screening process that takes into account both the quantity of emissions from the facility and the proximity to the Class I areas protected by the regional haze program.

The United States Environmental Protection Agency's (U.S. EPA) guidelines in 40 CFR Part 51.308 were used to evaluate control options for the emission source equipment. In establishing a reasonable progress goal for any mandatory Class I Federal area within the State, the State must consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.

The purpose of this report is to provide information to UDAQ on available control technologies for NOx and SO_2 emissions reductions and its applicability to the Leamington facility. Since control options are only relevant for the Regional Haze Rule (RHR) if they result in a reduction in the existing visibility impairment in a Class I area, AGC assumes that UDAQ will only move forward with requiring emission reductions from the Leamington facility if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost effective controls among all options available to UDAQ.

Based on the following analysis, AGC believes that BART level controls are already in place for the Kiln system as follows:

SO_2 – AGC currently uses inherently low sulfur raw materials, thus there is very little sulfur available to create SO_2 in the raw mill. Further, a preheater/precalciner type kiln system is used such that the majority of any fuel bound sulfur is adsorbed by the clinker and becomes part of the cement product. The result is an actual emission rate in the range of 0.02 lb/ton clinker (2019 actual emission level). The current emission rate limit is 0.4 lb/ton which is considered BACT. Add on SO_2 controls would have no impact at the low existing concentrations, and fuel sulfur reductions would have no recognizable impact on emissions. Consequently, the current system of inherently low sulfur raw materials and natural scrubbing are considered BART for the facility.

NO_x – AGC uses a Low NO_x Burner (LNB) and Selective Non-Catalytic Reduction (SNCR) to reduce and control NO_x emissions. These are commonly applied methods/technologies in current Best Available Control Technology (BACT) determinations for new preheater/precalciner kilns. The only other potential NO_x emission control evaluated for this kiln is Selective Catalytic Reduction (SCR). There is one instance of SCR installation on a cement kiln in the U.S. for NO_x control. This installation was recently implemented on a long dry cement kiln at the Joppa Cement Plant, which is significantly different from the preheater/precalciner kiln system at the Leamington facility, and was installed as a result of a consent decree. AGC believes that the currently installed control systems provide reliable reductions in NO_x emissions and an SCR installation is currently not commercially available on this type of kiln system and is cost-prohibitive. Per an Approval Order dated February 3, 2016, the DEQ indicated that SNCR control at AGC would result in an estimated decrease in NO_x of up to 817.89 tons per year and that the kiln stack would be limited to 2.8 lb NO_x/ton clinker on a 30-day rolling average basis. These emission levels and controls are consistent with current BACT analyses for existing preheater/precalciner type kiln systems. Consequently, the current system of LNB and SNCR is considered BART for the facility.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to natural conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. In establishing a reasonable progress goal for a Class I area, the state must:

(A) *Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A).*

(B) *Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(d)(1)(i)(B).*

In October 2019, UDAQ sent a letter notifying AGC that they had been selected to conduct "a four-factor analysis under the regional haze program" for the Leamington facility. AGC understands that the information provided in a four-factor review of control options will be used by UDAQ in their evaluation of reasonable progress goals for Utah. Since emission reductions are only relevant if they result in a reduction in the existing visibility impairment, ultimately helping the State show progress towards its goals, AGC assumes that UDAQ will only move forward with requiring emission reductions if the emission reductions can be demonstrated to be needed to show further reasonable progress towards the goals established based on the uniform rate of visibility improvement that is required to be demonstrated.

Therefore, the purpose of this report is to provide information to the UDAQ on available control technologies for SO_2 and NO_x emissions reductions and its applicability to the Leamington facility.

The information presented in this report considers the following four factors for the emission reductions:

Factor 1. Costs of compliance
Factor 2. Time necessary for compliance
Factor 3. Energy and non-air quality environmental impacts of compliance
Factor 4. Remaining useful life of the kilns

The approach contained in this four factor report was to first identify all technically feasible measures by conducting a step-wise review of emission reduction options in a top-down fashion like the top-down approach that is included in the U.S. EPA RHR guidelines[1] for conducting a review of Best Available Retrofit Technology (BART) for a unit. These steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Factor 4 is also addressed in the stepwise review of the emission reduction options, primarily in the context of the costing of emission reduction options, if any, and whether any capitalization of expenses would be impacted by limited equipment life. Once the stepwise review of reduction options was completed, a review of the timing of the emission reductions is provided to satisfy Factor 2 of the four factors.

[1] The BART provisions were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308 on July 5, 2005.

3. SOURCE DESCRIPTION

The AGC Leamington facility is located in Juab County, Utah, approximately 6 miles northeast of Leamington. The nearest Class I area to the facility is the Capitol Reef National Park. It is approximately 84 miles southeast of the Leamington facility.

The facility operates one preheater/precalciner type cement kiln. The majority of the kiln exhaust gas is directed through a raw mill for preheating before being vented through a baghouse prior to the main stack. A small fraction of the kiln gas is also directed to the coal mill for pre-heating the fuel prior to being directed to the coal mill baghouse/stack.

The Kiln System is currently permitted to use the following fuels:

A. Coal

B. Diaper Derived Fuel (DDF)

C. Tire Derived Fuel (TDF) – not to exceed 15% of energy input

D. Natural Gas

E. Coke

F. Fuel Oil

G. Used Oil Fuel

H. Synthetic Fuel

I. Wood

J. Cherry Pits

K. Tire Poly Cord Fuel

L. Plastic Resin Waste

M. Coal Additives consisting of alternative fuels approved by the Director – not to exceed 15% of energy input

4. EXISTING EMISSIONS

This section summarizes emission rates from calendar year 2019 that are used as baseline rates in the four factor analyses presented in Sections 5, 6, and 7 of this report.

Baseline annual emissions for SO_2 are calculated based on stack test data and annual production levels. Baseline emissions of NO_x are based on CEMS data. These same baseline rates are provided to UDAQ for use in the on-the-books/on-the-way basis for modeling because no changes to kiln operation are expected between now and 2028. The baseline annual emission rates are summarized in Table 4-1.

Table 4-1. Annual Baseline Emission Rates

Pollutant	Kiln
NO_x	1198
SO_2	8.0

The four-factor analysis is satisfied by conducting a stepwise review of emission reduction options in a top-down fashion. The steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Cost (Factor 1) and energy / non-air quality impacts (Factor 3) are key factors determined in Step 4 of the stepwise review. However, timing for compliance (Factor 2) and remaining useful life (Factor 4) are also discussed in Step 4 to fully address all four factors as part of the discussion of impacts. Factor 4 is primarily addressed in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by a limited equipment life.

The baseline SO_2 emission rates that are used in the SO_2 four-factor analysis are summarized in Table 4-1. The basis of the emission rates is provided in Section 4 of this report. The kiln system and two (2) emergency generators are the sources at the Leamington facility which emit SO_2. However, as emissions from the generators contribute less than 0.01 tons of SO_2, they will not be analyzed.

5.1. STEP 1: IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES

Sulfur, in the form of metallic sulfides (pyrite), sulfate, or organosulfur compounds, is often found in the raw materials used to manufacture cement and in the solid and liquid fuels burned in cement kilns. The raw materials and fuels for the Leamington plant are no exception. Sulfur dioxide can be generated by the oxidation of sulfur compounds in the raw materials and fuels during operation of the pyroprocess. Constituents found in fuels, raw materials, and in-process materials, such as the alkali metals (sodium and potassium), calcium carbonate, and calcium oxide often react with SO_2 within the pyroprocess to limit emissions of SO_2 as much of the sulfur leaves the process in the principle product of the kiln system called clinker.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for the Leamington kiln are as follows:

- Fuel Substitution
- Semi-Dry scrubbing – Add on control
- Wet Scrubbing – Add on control

The retrofit controls include both add-on controls that reduce SO_2 after it is formed and switching to lower sulfur fuels which reduce the opportunity for formation of SO_2.

5.1.1. Fuel Substitution

The concept of fuel substitution in a combustion system is that if the fuel sulfur is reduced, the amount of sulfur available for oxidation into SO_2 is reduced, and thus there should then be a direct relationship between the reduction of sulfur and the reduction of SO_2 emissions.

And, although for a typical industrial type boiler that is correct, the process is not that simple in a modern preheater/precalciner type portland cement kiln. In a portland cement kiln, fuel bound sulfur is released from the fuel during combustion and forms SO_2. However, combustion is occurring at the hot ends of the system where there are also very high concentrations of CaO (lime, which is the material used in lime scrubbing) and other volatilized alkalis. The combination of high levels of CaO and high temperatures results in the majority of any SO_2 immediately reacting to form calcium and alkali sulphates which bind to the clinker and ultimately become part of the cement product. Consequently, variations in the fuel sulfur content have very little impact on SO_2 emission levels from the kiln stack (which are instead typically dominated by SO_2 driven off from the raw materials in the raw mill, prior to the formation of CaO in the system)[2].

Regardless, AGC already has restrictions on fuel sulfur content, and does not anticipate that further restrictions would have any impact on SO_2 emission levels from the main stack. Currently, AGC is limited to a sulfur content of fuel burned to no greater than 1.0 lbs sulfur/MMBtu for any mixture of coal and 0.85 pounds sulfur per million gross Btu heat input for any oil except used oil or 0.5 percent by weight for any used oil.

5.1.2. Wet Scrubbing

A wet scrubber is a tailpipe technology that may be installed downstream of the kiln and raw mill. In a typical wet scrubber, the flue gas flows upward through a reactor vessel that has an alkaline reagent flowing down from the top. The scrubber mixes the flue gas and alkaline reagent using a series of spray nozzles to distribute the reagent across the scrubber vessel. The alkaline reagent, often a calcium compound, reacts with the SO_2 in the flue gas to form calcium sulfite and/or calcium sulfate that is removed with the scrubber sludge and disposed. Most wet scrubber systems used forced oxidation to assure that only calcium sulfate sludge is produced.

5.1.3. Semi-Wet/Dry Scrubbing

This technology is considered a semi-wet or semi-dry control technology. A scrubber tower is installed prior to the baghouse. Atomized hydrated lime slurry is sprayed into the exhaust flue gas. The lime absorbs the SO_2 in the exhaust and is converted to a powdered calcium/sulfur compound. The particulate control device removes the solid reaction products from the gas stream.

5.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

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[2] Moses P.M. Chinyama (August 9th 2011). Alternative Fuels in Cement Manufacturing, Alternative Fuel, Maximino Manzanera, IntechOpen, DOI: 10.5772/22319. Available from: https://www.intechopen.com/books/alternative-fuel/alternative-fuels-in-cement-manufacturing, Section 2.4.

5.2.1. Fuel Substitution

Although fuel substitution is a feasible technology for older wet-type kilns or long-dry kilns, it is widely accepted that the design of a preheater/precalciner kiln system is such that nearly 100% of the sulfur contained in the fuel is absorbed in the clinker product and is not available to be converted to SO_2. Therefore, reducing the sulfur in the fuel input to the kiln is not expected to result in any appreciable reduction in SO_2 emissions from the kiln. As AGC anticipates that lowering the input of sulfur through fuel substitution would not have any impact on reducing SO_2 emissions, it is not considered an effective SO_2 control technology for this kiln system and will not be considered further.

5.2.2. Wet Scrubbing

A wet scrubbing system utilizes a ground alkaline agent, such as lime or limestone in slurry to remove SO_2 from the stack gas. The spent slurry is dewatered using settling basins and filtration equipment. Recovered water is typically reused to blend new slurry for the wet scrubber. A significant amount of makeup water is required to produce enough slurry to maintain the scrubber's design removal efficiency. Water losses from the system occur from evaporation into the stack gas, evaporation from settling basins, and retained moisture in scrubber sludge.

Wet scrubbing systems are commonly used to reduce SO_2 concentrations from gas streams in the 500 ppm to 1000 ppm range or higher down to the 50 ppm to 100 ppm range. Ash Grove's kiln system has SO_2 concentrations in the 1 to 2.5 ppm range. For example, the most recent test of the kiln system stack, June 20, 2019, had and average SO_2 concentration of 0.9 ppm. As AGC's kiln exhaust concentrations are extremely low, wet scrubbing would have no impact on SO_2 emission levels. Consequently, this technology is not considered technically feasible and will not be considered further.

5.2.3. Semi-Dry Scrubbing

Semi-Dry scrubbing is similar to wet scrubbing and commonly used to reduce SO_2 concentrations from gas streams in the 500 ppm to 1000 ppm range or higher down to the 50 ppm to 100 ppm range. As AGC's kiln system has SO_2 concentrations in the 1 to 2.5 ppm range, semi-dry scrubbing would have no impact on SO_2 levels. Consequently, this technology is not considered technically feasible and will not be considered further.

5.3. STEP 3: RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS

Step 3 of the top-down control review is to rank the technically feasible options by effectiveness. As no technologies are available to reduce the SO_2 concentrations below what are already extremely low levels, no further technologies will be evaluated.

5.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS

Step 4 of the top-down control review is the impact analysis. Ash Grove's actual emission rate of SO_2 in 2019 was 8.0 tons or approximately 0.02 lbs/ton clinker. As this emission rate is well below the NSPS for new sources, and no technologies are available to reduce it further, the current process of using inherently low sulfur raw materials and natural scrubbing is considered BART for the kiln system.

The four-factor analysis is satisfied by conducting a stepwise review of emission reduction options in a top-down fashion. The steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Cost (Factor 1) and energy / non-air quality impacts (Factor 3) are key factors determined in Step 4 of the stepwise review. However, timing for compliance (Factor 2) and remaining useful life (Factor 4) are also discussed in Step 4 to fully address all four factors as part of the discussion of impacts. Factor 4 is primarily addressed in in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by a limited equipment life.

The baseline NO_x emission rates that are used in the NO_x four-factor analysis are summarized in Table 4-1. The basis of the emission rates is provided in Section 4 of this report. The kiln system and two (2) emergency generators are the sources at the Leamington facility which emits NO_x. However, emissions from the generators contribute only 0.2 tons of total NO_x and will not be analyzed.

6.1. STEP 1: IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

NO_x emissions are produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms "thermal" NO_x and "fuel" NO_x when describing NO_x emissions from the combustion of fuel. Thermal NO_x emissions are produced when elemental nitrogen in the combustion air is admitted to a high temperature zone and oxidized. A small portion of NO_x is formed from nitrogen in the fuel that is liberated and reacts with the oxygen in the combustion air.

Step 1 of the top-down control review is to identify available retrofit control options for NO_x. The available NO_x retrofit control technologies for the AGC kiln (preheater/precalciner) and raw mill are summarized in Table 6-1.

Table 6-1. Available NO_X Control Technologies for the Kiln System

NO_x Control Technologies	
Combustion Controls	Low-NO_x Burners (LNB)
Post-Combustion Controls	Selective Catalytic Reduction (SCR)
	Selective Non-Catalytic Reduction (SNCR) (Already Installed)

NO_x emissions controls, as listed in Table 6-1, can be categorized as combustion or post-combustion controls. Combustion controls reduce the peak flame temperature and excess air in the kiln burner, which minimizes NO_x formation. Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) convert NO_x in the flue gas to molecular nitrogen and water.

The kiln system currently utilizes a LNB and SNCR system.

6.1.1. Combustion Controls

6.1.1.1. Low-NO_X Burners (LNBs)

LNBs reduce the amount of NO_x initially formed in the flame. The principle of all LNBs is the same: stepwise or staged combustion and localized exhaust gas recirculation (i.e., at the flame). LNBs are designed to reduce flame turbulence, delay fuel/air mixing, and establish fuel-rich zones for initial combustion. The longer, less intense flames reduce thermal NO_x formation by lowering flame temperatures. Control of air turbulence and speed is often controlled via mixing air fans. Some of the burner designs produce a low-pressure zone at the burner center by injecting fuel at high velocities along the burner edges. Such a low-pressure zone tends to recirculate hot combustion gas which is retrieved through an internal reverse flow zone around the extension of the burner centerline. The recirculated combustion gas is deficient in oxygen, thus producing the effect of flue gas recirculation. Reducing the oxygen content of the primary air creates a fuel-rich combustion zone that then generates a reducing atmosphere for combustion. Due to fuel-rich conditions and lack of available oxygen, formation of thermal NO_x and fuel NO_x are minimized[3]. The Leamington facility has already installed a LNB on the kiln and has demonstrated compliance with a federally enforceable NO_x emission rate of 2.8 lbs/ton clinker (30 day rolling average).[4]

6.1.2. Post Combustion Controls

6.1.2.1. Selective Catalytic Reduction (SCR)

SCR is an exhaust gas treatment process in which ammonia (NH_3) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 and nitric oxide (NO) or nitrogen dioxide (NO_2) react to form diatomic nitrogen and water. The overall chemical reactions can be expressed as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

When operated within the optimum temperature range of 500°F to 800°F, the reaction can result in removal efficiencies between 70 and 90 percent.[5] The rate of NO_x removal increases with temperature up to a maximum removal rate at a temperature between 700°F and 750°F. As the temperature increases above the optimum temperature, the NO_x removal efficiency begins to decrease. SCR use in the cement industry is incredibly limited, with only a handful of uses in Europe and one instance, i.e. the Joppa Cement Plant operated by LaFargeHolcim in the United States.

6.1.2.2. Selective Non-Catalytic Reduction (SNCR)

In SNCR systems, a reagent is injected into the flue gas within an appropriate temperature window. The NO_x and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent

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[3] USEPA, Office of Air Quality Planning and Standards. Alternative Control Technologies Document – NOx Emissions from Cement Manufacturing. EPA-453/R-94-004, Page 5-5 to 5-8.

[4] Per UDAQ Class I Permit #2300015004

[5] Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NO_x Controls, EPA/452/B-02-001, Page 2-9 and 2-10.

storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems.

Like SCR, SNCR uses ammonia or a solution of urea to reduce NO_x through a similar chemical reaction.

$$2NO+4NH3+2O2 \rightarrow 3N2+6H2O$$

SNCR requires a higher temperature range than SCR of between 1,600°F and 1,900°F due to the lack of a catalyst to lower the activation energies of the reactions.

The Leamington facility has already installed a SNCR system on the kiln and has demonstrated compliance with a federally enforceable NO_x emission rate of 2.8 lbs/ton clinker (30 day rolling average).[6]

6.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible NO_x control measures that are identified as available reduction options in Step 1. Since a LNB and SNCR have already been installed on the kiln, only the SCR will be evaluated for technical feasibility in this section.

6.2.1. Post Combustion Controls

6.2.1.1. Selective Catalytic Reduction (SCR)

Efficient operation of the SCR process requires constant exhaust temperatures (usually ± 200°F).[7] Fluctuation in exhaust gas temperatures reduces removal efficiency. If the temperature is too low, ammonia slip occurs. Ammonia slip is caused by low reaction rates and results in both higher NO_x emissions and appreciable ammonia emissions. If the temperature is too high, oxidation of the NH_3 to NO can occur. Also, at higher removal efficiencies (beyond 80 percent), an excess of NH3 is necessary, thereby resulting in some ammonia slip. Other emissions possibly affected by SCR include increased PM emissions (from ammonia salts in a detached plume) and increased SO_3 emissions (from oxidation of SO_2 on the catalyst). These ammonia, PM, and ammonia salt emissions contribute negatively to visibility impairment in the region—an effect that is directly counter to the goals of the program.

To reduce fouling the catalyst bed with the PM in the exhaust stream, an SCR unit can be located downstream of the particulate matter control device (PMCD). However, due to the low exhaust gas temperature exiting the PMCD (approximately 350 °F); a heat exchanger system would be required to reheat the exhaust stream to the desired reaction temperature range of between 480 °F to 800 °F. The source of heat for the heat exchanger would be the combustion of fuel, with combustion products that would enter the process gas stream and generate additional NO_x.[8] Therefore, in addition to storage and handling equipment for the ammonia, the required equipment for the SCR system will include a catalytic reactor, heat

[6] Per UDAQ Class I Permit #2300015004

[7] USEPA, Office of Air Quality Planning and Standards. Alternative Control Technologies Document – NOx Emissions from Cement Manufacturing. EPA-453/R-94-004, Page 2-11

[8] The fuel would likely be natural gas supplied at the facility through a pipeline while coal will be excluded, as it would require an additional dust collector.

exchanger and potentially additional NO_x control equipment for the emissions associated with the heat exchanger fuel combustion.

High dust and clean-side SCR technologies are still highly experimental. A high dust SCR would be installed prior to the dust collectors, where the kiln exhaust temperature is closer to the optimal operating range for an SCR. It requires a larger volume of catalyst than a tail pipe unit, and a mechanism for periodic cleaning of catalyst. A high dust SCR also uses more energy than a tail pipe system due to catalyst cleaning and pressure losses.

A clean-side system is similar to a high dust system. However, the SCR is placed downstream of the baghouse.

Only one cement kiln in the U. S. is using SCR, and the details of its installation and use remain confidential. While several cement kilns in Europe have installed SCR, the cement industries between Europe and the U.S. differ significantly due to the increased sulfur content found in the processed raw materials in U.S. cement kiln operations. The pyritic sulfur found in raw materials used by U.S. cement plants have high SO_3 concentrations that result in high-dust levels and rapid catalyst deactivation. In the presence of calcium oxide and ammonia, SO_3 forms calcium sulfate and ammonium bisulfate via the following reactions:

$$SO_3 + CaO \rightarrow CaSO_4$$

$$SO_3 + NH_3 \rightarrow (NH_4)HSO_4$$

Calcium sulfate can deactivate the catalyst, while ammonium bisulfate can plug the catalyst. Catalyst poisoning can also occur through the exposure to sodium, potassium, arsenic trioxide, and calcium sulfate.[9] This effect directly and negatively impacts SCR effectiveness for NOx reduction.

Dust buildup on the catalyst is influenced by site-specific raw material characteristics present in the facility's quarry, such as trace contaminants that may produce a stickier particulate than is experienced at sites where the technology is being demonstrated. This buildup is typical of cement kilns, resulting in reduced effectiveness, catalyst cleaning challenges, and increased kiln downtime at significant cost.[10]
In the EPA's guidance for regional haze analysis, the term "available," one of two key qualifiers for technical feasibility in a BART analysis, is clarified with the following statement:

> *Consequently, you would not consider technologies in the pilot scale testing stages of development as "available" for the purposes of BART review.*

The EPA has also acknowledged, in response to comments made by the Portland Cement Association's (PCA) comments on the latest edition of the Control Cost Manual, that:

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[9] Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NOx Controls, EPA/452/B-02-001, Page 2-6 and 2-7.

[10] Preamble to NSPS subpart F, 75 FR 54970.

For some industrial applications, such as cement kilns where flue gas composition varies with the raw materials used, a slip stream pilot study can be conducted to determine whether trace elements and dust characteristics of the flue gas are compatible with the selected catalyst.

Based on these conclusions, SCR is not widely available for use with cement kilns, in large part because the site-specificity limits the commercial availability of systems. For this reason, high-dust and clean-side SCR's are not considered technically feasible for this facility at this time.

6.3. STEP 3: RANK OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS BY EFFECTIVENESS

Step 3 of the top-down control review is to rank the technically feasible options in order of effectiveness. All technically feasible control options, LNB and SNCR, have already been installed by the Leamington facility.

6.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step 4 of the top-down control review is the impact analysis. While the impact analysis considers the cost of compliance, energy impacts, non-air quality impacts, and the remaining useful life of the source, AGC has already installed the control strategies with the greatest level of control: LNB and SNCR.

Therefore, AGC believes that reasonable progress compliant controls are already in place. AGC's actual NO_x emission level of 1198 tpy is adequate and the Leamington facility does not propose any change to their current limit of 2.8 lbs/ton clinker on a 30-day rolling average basis.

7. CONCLUSION

This report outlines AGC's evaluation of possible options for reducing the emissions of NO_x and SO_2 at its Leamington facility. There are currently no technically feasible and cost-effective reduction options available for the Leamington facility beyond current best practices and controls.

APPENDIX C.1.B – Ash Grove UDAQ Four-Factor Analysis Evaluation

State of Utah

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Governor

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Lieutenant Governor

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Bryce C. Bird
Director

DAQP-062-21

July 27, 2021

Paul Pederson
Ash Grove Cement Company
Hwy 132 6 Miles E
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Dear Mr. Pederson,

The DAQ has received your four-factor analyses for the Ash Grove Cement Company prepared for the second planning period of Utah's Regional Haze State Implementation Plan. Enclosed is an engineering review of each analysis outlining some outstanding issues for you to be aware of. Please provide us with amendments or reasoning for these issues by **August 31st, 2021**. If you have any questions, please contact John Jenks at jjenks@utah.gov or (385) 306-6510.

Sincerely,

Chelsea Cancino
Environmental Scientist

RNC:CC:GS:jf

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Regional Haze – Second Planning Period
SIP Evaluation Report:

Ash Grove Cement Company

Utah Division of Air Quality

July 30, 2021

SIP EVALUATION REPORT

Ash Grove Cement Company

1.0 Introduction

The following is part of the Technical Support Documentation for the Second Planning Period of the Regional Haze SIP (aka the Visibility SIP). This document specifically serves as an evaluation of the Ash Grove Cement Company facility.

1.1 Facility Identification

Name: Ash Grove Cement Company
Address: Hwy. 132, Leamington, Utah 84638
Owner/Operator: Ash Grove Cement Company
UTM coordinates: 4,379,850 m Northing, 397,000 m Easting, Zone 12

1.2 Facility Process Summary

Ash Grove Cement Company (Ash Grove) operates the Leamington Cement Plant. This plant has been in operation since 1981. At the Leamington cement plant, cement is produced when inorganic raw materials, primarily limestone (quarried on site), are correctly proportioned, ground and mixed, and then fed into a rotating kiln. The kiln alters the materials and recombines them into small stones called cement clinker. The clinker is cooled and ground with gypsum and additional limestone into a fine powdered cement. The final product is stored on site for later shipping. The major sources of air emissions are from the combustion of fuels for the kiln operation, from the kiln, and from the clinker cooling process.

1.3 Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

- Unit Designation: Kiln 1
  Kiln 1 has the following installed:
  SNCR for NOx control; NOx, CO, Total Hydrocarbons (VOC), and Oxygen (O2) CEMS on main stack; Mercury (Hg) CEMS or integrated sorbent trap monitoring system on main stack; TSP (PM) Continuous Parametric Monitoring System (CPMS) on main kiln and clinker cooler stack.

1.4 Facility Current Potential to Emit

The current PTE values for Ash Grove, as established by the most recent NSR permit issued to the source (DAQE-AN103030029-19) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
SO_2	192.50
NO_x	1347.20

2.0 Four Factor Review Methodology

Each source reviewed in this second planning period submitted a report on the available control technologies for SO2 and NOx emission reductions and the application of each technology to that facility. The information on available controls should consider the following four factors when analyzing the possible emission reductions:

1. Factor 1 – The Costs of Compliance
2. Factor 2 – Time Necessary for Compliance
3. Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance
4. Factor 4 – Remaining Useful Life of the Source

Although not specifically required, the recommended approach was to follow a step-wise review of possible emission reduction options in a "top-down" fashion similar to U.S. EPA's guidelines for review of BART or Best Available Retrofit Technology (as found in 40 CFR 51, Section 308 amendments, pub. July 5, 2005). The steps involved are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document results

The process is inherently similar to that used in selecting BACT (Best Available Control Technology) under the NSR/PSD (Title I) permitting program. UDAQ evaluated the submissions from each source following the methodology outlined above. Where a particular submission may have differed from the recommended process, UDAQ will make note, and provide additional information as necessary.

3.0 Analysis for SO2 Emission Reductions

Foremost, Ash Grove identified a baseline emission value of 8.0 tons/year as the starting point for all SO2 evaluations. Baseline annual emissions for SO2 were calculated based on stack test data and annual production levels. The calculations were not provided as part of the four factor analysis submission, but generally match the actual emissions inventory submitted by the company to DAQ on an annual basis.

Ash Grove followed the recommended approach, using a top-down style methodology for its analysis.

<u>Step 1:</u>

Ash Grove identified Fuel Substitution, Semi-Dry Scrubbing and Wet Scrubbing as possible controls for SO2 emissions.

Fuel substitution, although a feasible technology, is somewhat limited by Ash Grove's existing permit structure – which already allows for the use of alternative fuels, and the nature of the cement kiln itself – which is somewhat inherently self-scrubbing of fuel-based SO2 emissions.

Both Semi-Dry and Wet Scrubbing are tail pipe (i.e. stack-based) control systems, using a reactor vessel that mixes the exhaust stream with an alkaline reagent (typically lime or a similar product) in a slurry or liquid form. The reagent is captured either as waste liquid or as particulate, while the exhaust gas is released to the main stack.

Step 2:

Ash Grove eliminated all three identified controls in this step, by stating that all three controls were designed for sources with inherently higher emissions of SO2 on a tons/year actuals basis. DAQ disagrees with this approach, as all three controls are technically feasible and can be applied for control of SO2 emissions. Whether the application of such controls should be applied is properly left until Step 4. For details on Ash Grove's findings, analysis and conclusions, please see the Ash Grove Four Factor Analysis page 5-3.

Step 3:

Under the Ash Grove approach, no ranking of the three identified systems is possible, as none would have advanced to this step. DAQ agrees that the level of further emission reduction possible through application of any of these systems is negligible and therefore, ranking of the three systems is academic.

Step 4:

DAQ agrees with Ash Grove's conclusion for SO2 emission controls. Given the inherently low level of actual SO2 emissions on an annual basis, the application of either fuel switching or add-on emission controls would have little to no impact on total SO2 emissions. DAQ does recommend a revisit of Ash Grove's annual PTE estimation given the seeming disparity between the two values.

4.0 Analysis for NOx Emission Reductions

As with SO2 emissions, Ash Grove identified a baseline emission value as the starting point for all NOx emission evaluations. NOx actual annual emissions were set at 1,198 tons/year. Baseline emissions of NOx are based on CEMS data. The CEM data was also provided as part of the four factor analysis submission, but matched the actual emissions inventory submitted by the company to DAQ.

Ash Grove followed the recommended approach, using a top-down style methodology for its analysis.

Step 1:

Ash Grove identified only three retrofit technologies for the control of NOx emissions at the Leamington plant: low-NOx burners (LNB), selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). All three control systems are technically feasible, with both LNB and SNCR being currently installed on the kiln.

DAQ has identified additional controls beyond those provided by Ash Grove; however, none are technically feasible and have been eliminated from further consideration. For informational purposes, these additional controls were:

- fuel switching and SNCR optimization, eliminated based on requirement to switch primarily to higher sulfur coal-based fuels;
- kiln modification, eliminated as the Ash Grove plant is already a pre-heater/pre-calciner type

kiln;

- kiln optimization, including: kiln feed uniformity, elimination of air infiltration, improvements in thermal efficiency, and returning kiln dust to the process – eliminated as Ash Grove undertakes these processes regularly, and additional benefit would be difficult to quantify
- Cemstar Process, eliminated as it requires the introduction of steel or blast furnace slag – this changes the chemical composition of the resulting cement, and is difficult/expensive to obtain/transport

LNBs reduce the amount of NOx initially formed in the flame. The principle of all LNBs is the same: stepwise or staged combustion and localized exhaust gas recirculation (i.e., at the flame). LNBs are designed to reduce flame turbulence delay fuel/air mixing and establish fuel-rich zones for initial combustion. The longer, less intense flames reduce thermal NOx formation by lowering flame temperatures. Control of air turbulence and speed is often controlled via mixing air fans. Some of the burner designs produce a low-pressure zone at the burner center by injecting fuel at high velocities along the burner edges. Such a low-pressure zone tends to recirculate hot combustion gas which is retrieved through an internal reverse flow zone around the extension of the burner centerline. The recirculated combustion gas is deficient in oxygen thus producing the effect of flue gas recirculation. Reducing the oxygen content of the primary air creates a fuel-rich combustion zone that then generates a reducing atmosphere for combustion. Due to fuel-rich conditions and lack of available oxygen formation of thermal NOx and fuel NOx are minimized. The Leamington facility has already installed a LNB on the kiln and has demonstrated compliance with a federally enforceable NOx emission rate of 2.8 lbs/ton clinker (30-day rolling average).

SCR is an exhaust gas treatment process in which ammonia (NH3) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH3 and nitric oxide (NO) or nitrogen dioxide (NO2) react to form diatomic nitrogen and water. The overall chemical reactions can be expressed as follows:

4NO + 4NH3 + O2 → 4N2 + 6H2O
2NO2 + 4NH3 + O2 → 3N3 + 6HzO

When operated within the optimum temperature range of 500°F to 800°F, the reaction can result in removal efficiencies between 70 and 90 percent. The rate of NOx removal increases with temperature up to a maximum removal rate at a temperature between 700°F and 750°F. As the temperature increases above the optimum temperature, the NOx removal efficiency begins to decrease. SCR use in the cement industry is incredibly limited with only a handful of uses in Europe and one instance, i.e the Joppa Cement Plant operated by LaFargeHolcim in the United States.

In SNCR systems a reagent is injected into the flue gas within an appropriate temperature window. The NOx and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems.

Like SCR, SNCR uses ammonia or a solution of urea to reduce NOx through a similar chemical reaction.
2NO+4NH3+2O2 → N2+6H2O

SNCR requires a higher temperature range than SCR often between 1,600°F and 1,900°F due to the lack of a catalyst to lower the activation energies of the reactions.

The Leamington facility has already installed a SNCR system on the kiln and has demonstrated compliance with a federally enforceable NOx emission rate of 2.8 lbs/ton clinker (30 day rolling average).

Step 2:

Ash Grove did not evaluate further the control options of LNB or SNCR as these two control systems have already been installed at the Leamington plant. Although the source could have evaluated more efficient/improved versions of either/both systems, the source did not supply any additional data on these options.

For SCR, Ash Grove supplied information on an SCR's temperature requirements, ammonia slip, and the catalyst fouling possibilities. Ash Grove reached the conclusion that SCR is not widely available for use with cement kilns, in large part because the site-specificity limits the commercial availability of systems. Therefore, neither high-dust nor clean-side SCR's were considered technically feasible.

Step 3:

Step 3 of the top-down control review is to rank the technically feasible options in order of effectiveness. All technically feasible control options, LNB and SNCR, have already been installed by the Leamington facility.

Step 4:

Ash Grove believes that reasonable progress compliant controls are already in place. Ash Grove's actual NOx emission level of 1198 tpy is adequate and the Leamington facility does not propose any change to their current limit of 2.8 lbs/ton clinker on a 30-day rolling average basis.

DAQ agrees with Ash Grove's conclusion for NOx emission controls. Although some additional information should be supplied on potential improvements in efficiency to the existing SNCR system, DAQ does not recommend any changes to the existing level of control at this time.

5.0 Conclusion

Although some additional information should be supplied by the source regarding SNCR efficiency, the Leamington Cement Plant appears to be adequately controlled at this time for purposes of the Second Planning Period.

APPENDIX C.1.C - Ash Grove Evaluation Response

ASH GROVE CEMENT COMPANY

ASH GROVE

A CRH COMPANY

WESTERN REGION
Hwy 132 6 Miles East of Leamington
LEAMINGTON, UTAH 84638
PHONE (435) 857-1200 FAX (435) 857-1288

August 26, 2021

Ms. Chelsea Cancino
Utah Department of Environmental Quality
195 North 1950 West
Salt Lake City, Utah 84114-4820

RE: Ash Grove Cement Company, Leamington Plant, Four-Factor Analysis – Supplemental Information

Dear Ms. Cancino:

We received your review of Ash Grove Cement Company's (AGC's) four-factor analysis for the Leamington facility dated July 27, 2021. Per your request, we are providing additional information.

Comment (paraphrased): The Department of Environmental Quality (DAQ) recommends that AGC revisit their annual potential to emit (PTE) estimation for SO_2 given the seeming disparity with the current actual annual emission rate values for SO_2.

Response:
AGCs actual emission rate is determined via source testing on a periodic basis. Recent source test results for the main kiln stack are as follows:

Date	SO2 – Method 6C (lb/ton)
8/26/2013	0.01
6/25/2015	0.07
6/12/2017	0.04
6/20/2019	0.02
6/2/2020	0.003
6/15/2021	0.02
Emission Limit	0.4

The actual emission rate has varied from 0.003 to 0.07 lbs/ton while the PTE is based on the emission limit of 0.4 lb/ton (30-day rolling average). The emission limit in this case corresponds with the NSPS Subpart F standard for new portland cement kilns.

Although the actual emission rate is indeed well below the emission limit used for PTE calculations, there are still factors that could cause actual SO_2 emission levels to increase and thus it would be a concern for Ash Grove to lower the PTE (limit). As pointed out in the four-factor analysis, sulfur is introduced into the system both from raw materials and fuel and both have variable sulfur contents. The sulfur content of the fuel is expected to largely be fully absorbed in the process, and is already limited to less than 1 lb/MMBtu of heat input, but the sulfur content of the raw material can vary and have an impact on SO_2

emission levels. Currently, the sulfur contents in the raw materials are relatively low, and in fact they are so low that from an overall process chemistry standpoint, it would actually be beneficial from a maintenance standpoint if the sulfur levels were slightly higher. That is, if sulfur is too low, the process chemistry can be such that a buildup of unwanted materials can occur in the system that leads to increased maintenance. Thus, from a process standpoint, it would not be beneficial to plant operation to lower sulfur contents in the raw materials. Further, the overall chemistry of the process requires the addition of aluminum and iron which comes from raw materials and the sulfur contents in these raw materials can vary depending on the source that is identified. These raw materials are not mined or produced onsite, and thus AGC does not have long term control over their sulfur levels or availability. Thus we cannot speculate that in the long term, raw materials with extremely low sulfur levels will always be available and must continue to have flexibility in the permit to allow for modest increases in SO_2 in the future (within reason of course, which we would consider to be the PTE levels).

Comment (paraphrased): Provide additional information on the potential for improvements in efficiency of the existing SNCR system.

Response:
The SNCR system was designed specifically for the Leamington plant to be able to achieve 2.8 lb NOx/ton clinker on a 30-day rolling average basis, and the plant typically operates in the 2.5 to 2.6 lb NOx/ton clinker range. For example, in 2020 the plant averaged 2.6 lb NOx/ton clinker. On a shorter term basis, the emission rate can be nearer to the 2.8 lb/ton range with the SNCR system operating at maximum capacity (maximum reagent flowrate). AGC certainly desires to operate as efficiently as possible, but AGC is not aware of any changes that could be made to achieve a higher level of control with the system. The plant uses an Aqua NH3 solution as the chemical reagent in the process and it is not feasible to add additional reagent in the existing design. That is, adding additional reagent would require additional and/or larger nozzles as well as an expansion or addition to the reagent storage tanks. The plant already receives reagent by truck every 2 days. Further, there is concern that the system is already near saturation with the aqua NH3 reagent rates such that adding additional NH3 may not increase the control efficiency but rather it would cause NH3 to slip from the system and be released from the stack.

Summary
AGC believes that the current SO_2 and NO_X limits reflect a reasonable level of safety margin relative to actual emission rates.

If you have any questions or comments, please do not hesitate to contact me at (435) 857-1283.

Sincerely,

Cody Watkins

Cody Watkins
Environmental Engineer

cc: Jeff Briggs, Ash Grove Cement Company, Montana City Plant

APPENDIX C.2 - Graymont

APPENDIX C.2.A – Graymont Four Factor Analysis

REASONABLE PROGRESS FOUR-FACTOR ANALYSIS

GRAYMONT WESTERN US INC.> Cricket Mountain, UT

GRAYMONT

Prepared By:

Anna Henolson – Managing Consultant
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April 2020

Project 204801.0003

Trinity Consultants

Environmental solutions delivered uncommonly well

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1. EXECUTIVE SUMMARY

This report documents the results of a four-factor control analysis of the five lime kilns at the Graymont Western US Inc. (Graymont) Cricket Mountain lime plant, which is located near Delta, Utah. All five kilns are rotary, preheater type kilns that can produce approximately 600 - 1400 tons per day of lime, each. This report is provided in response to the Utah Department of Environmental Quality (DEQ) request made verbally to Graymont in December 2019.

Graymont was not identified as an eligible facility for the best available retrofit technology (BART) program during the first round of regional haze as it was built after August 7, 1977. DEQ has identified the Cricket Mountain plant as an eligible source for the regional haze program reasonable progress analysis based on a screening process that takes into account both the quantity of emissions from the facility and the proximity to the Class I areas protected by the regional haze program.

The U.S. EPA's guidelines in 40 CFR Part 51.308 are used to evaluate control options for the lime kilns. In establishing a reasonable progress goal for any mandatory Class I Federal area within the State, the State must consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these four factors are taken into consideration in selecting the goal (40 CFR 51. 308(d)(1)(i)(A)).

The purpose of this report is to provide information to DEQ regarding potential NO_X emission reduction options for the Graymont Cricket Mountain lime kilns. Based on the Regional Haze Rule, associated EPA guidance, and DEQ's request, Graymont understands that DEQ will only move forward with requiring emission reductions from the Graymont Cricket Mountain kilns if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost effective controls among all options available to DEQ. In other words, control options are only relevant for the Regional Haze Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

The report identifies several potential control technologies for the Graymont lime kilns, as summarized in Table 1-1 below.

Table 1-1. Potential Control Technologies

Pollutant	Emission Reduction Measure	Technically Feasible?	Cost Effective?	Appropriate for Emissions Reduction?	Notes
NO_X	Reduce Peak Flame Zone Temperature	No	N/A	No	Kiln must achieve sufficient peak flame temperature for proper calcination of limestone.
	Low NO_X Burners (LNB)	Yes	Yes	Yes	Already installed and operating.
	Proper Kiln Operation	Yes	Yes	Yes	Proper kiln operation is technically feasible and currently employed at this facility.
	Preheater Kiln Design	Yes	Yes	Yes	The kilns currently feature a preheater.
	Selective Catalytic Reduction (SCR)	No	N/A	No	SCR is largely unproven on lime kilns, as there is no documented instance of this technology in the industry.
	Selective Non-Catalytic Reduction (SNCR)	No	No	No	There is only one RBLC entry for a lime kiln installing SNCR, and the details of its installation remain private. Even if feasible, SNCR is also not cost effective for Cricket Mountain.

It is also worth noting that these five lime kilns were all permitted under EPA's PSD program and were determined to meet BACT at the time those permits were issued and the sources constructed. Furthermore, the NO_X controls that the Cricket Mountain kilns currently utilize are consistent with recent BACT determinations for new rotary preheater lime kilns.[1] Graymont expects that control programs under the current regional haze efforts will not go beyond BACT.

This report outlines Graymont's evaluation of possible options for reducing the emissions of NO_X at its Cricket Mountain facility near Delta, Utah. There are currently no technically feasible and cost effective reduction options available beyond current best practices for the Graymont facility. Therefore, the baseline emissions provided in this analysis are expected to be the same as those of the "control scenario" for the Graymont Cricket Mountain facility.

[1] See Appendix A, the RBLC Search Results, for a list of recent BACT determinations.

Table 1-1. Potential Control Technologies

Pollutant	Emission Reduction Measure	Technically Feasible?	Cost Effective?	Appropriate for Emissions Reduction?	Notes
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	Preheater Kiln Design	Yes	Yes	Yes	The kilns currently feature a preheater.
	Selective Catalytic Reduction (SCR)	No	N/A	No	SCR is largely unproven on lime kilns, as there is no documented instance of this technology in the industry.
	Selective Non-Catalytic Reduction (SNCR)	No	No	No	There is only one RBLC entry for a lime kiln installing SNCR, and the details of its installation remain private. Even if feasible, SNCR is also not cost effective for Cricket Mountain.

It is also worth noting that these five lime kilns were all permitted under EPA's PSD program and were determined to meet BACT at the time those permits were issued and the sources constructed. Furthermore, the NO_X controls that the Cricket Mountain kilns currently utilize are consistent with recent BACT determinations for new rotary preheater lime kilns.[1] Graymont expects that control programs under the current regional haze efforts will not go beyond BACT.

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[1] See Appendix A, the RBLC Search Results, for a list of recent BACT determinations.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to natural conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. In establishing a reasonable progress goal for a Class I area, the state must (40 CFR 51.308(d)(*i*)):

> (A) *consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.*
>
> (B) *Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction.*

With the second planning period under way for regional haze efforts, there are a few key distinctions from the processes that took place during the first planning period. Most notably, the second planning period analysis will distinguish between "natural" and "anthropogenic" sources. Using a Photochemical Grid Model (PGM), the EPA will establish what are, in essence, background concentrations both episodic and routine in nature to compare manmade source contributions against.

DEQ requested Graymont's assistance in developing a four-factor analysis of potential emission reduction options for NO_X at the Cricket Mountain facility. Graymont understands that the information provided in a four-factor review of control options will be used by EPA in their evaluation of reasonable progress goals for Utah. The purpose of this report is to provide information to DEQ regarding potential NO_X emission reduction options for the Graymont Cricket Mountain lime kilns. Based on the Regional Haze Rule, associated EPA guidance, and DEQ's request, Graymont understands that DEQ will only move forward with requiring emission reductions from the Graymont Cricket Mountain lime kilns if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost effective controls among all options available to DEQ. In other words, control options are only relevant for the Regional Haze Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

The information presented in this report considers the following four factors for the emission reductions:

Factor 1. Costs of compliance
Factor 2. Time necessary for compliance
Factor 3. Energy and non-air quality environmental impacts of compliance

Factor 4. Remaining useful life of the kilns

Factors 1 and 3 of the four factors that are listed above are considered by conducting a step-wise review of emission reduction options in a top-down fashion similar to the top-down approach that is included in the EPA RHR guidelines[2] for conducting a review of Best Available Retrofit Technology (BART) for a unit[3]. These steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Factor 4 is also addressed in the step-wise review of the emission reduction options, primarily in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by limited equipment life. Once the step-wise review of control options was completed, a review of the timing of the emission reductions is provided to satisfy Factor 2 of the four factors.

A review of the four factors for NO_X can be found in Sections 5 this report. Section 4 of this report includes information on the Graymont Cricket Mountain kilns' existing/baseline emissions.

[2] The BART provisions were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308 on July 5, 2005.

[3] References to BART and BART requirements in this Analysis should not be construed as an indication that BART is applicable to the Graymont Cricket Mountain facility.

3. SOURCE DESCRIPTION

The Graymont Western US, Inc. Cricket Mountain Plant is located in Millard County, Utah, approximately 30 miles southwest of Delta. The nearest Class I area to the plant is the Capitol Reef National Park. It is approximately 81 miles (131 kilometers) southeast of the Cricket Mountain plant.

The facility operates five horizontal rotary preheater lime kilns. The five kilns are nearly identical in design and operations, although the production rates for each kiln vary.

Table 3-1. Kiln Production Rates

Kiln	Nominal Lime Production (tons/day)
1	600
2	600
3	840
4	1,266
5	1,400

All five kilns use coal as a primary fuel source. Typical annual fuel usage rates for the five kilns combined are approximately 180,000 tons per year of coal (based on 2014 operation and 11,400 Btu/lb). Fuels typically used for kiln startup include diesel and propane. Natural gas is not available at the plant.

Further details of the fuel throughputs and emission rates are provided in Section 4.

This section summarizes emission rates that are used as baseline rates in the four factor analysis presented in Section 5 of this report.

Baseline annual emissions for NO_X are calculated based on stack test data and annual production rates and are consistent with annual emission inventory reports. For the purposes of this regional haze four-factor analysis, the baseline emissions for the Graymont Cricket Mountain kilns are the average NO_X emissions for the years 2014-2018, which are summarized in Table 4-1 below.

Table 4-1. Baseline NO_x Emission Rates

Kiln	NOx Baseline Emission Rate [a] (ton/yr)
1	85.5
2	60.3
3	50.0
4	107.1
5	336.1
Total	639.0

[a] Baseline emissions are the average NO_X emissions for years 2014-2018, based on stack test data and annual production rates.

The four-factor analysis is satisfied by conducting a step-wise review of emission reduction options in a top-down fashion. The steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Cost (Factor 1) and energy / non-air quality impacts (Factor 3) are key factors determined in Step 4 of the step-wise review. However, timing for compliance (Factor 2) and remaining useful life (Factor 4) are also discussed in Step 4 to fully address all four factors as part of the discussion of impacts. Factor 4 is primarily addressed in in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by a limited equipment life.

The baseline NO_X emission rates that are used in the NO_X four-factor analysis are summarized in Table 4-1. The basis of the emission rates is provided in Section 4 of this report. The kilns currently utilize low-NO_X burners (LNB), as described in Section 5.1.1.2, below.

5.1. STEP 1: IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

NO_X is produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms "thermal" NO_X and "fuel" NO_X when describing NO_X emissions from the combustion of fuel. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is oxidized in a high temperature zone. Fuel NO_X emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

Most of the NO_X formed within a rotary lime kiln is classified as thermal NO_X. Virtually all of the thermal NO_X is formed in the region of the flame at the highest temperatures, approximately 3,000 to 3,600 degrees Fahrenheit (°F). A small portion of NO_X is formed from nitrogen in the fuel that is liberated and reacts with the oxygen in the combustion air.

Step 1 of the top-down control review is to identify available retrofit control options for NO_X. The available NO_X retrofit control technologies for the Cricket Mountain kilns are summarized in Table 5-1.

Table 5-1. Available NO_X Control Technologies for Cricket Mountain Kilns 1-5

NO_x Control Technologies	
Combustion Controls	Reduce Peak Flame Zone Temperature Low NO_x Burners (LNB) Proper Kiln Operation Preheater Kiln Design
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

NO_X emissions controls, as listed in Table 5-1, can be categorized as combustion or post-combustion controls. Combustion controls reduce the peak flame temperature and excess air in the kiln burner, which minimizes NO_X formation. Post-combustion controls such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) convert NO_X in the flue gas to molecular nitrogen and water.

5.1.1. Combustion Controls

5.1.1.1. Reduce Peak Flame Zone Temperature

These are methods of reducing the temperature of combustion products in order to inhibit the formation of thermal NO_X. They include (1) using fuel rich mixtures to limit the amount of oxygen available; (2) using fuel lean mixtures to limit amount of energy input; (3) injecting cooled, oxygen depleted flue gas into the combustion air; and (4) injecting water or steam.

5.1.1.2. Low NO_X Burners

LNBs reduce the amount of NO_X initially formed in the flame. The principle of all LNBs is the same: stepwise or staged combustion and localized exhaust gas recirculation (i.e., at the flame). LNBs are designed to reduce flame turbulence, delay fuel/air mixing, and establish fuel-rich zones for initial combustion. The longer, less intense flames reduce thermal NOx formation by lowering flame temperatures. Control of air turbulence and speed is often controlled via mixing air fans. Some of the burner designs produce a low pressure zone at the burner center by injecting fuel at high velocities along the burner edges. Such a low pressure zone tends to recirculate hot combustion gas which is retrieved through an internal reverse flow zone around the extension of the burner centerline. The recirculated combustion gas is deficient in oxygen, thus producing the effect of flue gas recirculation. Reducing the oxygen content of the primary air creates a fuel-rich combustion zone that then generates a reducing atmosphere for combustion. Due to fuel-rich conditions and lack of available oxygen, formation of thermal NO_X and fuel NO_X are minimized[4].

5.1.1.3. Preheater Kiln Design/ Proper Combustion Practices

The use of staged combustion and preheating alone can lead to effective reduction of NO_X emissions. By allowing for initial combustion in a fuel-rich, oxygen-depleted zone, necessary temperatures can be achieved without concern for the oxidation of nitrogen. This initial combustion is then followed by a secondary combustion zone that burns at a lower temperature, allowing for the addition of additional combustion air without significant formation of NO_X.[5]

5.1.2. Post Combustion Controls

5.1.2.1. Selective Catalytic Reduction

Selective catalytic reduction (SCR) is an exhaust gas treatment process in which ammonia (NH_3) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 and nitric oxide (NO) or nitrogen dioxide (NO_2) react to form diatomic nitrogen and water. The overall chemical reactions can be expressed as follows:

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[4] USEPA, Office of Air Quality Planning and Standards. Alternative Control Technologies Document – NOx Emissions from Cement Manufacturing. EPA-453/R-94-004, Page 5-5 to 5-8.

[5] Ibid, Page 58.

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

When operated within the optimum temperature range of 480°F to 800°F, the reaction can result in removal efficiencies between 70 and 90 percent.[6] The rate of NO_X removal increases with temperature up to a maximum removal rate at a temperature between 700°F and 750°F. As the temperature increases above the optimum temperature, the NO_X removal efficiency begins to decrease. As of this report, there are no known instances of SCRs installed on lime kilns.

5.1.2.2. Selective Non-Catalytic Reduction

In SNCR systems, a reagent is injected into the flue gas within an appropriate temperature window. The NO_X and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia and urea SNCR processes require three to four times as much reagent as SCR systems to achieve similar NO_X reductions.

Like SCR, SNCR uses ammonia or a solution of urea to reduce NO_X through a similar chemical reaction.

$$2NO + 4NH_3 + 2O_2 \rightarrow 3N_2 + 6H_2O$$

SNCR residence time can vary between 0.001 seconds and 10 seconds.[7] However, increasing the residence time available for mass transfer and chemical reactions at the proper temperature generally increases the NO_X removal. There is a slight gain in performance for residence times greater than 0.5 seconds. The EPA Control Cost Manual indicates that SNCR requires a higher temperature range than SCR of between approximately 1,550°F and 1,950°F,[8] due to the lack of a catalyst to lower the activation energies of the reactions; however, the control efficiencies achieved by SNCR vary across that range of temperatures. That said, the effectiveness of SNCR on lime kilns is largely unproven. Lime kilns present unique technical challenges not experienced by cement kilns. While mid-kiln injection is often the most effective method of implementing SNCR on cement kilns, injection at that location is not feasible for a lime kiln. Lime kilns experience lower NO_X concentrations at a given point in the kiln, have shorter residence times, and face issues in the stability of temperature profiles when compared to cement kilns. At higher temperatures, NO_X reduction is less effective.[9] In addition, a greater residence time is required when operating at lower temperatures.

In cement kilns SNCR can be applied as a tailpipe technology or in a certain combustion zone of kilns to facilitate SNCR in a non-tailpipe mode (mid-kiln SNCR). However, there are important differences between and lime kiln and cement kiln that cause technical barriers to mid-kiln firing. The lime industry has a

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[6] Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NOx Controls, EPA/452/B-02-001, Page 2-9 and 2-10.

[7] Air Pollution Control Cost Manual, Section 4, Chapter 1, Selective Non-Catalytic Reduction, NOx Controls, EPA/452/B-02-001, Page 1-8

[8] Ibid, Page 1-6

[9] USEPA, Office of Air Quality Planning and Standards. Alternative Control Technologies Document – NO_X Emissions from Cement Manufacturing. EPA-453/R-94-004, Section 5.2.2, Page 5-21.

severely limited track record in determining the feasibility or control level that could be attained if mid-kiln SNCR were attempted on the Cricket Mountain kilns. The aforementioned technical barriers to SNCR implementation have limited the technology's use in the industry, with temperature, residence time, and lower NO_X concentrations distinguishing lime production from the cement production process. The RACT/BACT/LAER Clearinghouse (RBLC) database includes only one instance of a lime kiln that was permitted with SNCR as control for NO_X emissions.[10] The permit documents indicate that after conducting a trial with the SNCR, a lower limit would be established that takes into account the control of NO_X emissions achieved by the SNCR (unless it is demonstrated to not provide effective control or result in unacceptable consequences). Updated permit files have not included a reduced permit limit, and there is no publicly available evidence of the trial results. Based on the record, the SNCR installation and reduction for this RBLC search result has not been demonstrated. Additionally, for the only other instances of known SNCR installations on different lime kilns (which do not appear in RBLC results), very limited information is available on the details of these kilns necessary for Graymont to evaluate whether the application of SNCR in that instance could be implemented at Cricket Mountain. Even though SNCR has not been demonstrated as a successful control option for NO_X emissions from lime kilns, indicating the technology may not meet the criteria to be considered available, Graymont conservatively evaluates the technical feasibility further.

5.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible NO_X control technologies that were identified in Step 1.

5.2.1. Combustion Controls

5.2.1.1. Reduce Peak Flame Zone Temperature

In a lime kiln, product quality is co-dependent on temperature and atmospheric conditions within the system. Although low temperatures inhibit NO_X formation, they also inhibit the calcination of limestone. For this reason, methods to reduce the peak flame zone temperature in a lime kiln burner are technically infeasible.

5.2.1.2. Low NO_X Burners

The facility currently operates low-NO_X burners in the lime kilns. Coal is delivered to the burners using a direct fired system. However, to limit NO_X, only enough primary air is used to sweep coal out of the mill. This is similar to using an indirect fired system, which also limits primary air to the burners while delivering fuels.

Baseline emissions are based on the operation of these low NO_X burners. All alternative methods of NO_X control in this analysis will assume that the kilns continue to operate these burners.

5.2.1.3. Preheater Kiln Design/Proper Combustion Practices

Proper combustion practices and preheater kiln design are considered technically feasible for Graymont and will be considered further.

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[10] RBLC Search results are provided in Appendix A, see the entry for the Mississippi Lime Company.

5.2.2. Post Combustion Controls

5.2.2.1. Selective Catalytic Reduction

Efficient operation of the SCR process requires fairly constant exhaust temperatures (usually ± 200°F).[11] Fluctuation in exhaust gas temperatures reduces removal efficiency. If the temperature is too low, ammonia slip occurs. Ammonia slip is caused by low reaction rates and results in both higher NO_X emissions and appreciable ammonia emissions. If the temperature is too high, oxidation of the NH_3 to NO can occur. Also, at higher removal efficiencies (beyond 80 percent), an excess of NH_3 is necessary, thereby resulting in some ammonia slip. Other emissions possibly affected by SCR include increased PM emissions (as ammonia salts result from the reduction of NO_X and are emitted in a detached plume) and increased SO_3 emissions (from oxidation of SO_2 on the catalyst).

To reduce fouling the catalyst bed with the PM in the exhaust stream, an SCR unit can be located downstream of the particulate matter control device (PMCD). However, due to the low exhaust gas temperature exiting the PMCD (approximately 350°F), a heat exchanger system would be required to reheat the exhaust stream to the desired reaction temperature range of between 480°F to 800°F. The source of heat for the heat exchanger would be the combustion of fuel[12], with combustion products that would enter the process gas stream and generate additional NO_X. Therefore, in addition to storage and handling equipment for the ammonia, the required equipment for the SCR system will include a catalytic reactor, heat exchanger and potentially additional NO_X control equipment for the emissions associated with the heat exchanger fuel combustion.

High dust and semi-dust SCR technologies are still highly experimental. A high dust SCR would be installed prior to the dust collectors, where the kiln exhaust temperature is closer to the optimal operating range for an SCR. It requires a larger volume of catalyst than a tail pipe unit, and a mechanism for periodic cleaning of catalyst. A high dust SCR also uses more energy than a tail pipe system due to catalyst cleaning and pressure losses.

A semi-dust system is similar to a high dust system. However, the SCR is placed downstream of an ESP or cyclone.

The main concern with high dust or semi-dust SCR is the potential for dust buildup on the catalyst, which can be influenced by site specific raw material characteristics present in the facility's quarry, such as trace contaminants that may produce a stickier particulate than is experienced at sites where the technology is being demonstrated. This buildup could reduce the effectiveness of the SCR technology, and make cleaning of the catalyst difficult, resulting in kiln downtime and significant costs.[13]

No lime kiln in the United States is using any of these SCR technologies. For the technical issues noted above, tail pipe, high dust and semi-dust SCR's are considered technically infeasible at this time.

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[11] Ibid, Page 2-11

[12] The fuel would likely be propane or diesel. There is no natural gas at the facility, and coal would require an additional dust collector.

[13] Preamble to NSPS subpart F, 75 FR 54970.

5.2.2.2. *Selective Non-Catalytic Reduction*

At temperatures above 2,100°F, NO_X generation starts to occur as shown in the reaction below:

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O$$

This reaction causes ammonia to oxidize and form NO instead of removing NO. When temperatures exceed 2200°F, NO formation dominates. This would likely be the case if ammonia were directly injected into the kiln tube. At temperatures below the required range, appreciable quantities of un-reacted ammonia will be released to the atmosphere via ammonia slip.

Based on the temperature profile, there are three locations in a rotary preheater lime kiln system where the ammonia /urea injection could theoretically occur: the stone/preheater chamber, the transfer chute, or after the PMCD. A fourth location that will be considered in this analysis is the kiln tube. In order for SNCR to be technically feasible, at least one of these locations must meet the following criteria: placement of injector to ensure adequate mixing of the ammonia or urea with the combustion gases, residence time of the ammonia with the combustion gases, and temperature profile for ammonia injection.

Figure 5-1 provides a schematic of a preheater/kiln system including typical process temperatures in the system.

Figure 5-1. Preheater – Cross Section

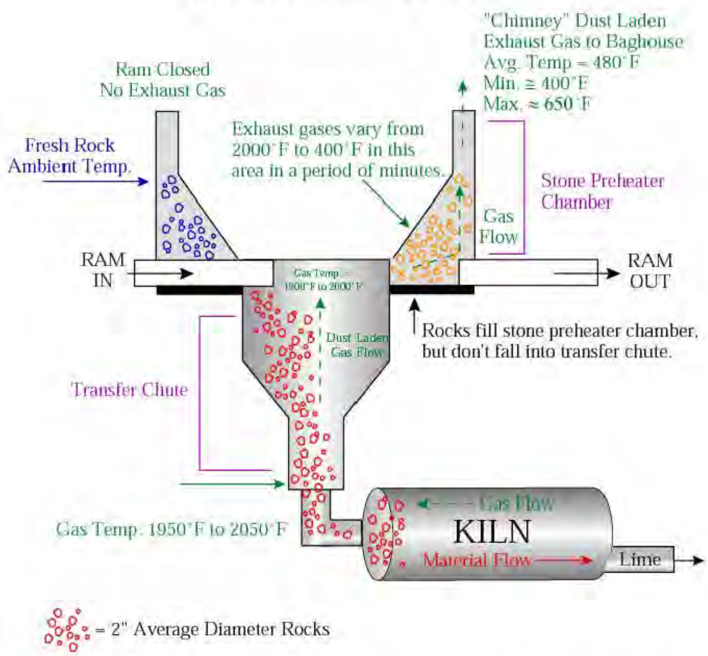

*Figure represents a typical lime kiln preheater, and is not specific to the kilns at the Graymont Cricket Mountain facility

SNCR Ammonia/Urea Injection Location - Stone Chamber/Preheater
The required temperature range for the reaction may occur within the preheater. However, the location of the temperature zone varies with time and location as explained below.

In each Graymont Cricket Mountain preheater, mechanical rams operate in sequence, transferring limestone, one ram at a time, from the stone chambers into the transfer chute. When a ram is in the "in" position, very little exhaust gas flows through the stone and out the duct. When the ram pulls out, the cold stone drops down and fills the stone heating chamber. The angle of repose of the stone and the configuration of the duct and chamber are such that stone does not continue to fall into the transfer chute. Hot gases, at approximately 1,950°F, then pass through the stone chamber filled with cold stone. The first gas to pass through the chamber exits the chimney at approximately 400°F. As the cold stone heats up, the exit gas temperature increases and reaches a high of approximately 600°F. The ram then strokes and pushes the heated stone into the transfer chute and starts the cycle again. The temperature profile in the stone chamber varies as shown in Figure 5-2.

Figure 5-2. Preheater Stone Chamber Temperature Variation with Time and Location

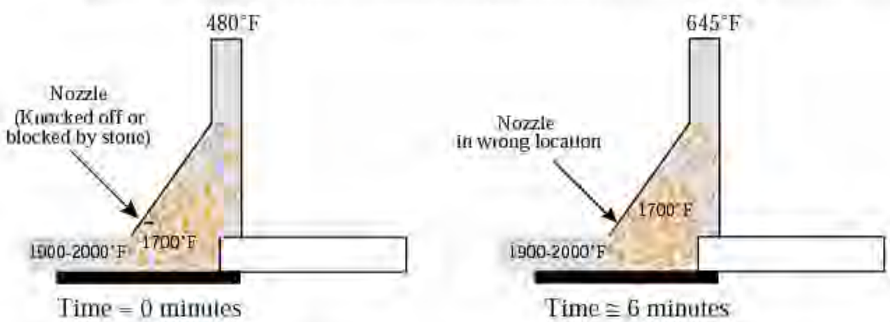

*Figure represents a typical lime kiln preheater, and is not specific to the kilns at the Graymont Cricket Mountain facility

Besides the fact that the optimal temperature zone varies in location, the fact that the stone chamber is filled with stone makes using nozzles for injecting the ammonia/urea infeasible. For example, if a nozzle protruded from the wall of the stone chamber, the moving packed bed of rock would either knock it off or wear it off in a very short time. If the nozzle were inset into the wall of the chamber, the moving packed bed of stone would block the spray, and the ammonia or the urea mixture would simply coat a few of the stones, rather than mixing evenly throughout the gas stream. Similarly, if the nozzle were positioned at the roof of the preheater, the ammonia or urea would not be distributed throughout the gas stream. The preheater is approximately 75 percent full of stone, so ammonia or urea sprayed from the top of the preheater would have minimal residence time for distribution through the combustion gases before it would be blocked from distribution by the stone. Regardless of the choice of location for the nozzle, the ammonia or urea would not be effectively distributed through the large surface area of the preheater. These problems make application of SNCR in the stone chamber technically infeasible[14].

[14] ReportConcerning BACT for SO_2 and NOx for Proposed Lime Kiln," prepared for Air Pollution Control Division, Clark County Health District, Las Vegas, Utah, April 1995.

SNCR Ammonia/Urea Injection Location – Transfer Chute

As shown in Figure 5-1, the temperature in the transfer chute is approximately 1,950°F for typical kilns. These temperatures are in the upper bound for the NO_X reduction reaction. Temperatures this high reportedly resulted in approximately 30 percent NO_X reduction in clean (non dust-laden) exhaust streams. Lime kilns do not have clean exhaust streams at this location. Rather, the back end of the transfer chute is an extremely dusty environment, and therefore the exhaust stream is dust-laden. The one SNCR installation in the lime industry has achieved control efficiencies of around 50% with the injection nozzles installed in the bottom of the preheater, at the preheater cone[15]. While this technology is certainly promising, this one example of SNCR installation on a rotary lime kiln does not necessarily transfer to other lime kilns. Effectiveness of SNCR is highly site-dependent, with a variety of factors having the potential to heavily influence the quantities of NO_X controlled. Given the significant range (35-58%) of control efficiencies found for cement kilns, a control efficiency considerably lower than the average for cement of 40% is expected given ideal temperature scenarios (many kilns in the cement industry that utilize SNCR do so in the combustion zone in the calciner, where temperatures are lower than in the kiln). Lime kilns experience significant technical barriers to successful SNCR implementation not shared by the cement industry. When compared to the cement process, lower NO_X concentrations, shorter residence times, and temperatures more frequently outside the optimal range for SNCR application yield lower control efficiencies for lime kilns. Therefore, a control efficiency of no more than 20% is anticipated for the Cricket Mountain kilns.

Locating an ammonia or urea injector nozzle in the chute to ensure mixing of the ammonia with the combustion gases would pose similar problems as the problems with the stone chamber location. Stones pour into the chute from the stone chamber, and in order to stabilize a nozzle for injection, the nozzle would need to be positioned out of the direct path of the flow of the stones. Further, the stone pieces that pour into the transfer chute from the chamber take up a large portion of the volume in the chute. Adequate mixing of the ammonia or urea with the combustion gases would be inhibited by the rock. The ammonia or urea would most likely end up on the stones, rather than mixing evenly throughout the gas stream.

The low percent NO_X reduction combined with the uncertainty of the nozzle placement and mixing requirement eliminate the transfer chute as a technically feasible option for Cricket Mountain Kilns 1 through 5.

SNCR Ammonia/Urea Injection Location - Inside Rotary Kiln

Ammonia/urea could be injected through a door or port in the kiln shell. Similar to the transfer chute, stone is traveling down the rotary kiln. Consequently, the nozzle would need to be positioned out of the direct path of the flow of the stones. Theoretically, the temperature inside a rotary lime kiln, which is above 2,200 F, would promote the formation of NO from injected ammonia.

Graymont is aware that there have been trials at competing lime facilities with mid-kiln ammonia injection and transfer chute ammonia/urea injection for NO_X reduction. However, the technology costs and technical details have not become publicly available, so Graymont cannot evaluate if the technology can be successfully applied specifically to the kilns at the Cricket Mountain facility.

Since a mid-kiln ammonia injection and transfer chute ammonia/urea injection systems would require extended trials to determine if the technology can effectively control NO_X on the Graymont lime kilns, Graymont must conclude that this type of SNCR is not "available" with respect to the Cricket Mountain plant

[15] EPA Control Cost Manual, SNCR Cost chapter. 7th Edition, 2016. Page 1-7. https://www3.epa.gov/ttn/ecas/docs/SNCRCostManualchapter7thEdition2016.pdf

because it is not commercially available. Since it is not commercially available, no vendor performance guarantees can be made to its success. Therefore, this technology cannot be considered technically feasible.

The technology is not commercially available, as defined in 40 CFR Subpart 51, Appendix Y which states that:

Two key concepts are important in determining whether a technology could be applied: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

Availability in this context is further explained using the following process commonly used for bringing a control technology concept to reality as a commercial product:

The typical stages for bringing a control technology concept to reality as a commercial product are:

- *Concept stage;*
- *Research and patenting;*
- *Bench scale or laboratory testing;*
- *Pilot scale testing;*
- *Licensing and commercial demonstration; and*
- *Commercial sales.*

A control technique is considered available, within the context presented above, if it has reached the stage of licensing and commercial availability. Similarly, we do not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as "available" for purposes of BART review.

Commercial availability by itself, however, is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or "applicable" to the source type under consideration.

Though the technology is not considered technically feasible for Graymont's Cricket Mountain facility for the reasons outlined above, cost calculations for the implementation of SNCR are included for completeness assuming a 20% control efficiency for NO_X.

5.3. STEP 3: RANK OF TECHNICALLY FEASIBLE NOX CONTROL OPTIONS BY EFFECTIVENESS

Step 3 of the top-down control review is to rank the technically feasible options to effectiveness. Table 5-2 presents potential NO_x control technologies for the kilns and their associated control efficiencies.

Table 5-2. Ranking of NO_X Control Technologies by Effectiveness

Pollutant	Control Technology	Potential Control Efficiency (%)
NO_x	SNCR Low NO_x Burner	20* Base case

* 20% control efficiency is used for cost evaluation based on evaluation of feasibility of SNCR at another Graymont facility.

5.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step 4 of the top-down control review is the impact analysis. The impact analysis considers the:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

5.4.1. Cost of Compliance

In order to assess the cost of compliance for the installation of SNCR, the EPA Control Cost Manual is used. Capital costs for the installation of the SNCR assumed a 20-year life span for depreciation, as well as the current bank prime rate of 4.75% for interest calculations. The total capital investment includes the capital cost for the SNCR itself, the cost of the air pre-heater required (per the EPA Control Cost Manual, the air pre-heater will require modifications for coal-fired units when SO_2 control is necessary. This value is conservatively assumed for all coal-fired units evaluated for SNCR installation[16]), and the balance of the plant. Annual costs include both direct costs such as maintenance, reagent, electricity, water, fuel, and waste disposal cost and indirect costs for administrative charges and the amortized capital costs as a capital recovery value. A retrofit factor of 1.5 is used to account for the technical barriers described in section 5.2.2.1, including the existence of only one RBLC reference for an SNCR retrofit on a lime kiln, the difficulty of identifying an injection point that allows for ammonia to enter the gas stream within an optimal temperature window, the low residence times of lime kilns relative to cement kilns, and the relatively low inlet NO_X concentrations that limit the effectiveness of the control technology. The total costs and cost effectiveness of control are summarized in Table 5-3, below.

[16] EPA Control Cost Manual, SNCR Cost chapter. 7th Edition, 2016. Page 1-44. https://www3.epa.gov/ttn/ecas/docs/SNCRCostManualchapter7thEdition2016.pdf

Table 5-3. SNCR Cost Calculation Summary

Kiln	Total Capital Investment	Total Annual Cost	NOx Emissions Removed [a] (tpy)	Cost Effectiveness ($/ton removed)
1	$5,425,232	$519,152	15.5	$33,571
2	$5,817,345	$552,963	10.9	$50,720
3	$6,482,717	$616,847	9.0	$68,276
4	$7,927,545	$755,901	19.4	$39,025
5	$7,547,629	$741,500	60.8	$12,199
Total Project	$33,200,469	$3,186,363	115.6	$27,575

[a] Baseline NO_X emissions are the average emissions from each kiln for the years 2014-2018.

5.4.2. Timing for Compliance

Graymont believes that reasonable progress compliant controls are already in place. However, if DEQ determines SNCR is necessary to achieve reasonable progress, it is anticipated that this change could be implemented during the second planning period of regional haze (approximately ten years following EPA's reasonable progress determination).

5.4.3. Energy Impacts and Non-Air Quality Impacts

As previously stated, the cost of energy and water required for successful operation of the SNCR are included in the calculations, which can be found in detail in Appendix B. The installation is expected to decrease the efficiency of the overall facility, particularly as significant energy and water use is needed beyond current plan operation requirements.

5.4.4. Remaining Useful Life

Graymont has assumed this control equipment will last for the entirety of the 20-year amortization period, which is reflected in the cost calculations.

5.5. NO_X CONCLUSION

The facility currently uses low NO_X burners in its five kilns to minimize NO_X emissions. The use of low NO_X burners is a commonly applied technology in current BACT determinations for new rotary preheater lime kilns today. The application of SCR has never been attempted on a lime kiln. SNCR has only one RBLC entry documenting implementation on a lime kiln. The use of these controls does not represent a cost effective control technology given the limited expected improvements to NO_X emission rates, high uncertainty of successful implementation, high capital investment, and high cost per ton NO_X removed.

6. CONCLUSION

This report outlines Graymont's evaluation of possible options for reducing the emissions of NO_X at its Cricket Mountain facility near Delta, Utah. There are currently no technically feasible and cost effective reduction options available for the Graymont facility beyond current best practices. Therefore, the emissions for the 2028 on-the-books/on-the-way modeling scenario are expected to be the same as those used in the "control scenario" for the Graymont Cricket Mountain facility.

APPENDIX A : RBLC SEARCH RESULTS

APPENDIX B : NO_X CONTROL COST CALCULATIONS

Table A-1. RBLC Search Results

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVERAGE TIME CONDITION	EMISSION LIMIT 2	EMISSION LIMIT 2 UNIT	EMISSION LIMIT 2 AVERAGE TIME CONDITION
IL-0117	MISSISSIPPI LIME COMPANY	MISSISSIPPI LIME COMPANY	IL	[illegible]	Two Rotary Kilns	Coal, petroleum coke	54	tons lime/hour, each	Nitrogen Oxides (NOx)	Low excess air to minimize formation of NOx and selective non-catalytic reduction (SNCR) to the kilns	[illegible]	LBS/TON LIME PRODUCT	30-DAY ROLLING AVERAGE	[illegible]	LBS/TON LIME PRODUCT	12-MONTH ROLLING AVERAGE
[illegible]	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	[illegible]	Rotary Kiln 1	natural gas, coal, and petroleum coke	[illegible]	tons per day	Nitrogen Oxides (NOx)		[illegible]	LB/TON OF LIME PROD		[illegible]		
[illegible]	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	[illegible]	Rotary Kiln 2	natural gas, coal, and petroleum coke	[illegible]	tons per day	Nitrogen Oxides (NOx)		[illegible]	LB/TON OF LIME PROD		[illegible]		
[illegible]	GRAYMONT (WI) LLC	GRAYMONT (WI) LLC	WI	[illegible]	[illegible] ROTARY LIME KILN	COAL	54	T/H STONE	Nitrogen Oxides (NOx)	GOOD COMBUSTION CONTROL OPTIMIZATION	[illegible]	LB/T	24 HOUR AVG.	[illegible]	LB/MONTH	MONTHLY AVG.
IL-0117	MISSISSIPPI LIME COMPANY	MISSISSIPPI LIME COMPANY	IL	[illegible]	Two Rotary Kilns	Coal, petroleum coke	54	tons lime/hour, each	Sulfur Dioxide (SO2)	Natural absorptive capacity of lime kiln dust	[illegible]	LBS/TON LIME	30-DAY ROLLING AVERAGE	[illegible]		
[illegible]	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	[illegible]	Rotary Kiln 1	natural gas, coal, and petroleum coke	[illegible]	tons per day	Sulfur Dioxide (SO2)	Limiting the fuel sulfur input in addition to the dry [illegible] in these systems.	[illegible]			[illegible]		
[illegible]	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	[illegible]	Rotary Kiln 2	natural gas, coal, and petroleum coke	[illegible]	tons per day	Sulfur Dioxide (SO2)	Limiting the fuel sulfur input in addition to the dry [illegible] in these systems.	[illegible]			[illegible]		
[illegible]	CLIFTON LIME PLANT	LHOIST NORTH AMERICA OF TEXAS, LTD	TX	[illegible]	[illegible]	[illegible]	[illegible]	T/YR	Sulfur Dioxide (SO2)	[illegible]	[illegible]	LB/TON [illegible]		[illegible]		
[illegible]	GRAYMONT (WI) LLC	GRAYMONT (WI) LLC	WI	[illegible]	[illegible] ROTARY LIME KILN	COAL	54	T/H STONE	Sulfur Dioxide (SO2)	FUEL SULFUR LIMIT, INHERENT [illegible] COLLECTION OF SULFUR [illegible]	[illegible]	LB/T	24 HOUR AVERAGE	[illegible]	PERCENT S	FUEL SULFUR LIMIT

Cost Estimate

Graymont Cricket Mountain Kiln 1

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	\$1,439,111 in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$1,006,120 in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	\$1,728,025 in 2018 dollars
Total Capital Investment (TCI) =	\$5,425,232 in 2018 dollars

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	\$1,439,111 in 2018 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$1,006,120 in 2018 dollars

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	\$1,728,025 in 2018 dollars

Table B-1. Summary of SNCR Costs - Graymont Cricket Mountain

Kiln	Total Capital Investment	Annual Cost	Tons NO_X In	Tons NO_X Reduced	Cost Effectiveness ($/ton reduced)
1	$5,425,232	$519,152	85.5	15.5	$33,571
2	$5,817,345	$552,963	60.3	10.9	$50,720
3	$6,482,717	$616,847	50.0	9.0	$68,276
4	$7,927,545	$755,901	107.1	19.4	$39,025
5	$7,547,629	$741,500	336.1	60.8	$12,199
Total	$33,200,469	$3,186,363	639	115.6	$27,575

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	\$104,388 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$512,459 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$616,847 in 2018 dollars

Direct Annual Costs (DAC)
DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	\$97,241 in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	\$6,025 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	\$306 in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	\$45 in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	\$708 in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	\$63 in 2018 dollars
Direct Annual Cost =		\$104,388 in 2018 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	\$2,917 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$509,542 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$512,459 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$616,847 per year in 2018 dollars
NOx Removed =	9 tons/year
Cost Effectiveness =	\$68,275.81 per ton of NOx removed in 2018 dollars

Cost Estimate

Graymont Cricket Mountain Kiln 4

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,935,617	in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$1,744,658	in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,417,838	in 2018 dollars
Total Capital Investment (TCI) =	$7,927,545	in 2018 dollars

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$1,935,617	in 2018 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$1,744,658	in 2018 dollars

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$2,417,838	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	\$129,229 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$626,672 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$755,901 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	\$118,913 in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	\$8,695 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	\$442 in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	\$65 in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	\$1,022 in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	\$91 in 2018 dollars
Direct Annual Cost =		\$129,229 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	\$3,567 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$623,105 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$626,672 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$755,901 per year in 2018 dollars
NOx Removed =	19 tons/year
Cost Effectiveness =	\$39,025.35 per ton of NOx removed in 2018 dollars

Cost Estimate

Graymont Cricket Mountain Kiln 5

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,858,982 in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$1,618,558 in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,328,328 in 2018 dollars
Total Capital Investment (TCI) =	$7,547,629 in 2018 dollars

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$1,858,982 in 2018 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$1,618,558 in 2018 dollars

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$2,328,328 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$144,860 in 2018 dollars
Indirect Annual Costs (IDAC) =	$596,640 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$741,500 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$113,214 in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$26,674 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$1,357 in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$201 in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$3,135 in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$279 in 2018 dollars
Direct Annual Cost =		$144,860 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$3,396 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$593,244 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$596,640 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$741,500 per year in 2018 dollars
NOx Removed =	61 tons/year
Cost Effectiveness =	$12,199.11 per ton of NOx removed in 2018 dollars

Cost Estimate

Graymont Cricket Mountain Kiln 2

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,513,946 in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$1,105,444 in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,855,490 in 2018 dollars
Total Capital Investment (TCI) =	$5,817,345 in 2018 dollars

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR)\times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$1,513,946 in 2018 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$1,105,444 in 2018 dollars

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$1,855,490 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$93,102 in 2018 dollars
Indirect Annual Costs (IDAC) =	$459,861 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$552,963 in 2018 dollars

Direct Annual Costs (DAC)
DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$87,260 in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$4,924 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$250 in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$37 in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$579 in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$51 in 2018 dollars
Direct Annual Cost =		$93,102 in 2018 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,618 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$457,243 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$459,861 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$552,963 per year in 2018 dollars
NOx Removed =	11 tons/year
Cost Effectiveness =	$50,720.13 per ton of NOx removed in 2018 dollars

Cost Estimate

Graymont Cricket Mountain Kiln 3

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,693,923 in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$1,361,865 in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,930,918 in 2018 dollars
Total Capital Investment (TCI) =	$6,482,717 in 2018 dollars

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$1,693,923 in 2018 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$1,361,865 in 2018 dollars

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$1,930,918 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$90,287 in 2018 dollars
Indirect Annual Costs (IDAC) =	$428,865 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$519,152 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$81,378 in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$7,509 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$382 in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$57 in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$883 in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$79 in 2018 dollars
Direct Annual Cost =		$90,287 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,441 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$426,423 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$428,865 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$519,152 per year in 2018 dollars
NOx Removed =	15 tons/year
Cost Effectiveness =	$33,571.44 per ton of NOx removed in 2018 dollars

APPENDIX C.2.B – Graymont UDAQ Four-Factor Analysis Evaluation

State of Utah
SPENCER J. COX
Governor
DEIDRE HENDERSON
Lieutenant Governor

Department of
Environmental Quality
Kimberly D. Shelley
Executive Director
DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQP-063-21

July 27, 2021

Hal Lee
Graymont Western US Incorporated
585 West Southridge Way
Sandy, UT 84070
nstettler@graymont.com

Dear Mr. Lee,

The DAQ has received your four-factor analysis for the Graymont Western Cricket Mountain Power Plant prepared for the second planning period of Utah's Regional Haze State Implementation Plan. Enclosed is an engineering review of the analysis outlining some outstanding issues for you to be aware of. Please provide the DAQ with amendments or reasoning for these issues by **August 31st, 2021**. If you have any questions, please contact John Jenks at jjenks@utah.gov or (385) 306-6510.

Sincerely,

Chelsea Cancino
Environmental Scientist

RNC:CC:GS:jf

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Regional Haze – Second Planning Period
SIP Evaluation Report:

Graymont Western US Incorporated - Cricket Mountain Plant

Utah Division of Air Quality

July 30, 2021

SIP EVALUATION REPORT

Graymont Western US Incorporated - Cricket Mountain Plant

1.0 Introduction

The following is part of the Technical Support Documentation for the Second Planning Period of the Regional Haze SIP (aka the Visibility SIP). This document specifically serves as an evaluation of the Source facility.

1.1 Facility Identification

Name: Cricket Mountain Plant
Address: 32 Miles Southwest of Delta, Utah; Highway 257
Owner/Operator: Graymont Western US Incorporated
UTM coordinates: 4,311,010 m Northing, 343,100 m Easting, Zone 12

1.2 Facility Process Summary

Graymont Western US Inc. (Graymont) operates the Cricket Mountain Lime Plant in Millard County. The Cricket Mountain Lime Plant consists of quarries and a lime processing plant, which includes five (5) rotary lime kilns (Kilns 1 through 5). The rotary kilns are used to convert crushed limestone ore into quicklime. The products produced for resale are lime, limestone, and kiln dust. The kilns operate on pet coke and coal. Sources of emissions at this source include mining, limestone processing, rotary lime kilns, post-kiln lime handling, and truck & loadout facilities.

1.3 Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

- Rotary Lime Kiln #1 rated at 600 tons of lime per 24-hour period with a preheater and baghouse emissions control system (D-85) rated at an exhaust gas flow rate 54,000 scfm and an Air to Cloth (A/C) ratio of 3.26:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA
- Rotary Lime Kiln #2 rated at 600 tons of lime per 24-hour period with a preheater, cyclone and baghouse emissions control system (D-275) rated at an exhaust gas flow rate of 48,000 scfm and an A/C ratio of 2.9:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA
- Rotary Lime Kiln #3 rated at 840 tons of lime per 24-hour period with a preheater, cyclone and baghouse emissions control system (D-375) rated at an exhaust gas flow rate of 55,000 scfm and a A/C ratio of 2.49:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA
- Rotary Lime Kiln #4 rated at 1266 tons of lime per 24-hour period with a preheater, cyclone and baghouse emissions control system (D-485) rated at an exhaust gas flow rate of 100,000 scfm and an A/C ratio of 5:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA
- Rotary Lime Kiln #5 rated at 1400 tons of lime per 24-hour period with a preheater and baghouse emissions control system (D-585) rated at an exhaust gas flow rate of 103,000 scfm and an A/C ratio of 3.5:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA

1.4 Facility Current Potential to Emit

The current PTE values for Source, as established by the most recent NSR permit issued to the source (DAQE-AN103130044-21) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
SO_2	760.29
NO_X	3,883.85

2.0 Four Factor Review Methodology

Each source reviewed in this second planning period submitted a report on the available control technologies for SO2 and NOx emission reductions and the application of each technology to that facility. The information on available controls should consider the following four factors when analyzing the possible emission reductions:

1. Factor 1 – The Costs of Compliance
2. Factor 2 – Time Necessary for Compliance
3. Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance
4. Factor 4 – Remaining Useful Life of the Source

Although not specifically required, the recommended approach was to follow a step-wise review of possible emission reduction options in a "top-down" fashion similar to U.S. EPA's guidelines for review of BART or Best Available Retrofit Technology (as found in 40 CFR 51, Section 308 amendments, pub. July 5, 2005). The steps involved are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document results

The process is inherently similar to that used in selecting BACT (Best Available Control Technology) under the NSR/PSD (Title I) permitting program. DAQ evaluated the submissions from each source following the methodology outlined above. Where a particular submission may have differed from the recommended process, DAQ will make note, and provide additional information as necessary.

3.0 Analysis for SO2 Emission Reductions

Graymont did not supply an analysis for SO2 emissions. Although potential SO2 emissions in Graymont's most recent AO could exceed 760 tons/year, Graymont supplied no information regarding SO2 emissions or controls. Perhaps this is because actual emissions of SO2 are typically far below the listed potential. The most recent inventory for the Cricket Mountain Plant showed SO2 emissions of only 40.8 tons/year.

DAQ does not agree with this approach. The source should still provide an analysis of potential controls following the recommended process outlined in Section 2 above. Given the low level of SO2 emissions, the most likely outcome of the analysis would be that no controls are recommended, but the analysis should still be supplied.

Given the lack of information in this section, DAQ cannot comment at this time.

4.0 Analysis for NOx Emission Reductions

Graymont supplied the following regarding potential NOx controls at the Cricket Mountain Plant:

Foremost, Graymont began by establishing the baseline emissions for each of the five kilns. The Baseline emissions are the average NOx emissions for years 2014-2018, based on stack test data and annual production rates. The calculations and data used were not supplied in the analysis, but do appear to match the annual emission inventory data supplied by the company to DAQ. The baseline emissions are as follows:

Kiln 1: 85.5 tons/year
Kiln 2: 60.3 tons year
Kiln 3: 50.0 tons/year
Kiln 4: 107.1 tons/year
Kiln 5: 336.1 tons/year

Step 1:

Graymont identified four combustion-type control systems and two post-combustion-type control systems for use in reducing NOx emissions:

Combustion controls: Reduce Peak Flame Zone Temperature, Low NOx Burners (LNB), Proper Kiln Operation, Preheater Kiln Design

Post combustion controls: Selective Catalytic Reduction (SCR), Selective Non-catalytic Reduction (SNCR)

Step 2:

Step 2 of the top-down control review is to eliminate technically infeasible NOx control technologies that were identified in Step 1.

Graymont provided the following for each of the Step 1 controls:

Reduce Peak Flame Zone Temperature
In a lime kiln, product quality is co-dependent on temperature and atmospheric conditions within the system. Although low temperatures inhibit NOx formation, they also inhibit the calcination of limestone. For this reason, methods to reduce the peak flame zone temperature in a lime kiln burner are technically infeasible.

Low NOx Burners
The facility currently operates low-NOx burners in the lime kilns. Coal is delivered to the burners using a direct fired system. However, to limit NOx, only enough primary air is used to sweep coal out of the mill. This is similar to using an indirect fired system, which also limits primary air to the burners while delivering fuels. Baseline emissions are based on the operation of these low NOx

burners. All alternative methods of NOx control in this analysis will assume that the kilns continue to operate these burners.

Preheater Kiln Design/Proper Combustion Practices
Proper combustion practices and preheater kiln design are considered technically feasible for Graymont and will be considered further.

Selective Catalytic Reduction
Efficient operation of the SCR process requires fairly constant exhaust temperatures (usually ± 200°F). Fluctuation in exhaust gas temperatures reduces removal efficiency. If the temperature is too low, ammonia slip occurs. Ammonia slip is caused by low reaction rates and results in both higher NOx emissions and appreciable ammonia emissions. If the temperature is too high, oxidation of the NH3 to NO can occur. Also, at higher removal efficiencies (beyond 80 percent), an excess of NH3 is necessary, thereby resulting in some ammonia slip. Other emissions possibly affected by SCR include increased PM emissions (as ammonia salts result from the reduction of NOx and are emitted in a detached plume) and increased SO3 emissions (from oxidation of SO2 on the catalyst). To reduce fouling the catalyst bed with the PM in the exhaust stream, an SCR unit can be located downstream of the particulate matter control device (PMCD). However, due to the low exhaust gas temperature exiting the PMCD (approximately 350°F), a heat exchanger system would be required to reheat the exhaust stream to the desired reaction temperature range of between 480°F to 800°F. The source of heat for the heat exchanger would be the combustion of fuel, with combustion products that would enter the process gas stream and generate additional NOx. Therefore, in addition to storage and handling equipment for the ammonia, the required equipment for the SCR system will include a catalytic reactor, heat exchanger and potentially additional NOx control equipment for the emissions associated with the heat exchanger fuel combustion.

High dust and semi-dust SCR technologies are still highly experimental. A high dust SCR would be installed prior to the dust collectors, where the kiln exhaust temperature is closer to the optimal operating range for an SCR. It requires a larger volume of catalyst than a tail pipe unit, and a mechanism for periodic cleaning of the catalyst. A high dust SCR also uses more energy than a tail pipe system due to catalyst cleaning and pressure losses. A semi-dust system is similar to a high dust system. However, the SCR is placed downstream of an ESP or cyclone. The main concern with high dust or semi-dust SCR is the potential for dust buildup on the catalyst, which can be influenced by site specific raw material characteristics present in the facility's quarry, such as trace contaminants that may produce a stickier particulate than is experienced at sites where the technology is being demonstrated. This buildup could reduce the effectiveness of the SCR technology, and make cleaning of the catalyst difficult, resulting in kiln downtime and significant costs.

No lime kiln in the United States is using any of these SCR technologies. For the technical issues noted above, tail pipe, high dust and semi-dust SCR's are considered technically infeasible at this time.

Selective Non-Catalytic Reduction
At temperatures above 2,100°F, NOx generation starts to occur as shown in the reaction below:

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O$$

This reaction causes ammonia to oxidize and form NO instead of removing NO. When temperatures exceed 2200°F, NO formation dominates. This would likely be the case if ammonia were directly injected into the kiln tube. At temperatures below the required range, appreciable quantities of un-reacted ammonia will be released to the atmosphere via ammonia slip.

Based on the temperature profile, there are three locations in a rotary preheater lime kiln system where the ammonia /urea injection could theoretically occur: the stone/preheater chamber, the transfer chute, or after the PMCD. A fourth location that will be considered in this analysis is the kiln tube. In order for SNCR to be technically feasible, at least one of these locations must meet the following criteria: placement of injector to ensure adequate mixing of the ammonia or urea with the combustion gases, residence time of the ammonia with the combustion gases, and temperature profile for ammonia injection.

The required temperature range for the reaction may occur within the preheater. However, the location of the temperature zone varies with time and location as explained below. In each Graymont Cricket Mountain preheater, mechanical rams operate in sequence, transferring limestone, one ram at a time, from the stone chambers into the transfer chute. When a ram is in the "in" position, very little exhaust gas flows through the stone and out the duct. When the ram pulls out, the cold stone drops down and fills the stone heating chamber. The angle of repose of the stone and the configuration of the duct and chamber are such that stone does not continue to fall into the transfer chute. Hot gases, at approximately 1,950°F, then pass through the stone chamber filled with cold stone. The first gas to pass through the chamber exits the chimney at approximately 400°F. As the cold stone heats up, the exit gas temperature increases and reaches a high of approximately 600°F. The ram then strokes and pushes the heated stone into the transfer chute and starts the cycle again.

Besides the fact that the optimal temperature zone varies in location, the fact that the stone chamber is filled with stone makes using nozzles for injecting the ammonia/urea infeasible. For example, if a nozzle protruded from the wall of the stone chamber, the moving packed bed of rock would either knock it off or wear it off in a very short time. If the nozzle were inset into the wall of the chamber, the moving packed bed of stone would block the spray, and the ammonia or the urea mixture would simply coat a few of the stones, rather than mixing evenly throughout the gas stream. Similarly, if the nozzle were positioned at the roof of the preheater, the ammonia or urea would not be distributed throughout the gas stream. The preheater is approximately 75 percent full of stone, so ammonia or urea sprayed from the top of the preheater would have minimal residence time for distribution through the combustion gases before it would be blocked from distribution by the stone. Regardless of the choice of location for the nozzle, the ammonia or urea would not be effectively distributed through the large surface area of the preheater. These problems make application of SNCR in the stone chamber technically infeasible.

The temperature in the transfer chute is approximately 1,950°F for typical kilns. These temperatures are in the upper bound for the NOx reduction reaction. Temperatures this high reportedly resulted in approximately 30 percent NOx reduction in clean (non-dust-laden) exhaust streams. Lime kilns do not have clean exhaust streams at this location. Rather, the back end of the transfer chute is an extremely dusty environment, and therefore the exhaust stream is dust-laden. The one SNCR installation in the lime industry has achieved control efficiencies of around 50% with the injection nozzles installed in the bottom of the preheater, at the preheater cone. While this technology is certainly promising, this one example of SNCR installation on a rotary lime kiln does not necessarily transfer to other lime kilns. Effectiveness of SNCR is highly site-dependent, with a variety of factors having the potential to heavily influence the quantities of NOx controlled.

Given the significant range (35-58%) of control efficiencies found for cement kilns, a control efficiency considerably lower than the average for cement of 40% is expected given ideal temperature scenarios (many kilns in the cement industry that utilize SNCR do so in the combustion zone in the calciner, where temperatures are lower than in the kiln). Lime kilns experience significant technical barriers to successful SNCR implementation not shared by the cement industry. When compared to the cement process, lower NOx concentrations, shorter residence times, and temperatures more frequently outside the optimal range for SNCR application yield lower control efficiencies for lime kilns. Therefore, a control efficiency of no more than 20% is anticipated for the Cricket Mountain kilns. Locating an ammonia or urea injector nozzle in the chute to ensure mixing of the ammonia with the combustion gases would pose similar problems as the problems with the stone chamber location. Stones pour into the chute from the stone chamber, and in order to stabilize a nozzle for injection, the nozzle would need to be positioned out of the direct path of the flow of the stones. Further, the stone pieces that pour into the transfer chute from the chamber take up a large portion of the volume in the chute. Adequate mixing of the ammonia or urea with the combustion gases would be inhibited by the rock. The ammonia or urea would most likely end up on the stones, rather than mixing evenly throughout the gas stream. The low percent NOx reduction combined with the uncertainty of the nozzle placement and mixing requirement eliminate the transfer chute as a technically feasible option for Cricket Mountain Kilns 1 through 5.

SNCR Ammonia/Urea Injection Location - Inside Rotary Kiln
Ammonia/urea could be injected through a door or port in the kiln shell. Similar to the transfer chute, stone is traveling down the rotary kiln. Consequently, the nozzle would need to be positioned out of the direct path of the flow of the stones. Theoretically, the temperature inside a rotary lime kiln, which is above 2,200 F, would promote the formation of NO from injected ammonia. Graymont is aware that there have been trials at competing lime facilities with mid-kiln ammonia injection and transfer chute ammonia/urea injection for NOx reduction. However, the technology costs and technical details have not become publicly available, so Graymont cannot evaluate if the technology can be successfully applied specifically to the kilns at the Cricket Mountain facility. Since a mid-kiln ammonia injection and transfer chute ammonia/urea injection systems would require extended trials to determine if the technology can effectively control NOx on the Graymont lime kilns, Graymont must conclude that this type of SNCR is not "available" with respect to the Cricket Mountain plant because it is not commercially available. Since it is not commercially available, no vendor performance guarantees can be made to its success. Therefore, this technology cannot be considered technically feasible.

The technology is not commercially available, as defined in 40 CFR Subpart 51, Appendix Y which states that:

Two key concepts are important in determining whether a technology could be applied: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

Availability in this context is further explained using the following process commonly used for bringing a control technology concept to reality as a commercial product:

The typical stages for bringing a control technology concept to reality as a commercial product are:

- Concept stage;
- Research and patenting;
- Bench scale or laboratory testing;
- Pilot scale testing;
- Licensing and commercial demonstration; and
- Commercial sales.

A control technique is considered available, within the context presented above, if it has reached the stage of licensing and commercial availability. Similarly, we do not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as "available" for purposes of BART review. Commercial availability by itself, however, is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or "applicable" to the source type under consideration.

Though the technology is not considered technically feasible for Graymont's Cricket Mountain facility for the reasons outlined above, cost calculations for the implementation of SNCR are included for completeness assuming a 20% control efficiency for NOx.

Step 3:

As Graymont found only SNCR and LNB as potential control technologies, and as the Cricket Mountain Plant already has LNB installed, the ranking of the control technologies becomes academic.

Step 4:

Cost of Compliance
In order to assess the cost of compliance for the installation of SNCR, the EPA Control Cost Manual is used. Capital costs for the installation of the SNCR assumed a 20-year life span for depreciation, as well as the current bank prime rate of 4.75% for interest calculations. The total capital investment includes the capital cost for the SNCR itself, the cost of the air pre-heater required (per the EPA Control Cost Manual, the air preheater will require modifications for coal-fired units when SO2 control is necessary. This value is conservatively assumed for all coal-fired units evaluated for SNCR installation), and the balance of the plant. Annual costs include both direct costs such as maintenance, reagent, electricity, water, fuel, and waste disposal cost and indirect costs for administrative charges and the amortized capital costs as a capital recovery value. A retrofit factor of 1.5 is used to account for the technical barriers described above, including the existence of only one RBLC reference for an SNCR retrofit on a lime kiln, the difficulty of identifying an injection point that allows for ammonia to enter the gas stream within an optimal temperature window, the low residence times of lime kilns relative to cement kilns, and the relatively low inlet NOx concentrations that limit the effectiveness of the control technology.

SNCR Cost Calculation Summary

Kiln #	Total Capital Investment (dollars)	Total Annual Cost (dollars)	NOx Removed (tons)	Cost Effectiveness ($/ton)
1	$5,425,232	$519,152	15.5	33,571
2	$5,817,345	$552,963	10.9	50,720
3	$6,482,717	$616,847	9.0	68,276
4	$7,927,545	$755,901	19.4	39,025
5	$7,547,629	$741,500	60.8	12,199
Total	$33,200,469	$3,186,363	115.6	27,575

Timing for Compliance
Graymont believes that reasonable progress compliant controls are already in place. However, if DEQ determines SNCR is necessary to achieve reasonable progress, it is anticipated that this change could be implemented during the second planning period of regional haze (approximately ten years following EPA's reasonable progress determination).

Energy Impacts and Non-Air Quality Impacts
As previously stated, the cost of energy and water required for successful operation of the SNCR are included in the calculations, which can be found in detail in Appendix B. The installation is expected to decrease the efficiency of the overall facility, particularly as significant energy and water use is needed beyond current plan operation requirements.

Remaining Useful Life
Graymont has assumed this control equipment will last for the entirety of the 20-year amortization period, which is reflected in the cost calculations.

Graymont Conclusion:
The facility currently uses low NOx burners in its five kilns to minimize NOx emissions. The use of low NOx burners is a commonly applied technology in current BACT determinations for new rotary preheater lime kilns today. The application of SCR has never been attempted on a lime kiln. SNCR has only one RBLC entry documenting implementation on a lime kiln. The use of these controls does not represent a cost-effective control technology given the limited expected improvements to NOx emission rates, high uncertainty of successful implementation, high capital investment, and high cost per ton NOX removed. Therefore, the emissions for the 2028 on-the-books/on-the-way modeling scenario are expected to be the same as those used in the "control scenario" for the Graymont Cricket Mountain facility.

5.0 DAQ Conclusion

DAQ disagrees with several points of Graymont's analysis. Setting aside the lack of SO2 analysis, DAQ found several errors in the Graymont NOx analysis which must be corrected.

1. Two additional control technologies were identified by DAQ as potential ways of reducing NOx emissions: fuel switching and alternative production techniques. The Graymont Cricket Mountain Plant is fueled by coal – alternative fuels should be investigated. Secondly, the kilns at this facility are long horizontal rotary preheater/precalciner style kilns. Other types of kilns such as vertical lime kilns should also be investigated.
2. Graymont has claimed that SNCR is not technically feasible for installation on rotary preheater kilns. However, that is not accurate as there have been other SNCR retrofits done at preheater

rotary lime kilns. Those lime kilns include the Lhoist North America O'Neal Plant in Alabama, the Unimin Corporation lime plant in Calera, Alabama, and the rotary lime kilns of the Lhoist North America Nelson Lime Plant in Arizona, as well as the Mississippi Lime Company plant in Illinois (specifically mentioned by Graymont as the only source listed on the RBLC).

3. A NOx reduction of 20% for SNCR is too low for use in the analysis, given that Graymont itself quoted the average NOx removal at cement kilns with SNCR was 40%, with the range of NOx removal efficiency between 35%-58%. At a minimum, Graymont should have evaluated the use of SNCR at 35% removal efficiency rather than merely 20%.
4. The current bank prime rate is 3.25% and not 4.75% as stated by Graymont. The economic analysis must be recalculated using the correct interest rate.
5. The cost of an air preheater was included – which appears to be a mistake based on an error (a typographical misprint) found in EPA's SNCR control cost spreadsheets. In one place the spreadsheet uses a value of 3.0 lb SO2/ton coal while in another the value is erroneously listed as 0.3 lb SO2/ton coal. Graymont apparently included the cost of the air preheater when burning coal which does not require such equipment as part of an SNCR installation.

Although DAQ has not fully evaluated these deficiencies, it has analyzed how Graymont's cost evaluation would change if the correct bank prime interest rate were used, if the cost of the air preheater were not included, and if the removal efficiency of the SNCR were increased to a minimum of 35%. To reflect the increased cost of a more efficient SNCR than that proposed by Graymont, the direct annual costs (energy, cost of ammonia, etc) were doubled as a conservative estimate. The results of these changes are as follows:

Kiln	Capital Costs ($)	Direct Annual Costs ($)	Total Annual Costs ($)	NOx Removed (tons)	Cost Effectiveness ($/ton)
1	$3,616,821	$180,574	$328,281	30	10,943
2	$3,878,230	$186,204	$343,367	22	15,608
3	$4,321,811	$208,776	$377,952	18	20,997
4	$5,285,030	$258,458	$461,703	38	12,150
5	$5,031,753	$289,720	$485,174	122	3,977

Based on these revised results, the application of SNCR may appear to be feasible, at least for Kiln #5. Additional analysis should be provided by the source to further detail these deficiencies.

APPENDIX C.2.C - Graymont Evaluation Response

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August 31, 2021

Ms. Chelsea Cancino *(VIA Electronic Mail)*
Environmental Scientist
Division of Air Quality
Department of Environmental Quality
195 North 1950 West
Salt Lake City, UT 84014
ccancino@utah.gov

**RE: Cricket Mountain Response to UDAQ Request for Additional Information
Graymont Western US, Inc.**

Dear Ms. Cancino

Graymont Western US, Inc. (Graymont) has prepared this letter in response to comments received on July 27, 2021 from the Utah Department of Air Quality (UDAQ) concerning the regional haze four-factor analysis for the Cricket Mountain Plant. This letter follows the four-factor analysis submitted on April 29, 2020.

In order to obtain a more accurate capital and operating cost estimate, Graymont commissioned a Class 4 engineering cost estimate to ascertain capital and operating costs associated with installing and operating Selective Non-Catalytic Reduction (SNCR) Nitrogen Oxides (NOx) abatement systems on Cricket Mountain kilns. The cost estimations performed by a third party engineer indicate that the total capital cost for installation of SNCR systems at Cricket Mountain exceed $6.9 MMUSD and operating costs exceed $1.4 MMUSD annually, resulting in a cost of $17,561 per ton of NO_x removed based upon a 20 percent removal efficiency[1]. A factor of 20 percent was utilized based on the temperature and residence time limitations of the SNCR reaction zone for each Cricket Mountain kiln combined with the Low NOx baseline concentration already achieved through use of Low NOx Burners (LNB).[2]

Graymont also compared the current NOx emissions from Cricket Mountain to publicly available information for the Lhoist North America (LNA) rotary preheater kilns which utilize SCNR. We can share the following observations:

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[1] Cricket Mountain SNCR Cost Effectiveness Calculations are detailed in Appendix A

[2] Lhoist North America indicated in a November 2020 4-factor analysis that Kilns 1, 2 & 3 would be capable of a maximum NOx control of 20%

32 miles SW of Delta (Hwy 257)
Delta UT, 84624
USA

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- The existing LNBs at Cricket Mountain have effectively reduced the NO_X emission intensity to a level more than three times less than the pre-control NO_X intensity of LNA's Nelson Plant which utilizes SNCR.

- Any additive efficiency that might be gained from Cricket Mountain's use of SNCR would be marginal, at best, as SNCR NOx removal efficiency is highly dependent upon the inlet NOx concentration, reaction zone temperature and residence time, all of these factors reduce the anticipated efficiency that can reasonably be assumed for the Cricket Mountain Kilns.

- The LNA SNCR technology for rotary lime kilns is proprietary and not unconditionally commercially available to Graymont. The technology appears to be patented, adding to its cost and the uncertainty as to its technical feasibility.

- SNCR addition at Cricket Mountain would have unintended negative environmental impacts and visibility disbenefits, including the generation of condensable particulate, an identified regional haze primary pollutant.

- The Cricket Mountain facility operates 5 rotary preheat lime kilns, each of which are substantially different technology than mid-fired cement kilns (more conducive reaction zone temperatures, higher NOx concentrations, and longer residence times). As such, it is not appropriate to draw direct comparisons with application of SNCR between cement kilns and lime kilns as referenced in your letter.

Based on Graymont's findings, requiring the installation of SNCR at Cricket Mountain would be unreasonable because it would be infeasible, unnecessary and counterproductive to making reasonable progress towards the goal of preventing future, and remedying any existing, anthropogenic impairment of visibility in mandatory Class I Federal areas in the context of Utah's pending Round 2 Regional Haze State Implementation Plan (RH SIP). Cricket Mountain's successful implementation of LNBs effectively controls NOx at the point of generation in kilns. These NOx rates are sufficient for inclusion in the UDAQ RH SIP since they are already some of the lowest achieved in the industry and far exceed what has been deemed BART at other kilns (such as the SNCR controlled kilns at the LNA Nelson Facility).

Evaluation of Sulfur Dioxide (SO_2) Emissions Reductions

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As provided in the UDAQ response, the SO2 emissions from the facility are very low as the reference year 2014 emissions inventory reflected 40.8 tons per year. This presents a Q/d of 0.3 for SO2 which places this site in a category where potential for these emissions to impact Class 1 area visibility are very low to negligible. Consistent with this data, Utah Department of Air Quality indicated in December 2019 not to include SO2 in our analysis because the emissions were so low. Please refer to Appendix B where you will find the email from Jay Baker confirming what was discussed in the meeting.

Evaluation of Alternative Fuels

Currently the Cricket Mountain kilns utilize coal as the fuel source for lime production. This fuel is utilized based on coal meeting the required Btu values to effectively calcine limestone within our operations. There are not comparable Btu value fuels in the required quantities currently available to the facility. Natural gas, a comparable Btu value fuel is currently not available to the site as the nearest natural gas pipeline is approximately 18 miles away and would require substantial infrastructure, easements, and process modification to connect to this supply. The resultant impact of natural gas on NOx emissions for the site would be negligible or equivalent to what is seen with the current coal combustion. Therefore, natural gas, for purposes of this regional haze analysis, would not be feasible based on the tens of millions of dollars that would be required to connect to this pipeline with no notable change in NOx emissions with natural gas.

Vertical Kiln Technology

In the comments received from UDAQ, Graymont was asked to investigate additional control technologies specifically vertical lime kilns. In the original four factor analysis this was not evaluated as an additional control technology as it is not an add-on control. In order to replace the existing Cricket Mountain kilns with vertical lime kilns Graymont would need to demolish the existing kilns and infrastructure to effectively build a new plant. This would be an extremely costly endeavor which would require hundreds of millions of dollars. Aside from the enormous cost to build a new plant with new vertical kilns, this could also lead to loss of customers and production volume as Cricket Mountain may not be able to produce the quantity and/or quality of lime to existing customers specifications.

Existing Low NOx Burners at Cricket Mountain Effectively Reduce NO_X Emission Intensity

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Graymont's Cricket Mountain kilns are currently equipped with LNB's that have effectively demonstrated excellent control of NOx generation during the combustion process. For purposes of comparison, the LNA Nelson, AZ facility information is utilized in our evaluation based on the availability of comprehensive information regarding application of SNCR technology. Table 1, below, compares the NO_X emission limits applicable to Graymont Cricket Mountain and LNA Nelson kilns. As shown, the uncontrolled NO_X emissions from the LNA Nelson plant prior to the installation of SNCR were substantially higher than the current NO_X emission levels achieved by the Graymont Cricket Mountain kilns, and even higher than the Cricket Mountain emission limitations.

Table 1. Summary of NO_X Emissions from the Graymont and Lhoist Lime Kilns

Facility	Kiln	Pre-SCNR Actual Emissions [a, b] (lb/ton lime)	Current Calculated Permit Emission Limit [c] (lb/ton lime)	SNCR Permit Emission Limit [a] (lb/ton lime)
Graymont Cricket Mountain	Kiln 1	2.15	3.6	--
	Kiln 2	2.15	4.8	--
	Kiln 3	0.93	4.6	--
	Kiln 4	2.33	3.8	--
	Kiln 5	2.42	3.6	--
Lhoist Nelson	Kiln 1	7.59	--	3.80
	Kiln 2	5.21	--	2.61

a. Uncontrolled emissions and the BART emission limits for the Lhoist Nelson plant kilns are obtained from the "Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Proposed Rule." Federal Register Vol. 79, No. 32 (February 18, 2014). Tables 18 and 19. https://www.govinfo.gov/content/pkg/FR-2014-02-18/html/2014-02714.htm

b. Actual emissions are based on the 2014 annual emission inventory submitted by Graymont.

c. Note that Cricket Mountain does not have a permit limit on a lb NO_X per ton of lime basis for kilns 1-4. These values are calculated solely for the purpose of comparison to cited Lhoist Nelson plant values and should not be construed as representing a permitted limit for the Cricket Mountain facility.

LNA realized this performance disparity in technologies as it too attempted to implement LNB controls at its Nelson Plant before turning to less effective SNCR. Yet, LNA was not able to make LNB work. This is explained in the 2013 Technical Support Document for Arizona's Federal Implementation Plan:

> "In 2001, LNA experimented with the installation of a bluff body LNBs on the Nelson Lime kilns. These LNB's wore out in approximately six months,

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> impacted production, caused brick damage, and resulted in unscheduled shutdowns for the kilns. We recognize that the staged combustion principle of LNB can present operational difficulties and potential product quality issues for lime production that are not exhibited in the cement industry. At this time, however, we consider LNB to be technically infeasible for the Nelson Plan Cement (lime) kilns, since we do not have any information to suggest otherwise at this time. The technical feasibility of LNB will be re-evaluated for lime kilns in a subsequent reasonable progress planning periods."

The site- and unit-specific feasibility of LNB emission control is supported by Graymont's successful implementation of this technology on the Cricket Mountain lime kilns. Graymont cannot speculate on why bluff body LNB's were unsuccessful at LNA's Nelson plant in 2001, but this failure forced LNA to advocate for use of its much less effective SNCR technology as BART in the Round 1 RH SIP process. Arizona proposed, and EPA approved, LNA's SNCR technology as BART. However, Graymont has demonstrated that bluff body LNBs can be successfully implemented on lime kilns and achieve NOx emission reductions that far exceed what might be achieved with SNCR. Plainly stated, Cricket Mountain's use of LNBs far exceeds what has been deemed to be BART, at least for the LNA Nelson Plant. It would be unreasonable to require Cricket Mountain to go even further in controlling NOx (i.e., beyond BART), especially when there is no evidence that such controls are needed or effective. This assertion is supported by the EPA's BART determination for the Nelson plant, where the Agency concludes that the proposed BART limit *"is consistent with the use of low-NO_X burners (LNB) and SNCR as control technologies"*[3] – indicating the emission limit would be similar for either technology. As demonstrated in the table above, Graymont can achieve actual emission levels on a 12-month basis with LNB technology that are lower than the Lhoist permitted values using SNCR.

Graymont is committed to continuing the use of LNB at Cricket Mountain and achieving the attendant NOx emission reductions in the future. Further reductions from Cricket Mountain are not reasonably necessary or needed to fulfill UDAQ's RH SIP obligations. Indeed, EPA recently approved the District of Columbia RH SIP concluding that it was reasonable for the District to have excluded a source from even undergoing a four-factor analysis where that facility had already installed LNB

[3] Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Proposed Rule. Federal Register Vol. 79, No. 32 (February 18, 2014). Tables 18 and 19. https://www.govinfo.gov/content/pkg/FR-2014-02-18/html/2014-02714.htm

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and was achieving low NOx emission rates. See, 86 Fed. Reg. at 19806 (April 15, 2021).

LNB technology represents a superior level of NOx control at the point of generation as compared SNCR where, in the case of the lime industry, includes unintended negative consequences that would be experienced in the form of condensable particulate formation as a byproduct of SNCR control.

Additive Efficiency for Cricket Mountain SNCR NOx Control Beyond LNBs would be Marginal at Best

As discussed above, Graymont has already implemented LNB control at Cricket Mountain, resulting in control efficiency comparable to, or better than, SNCR control efficiencies. As indicated in the four-factor analysis submitted by Graymont for the Cricket Mountain facility the control efficiency achieved by SNCR as a retrofit technology is highly dependent on the inlet NO_X concentration, temperature of reaction zone and residence time.

Even if SNCR could provide some emission reduction for Graymont's Cricket Mountain kilns, the achievable control efficiency is expected to be much lower than the Nelson lime kilns because of Nelson's higher uncontrolled NO_X emission rates. This difference is in large part due to the successful implementation of LNB's on the Cricket Mountain kilns.

While it is difficult to ascertain what the as-built additive removal of SNCR control on top of LNB control might be, we can expect that SNCR control would be poor. From LNA's Apex plant November 2020 4-Factor submission to Nevada Division of Environmental Protection (NDEP):

> *"....this (reported 50% NOx removal efficiency conducted at a different LNA facility) one example of SNCR installation on a preheater rotary lime kiln does not necessarily transfer to other lime kilns. Effectiveness of SNCR is highly source-dependent, with a variety of factors having the potential to heavily influence the quantities of NOx controlled."* ...."[4]

And:

[4]REGIONAL HAZE SECOND PLANNING PERIOD FOUR-FACTOR ANALYSIS, Lhoist North America, Apex Lime Plan, Source 00003, Page 33, Trinity Consultants, March 2020, Revised June 2020, Revised November 2020.

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> "…. *When compared to the cement process, lower NOx concentrations, shorter residence times, and temperatures more frequently outside the optimal range for SNCR application yield lower control efficiencies for lime kilns.* ***Therefore, a control efficiency of no more than 20% at (Apex plant) Kiln 1, 2 and 3 and no more than 50% at Kiln 4, can be guaranteed at the Facility's kilns without testing.*** *Trying to achieve a 50% removal efficiency on Kilns 1, 2 and 3 is more likely to result in ammonia slip which can cause its own health and visibility problems….*"[5]

LNA's acknowledgement that SNCR NOx removal is kiln specific is instructive for any expectation that the Cricket Mountain kilns could achieve greater than 20% NOx removal efficiency. Graymont agrees with LNA on this point.

Graymont does not believe it is rational or reasonable to assume that Cricket Mountain kilns are capable of an additional 50% NOx reduction. Through implementation of LNBs, the Cricket Mountain kilns show an average emission rate of 2.00 lbs of NOx / ton of lime compared to the Nelson Kilns 1 and 2 pre-control average of 6.4 lbs of NOx / ton of lime. The Nelson Kilns generated NOx emissions are more than three times greater than the current LNB emissions in Cricket Mountain. Based on the significantly reduced gas stream NOx concentrations at Cricket Mountain, the SNCR additive removal efficiency would decay making this control less effective. For kilns where LNB technology has already been applied, it is likely that any additive removal efficiency benefit would be marginal at best.

Graymont did not request a vendor guarantee for the Class 4 engineering cost estimate we received from our vendors. Vendor guarantees would be premature at the level of a Class 4 engineering estimate. Additional design and initial feasibility testing would be required to begin to make any estimate about the viability, regardless of the efficiency, of such a novel abatement system. Graymont's vendors are not, at the present time, in any position to make guarantees about removal efficiency at the current conceptual stage of this project.

Moreover, and elaborated upon below, ammonia slip from an SNCR application would result in an unintended, but material, increase in condensable particulate emissions in the form of ammonium nitrate, ammonium sulfate and ammonium chloride salts which would contribute anthropogenic with new additive impacts on visibility pollutants of concern. In this manner, a well-intended NOx abatement

[5] REGIONAL HAZE SECOND PLANNING PERIOD FOUR-FACTOR ANALYSIS, Lhoist North America, Apex Lime Plan, Source 00003, Page 33, Trinity Consultants, March 2020, Revised June 2020, Revised November 2020. Emphasis added.

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project would almost certainly result in cost prohibitive, low value installations resulting in impact(s) that are counterproductive to UDAQ's RH program goals.

In summary, Graymont cannot characterize the potential for SNCR NOx reduction at Cricket Mountain beyond 20% because the removal efficiency of the system cannot be estimated or derived. Any vendor guarantee on the removal efficiency of a conceptual system is premature and would mean little at this time, even if a vendor were willing to provide one. Moreover, achieving additive control over and above LNB control with emission intensities three times less than LNA's Nelson Plant ensures that removal efficiencies would be marginal at best.

SNCR Technology for Rotary Lime Kilns is not Unconditionally Commercially Available to Graymont

Based upon available information, it appears that the SNCR technology is proprietary to LNA. Graymont conducted a patent search to identify intellectual property owned by LNA and directed toward SNCR on preheater lime kilns. Graymont identified LNA Patent 7,377,773: "Method of Reducing NO_x Emissions in Rotary Preheater Mineral Kilns" from May 27, 2008. While Graymont has not investigated the validity of the patent, nor does Graymont concede the patentability of the SNCR technology, it is likely that the SNCR technology employed by LNA, specifically directed toward preheater lime kilns, is protected by a patent. The reader is directed to Appendix C wherein a discussion of LNA's SNCR patent can be reviewed.

This is consistent with conclusions made by the Illinois Environmental Protection Agency (Illinois EPA) in the Responsiveness Summary for the PSD permit application for Mississippi Lime company in 2015, where the Illinois EPA noted "Lhoist continues to note that the SNCR systems for those kilns may incorporate proprietary technology and equipment and will need to be treated as confidential business information by USEPA."[6]

As stated in the four-factor analysis, 40 CFR Subpart 51 Appendix Y defines availability, a prerequisite for determining whether a technology could be applied for the Regional Haze Rule, stating that "a technology is considered 'available' if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term." Inherent in the determination made

[6] Illinois Environmental Protection Agency Bureau of Air, "Responsiveness Summary for the Public Comment Period on the Issuance of A Construction Permit/PSD Approval for Mississippi Lime Company to Construct a Lime Plant in Prairie du Rocher, Illinois," Page 23. (September 2015). http://www.epa.state.il.us/public-notices/2014/mississippi-lime/responsiveness-summary.pdf

by the Illinois EPA for PSD-BACT (a program with different and more stringent requirements than the regional haze program) is the conclusion that this technology is not considered unconditionally commercially available.

LNA's existing SNCR patent directed toward preheater lime kilns, if determined to be valid and patentable, could have material implications for Graymont's attached cost analysis. Graymont's current cost analysis does not make any attempt to reconcile potential intellectual property costs that might be associated with a patent license or any royalty payment structure. Were Graymont to make some assessment of those potential costs, the already infeasible costs associated with SNCR at Cricket Mountain would become even more untenable for installation.

Instead of making any attempt to represent what additional costs for intellectual property might look like beyond the costs represented in the cost analysis, Graymont instead provides UDAQ with the following disclaimers:

- Graymont has not investigated the validity of LNA's '773 Patent, nor do we concede the patentability of the LNA SNCR technology,
- It is our belief that LNA will defend its exclusive patent rights if the LNA SNCR technology is implemented by Graymont or at a minimum expect Graymont to take a license to the '773 Patent in order to implement the technology,
- Graymont notes here that project capital and operational costs represented in this letter and its attachments do not attempt to account for any licensing fees or royalties that might apply to this analysis and so estimated costs could be substantially higher than estimated in this letter and its attachments.

As UDAQ ponders its Regional Haze SIP, the agency is encouraged to consider that the implications of LNA's intellectual property holdings as they relate to Utah's Regional Haze initiative are not fully understood at this time by Graymont.

Updated Cost Calculations and Vendor Estimate

In order to obtain a more accurate capital and operating cost estimate for the installation of SNCR, Graymont commissioned a Class 4 engineering cost estimate. The Class 4 estimate was performed by an independent third party with a sound engineering approach.

The Class 4 results are provided in Table 2:

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Table 2: Summary of Cricket Mountain SNCR Costs[7]

Kiln	Total Capital Investment	Annual Operating Cost	Total Annual Cost[8]	Tons NOx Reduced[9]	Cost Effectiveness ($/ton of NOx removed)
1	$1,253,169	$181,511	$266,806	13.7	$19,519
2	$1,253,169	$236,442	$321,737	22.8	$14,130
3	$1,253,169	$160,283	$245,578	10.2	$24,191
4	$1,253,169	$186,881	$272,176	14.6	$18,695
5	1,898,051	$667,035	$796,223	70.6	$11,270
Total	**$6,910,727**	**$1,432,152**	**$1,902,520**	131.9	**$17,561**

Note that Graymont's cost estimate makes no attempt to reconcile any potential intellectual property costs that might be required in the event that Graymont were forced to pursue licensing or royalty fees.

The Technical Feasibility of SNCR on Preheater Lime Kilns is a Novel Technology Not Proven in Broad Application

Lime kilns vary considerably in design, so implementation at two facilities does not indicate feasibility for all lime kilns. Particularly in the case of technologies that are not widely used in an industry, where the emission unit in question is as site-specific and unit-specific in its operating parameters and methods as a lime kiln, technical feasibility must be assessed on a unit-by-unit basis. Each kiln has its own design and operating conditions, with variables like temperature, residence time, and physical configuration playing a major role in whether a control technology retrofit is possible and what level of emissions control is achievable.

Graymont has reviewed the design characteristics specific to the kilns installed at the Cricket Mountain facility to determine the temperature and residence time of kiln gas in the transfer chute. The models indicated an average temperature of 1,727 °F and a maximum of 2,100 °F. For residence time, the models indicated that the average residence time of gases in the transfer chute is 0.5 seconds (maximum of 0.6 seconds). Please see Appendix E to review Graymont's temperature and residence

[7] Class 4 engineering cost estimates are detailed in Appendix D.
[8] Total Annual Cost = Annual Operating Cost + Annual cost of capital investment at 3.25% for 20 years
[9] Tons NOx reduced based upon 20% control efficiency.

time calculations. The EPA Air Pollution Control Cost Manual (CCM) cites an ideal temperature range of 1,550 °F to 1,950 °F.

The CCM also states that a residence time of 1 second is required for sources to be considered well-suited for SNCR. With a residence time of half the recommended minimum value provided by the EPA, the concerns expressed in Graymont's four-factor analysis regarding the ability of an SNCR ammonia injection system to achieve sufficient mixing for the conversion of NO_X emissions are substantiated. The short residence time, in conjunction with the high dust loading in the transfer chute, pose substantial technical concerns for the feasibility of SNCR as a NO_X control technology.

SNCR Addition at Cricket Mountain would have Unintended Negative Repercussions and Generate Condensable Particulate

As part of the regional haze program UDAQ must also consider the energy and environmental impacts of SCNR and has the flexibility to consider visibility benefits.[10] On this point, condensable particulate emissions from lime kilns occurs when cations and anion species react in the kiln system to create condensable particulate salts. Kiln exhausts are cation-limited as ample anion species are available to form salts. Sulfates, nitrates, and chloride species are present in lime kiln exhaust but do not form condensable particulate species at levels that create non-compliance with condensable particulate emission limits due typically to the relative stochiometric unavailability of a candidate cation species.

The addition of SNCR in lime kilns requires the addition of ammonia or urea to lime kiln exhausts to control NOx emissions. While addition of reagent in lime kiln exhausts can, in favorable physical configurations with appropriate temperature and residence times, have the effect of abating NOx production, the addition of reagent will also have unintended negative effects. Over-injection of reagent results in ammonia slip, which produces unintended ammonia emissions, but also contributes to the formation of condensable particulate. Reactions with sulfates, chlorides and nitrates that were previously cation-limited are no longer cation-limited and robust salt formation of ammonium sulfate, ammonium chloride and ammonium nitrate are promoted. Even when ammonia slip is limited through monitoring and injectate control, condensable particulate formation will be enhanced in the kiln system.

[10] See, *e.g.*, Responses to Comments on Protection of Visibility: Amendments to Requirements for State Plans; Proposed Rule (81 FR 26942, May 4, 2016), Docket Number EPA–HQ–OAR–2015–0531, U.S. Environmental Protection Agency at 186; August 2019, EPA issued "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" ("2019 Guidance") at 36–37.

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Generation of additional condensable particulate creates two practical problems relative to this discussion. First, increases of condensable particulate salt formation will have the immediate effect of increasing PM2.5/PM10 emissions from the Cricket Mountain kilns. Condensable particulate emissions from the Cricket Mountain kilns are currently emitted at a rate where Graymont can remain in compliance with PM10 and PM2.5 emission limits. Addition of reagent to the kiln exhaust will remove the cation-limited condition in the kiln exhausts and promote additional condensable salt formation not accounted for in Graymont's current air permit. Graymont anticipates that if SNCR systems are required on Cricket Mountain kilns that the addition of more cation species will require study to characterize condensable salt formation increases and to develop a program to increase the PM10 and PM2.5 emission limits at Cricket Mountain.

A second problem envisioned if SNCR were required at Cricket Mountain would be post control generated sources of ammonium nitrate, ammonium sulfate and ammonium chloride emissions produced as PM10 emissions. SNCR would not benefit visibility at the Class I areas if NOx reductions would simply be replaced by PM10 emissions.[11] It is noteworthy to recall that condensable particulate emissions cannot be controlled by gas stream filtration. Condensable particulate emissions can only be controlled by limiting the availability of condensable particulate salt-forming species in the kiln system – which means avoiding the installation of SNCR.

Another environmental impact associated with retrofitting SNCR on the Cricket Mountain facility would be the addition of ammonia or urea storage and handling systems. Anhydrous ammonia and aqueous ammonia above 20 percent are considered dangerous to human health. SNCR also creates potential safety hazards associated with the transportation of anhydrous ammonia.[12]

If you have any questions or comments about the information presented in this letter, please do not hesitate to call me at 814-353-2106 or Nate Stettler at 801-716-2621.

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[11] NDEP recognized the potential visibility disbenefits of SNCR in previous BART analyses. See, Revised Nevada Division of Environmental Protection BART Determination Review of NV Energy's Tracy Generating Station Units 1, 2 and 3(revised October 15, 2009); Revised Nevada Division of Environmental Protection BART Determination Review of NV Energy's Fort Churchill Generating Station Units 1 and 2 (revised October 15, 2009).

[12] NDEP recognized the potential for ammonia releases in previous BART analyses. *Supra*, fn. 21.

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Sincerely,

John A. Maitland
Director, Corporate Affairs, Environment & Sustainability North America
GRAYMONT

Attachments

cc:

Blake Bills, Graymont
Robert Covington, Graymont
Hal Lee, Graymont
Nate Stettler, Graymont

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Appendix A

Cricket Mountain SNCR Cost Effectiveness Calculations

Cost Estimate

Total Capital Investment (TCI)*	
SNCR Capital Costs ($SNCR_{cost}$)	
Kiln 1	$1,253,169
Kiln 2	$1,253,169
Kiln 3	$1,253,169
Kiln 4	$1,253,169
Kiln 5	$1,898,051
Total SNCR Capital Costs ($SNCR_{cost}$) =	$6,910,727

*Based on class 4 engineering cost estimate

Annual Costs*	
Total Annual Cost (TAC)	
TAC = Direct Annual Costs + Indirect Annual Costs	
Kiln 1, Kiln 2, Kiln 3, Kiln 4, Kiln 5 Combined	$1,902,520
Direct Annual Costs (DAC)	
Kiln 1, Kiln 2, Kiln 3, Kiln 4, Kiln 5 Combined	$1,432,152
Indirect Annual Cost (IDAC)	
IDAC = Capital Recovery Costs	
Capital Recovery Costs	$470,368
Rate =	3.25%
Years =	20

*Based on class 4 engineering cost estimate

Cost Effectiveness*	
Cost Effectiveness = Total Annual Cost/ NOx Removed/year	
Cost Effectiveness =	$17,561 per ton of NOx removed
Total Annual Cost (TAC) =	$1,902,520
Kiln 1	19,519.0 per ton of NOx removed
Kiln 2	14,130.0 per ton of NOx removed
Kiln 3	24,191.0 per ton of NOx removed
Kiln 4	18,695.0 per ton of NOx removed
Kiln 5	11,270.0 per ton of NOx removed

*tons of Nox reduced based on 20% control efficiency

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Appendix B

Email from UDAQ Regarding SO_2 Analysis

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Appendix C

LNA SNCR Technology Michael Best Legal Memo

Generally speaking, the '773 Patent relates to a method for reducing NOx emissions from rotary preheater mineral kilns by coupling the temperature control and gas composition afforded by high temperature mixing systems with the injection of nitrogen containing chemical additives at a predetermined location and within an optimal temperature window. The method is specifically directed to rotary preheater limestone kilns.

The '773 Patent includes 9 claims that define its invention, and what LNA has the exclusive right to make, use, sell and offer for sale. Two of the claims are independent (claims 1 and 9), which include the broadest recitation of LNA's invention, and remaining claims 2-8 depend from claim 1.

The '773 Patent claims as its invention a method of reducing NOx emissions in a rotary preheater limestone kiln having a feed zone, a preheat zone, a calcining zone and a cooling and discharge zone. Independent claim 1 requires each of the following elements, or an equivalent thereof:

1. Feeding a supply of limestone to the feed zone;
2. Moving the limestone through the preheat zone having a preheat temperature range resulting from the circulation of hot gases from the calcining zone to the preheat zone, the preheated limestone being passed to an upper end of the calcining zone where the limestone is heated to a temperature and for a time sufficient to convert the limestone to quicklime;
3. Introducing a source of ammonia or an ammonia precursor at a point where the temperature in the kiln is within 1600°F to 2200°F;
4. Injecting turbulent air at a preselected point or points downstream of the preheat zone; and
5. Passing the calcined limestone from the calcining zone to the cooling and discharge zone and discharging the resulting quicklime from the kiln.

Independent claim 9 requires elements 1, 2, 4 and 5 listed above for claim 1, or an equivalent thereof, as well as:

6. Introducing a source of ammonia or an ammonia precursor into the limestone upstream of the primary region of the calcining zone;
7. Introducing the source of ammonia or an ammonia precursor at a point where the kiln temperature is generally in the preheat temperature range from about 1600°F to 2200°F.

Because no information is available directly from LNA or NDEP as to what the LNA SNCR technology entails, we are assuming that the LNA SNCR technology mentioned by NDEP is the SNCR technology described and patented by the '773 Patent. Therefore, the LNA SNCR technology is not commercially available to Graymont because it is protected by the '773 Patent and LNA has the exclusive right to make, use, sell and offer for sale the LNA SNCR technology.

We have not investigated the validity of the '773 Patent, nor do we concede the patentability of the LNA SNCR technology. However, because the LNA SNCR technology is patented, it is our belief that LNA will defend its exclusive patent rights if the LNA SNCR technology is implemented by Graymont or at a minimum expect Graymont to take a license to the '773 Patent in order to implement the LNA SNCR technology.

If Graymont is required to implement the LNA SNCR technology, it will likely need to do so subject to a license from LNA to the '773 Patent as the LNA SNCR technology is not

Michael Best

Memorandum

VIA EMAIL

Client Matter: 212321-9001

To: Hal Lee, Graymont Western US

From: Gayle A. Bush
Todd E. Palmer

Date: March 9, 2021

Subject: LNA SNCR Technology

Graymont Western US Inc. (Graymont) owns and operates the Pilot Peak lime kiln facility located near West Wendover, Nevada. The Pilot Peak Facility achieves low NOx emission rates through the utilization of low NOx burner (LNB) technology in its kilns. Nonetheless, the Nevada Division of Environmental Protection (NDEP) has initially selected the Pilot Peak Facility for an analysis of additional NOx emission control measures that might demonstrate reasonable further progress towards achieving Nevada's visibility improvement goals in the State's Round 2 regional haze SIP. Lhoist North America (LNA) has developed SNCR technology for use on lime kilns and has installed the technology at five facilities. NDEP has suggested that the Pilot Peak Facility also utilize the LNA SNCR technology to further reduce NOx emissions beyond what is already being achieved with LNBs. LNA has informed NDEP that the technology capital costs are approximately $500,000 per kiln to install; however, Graymont believes the costs will be substantially higher.

There is not much information available regarding the LNA SNCR technology or whether LNA has sought or received patents for its technology. Graymont asked Michael Best to conduct a patent search to determine whether LNA has any patents or patent applications for its SNCR technology, and to learn more about the SNCR technology it is pushing regulators to require. In summary, we identified one granted patent that is owned by LNA and is related to use of SNCR technology for NOx emission reduction in a rotary preheater mineral kiln.

We conducted a patent search to identify any US patents or patent applications 1) owned by LNA, or its related companies, and 2) related to SNCR technology. The search yielded about 58 active and 69 expired/abandoned patents/applications for LNA and its related companies. Based on our understanding of SNCR technology, we analyzed the patent search results and identified U.S. Patent No. 7,377,773 ("the '773 Patent") as the only result relevant to SNCR technology.

The '773 Patent was filed on August 3, 2006 by Chemical Lime Company and granted on May 27, 2008. The '773 Patent will expire on September 8, 2026. Post-grant, Chemical Lime Company changed its name to Lhoist North America, Inc.

commercially available without a patent license. Any license will likely be subject to a license fee, which will incur additional costs associated with an implementation of the LNA SNCR technology at the Pilot Peak Facility.

Most patent licenses are subject to one or more of the following types of license fees: an up-front license fee, continuous lump sum license fee payments, and/or rolling royalty fee payments. In our experience, license fees are difficult to predict as average fees and rates are typically industry specific, there is uncertainty and changes in market over the term of the patent, and most importantly licenses are subject to negotiation between the licensor and licensee.

Due to the factors listed above, predicting an up-front license fee or continuous lump sum license fee payment is challenging. Estimating potential license fee costs associated with a royalty fee presents challenges as well; however, there are for-fee services available that will provide average royalty rate information on an industry-by-industry basis, as well as by deal-type. These resources can be used as a starting point for estimation purposes.

Under a license based on a reasonable royalty, the fee might be based on a production metric associated with the Pilot Peak Facility and the LNA SNCR technology. For example, the royalty could be based on sales revenue of the final product or a production quantity, such as weight of produced quicklime (e.g., price per pound produced). In our experience, royalties for non-exclusive licenses based on net sales are typically 1% to 5% of the net sales. We did identify one article from an on-line legal service provider (Patent Licensing Royalty Rates | UpCounsel 2020) that referenced an average royalty rate for energy and environmental industries as 8% and construction industries as 5.6%; however, this estimate is based on royalties offered by others in comparable industries and does not truly compare similar deals. Based on the above information, we would guess that a royalty for a license to the '773 Patent could be in the range that would add significant expense to the cost of installing and operating the LNA SNCR technology – assuming the patent is valid.

In summary, implementing the LNA SNCR technology at the Pilot Peak Facility would incur additional costs associated with the '773 Patent that are beyond the estimated $500,000 per kiln capital cost to install. In order to implement the LNA SNCR technology, Graymont would need to negotiate a license with LNA for use of the technology.

GAB:mgd

Attachments

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Appendix D

Class 4 Engineering Cost Estimate for Cricket Mountain
SNCR Capital and Operating Costs

Project: Cricket Mountain SNCR Estimate

Budget Class 4
Revised: 2021-06-21
By: Sean Brinkmann

Description	References	Qty	Unit	Material & Equipment Unit cost	Material & Equipment Cost	Qty	Unit	Installation Unit cost	Installation Cost	TOTAL K5	TOTAL K4	TOTAL K3	TOTAL K2	TOTAL K1	Comments
Penta Project Cost Estimate															
Contractor General									76,450 $	76,450 $	76,290 $	76,290 $	76,290 $	76,290 $	
Construction Equipment									75,600 $	75,600 $	75,600 $	75,600 $	75,600 $	75,600 $	
Civil Site Work, Parking Area and Road (Gravel access and parking for offloading delivery truck)					6,367 $				6,600 $	12,967 $	12,967 $	12,967 $	12,967 $	12,967 $	
Fire Water Extension Allowance		100	lnFT		5,249 $				4,143 $	9,392 $	9,392 $	9,392 $	9,392 $	9,392 $	
Ammonia Tank Piers, Secondary Containment, Roof Structure, and Pump Pad					60,952 $				46,800 $	96,752 $	60,051 $	60,051 $	60,051 $	60,051 $	only one pump skid, with Kiln 5
Fencing					16,000 $				4,600 $	20,600 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Ammonia Tank and Pump, Meter Systems		30000	gal		284,600 $				39,000 $	323,600 $	305,170 $	305,170 $	305,170 $	305,170 $	
Refractory Repair Inside Kiln	Not included									not included	not included	not included	not included	not included	assumed to be with other Kiln repair costs
Pipe 2" dia. from Truck Unload to Storage Tank		50	lnFT		3,152 $				2,750 $	5,902 $	5,202 $	5,202 $	5,202 $	5,202 $	
Pipe 2" dia from Tank to Preheater Transfer Pumps		50	lnFT		5,498 $				3,410 $	8,908 $	8,908 $	8,908 $	8,908 $	8,908 $	
Pipe 1.5" dia. from Pumps to Preheater		350	lnFT		24,719 $				18,904 $	43,623 $	42,900 $	42,900 $	42,900 $	42,900 $	
Pipe 2" dia Up Preheater to Injection		100	lnFT		3,876 $				3,777 $	7,653 $	6,448 $	6,448 $	6,448 $	6,448 $	
Compressed Air Tap, Piping, Receiver and Water Dual Basket Strainer, Water Pipe		200	lnFT		31,851 $				21,903 $	53,754 $	28,704 $	28,704 $	28,704 $	28,704 $	
Install Injection Nozzles in Chute Below Preheater		4	ea		5,197 $				7,847 $	13,043 $	13,043 $	13,043 $	13,043 $	13,043 $	
Electrical		1	lot		63,383 $				63,382 $	126,765 $	92,482 $	92,482 $	92,482 $	92,482 $	Kiln 5 has truck unload pumps
Controls	By Andritz						hrs	0 $		By Andritz	By Andritz	By Andritz	By Andritz	By Andritz	
HAZOP Senior Engineer Participation									12,000 $	12,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
TOTAL FOR Penta Base Estimate										**887,120 $**	**737,236 $**	**737,236 $**	**737,236 $**	**737,236 $**	Contingency carried on total project, not specific segments to not compound contingency
Penta Indirect Cost Estimate															
Taxes										not included	not included	not included	not included	not included	
Freight	5%								16,184 $	16,184 $	16,184 $	16,184 $	16,184 $	16,184 $	
Permits									35,000 $	35,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Geotechnical									10,000 $	10,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Surveys / Scans									20,000 $	20,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Contractor Support During Commission		1							31,020 $	31,020 $	31,020 $	31,020 $	31,020 $	31,020 $	
NDT Pipe Inspection									10,000 $	10,000 $	10,000	10,000	10,000	10,000	
Engineering	15%									133,068 $	66,534 $	66,534 $	66,534 $	66,534 $	
Contractor Overhead and Profit	10%									114,239 $	86,097 $	86,097 $	86,097 $	86,097 $	
TOTAL Penta Indirect Cost Estimate										**369,511 $**	**209,835 $**	**209,835 $**	**209,835 $**	**209,835 $**	
Andritz Automation Controls Estimate															
PLC Equipment									58,333 $	11,667 $	11,667 $	11,667 $	11,667 $	11,667 $	
Instruments									15,167 $	3,033 $	3,033 $	3,033 $	3,033 $	3,033 $	
MCC									39,833 $	7,967 $	7,967 $	7,967 $	7,967 $	7,967 $	
Detailed Design & Programming									90,667 $	18,133 $	18,133 $	18,133 $	18,133 $	18,133 $	
Site Services and Expenses									56,167 $	11,233 $	11,233 $	11,233 $	11,233 $	11,233 $	
Burner management system (BMS) programing - ammonia sensors									30,000 $	30,000 $	30,000 $	30,000 $	30,000 $	30,000 $	
HAZOP Senior Engineer									12,000 $	12,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
TOTAL FOR Controls Estimate										**94,033 $**	**82,033 $**	**82,033 $**	**82,033 $**	**82,033 $**	
Penta Excluded Equipment															
Air Compressor, Dryer & Receivers		1	lot	80,176 $	80,176 $	60	hrs.	55 $	3,300 $	83,476 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Contractor Overhead and Profit	10%									8,348 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
HAZOP Facilitator									15,000 $	15,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
HAZOP (Ammonia Safety Training Institute)									12,000 $	12,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Emergency response equipment (level E suits, SCBA mask, suit, gloves)		6	set	6,000 $	36,000 $					36,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Develop ammonia safety program - consultant									10,000 $	10,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Develop ammonia safety program - Graymont						40	hrs	100 $	4,000 $	4,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	HSE manager
Develop respiratory protection program						60	hrs	100 $	6,000 $	6,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	HSE manager
Area ammonia sensors									20,000 $	20,000 $	20,000 $	20,000 $	20,000 $	20,000 $	
BMS ammonia sensors									20,000 $	20,000 $	20,000 $	20,000 $	20,000 $	20,000 $	
TOTAL FOR Penta Excluded Equipment										**91,824 $**	**0 $**	**0 $**	**0 $**	**0 $**	
CEMS															
Project Management and Administration						1	lot	20,000 $	20,000 $	20,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
- Equipment & Install															
Thermo 42iQ NOx analyzers	CEMS Solutions Quote	1	ea.	15,140 $	15,140 $					15,140 $	15,140 $	15,140 $	15,140 $	15,140 $	
CEMS Provider Start-up, training, and Administration	CEMS Solutions Quote					1	lot	14,573 $	14,573 $	14,573 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Unisearch Dual Range NH3 TDL, integrate into exiting CEMS	MSI Quote	1	ea.	90,000 $	90,000 $					90,000 $	90,000 $	90,000 $	90,000 $	90,000 $	
CEMLink DAS programming and configuration NH3	VIM Budget Quote					1	lot	10,500 $	10,500 $	10,500 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
NH3 TDL installation						1	ea.	5,000 $	5,000 $	5,000 $	5,000 $	5,000 $	5,000 $	5,000 $	
- Commissioning & CEMS Certification Costs															

https://graymont-my.sharepoint.com/personal/nstettler_graymont_com/Documents/Documents/Graymont Documents/Environmental/Cricket/Regional Haze Cricket Mountain UDAQ Request 7-27-2021/Copy of Graymont Estimate Combined - DM - Final

Mobilization and one week FTIR shakedown testing to assess injection lance placement, NOX and NH3 measurement performance etc	Eric Ehlers, Mostardi Platt communication					1	lot	33,000 $	33,000 $	33,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Laura Kinner Ph. D. oversight and review of shakedown and RATA FTIR testing of FTIR						1	lot	5,000 $	5,000 $	5,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Incremental cost for NOx and NH3 RATA testing for five kilns if performed during annual compliance test	Eric Ehlers, Mostardi Platt communication					1	lot	10,000 $	10,000 $	10,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
MSI on-site for RATA test						1	lot	8,000 $	8,000 $	8,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Graymont time for training in O&M, technical requirements, and reporting recordkeeping	16 hours technician, 16 hours Envr. Management					32	hr	88 $	2,800 $	2,800 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Graymont time for 7-day calibration drift tests and calibration error tests for certification and reporting for five kilns	24 hours technician, 12 hours Envr. Management					36	hr	83 $	3,000 $	3,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Update QA manual for NOx and NH3 additions (does not include technical procedures or corrective action to be provided by MSI)	VIM Budget Quote					1	lot	1,000 $	1,000 $	1,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Corrective action and technical procedures for NH3 monitors						1	lot	5,000 $	5,000 $	5,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
- Condensable Particulate Issues															
Diagnostic testing to determine effects of SNCR reagent injection on formation of condensable PM. Test two kilns at three conditions each (injection off, low injection, high injection). Two test crews for three test days with mobilization and reporting	Eric Ehlers, Mostardi Platt communication					1	lot	40,000 $	40,000 $	40,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Review and analysis of data, and EMI theoretical calculations. Graymont negotiation of Condensable PM permit limit						1	lot	20,000 $	20,000 $	20,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
TOTAL FOR CEMS										283,013 $	110,140 $	110,140 $	110,140 $	110,140 $	
Sub-Total										1,725,501 $	1,139,245 $	1,139,245 $	1,139,245 $	1,139,245 $	
Contingency						10%				172,550 $	113,924 $	113,924 $	113,924 $	113,924 $	
TOTAL =										1,898,051 $	1,253,169 $	1,253,169 $	1,253,169 $	1,253,169 $	

All Five Kilns Before Contingency	6,282,479 $
Contingency Total	620,248 $
Grand Total	**6,910,727 $**

Annual Operating Costs

Description	References	Qty	Unit	Material / Vendor Unit cost	Material / Vendor Cost	Qty	unit	Plant Labor/Staff Unit cost	Plant Labor/Staff Cost	TOTAL K5	TOTAL K4	TOTAL K3	TOTAL K2	TOTAL K1	Comments
Delivered Ammonia (6000 gal Truck) K5	Aircas Quote	46	Trucks	8,403 $	387,635 $					387,635 $					
Delivered Ammonia (6000 gal Truck) K4	Aircas Quote	10	Trucks	8,403 $	79,881 $						79,881 $				
Delivered Ammonia (6000 gal Truck) K3	Aircas Quote	7	Trucks	8,403 $	55,701 $							55,701 $			
Delivered Ammonia (6000 gal Truck) K2	Aircas Quote	15	Trucks	8,403 $	124,936 $								124,936 $		
Delivered Ammonia (6000 gal Truck) K1	Aircas Quote	9	Trucks	8,403 $	74,999 $									74,999 $	
Pump & valve rebuilds and maintenance		1	ea	1,500 $	1,500 $	20	hr	75 $	1,500 $	6,000 $	3,000 $	3,000 $	3,000 $	3,000 $	20hrs/pump skid (1 injection/Kiln & 1 transfer pump skid w/K5)
Daily inspection Ammonia Tank & Pump skids						182	hr	75 $	13,650 $	13,650 $	13,650 $	13,650 $	13,650 $	13,650 $	30 minutes per day x 7 days per week of Kiln attendant
Containment cleanout allowance					10,000 $	8	hr	75 $	600 $	10,600 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Compressor and Dryer Maintenace					4,000 $	16	hr	75 $	1,200 $	5,200 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Tank Testing					3,000 $					3,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Nozzle maintenance					1,000 $	16	hr	75 $	1,200 $	2,200 $	2,200 $	2,200 $	2,200 $	2,200 $	
Power Consumption - Compressor - 50HP		3E+05	KW	0.06 $	20,490 $					4,098 $	4,098 $	4,098 $	4,098 $	4,098 $	Assumes operating 90% of the year
Power Consumption - Injection Pumps (10 HP ea)		63242	KW	0.06 $	4,098 $					4,098 $	4,098 $	4,098 $	4,098 $	4,098 $	Assumes operating 90% of the year
Power Consumption - Blowers (10 HP ea)		63242	KW	0.06 $	4,098 $					4,098 $	4,098 $	4,098 $	4,098 $	4,098 $	Assumes operating 90% of the year
Ammonia Safety Program															
Annual 24 hour emergency response training training					30,000 $	600	hr	75 $	45,000 $	75,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Annual 1 hr awareness training					3,000 $	70	hr	75 $	5,250 $	8,250 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Replacement of SCBA tanks, masks, chem suits gloves					10,000 $					10,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
SCBA annual inspections/3 year hydrostatic testing					4,000 $					4,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Annual fit testing, PFT, medical clearance exams					4,000 $	16	hr	75 $	1,200 $	5,200 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	
Maintain area ammonia sensors (bump test, calibrate, replace)					5,000 $	50	hr	75 $	3,750 $	8,750 $	8,750 $	8,750 $	8,750 $	8,750 $	
Maintain kiln BMS ammonia sensors (bump test, calibrate, replace sensors) maintain communication system					5,000 $	50	hr	75 $	3,750 $	8,750 $	8,750 $	8,750 $	8,750 $	8,750 $	
Maintain Ammonia safety program/respiratory protection program						20	hr	100 $	2,000 $	2,000 $	with Kiln 5	with Kiln 5	with Kiln 5	with Kiln 5	HSE manager
- On-going Annual Costs for O&M Reporting and Recordkeeping															
Annual calibration gases SO2/NOx blends and NH3 audit gases plus Graymont management									2,500 $	2,500 $					
Daily cal drift check review and brief inspection						87	hr	75 $	6,500 $	6,500 $	6,500 $	6,500 $	6,500 $	6,500 $	20 minutes per day per kiln x 5 days per week of technician time
Preventive maintenance and corrective action						48	hr	75 $	3,600 $	3,600 $	3,600 $	3,600 $	3,600 $	3,600 $	4 hrs per month per kiln x 12 months of technician time
Monthly data review & reports to management re NOx emissions, NH3 slip, CEMS availability						36	hr	100 $	3,600 $	3,600 $	3,600 $	3,600 $	3,600 $	3,600 $	3 hours per month per kiln x 12 months of Envir Management time

Description	References	Qty	Unit	Material / Vendor Unit cost	Material / Vendor Cost	Qty	Unit	Plant Labor/Staff Unit cost	Plant Labor/Staff Cost	TOTAL K5	TOTAL K4	TOTAL K3	TOTAL K2	TOTAL K1	Comments
Quarterly NH3 cylinder gas audits, laser alignment, and preventive maintenance by MSI (2 days on site plus travel expenses) with Graymont technician support		4	qtr.	8,000 $	32,000 $	64	hr	75 $	4,800 $	12,267 $	12,267 $	12,267 $	12,267 $	12,267 $	MSI communication (assume $8000 per quarter) plus 16 hours Graymont technician time. (Assumed Cost divided equally, and scaled up for two additional kilns)
VIM DAS incremental annual maintenance cost	Vim Budget quote	1	lot	500 $	500 $					500 $	500 $	500 $	500 $	500 $	
Mobilization and one week annual FTIR RATA testing for NOx and NH3 CEMS for five kilns		1	lot	55,000 $	55,000 $	88	hr	90 $	7,500 $	12,500 $	12,500 $	12,500 $	12,500 $	12,500 $	Eric Ehlers Mostardi Platt communication plus 20 hours technician support and 30 hours Envr. Management coordination, report review and submission (Assumed Cost divided equally, and scaled up for two additional kilns)
Semi-Annual reporting of regulatory NOx monitoring results, QA results, CEMS downtime						12	hr.	100 $	1,200 $	1,200 $	1,200 $	1,200 $	1,200 $	1,200 $	6 hours per kiln per report of Envr. Management time
Semi-Annual reporting of regulatory NH3 monitoring results, QA results, CEMS downtime if regulatory monitor						12	hr.	100 $	1,200 $	1,200 $	1,200 $	1,200 $	1,200 $	1,200 $	6 hours per kiln per report of Envr. Management time
TOTAL FOR COAL HANDLING										**606,396 $**	**169,892 $**	**145,712 $**	**214,947 $**	**165,010 $**	
Sub-Total										**606,396 $**	**169,892 $**	**145,712 $**	**214,947 $**	**165,010 $**	
Contingency						10%				60,640 $	16,989 $	14,571 $	21,495 $	16,501 $	
TOTAL =										**667,035 $**	**186,881 $**	**160,283 $**	**236,442 $**	**181,511 $**	

All Five Kilns Before Contingency	1,301,956 $
Contingency Total	130,196 $
Grand Total	**1,432,152 $**

Description	References	Qty	Unit	Material / Vendor Unit cost	Material / Vendor Cost	Qty	Unit	Plant Labor/Staff Unit cost	Plant Labor/Staff Cost	TOTAL K5	TOTAL K4	TOTAL K3	TOTAL K2	TOTAL K1	Comments
Capital over 20 Year Loan	DAQ Response	20	Years		3.25%					129,188 $	85,295 $	85,295 $	85,295 $	85,295 $	Per Year
Operational Cost annually										667,035 $	186,881 $	160,283 $	236,442 $	181,511 $	Per Year
TOTAL Annual Costs										**796,223 $**	**272,176 $**	**245,578 $**	**321,737 $**	**266,806 $**	
NOx Emmissions Reduced		20	%							70.6	14.6	10.2	22.8	13.7	Tons/Year
TOTAL $/Ton =										**11,270 $**	**18,695 $**	**24,181 $**	**14,130 $**	**19,519 $**	**$/Ton**

Average **17,561 $** **$/Ton**

https://graymont-my.sharepoint.com/personal/hstettler_graymont_com/Documents/Documents/Graymont Documents/Environmental/Cricket/Regional Haze Cricket Mountain/UDAQ REquest 2-27-2021/Copy of Graymont Estimate Combined - CM - Final

GRAYMONT

Appendix E

Graymont Process Engineering Temperature and Residence Time Calculations

CM TCH Modeling Residence Time and Temperatures

Summary Avg. TCH Temperatures							
Description	Units	K1	K2	K3	K4	K5	Comments
Avg. Production Rate	TPD	339.46	360.51	441.29	689.07	1019.74	Source: Aug 2018 - Aug 2021 ODE Production Data
Estimated Gas Vol. Flow Rate	ACFM	84,695.70	81,409.57	127,185.39	183,227.62	256,092.25	**@ kiln feed, 36%CO2 and 1782 F K1, 1537 F K2, 1800 F K3, 1700 F K4, 1800 F K5**
Estimated Residence Time	sec	0.4	0.4	1.1	0.8	1.1	Transfer Chute Nozzle Location-Preheater stone contact
Max. Production Rate	TPD	518.02	540.03	691.06	1205.05	1385.00	Source: Aug 2018 - Aug 2021 ODE Production Data
Estimated Gas Vol. Flow Rate	ACFM	129,247.20	121,946.35	190,176.27	320,428.46	334,787.42	**@ kiln feed, 36%CO2 and 1782 F K1, 1537 F K2, 1800 F K3, 1700 F K4, 1800 F K5**
Estimated Residence Time	sec	0.3	0.3	0.7	0.4	0.9	Transfer Chute Nozzle Location-Preheater stone contact

Average RT (sec) for Avg. TCH Temp 0.5

Summary Max. TCH Temperatures							
Description	Units	K1	K2	K3	K4	K5	Comments
Avg. Production Rate	TPD	339.46	360.51	441.29	689.07	1019.74	Source: Aug 2018 - Aug 2021 ODE Production Data
Estimated Gas Vol. Flow Rate	ACFM	89,153.36	92,131.01	130,576.24	183,227.62	279,215.00	**@ kiln feed, 36%CO2 and 1900 F K1, 1800 F K2, 1970 F K3, 1970 F K4, 2100 F K5**
Estimated Residence Time	sec	0.4	0.4	1.0	0.8	1.0	Transfer Chute Nozzle Location Preheater stone contact
Max. Production Rate	TPD	518.02	540.03	691.06	1205.05	1385.00	Source: Aug 2018-Aug. 2021 ODE Production Data
Estimated Gas Vol. Flow Rate	ACFM	136,049.68	138,006.38	204,481.56	320,428.46	379,228.23	**@ kiln feed, 36%CO2 and 1900 F K1, 1800 F K2, 1970 F K3, 1970 F K4, 2100 F K5**
Estimated Residence Time	sec	0.2	0.2	0.7	0.4	0.8	Transfer Chute Nozzle Location-Preheater stone contact

Average RT (sec) for Max. TCH Temp **0.6**

APPENDIX C.3 – PacifiCorp

APPENDIX C.3.A – PacifiCorp Four-Factor Analysis

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 Coal 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

A BERKSHIRE HATHAWAY ENERGY COMPANY

PacifiCorp – Utah Coal Generation Facilities

REGIONAL HAZE - SECOND PLANNING PERIOD
REASONABLE PROGRESS ANALYSIS

APRIL 2020

Table of Contents

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

[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.

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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).

[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

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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 ($NOx+SO_2$ 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 NOx, 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.

[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;

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[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 (NOx+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

PACIFICORP

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:

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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.

[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 system

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.*

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[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 80°F 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.

- SCR Location. 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.

- 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 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.

- 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 1-2 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	$ 5,621

Attachment 3

Energy and Non-Air Quality Related Impacts Support Calculations

Energy Impacts

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

Consumption of Natural Resources

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%

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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

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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 4

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 5

HUNTER POWER STATION

NO_X CONTROL COST DEVELOPMENT AND ANALYSIS

Prepared for:

PACIFICORP

April 9, 2020
Project 11778-036

Prepared by:

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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 system

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 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 80°F 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	$ 5,763

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 6

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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	7312	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

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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

APPENDIX C.3.B – PacifiCorp UDAQ Four-Factor Analysis Evaluation

State of Utah
SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of
Environmental Quality

Kimberly D. Shelley
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQP-049-21

June 16, 2021

Regina Harris
PacifiCorp
1407 West North Temple
Salt Lake City, Utah 84116

RE: PacifiCorp's Four Factor Analyses for the Hunter and Huntington Power Plants

Dear Ms. Harris:

We received your four factor analyses for the Hunter and Huntington Power Plants prepared for the second planning period of Utah's Regional Haze State Implementation Plan. Enclosed is an engineering review of each analysis outlining some issues we have identified for you to be aware of in preparation for our upcoming meeting on June 23, 2021. If you have any questions, please feel free to contact John Jenks at jjenks@utah.gov or (385) 306-6510.

Sincerely,

Chelsea Cancino
Chelsea Cancino (Jun 16, 2021 13:11 MDT)

Chelsea Cancino
Environmental Scientist

DM:CC:jf

CC: James Owen, PacifiCorp
Jim Doak, PacifiCorp

Enclosure: Utah Division of Air Quality Engineering Review

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Regional Haze – Second Planning Period
SIP Evaluation Report:

PacifiCorp Hunter Power Plant

Utah Division of Air Quality

May 31, 2021

SIP EVALUATION REPORT

PacifiCorp Hunter Power Plant

1.0 Introduction

The following is part of the Technical Support Documentation for the Second Planning Period of the Reginal Haze SIP (aka the Visibility SIP). This document specifically serves as an evaluation of the PacifiCorp Hunter Power Plant facility.

1.1 Facility Identification

Name: Hunter Power Plant
Address: P.O. Box 569, Castle Dale, UT 84513
Owner/Operator: PacifiCorp
UTM coordinates: 497,800 m Easting, 4,335,800 m Northing, UTM Zone 12

1.2 Facility Process Summary

The Hunter Power Plant is located near Castle Dale in Emery County. The plant is classified as a PSD source and is a Phase II Acid Rain source. The source is PSD major for SO2, NOx, PM10, and CO and also major for VOC and HAPs. The source is subject to the provisions of 40 CFR 52.21(aa); 40 CFR 60 Subparts A, D, Da, Y, and HHHH; and 40 CFR 63 Subparts A, ZZZZ, and UUUUU.

1.3 Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

- Steam Generating Unit #1 - Nominal 480 MW gross capacity dry bottom, tangentially-fired boiler fired on subbituminous & bituminous coal using distillate fuel oil during start-up & flame stabilization. System is equipped with a low-NOx burner/overfire air system (OFA), baghouse, and SO2 Wet FGD (WFGD) scrubber with no scrubber bypass.
- Steam Generating Unit #2 - Nominal 480 MW gross capacity dry bottom, tangentially-fired boiler fired on subbituminous & bituminous coal using distillate fuel oil during start-up & flame stabilization. System is equipped with a low-NOx burner/OFA, baghouse, and SO2 WFGD scrubber with no scrubber bypass.
- Steam Generating Unit #3 - Nominal 495 MW gross capacity dry bottom, wall-fired boiler fired on subbituminous & bituminous coal using distillate fuel oil during start-up & flame stabilization. System is equipped with baghouse, a low NOx burner/OFA, and SO2 FGD scrubber.

1.4 Facility Current Potential to Emit

The current PTE values for the Hunter Power Plant, as established by the most recent NSR permit issued to the source (DAQE-AN102370028-18) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
SO_2	5,537.5

NO_x	15,095

2.0 Four Factor Review Methodology

Each source reviewed in this second planning period submitted a report on the available control technologies for SO2 and NOx emission reductions and the application of each technology to that facility. The information on available controls should consider the following four factors when analyzing the possible emission reductions:

1. Factor 1 – The Costs of Compliance
2. Factor 2 – Time Necessary for Compliance
3. Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance
4. Factor 4 – Remaining Useful Life of the Source

Although not specifically required, the recommended approach was to follow a step-wise review of possible emission reduction options in a "top-down" fashion similar to U.S. EPA's guidelines for review of BART or Best Available Retrofit Technology (as found in 40 CFR 51, Section 308 amendments, pub. July 5, 2005). The steps involved are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document results

The process is inherently similar to that used in selecting BACT (Best Available Control Technology) under the NSR/PSD (Title I) permitting program. UDAQ evaluated the submissions from each source following the methodology outlined above. Where a particular submission may have differed from the recommended process, UDAQ will make note, and provide additional information as necessary.

3.0 PacifiCorp's Analysis for Emission Reductions

PacifiCorp's reasonable progress analysis for the emissions limit addresses NOx and SO2 control measures. PacifiCorp's proposal will also have impacts on PM/PM10 emissions, although these were not required under UDAQ's request.

As part of Hunter's four-factor reasonable progress analysis, PacifiCorp proposed and provided an analysis of a combined NOx and SO2 emission limit as a control measure, which PacifiCorp asserts will provide reasonable progress for the second planning period. Specifically, PacifiCorp proposed a plantwide combined NOx + SO2 emission limit of 17,000 tons/year that would 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.

SO2 reductions have been shown to produce greater visibility benefits than NOx for Class I areas on the Colorado plateau. The SO2 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 SO2 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.

Because each of the Hunter units already have the specific, effective control technologies in place for controlling SO2 emissions that EPA identified in its 2019 Guidance, PacifiCorp has not provided an analysis for additional equipment or retrofits to further control SO2. As anticipated by EPA's 2019 Guidance, effective controls are already in place. PacifiCorp believes it is reasonable no additional SO2 controls are needed for the upcoming implementation period.

PacifiCorp derived the Hunter RPEL 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 SO2 PALs. Hunter's current NOx PAL is 15,095 tons/year and its SO2 PAL is 5,537.5 tons/year, providing a combined annual NOx+SO2 PAL of 20,632.5 tons/year.
Second, PacifiCorp re-calculated the PALs, theoretically assuming SNCR were installed on all three units. In this theoretical SNCR case, the Hunter plant's NOx+SO2 PAL would be 17,773 tons/year.
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+SO2 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, SO2, and PM control measures +SNCR
(2) Current NOx, SO2, and PM control measures +SCR
(3) Current NOx, SO2, 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.

3.1 Cost of Compliance

Cost analyses for SNCR and SCR installation at Hunter were completed by Sargent & Lundy in March 2020.

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 SO2 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 SO2 emission limit of 0.12 lb/MMBtu. Based on these rates, the achievable NOx+SO2 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+SO2 was attributed to Unit 1, the Unit would need to scrub to an SO2 emission rate of 0.032 lb/MMBtu to achieve the RPEL. Scrubbing to an SO2 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. 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.

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 SO2 emission limit of 0.12 lb/MMBtu. Based on these rates, the achievable NOx+SO2 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+SO2 was attributed to Unit 2, the Unit would need to scrub to an SO2 emission rate of 0.032 lb/MMBtu to achieve the RPEL. Scrubbing to an SO2 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. 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.

Hunter Unit 3 has a lowest achievable NOx emission rate of 0.31 lb/MMBtu (with the existing LNB/SOFA control equipment), and an SO2 emission limit of 0.12 lb/MMBtu. Based on these rates, the achievable NOx+SO2 emissions would be 9,247 tons/year without additional scrubbing. If 7,352 tons/year of the Hunter RPEL's 17,000 tons/year of NOx+SO2 was attributed to Unit 3, the Unit would need to scrub to an SO2 emission rate of 0.032 lb/MMBtu to achieve the RPEL. Scrubbing to an SO2 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. 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.

3.2 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 NOX control technologies, if required, could be installed at Hunter Units 1, 2, and 3 by the end of the second planning period in 2028.

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.

3.3 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.

3.3.1 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. 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.

3.3.2 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 CO2 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.

3.3.3 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).

3.3.4 Greenhouse Gas Emissions

A byproduct of the coal combustion process is the generation of carbon dioxide (CO2) 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 CO2 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 CO2 per year. Thus, the RPEL provides a potential annual CO2 emission decrease of 1,832,266 tons per year compared with SCR and SNCR.

3.3.5 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 to and disposed in the Hunter 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 three Hunter boilers.

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

3.3.7 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. 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.

3.4 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 to determine that the Hunter RPEL, as proposed, would not contribute to reasonable progress, PacifiCorp respectfully requests that the State propose an alternative RPEL (NOx+SO2 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.

4.0 UDAQ's Analysis

Revising PacifiCorp's analysis to address the deficiencies noted would be problematic, as some of these deficiencies may be justified. In fact, only the use of the incorrect interest rate and the inconsistent cost of auxiliary power are easily corrected without additional input from the source. However, even these two adjustments make a noticeable change in the overall cost of the NOx controls. This is shown in the table below:

Recalculation of Cost Effectiveness at 3.25% Interest Rate

Unit #	Cost Effectiveness of SNCR	Cost Effectiveness of SCR
Hunter 1	$4,130	$4,449
Hunter 2	$4,171	$4,425
Hunter 3	$3,148	$3,024

With these revisions, the cost of these controls appears to be more viable. However, this only represents an annual $/ton result, and does not represent the full impact of installing the control options (as was noted in PacifiCorp's own analysis). The source should expand its analysis of mitigating factors, excessive capital costs, alternative solutions, and other costs in order to justify the removal of either SNCR and/or SCR as viable control options.

PacifiCorp's suggested control alternative, the RPEL option is lacking. PacifiCorp has proposed reductions in combined emissions based on the theoretical implementation of SNCR – without actually installing SNCR. This does not represent a reduction in actual emissions. Over the last several years under both the previous PAL and the current PAL levels, PacifiCorp has routinely operated below these maximum emission rates. PacifiCorp has operated below the 80% planning threshold UDAQ used in its calculation methodology for establishment of the PALs during both the initial and renewal 10-year periods. PacifiCorp has provided additional information suggesting that the plant has always had the option to adjust operations to return to permitted levels – and thus the taking of an additional limit beyond the PALs would represent a genuine reduction in emissions.

UDAQ disagrees with this argument, as historical emissions have been trending consistently downward – leading to a reduction of the PAL limits for both NOx and SO2 upon renewal – and have been on this trend for a long enough period that expectations of a sudden increase in emissions to permitted levels seems extremely far-fetched. PacifiCorp itself offers many counter-arguments to this idea in its own analysis when discussing trends in power production in western states.

UDAQ is not opposed to the RPEL conceptually, and believes that the approach of additional limit(s) beyond the PALs offers a unique approach to limiting total emissions in this SIP.

5.0 Conclusion

At this time, UDAQ is unable to proceed with its review and requests additional information as follows:

1. The source needs to resubmit the Four Factor analysis correcting the errors mentioned above.
2. Additional information must be provided regarding the infeasibility of SCR.
   a. This information can include additional details on economics as well as technical limitations.
3. Additional information must be provided regarding the infeasibility of SNCR.
   a. As with SCR, this information can include additional details on economics as well as technical limitations.
4. Supplemental details regarding the RPEL approach, including the selection of allowable limits should be provided. The methodology used for setting the allowable limits should be discussed in detail.
5. Any other pertinent information PacifiCorp feels is warranted should also be provided in order to assist UDAQ in the review process.

Regional Haze – Second Planning Period
SIP Evaluation Report:

PacifiCorp Huntington Power Plant

Utah Division of Air Quality

May 31, 2021

SIP EVALUATION REPORT

PacifiCorp Huntington Power Plant

1.0 Introduction

The following is part of the Technical Support Documentation for the Second Planning Period of the Reginal Haze SIP (aka the Visibility SIP). This document specifically serves as an evaluation of the PacifiCorp Huntington Power Plant facility.

1.1 Facility Identification

Name: Huntington Power Plant
Address: P.O. Box 680, Huntington, UT 84528
Owner/Operator: PacifiCorp
UTM coordinates: 493,130 Easting 4,358,840 Northing, UTM Zone 12

1.2 Facility Process Summary

The PacifiCorp Huntington Power Plant is a coal-fired steam electric generating facility consisting of two (2) boilers. Unit #1 is a 480 MW unit constructed in October 1973; Unit #2 is a 480 MW unit that commenced construction in April 1970. Bituminous and sub-bituminous coal is the primary fuel source for the dry bottom, tangentially-fired boilers. Fuel oil is used to start up the boilers from a cold start and for boiler flame stabilization. The Huntington Power Plant uses low-NOx burners, separated overfire air system, SO2 FGD scrubber system, and pulse jet fabric filters for both units.

1.3 Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

- Boiler Unit #1 - Nominal 480 MW gross capacity dry bottom, tangentially-fired utility boiler fired on subbituminous and bituminous coal using fuel oil during startup & flame stabilization. Equipped with a fabric filter baghouse, low NOx burners with overfire air system, and an SO2 FGD scrubber. NSPS Subpart D.
- Boiler Unit #2 - Nominal 480 MW gross capacity dry bottom tangentially-fired utility boiler fired on subbituminous and bituminous coal using fuel oil during startup & flame stabilization. Equipped with a fabric filter baghouse, low-NOx burners with overfire air system, and an SO2 FGD scrubber.

1.4 Facility Current Potential to Emit

The current PTE values for the Huntington Power Plant, as established by the most recent NSR permit issued to the source (DAQE-AN102370028-18) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
SO_2	3,105

NO_x	7,971

2.0 Four Factor Review Methodology

Each source reviewed in this second planning period submitted a report on the available control technologies for SO2 and NOx emission reductions and the application of each technology to that facility. The information on available controls should consider the following four factors when analyzing the possible emission reductions:

1. Factor 1 – The Costs of Compliance
2. Factor 2 – Time Necessary for Compliance
3. Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance
4. Factor 4 – Remaining Useful Life of the Source

Although not specifically required, the recommended approach was to follow a step-wise review of possible emission reduction options in a "top-down" fashion similar to U.S. EPA's guidelines for review of BART or Best Available Retrofit Technology (as found in 40 CFR 51, Section 308 amendments, pub. July 5, 2005). The steps involved are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document results

The process is inherently similar to that used in selecting BACT (Best Available Control Technology) under the NSR/PSD (Title I) permitting program. UDAQ evaluated the submissions from each source following the methodology outlined above. Where a particular submission may have differed from the recommended process, UDAQ will make note, and provide additional information as necessary.

3.0 PacifiCorp's Analysis for Emission Reductions

As part of Huntington's four-factor reasonable progress analysis, PacifiCorp proposes and provides analysis of a NOx and SO2 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 + SO2 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 SO2 and PM. However, the RPEL has the added benefit of reducing both SO2 and PM emissions in comparison with SCR and SNCR.

SO2 reductions have been shown to produce greater visibility benefits than NOx for Class I areas on the Colorado plateau.5 The SO2 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 SO2 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 SO2 plantwide applicability limits (PAL). Huntington's current NOx PAL is 7,971 tons/year and its SO2 PAL is 3,105 tons/year, providing a combined annual NOx+SO2 PAL of 11,076 tons/year.
- Second, PacifiCorp re-calculated the PALs, theoretically assuming SNCR were installed on both units. In this theoretical SNCR case, the Huntington plant's NOx+SO2 PAL would be 10,491 tons/year.
- 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+SO2 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 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, SO2, and PM control measures +SNCR
(2) Current NOx, SO2, and PM control measures +SCR
(3) Current NOx, SO2, 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.

3.1 Cost of Compliance

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 SO2 to ensure the RPEL is met.

Huntington Unit 1 has a lowest achievable NOx emission rate of 0.20 lb/MMBtu (with the existing LNB/SOFA control equipment), and an SO2 emission limit of 0.12 lb/MMBtu. Based on these rates, the achievable NOx+SO2 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+SO2 was attributed to Unit 1, the Unit would need to scrub to an SO2 emission rate of 0.030 lb/MMBtu to achieve the RPEL. Scrubbing to an SO2 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.

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 SO2 emission limit of 0.12 lb/MMBtu. Based on these rates, the achievable NOx+SO2 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+SO2 was attributed to Unit 2, the Unit would need to scrub to an SO2 emission rate of 0.030 lb/MMBtu to achieve the RPEL. Scrubbing to an SO2 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.

3.2 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 NOX control technologies, if required, could be installed at Huntington Units 1 and 2 by the end of the second planning period in 2028.

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.

3.3 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.

3.3.1 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 8.6MW. 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 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.

3.3.2 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.

3.3.3 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).

3.3.4 Greenhouse Gas Emissions

A byproduct of the coal combustion process is the generation of carbon dioxide (CO2) 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 CO2 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 CO2 per year. Thus, the RPEL provides a potential annual CO2 emission decrease of 581,040 tons per year compared with SCR and SNCR.

3.3.5 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. 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;
- A reduction of ash transported 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.

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

3.3.7 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. 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.

3.4 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 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.

4.0 UDAQ's Analysis

UDAQ has found the following issues with PacifiCorp's analysis which require additional information and/or feedback from the source:

4.1 Use of an Incorrect Interest Rate

PacifiCorp's SCR and SNCR cost effectiveness analyses used an interest rate of 7.0% for amortizing capital costs of SCR and SNCR over the assumed lifetimes of the SCR and SNCR (for which PacifiCorp assumed 30 years for SCR and 20 years for SNCR). EPA's Cost Estimation spreadsheets state that the "User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/)." Over the past five years, the bank prime rate has not been higher than 5.5% and at present the current bank prime rate is 3.25%. The Federal Reserve has indicated that it expects interest rates to remain at these same low levels at least through 2023. Based on EPA's Control Cost Manual spreadsheets, the interest rate should be set at the bank prime rate of 3.25%.

4.1 Additional Information Should be Provided on Control Efficiency

UDAQ believes that PacifiCorp's analysis is lacking with respect to the expected control efficiency of both SCR and SNCR when applied to the Huntington Plant. UDAQ agrees that some allowances must be made for retrofitting control technology onto existing boilers with established exhaust trains and some degree of previously installed NO_x emission controls. However, annual emission rates lower than the estimates provided by PacifiCorp have been achieved at similar facilities. PacifiCorp should provide additional explanation as to why these lower emission rates are not achievable at the Huntington Plant.

4.2 Additional Information Should be Provided on Control Costs

Similarly, PacifiCorp has deviated from the standard methodology in calculation of the cost of controls. Specifically:

- the inclusion of EPM (engineering, procurement and management) costs which may not be justified
- the use of two different auxiliary power costs - $30/MW-hr for SCR, $50/MW-hr for SNCR

- the inclusion of an air-preheater for SNCR which may not be justified

Although UDAQ does not completely disagree with the inclusion of the air-preheater and EPM costs, additional justification should be provided. However, the use of two different values for the cost of auxiliary power is a different matter and should be corrected.

4.3 UDAQ's Analysis

Revising PacifiCorp's analysis to address the deficiencies noted would be problematic, as some of these deficiencies may be justified. In fact, only the use of the incorrect interest rate and the inconsistent cost of auxiliary power are easily corrected without additional input from the source. However, even these two adjustments make a noticeable change in the overall cost of the NOx controls. This is shown in the table below:

Recalculation of Costs at 3.25% Interest Rate

Unit #	Cost Effectiveness of SNCR	Cost Effectiveness of SCR
Huntington 1	$3,987	$4,069
Huntington 2	$4,152	$4,277

With these revisions, the cost of these controls appears to be more viable. However, this only represents an annual $/ton result, and does not represent the full impact of installing the control options (as was noted in PacifiCorp's own analysis). The source should expand its analysis of mitigating factors, excessive capital costs, alternative solutions, and other costs in order to justify the removal of either SNCR and/or SCR as viable control options.

PacifiCorp's suggested control alternative, the RPEL option is lacking. PacifiCorp has proposed reductions in combined emissions based on the theoretical implementation of SNCR – without actually installing SNCR. This does not represent a reduction in actual emissions. Over the last several years under both the previous PAL and the current PAL levels, PacifiCorp has routinely operated below these maximum emission rates. PacifiCorp has operated below the 80% planning threshold UDAQ used in its calculation methodology for establishment of the PALs during both the initial and renewal 10-year periods. PacifiCorp has provided additional information suggesting that the plant has always had the option to adjust operations to return to permitted levels – and thus the taking of an additional limit beyond the PALs would represent a genuine reduction in emissions.

UDAQ disagrees with this argument, as historical emissions have been trending consistently downward – leading to a reduction of the PAL limits for both NOx and SO2 upon renewal – and have been on this trend for a long enough period that expectations of a sudden increase in emissions to permitted levels seems extremely far-fetched. PacifiCorp itself offers many counter-arguments to this idea in its own analysis when discussing trends in power production in western states.

UDAQ is not opposed to the RPEL conceptually, and believes that the approach of additional limit(s) beyond the PALs offers a unique approach to limiting total emissions in this SIP.

5.0 Conclusion

At this time, UDAQ is unable to proceed with its review and requests additional information as follows:

1. The source needs to resubmit the Four Factor analysis correcting the errors mentioned above.
2. Additional information must be provided regarding the infeasibility of SCR.
    a. This information can include additional details on economics as well as technical limitations.
3. Additional information must be provided regarding the infeasibility of SNCR.
    a. As with SCR, this information can include additional details on economics as well as technical limitations.
4. Supplemental details regarding the RPEL approach, including the selection of allowable limits should be provided. The methodology used for setting the allowable limits should be discussed in detail.
5. Any other pertinent information PacifiCorp feels is warranted should also be provided in order to assist UDAQ in the review process.

APPENDIX C.3.C - PacifiCorp Evaluation Response

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

August 31, 2021

Bryce C. Bird, Director
Chelsea Cancino, Environmental Scientist
Utah Division of Air Quality
195 North 1950 West
Salt Lake City, Utah 84114-4820

Re: **The State of Utah's Second Planning Period Analysis for Regional Haze that Impacts PacifiCorp's Hunter and Huntington Power Plants**

Dear Ms. Cancino and Mr. Bird:

The purpose of this letter is to provide additional information regarding the questions and issues raised in your June 16, 2021, letter regarding the four-factor analyses for the Hunter and Huntington power plants. Below are specific responses and information about those issues. PacifiCorp looks forward to meeting with the Division and discussing these matters in person.

Additional Information and Clarification:

1. **Incorrect interest rate:** UDAQ indicated that PacifiCorp's use of a 7.00% interest rate in its SNCR and SCR regional haze second planning period cost analyses is incorrect and suggested that 3.25% is a more appropriate interest rate. PacifiCorp disagrees and is providing information supporting use of a 7.303% rate. PacifiCorp provided similar information to EPA within the last year relating to the appropriate discount rate for SCR cost analysis. Based on this investigation, the 7% interest rate used by PacifiCorp in previous regional haze four-factor analyses is actually low and should be replaced by PacifiCorp's actual weighted average cost of capital, which is 7.303%, using EPA's Control Cost Manual total capital investment ("TCI") methodology. PacifiCorp understands that the interest rate should be set using this TCI methodology.
    a. PacifiCorp's discount rate, or actual weighted average cost of capital, has consistently exceeded 7% over the past several years.

b. The actual weighted average cost of capital is calculated using the rates approved by the six state regulatory authorities where PacifiCorp conducts business and the percentage of energy delivered by PacifiCorp to each of those states. *See* Attachment A. Thus, PacifiCorp's 7.303% actual average cost of capital rate is more appropriate than the 7% rate used by S&L.

c. PacifiCorp has recalculated costs using the 7.303% rate, and the new costs are provided in Attachment B.

2. **UDAQ methodology for SNCR calculations:** For purposes of comparison only, PacifiCorp recalculated Hunter and Huntington SNCR and SCR cost effectiveness using a 3.25% interest rate and a $30/MWh auxiliary power cost to align with Utah's methodology. PacifiCorp's SCR calculations closely match UDAQ's values; however, PacifiCorp's SNCR cost effectiveness values are significantly higher than UDAQ's values. Table 1 compares UDAQ's 3.25% interest rate cost effectiveness values to PacifiCorp's calculated value.

Table 1: PacifiCorp vs. UDAQ SNCR and SCR Cost Effectiveness

	SNCR Life (years) Interest Rate		20 3.25%	SCR Life (years) Interest Rate		30 3.25%
	SNCR			SCR		
	PacifiCorp ($/ton)	UDAQ ($/ton)	Difference ($/ton)	PacifiCorp ($/ton)	UDAQ ($/ton)	Difference ($/ton)
Hunter 1	$5,752	$4,130	$1,622	$4,448	$4,449	$1
Hunter 2	$5,702	$4,171	$1,531	$4,423	$4,425	$2
Hunter 3	$4,906	$3,148	$1,758	$3,023	$3,024	$1
Huntington 1	$5,673	$3,987	$1,686	$4,077	$4,069	$8
Huntington 2	$5,783	$4,152	$1,631	$4,286	$4,277	$9

While SCR cost calculations generally align between PacifiCorp and UDAQ, PacifiCorp has conducted further analysis of differences with UDAQ calculations for SNCR. Based on this analysis, PacifiCorp suggests the following adjustments. First, some of UDAQ's estimates rely on default or general values or rather than site-specific information. PacifiCorp uses values from Sargent & Lundy's (S&L) engineering studies which were conducted for each plant. EPA's 2019 Guidance favors the use of source-specific cost estimates over default values when available, since site-specific information produces more accurate results. *See* EPA, 2019 Control Cost Manual, Section 1, Ch. 1, 1-7.

With this in mind, PacifiCorp suggests replacing UDAQ's NOx control effectiveness rates (approximately 23% and varying slightly from unit to unit). PacifiCorp is uncertain how UDAQ arrived at these rates but finds it more appropriate to use a 20% NOx control effectiveness rate across all units. This is the anticipated control effectiveness rate for SNCR based on S&L's 2020 study. It is more conservative and slightly higher than the rates PacifiCorp used in its original analysis.

PacifiCorp also suggests that the capital and operation and maintenance cost estimates from the S&L studies be used in place of the default values used by UDAQ. As above, because these values were arrived at based on a site-specific engineering study, they are more appropriate and accurate than the default values from EPA's Control Cost Manual.

Finally, the updated "interest" rate of 7.303% should be used based on the reasoning presented in Response 1 above. All of these suggestions have been incorporated into a new cost calculation for SNCR, and PacifiCorp recommends using this cost calculation to determine the cost effectiveness of SNCR. *See* Attachment C.

3. **Control efficiency:** *See* no. 6 below – analysis of SCR/SNCR mitigating factors.

4. **EPM and auxiliary power:** In its review of PacifiCorp's Hunter and Huntington four-factor analyses, UDAQ notes that PacifiCorp used different O&M costs for auxiliary power in the SNCR and SCR cost effectiveness calculations; \$50/MWh for SNCR auxiliary power and \$30/MWh for SCR auxiliary power. In order to provide similar auxiliary power costs for both NOx control technologies, PacifiCorp has recalculated Hunter and Huntington SNCR cost effectiveness using the more conservative \$30/MWh auxiliary power cost. Table 2 summarizes SNCR and SCR cost effectiveness using a 7.303% interest rate. Table 3 summarizes SNCR and SCR cost effectiveness using a 3.25% interest rate.

Table 2: Auxiliary Power Cost Effectiveness at 7.303% discount rate

	SNCR		SCR
	$50/MWh Auxiliary Power Cost	$30MWh Auxiliary Power Cost	$30/MWh Auxiliary Power Cost
7.303% Disc Rate	Cost ($/ton)	Cost ($/ton)	Cost ($/ton)
Hunter 1	$6,588	$6,536	$6,533
Hunter 2	$6,523	$6,469	$6,488
Hunter 3	$5,455	$5,417	$4,401
Huntington 1	$6,482	$6,431	$5,979
Huntington 2	$6,632	$6,579	$6,294

Table 3: Auxiliary Power Cost Effectiveness at 3.25% Interest Rate

	SNCR		SCR
	$50/MWh Auxiliary Power Cost	$30MWh Auxiliary Power Cost	$30/MWh Auxiliary Power Cost
3.25% Disc Rate	Cost ($/ton)	Cost ($/ton)	Cost ($/ton)
Hunter 1	$5,804	$5,752	$4,448
Hunter 2	$5,755	$5,702	$4,423
Hunter 3	$4,943	$4,906	$3,023
Huntington 1	$5,725	$5,673	$4,077
Huntington 2	$5,836	$5,783	$4,286

As indicated in Tables 2 and 3, the reduction of SNCR auxiliary power costs from $50/MWh to $30/MWh does not result in a substantial cost effectiveness reduction.

5. **Air preheater costs not justified:** In its June 16th letter regarding PacifiCorp's Huntington and Hunter SNCR cost analyses, UDAQ includes the statement "*the inclusion of an air-preheater for SNCR which may not be justified*". Note that the Huntington and Hunter units already utilize air preheaters; the S&L cost analyses indicate that the units' air preheater equipment may require material upgrades due to excess ammonia from the SNCR process which has a potential to corrode and/or plug the existing air preheater equipment. PacifiCorp believes its position is reasonable based on the analysis done by experts in the field.

6. **More analysis of factors weighing against SCR/SNCR:**

a. **SCR emissions rates:** In the analysis included with the June 16th letter, UDAQ indicated that the SCR emission rate should be lower than 0.05 lb/MMBtu. The indicated SCR NOx reductions are unit-specific incremental improvement estimates based on each specific unit's boiler operational characteristics and the existing installation of low-NOx burners with separated overfire air. The proposed 0.05 lb/MMBtu SCR emission rate is consistent with the lowest guaranteed emission rates that have been reported for SCR technology. The SCR emission rate of 0.05 lb/MMBtu is the rate that is reasonably achievable with these controls and is in the lower end range of what can be achieved with these technologies on an emission basis (lb/MMBtu), and is consistent with permit/design limits for similar systems.
b. EPA has found this rate to be appropriate for these specific units. *See* 85 FR 75860, 75868 ("Additionally, while the commenters cite actual annual emission rates found in the EPA's Air Markets Program Database (AMPD) to support their claim that an annual emission rate of 0.04 lb/MMBtu is achievable with SCR, a more thorough review of the data supports the EPA's conclusion that an annual emission rate no lower than 0.05 lb/MMBtu is representative of what can be achieved when retrofitting SCR to an existing boiler. . . . Notwithstanding the site-specific nature of SCR retrofits, these data support the conclusion that an annual emission rate of 0.05 lb/MMBtu is appropriate for the Utah BART units, and confirm that the assumption is relatively conservative because the majority of EGUs equipped with SCR have actual annual emission rates that are higher."). Utah has supported this position previously and should not change that position now.
c. EPA has found the 0.05 lb/MMBtu NOx emissions rate appropriate for many other regional haze-related SCR analyses. *See e.g.,* Arkansas, 81 FR 66332, 663837-38 (September 27, 2016) ("Regarding the Sierra Club's consultant's SCR control cost analysis, we do not believe that a NOX emission limit of 0.04 lbs/MMBtu has been maintained on a 30 boiler-operating-day average at other similar facilities. We conclude that, as we did in our New Mexico FIP, a 30 boiler-operating-day NOX average of 0.05 lbs/MMBtu is an appropriate assumption for SCR installation at the Flint Creek facility."); New Mexico, 79 FR 60978, 60984 (Oct. 9, 2014) ("We disagree that lower control rates needed to be evaluated for SCR. We evaluated the monthly emission data from these two facilities for the past several years (available at EPA's Air Market Program data Web site: www.epa.gov/ampd). All three units

have monthly emission rates that sometimes exceed 0.04 lb/MMBtu. Indeed, the Morgantown units have months where the monthly emission rate is 0.05 lb/MMBtu or higher. In promulgating the FIP, we evaluated the performance of both new and retrofit SCRs and determined that 0.05 lb/MMBtu on a 30-boiler-operating-day average was the appropriate emission limit for SCR at the SJGS units.").

d. **SCR Cost Impacts:** PacifiCorp anticipates that the financial consequences of a requirement to install SCR on any of the Hunter or Huntington units would be early retirement of the unit. Due to the substantial capital costs of SCR, the associated O&M costs, the parasitic load imposed by the SCR, the transmission constraints within which the Hunter and Huntington plants operate, and the increasingly competitive energy markets and regulatory restrictions that govern PacifiCorp's operations in Utah, an SCR determination for the Hunter or Huntington units would have such an onerous financial impact that PacifiCorp would be forced to retire the units rather than install the SCR.

e. Even where a control technology may be found cost effective, EPA's regulations allow decision makers to take a source's ability to afford a technology into account if "the installation of controls would affect the viability of continued plant operations." 40 CFR part 51, appendix Y, section IV.E.3.1.3. Such consideration is appropriate where "effects on product prices, the market share, and profitability of the source . . . are judged to have a severe impact on plant operations."

f. If UDAQ is seriously considering SCR as a requirement for any unit to fulfill second planning period requirements, PacifiCorp requests additional time to provide "an economic analysis that demonstrates, in sufficient detail for public review, the specific economic effects, parameters, and reasoning" to show such a requirement would have a severe impact on unit operations. *See, e.g.* 79 FR 5032, 5171 (2014) (discussion of an affordability analysis for the Laramie River plant in Wyoming); 76 FR 36334 (2011) (discussion of an affordability analysis for the TASCO facility in Idaho); 78 FR 79344, 79353-54 (2013) (using an affordability analysis to reject a BART control at the Intalco plant in Washington).

7. **More support for RPEL:** UDAQ requests additional information on methodology for selecting the RPEL allowable limits in the original four-factor analysis. This is provided below.

a. PALs: are voluntary permit limits that PacifiCorp proposed and UDAQ implemented. PALs were established so that the PAL pollutants (NOx and SO2) are exempt from future NSR/PSD permitting actions as long as emissions for the pollutants stay below the PALs. It is expected that PacifiCorp operate below the PALs, since a margin of safety/error is expected for permit limits. PacifiCorp believes it is important that companies not be "punished" for operating within a safe margin below their permit limits.
b. PacifiCorp used the following 4-step methodology to select the RPEL allowable limits put forth in its original four-factor analysis:
   i. First, each unit's maximum boiler heat input was multiplied by an SNCR-equivalent lb/MMBtu NOx emission rate to calculate the potential annual NOx emission rate for each unit (tons/year) if SNCR were implemented.
   ii. Second, the individual unit SNCR-equivalent annual NOx emissions were summed to determine the total facility potential NOx emissions if SNCR were implemented. For Hunter this value was 12,235 tons/year, and for Huntington it was 7,386 tons/year.
   iii. Third, each facility's PAL-permitted annual SO_2 emission limit was added to the SNCR-equivalent NOx emissions. Hunter has an SO_2 PAL limit of 5,537.5 tons/year and Huntington has an SO_2 PAL limit of 3,105 tons/year. Summing the SO_2 PALs with the SNCR-equivalent annual NOx emissions provides NOx + SO_2 values of 17,773 tons/year for Hunter, and 10,491 tons/year for Huntington.
   iv. Fourth, the summed values were rounded down to the nearest 1,000 ton/year value to ensure emission reductions below the potential SNCR values. This provided the proposed RPEL values of 17,000 tons/year for Hunter and 10,000 tons/year for Huntington.
c. PacifiCorp used this process to demonstrate that the proposed RPEL limits were both: (1) less that the plants' existing NOx + SO_2 PALs. (Hunter's current NOx + SO_2 PALs are equivalent to 20,632 tons/year and Huntington's are equivalent to 11,076 tons/year) and (2) less than reductions that would be achieved through installation of SNCR on all units.
d. UDAQ has also requested PacifiCorp to consider a revised RPEL or other options to address historical and recent actual emission trends.

PacifiCorp is currently analyzing options in response to this request and would like to discuss with the agency its concerns about UDAQ's approach. We would like to further discuss the appropriate ways to address these second planning period issues in light of the current Tenth Circuit mediation process for the first planning period SIP.

8. Visibility considerations
   a. Section 2.0 of UDAQ's analysis refers to the "four-factor" test for reasonable progress, but there is no mention of "visibility improvement". In previous reasonable progress determinations during the first planning period, EPA explicitly relied on modeled visibility impacts in addition to the four factors to determine appropriate emission reduction measures. *See North Dakota v. U.S. EPA*, 730 F.3d 750 (8th Cir. 2013) and *National Parks Conservation Assoc. v. U.S. EPA*, 788 F.3d 1134 (9th Cir. 2015). No changes have been made to the applicable statutes or rules that would mandate a different approach.
   b. PacifiCorp strongly urges UDAQ to give the visibility factor significant weight in its regional haze "visibility improvement" program. The statute that forms the legal basis for the Regional Haze Program declares that the goal of the program is "the prevention of any future, and the remedying of any existing, impairment of **visibility** in mandatory class I Federal areas which impairment results from manmade air pollution." *See* 42 U.S.C. § 7491(a)(1) (emphasis added); *see also* 86 FR 15104, 15105 ("The **regional haze** regulations require states to demonstrate reasonable progress toward meeting the national **goal** of restoring natural **visibility** conditions for Class I areas by 2064."); 85 FR 3558, ("Regional haze SIPs must assure reasonable progress toward the national goal of achieving **natural visibility conditions in Class I areas**, which, for the first implementation period, includes satisfying the BART requirements."). Therefore, any actions required by a state's regional haze SIP must prevent, or remedy existing, visibility impairment in Class I areas, and it is the state's burden to establish the same. EPA guidance therefore correctly allows states discretion to consider "visibility improvement" in their 2PP analysis.
      i. "EPA has also explained that, in addition to the four statutory factors, states have flexibility under the CAA and RHR to reasonably consider visibility benefits as an optional fifth factor alongside the four statutory factors. Here, again, the 2019

Guidance provides recommendations for the types of information that can be used to characterize the four factors (with or without visibility), as well as ways in which states might reasonably consider and balance that information to determine which of the potential control options is necessary to make reasonable progress. See 2019 Guidance at 30-36." 86 FR 19793, 19798.

c. Given the goal of the Regional Haze Program, PacifiCorp urges UDAQ to review and apply the available modeling and "visibility benefit" data that the state and region have worked so hard to produce. Application of regional visibility modeling data to ensure appropriate regional haze controls is consistent with Utah's past practice for evaluating its Long-Term Strategies. *See* Subsection K, Projection of Visibility Improvement Anticipated From Long-Term Strategy, Utah State Implementation Plan, Section XX, Regional Haze. PacifiCorp believes that Utah should follow the same "Long-Term Strategy" methodology it used for its previous regional haze SIP because no new statutes or regulations have been adopted since Subsection K of Utah's Regional Haze SIP was adopted that would require, or even allow, a change in methodology.
d. Failure to apply visibility data would set a dangerous precedent that the regional haze program can require retrofit equipment and emission reductions with no evidence that such expenditures are necessary to improve visibility and fulfill the purpose of the statute.

PacifiCorp hopes this information is helpful and responds to the questions raised by UDAQ and would be happy to meet in person and discuss these matters in more detail.

Sincerely,

James Owen
Director, Environmental

CC: Jim Doak
Marie Durrant
Laren Huntsman
Blaine Rawson - Ray Quinney & Nebeker P.C

Attachment A

Discount Rate for SCR Control Costs at Hunter and Huntington

PacifiCorp's discount rate, or its actual weighted average cost of capital, is calculated using the rates approved by the six state regulatory authorities where PacifiCorp conducts business and the percentage of energy delivered by PacifiCorp to each of those states. PacifiCorp's actual weighted average cost of capital is 7.303% using an authorized return weighted by Year 2020 retail sales. *See* Exhibit A. This rate is historical and does not change dramatically from year to year.

According to EPA's updated Cost Control Manual, SCR costs should be estimated using the total capital investment ("TCI") methodology.[1] The TCI methodology accounts for financing costs, including interest rates. As EPA explains, "The interest rate at which a firm borrows is a key component in estimating the total costs of compliance".[2] with a government regulation, and EPA recommends using a source's actual borrowing rate when possible:

> Different firms may structure how they finance their purchases differently. Some may choose to finance their purchases through cash holding or other means of equity; some may choose to borrow to finance their investment. When firms choose to borrow, depending on the size of the investment, borrowing could be structured very differently at very different interest rates given the choices firms have for financing an investment. . . . For input to analysis of rulemakings, assessments of private cost should be prepared using firm-specific nominal interest rates if possible. . . . In assessing these private decisions, interest rates that face firms must be used, not social rates.[3]

PacifiCorp's interest rate for all capital investments, including required regulatory investments such as an SCR, is governed by its state regulators. PacifiCorp finances its capital expenditures using a mix of debt and common equity capital of approximately 48/52 percent, respectively, which aligns with the average capital structure approved in the six state jurisdictions where the company operates. State regulators also approve the cost of debt and cost of equity assigned to the components of the capital structure. The resulting interest rate, more commonly referred to as the weighted average cost of capital, is a weighting of the Company's cost of debt and cost of equity multiplied by the approved debt and equity components of the capital structure.[4]

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[1] EPA, Cost Control Manual, Ch. 2 (Selective Catalytic Reduction), s. 2.4.1 (June 2019). *See also* 79 FR 5032, 5136-37 (Wyoming) (Jan. 30, 2014) (discussing that cost analysis for an SCR requirement is "related to government regulations" and involves a discount rate).
[2] EPA Cost Control Manual, Section 1, Ch. 2 (Cost Estimation: Concepts and Methodology), s. 2.5.1 (Nov. 2017), at 15.
[3] *Id.*
[4] PacifiCorp must maintain an average overall common equity component in excess of 52 percent to maintain its credit rating and finance the debt component of its capital structure at

Based on state orders currently in effect, PacifiCorp's interest rate (weighted average cost of capital) ranges from a low of 7.13% in Oregon to a high of 7.98% in Idaho. *See* Exhibit B. As stated by the Idaho Public Utilities Commission, "[T]he Commission has authorized PacifiCorp to maintain adequate equity and debt authority thereby allowing PacifiCorp to access capital markets at reasonable costs."[5] Using 2020 retail sales in megawatt hours from each of the six state jurisdictions where the company operates, the weighted interest rate for PacifiCorp is calculated at 7.303%. *See* Exhibit A.

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the lowest reasonable cost to its customers. This capital structure enables the company's continued investment in infrastructure to provide safe and reliable service to its customers at reasonable costs.

[5] Idaho Public Utilities Commission, Case No. PAC-E-10-07, Order No. 32196, Feb. 28, 2011, at 12.

Exhibit A: Weighted Authorized Cost of Capital

	2020 Retail Sales MWH	Weighted Percent	Authorized Return	Weighed Authorized Return
CALIFORNIA	758,832	1.39%	7.622%	0.106%
OREGON	12,993,459	23.82%	7.137%	1.700%
WASHINGTON	4,065,151	7.45%	7.169%	0.534%
UTAH	24,850,549	45.55%	7.342%	3.344%
IDAHO	3,534,206	6.48%	7.980%	0.517%
WYOMING	8,357,790	15.32%	7.192%	1.102%
TOTAL	54,559,978	100.00%		**7.303%**

The weighted authorized return is calculated using authorized return weighted by Year 2020 retail sales (MWh)

Exhibit B: State Approved Cost of Capital Rates

The state findings establishing the cost of capital rates are summarized in the tables below:

Wyoming Public Service Commission, DOCKET No. 20000-578-ER-20 (RECORD No. 15464), July 15, 2021.

Par. 177: Based on our conclusions and findings, we have therefore determined RMP's capital structure and RORB [return on rate base] should be:

Component	Percent of Total	% Cost	Weighted Average
Long Term Debt	48.99%	4.79%	2.347%
Preferred Stock	0.01%	6.75%	0.001%
Common Equity Stock	51.00%	9.50%	4.845%
	100.000%		7.192%

Utah Public Service Commission, PacifiCorp dba Rocky Mountain Power 2021 General Rate Case, Docket No. 20-035-04, Dec. 30, 2020

Par. 51: Table 2 presents the final capital structure, ROE [return on equity], and overall rate of return we approve.

Ordered Cost of Capital			
	Capital Structure	Rate	Weighted Rate
Long Term Debt	47.50%	4.79%	2.275%
Preferred Stock	0.00%	0.00%	0.00%
Common Equity Stock	52.50%	9.65%	5.066%
	100.000%		7.342%

Oregon Public Utility Commission, Order No. 20-473 Dec. 18, 2020

Ordered Cost of Capital			
	Capital Structure	Embedded Cost	Weighted Rate
Debt %	49.99%	4.774%	2.387%
Preferred %	0.01%	6.750%	0.001%
Common Equity Stock	50.00%	9.500%	4.750%
	100.000%		7.137%

California Public Utilities Commission, Decision 20-02-025, Feb. 6, 2020

S. 4.0: We adopt a cost of capital of 7.622 percent . . . .

S. 4.3 Return on Equity

Adopted Capital Structure and Return		
	Capital Structure	Return
Long-Term Debt	48.02%	5.05%
Preferred Stock	0.02%	6.75%

Common Equity	51.96%	10.0%
[Weighted Rate]		[7.622%]

Idaho Public Utilities Commission, Case No. PAC-E-10-07, Order No. 32196, Feb. 28, 2011

"The Commission reaffirms . . . an overall weighted cost of capital and rate of return of 7.98% as approved in Interlocutory Order No. 32151." On page 2.

On page 12:

Component	Percentage of Capital Structure	Cost	Weighted Cost
Debt	47.6%	5.88%	2.80%
Preferred Stock	0.3%	5.42%	0.02%
Common Equity	52.1%	9.9%	5.16%
	100.00%		7.98%

. . . . This decision supports capitalization requirements by rejecting proposals to reduce equity balances. In separate security filings, the Commission has authorized PacifiCorp to maintain adequate equity and debt authority thereby allowing PacifiCorp to access capital markets at reasonable costs.

Washington Utilities and Transportation Commission, Order 09, 07, 12, Docket UE-191024, Dec 14, 2020

	Share	Cost	Weighted Cost
Equity	49.10%	9.50%	4.665%
LT Debt	50.88%	4.92%	2.503%
ST Debt	0.19%	1.73%	-----
Pf. Stock	0.02%	6.75%	0.01%
ROR			7.169%

Attachment B

Utah Regional Haze Second Planning Period SNCR and SCR Cost Analyses

SNCR COST EFFECTIVENESS	Unit 1 ($/ton)	Unit 2 ($/ton)	Unit 3 ($/ton)
Hunter	$6,530	$6,469	$5,417
Huntington	[illegible]	$6,579	NA

SCR COST EFFECTIVENESS	Unit 1 ($/ton)	Unit 2 ($/ton)	Unit 3 ($/ton)
Hunter	$6,533	$6,088	[illegible]
Huntington	$5,979	$6,294	NA

INPUTS

Interest Rate (i)	7.303%	(Input SNCR and SCR Cost of Capital Interest Rate)		
SNCR Life (n) (years)	20	(Input SNCR Equipment Life)		
CRF (SNCR)	0.09663	(Calculated CRF for given SNCR equipment life and interest rate)	Capital Recovery Factor (CRF)	Capital Recovery Factor $i(1+i)^n / ((1+i)^n - 1)$
SNCR Auxiliary Power Cost	$30	(Input SNCR auxiliary power cost $/MWh)		
SNCR Removal Efficiency	20.0%	(Input SNCR Removal Efficiency)		
SCR Life (n) (years)	30	(Input SCR Equipment Life)		
CRF (SCR)	0.08305	(Calculated CRF for given SCR equipment life and interest rate)	Capital Recovery Factor (CRF)	Capital Recovery Factor $i(1+i)^n / ((1+i)^n - 1)$

SNCR COSTS	Unit 1 SNCR Capital Cost	Unit 2 SNCR Capital Cost	Unit 3 SNCR Capital Cost	Unit 1 SNCR Total Indirect Costs	Unit 2 SNCR Total Indirect Costs	Unit 3 SNCR Total Indirect Costs	Unit 1 SNCR Total Capital Investment (TCI)	Unit 2 SNCR Total Capital Investment (TCI)	Unit 3 SNCR Total Capital Investment (TCI)	Unit 1 SNCR Annualized Capital Cost	Unit 2 SNCR Annualized Capital Cost	Unit 3 SNCR Annualized Capital Cost	Unit 1 SNCR Annual O&M Cost	Unit 2 SNCR Annual O&M Cost	Unit 3 SNCR Annual O&M Cost	Unit 1 SNCR Total Annual Cost	Unit 2 SNCR Total Annual Cost	Unit 3 SNCR Total Annual Cost
Hunter	$7,574,000	$7,574,000	$7,574,000	$8,430,000	$8,430,000	$8,430,000	$16,004,000	$16,004,000	$16,004,000	$1,546,421	$1,546,421	$1,546,421	$2,168,400	$2,208,800	$3,176,600	$3,711,821	$3,755,221	$4,723,021
Huntington	$7,644,000	$7,644,000	NA	$8,508,000	$8,508,000	NA	$16,152,000	$16,152,000	NA	$1,560,724	$1,560,724	NA	$2,256,200	$2,256,000	NA	$3,816,924	$3,716,724	NA

SCR COSTS	Unit 1 SCR Capital Cost	Unit 2 SCR Capital Cost	Unit 3 SCR Capital Cost	Unit 1 SCR Total Indirect Costs	Unit 2 SCR Total Indirect Costs	Unit 3 SCR Total Indirect Costs	Unit 1 SCR Total Capital Investment (TCI)	Unit 2 SCR Total Capital Investment (TCI)	Unit 3 SCR Total Capital Investment (TCI)	Unit 1 SCR Annualized Capital Cost	Unit 2 SCR Annualized Capital Cost	Unit 3 SCR Annualized Capital Cost	Unit 1 SCR Annual O&M Cost	Unit 2 SCR Annual O&M Cost	Unit 3 SCR Annual O&M Cost	Unit 1 SCR Total Annual Cost	Unit 2 SCR Total Annual Cost	Unit 3 SCR Total Annual Cost
Hunter	$76,395,000	$76,395,000	$81,894,000	$69,797,000	$69,797,000	$77,538,000	$146,192,000	$146,192,000	$162,132,000	$12,141,691	$12,141,691	$13,490,472	$1,771,000	$1,807,000	$2,264,000	$13,912,691	$13,948,691	$15,754,472
Huntington	$75,707,120	$75,707,120	NA	$66,216,136	$66,216,136	NA	$141,923,256	$141,923,256	NA	$11,787,158	$11,787,158	NA	$1,763,000	$1,720,000	NA	$13,550,158	$13,507,158	NA

SNCR and SCR BASELINE EMISSIONS	Unit 1 Baseline Heat Input (MMBtu/year)	Unit 2 Baseline Heat Input (MMBtu/year)	Unit 3 Baseline Heat Input (MMBtu/year)	Unit 1 Baseline NOx Emission Rate (lb/MMBtu)	Unit 2 Baseline NOx Emission Rate (lb/MMBtu)	Unit 3 Baseline NOx Emission Rate (lb/MMBtu)	Unit 1 Baseline NOx Emissions (tons/year)	Unit 2 Baseline NOx Emissions (tons/year)	Unit 3 Baseline NOx Emissions (tons/year)
Hunter	28,482,643	30,101,030	31,182,279	0.200	0.193	0.280	2,842	2,902	4,359
Huntington	28,063,728	27,150,145	NA	0.212	0.208	NA	2,968	2,825	NA

SNCR EMISSIONS	Unit 1 Baseline Heat Input (MMBtu/year)	Unit 2 Baseline Heat Input (MMBtu/year)	Unit 3 Baseline Heat Input (MMBtu/year)	Unit 1 SNCR NOx Emission Rate (lb/MMBtu)	Unit 2 SNCR NOx Emission Rate (lb/MMBtu)	Unit 3 SNCR NOx Emission Rate (lb/MMBtu)	Unit 1 SNCR NOx Emissions (tons/year)	Unit 2 SNCR NOx Emissions (tons/year)	Unit 3 SNCR NOx Emissions (tons/year)
Hunter	28,482,643	30,101,030	31,182,279	0.160	0.154	0.224	2,273	2,322	3,487
Huntington	28,063,728	27,150,145	NA	0.169	0.166	NA	2,374	2,260	NA

SCR EMISSIONS	Unit 1 Baseline Heat Input (MMBtu/year)	Unit 2 Baseline Heat Input (MMBtu/year)	Unit 3 Baseline Heat Input (MMBtu/year)	Unit 1 SCR NOx Emission Rate (lb/MMBtu)	Unit 2 SCR NOx Emission Rate (lb/MMBtu)	Unit 3 SCR NOx Emission Rate (lb/MMBtu)	Unit 1 SCR NOx Emissions (tons/year)	Unit 2 SCR NOx Emissions (tons/year)	Unit 3 SCR NOx Emissions (tons/year)
Hunter	28,482,643	30,101,030	31,182,279	0.05	0.05	0.05	712	753	780
Huntington	28,063,728	27,150,145	NA	0.05	0.05	NA	702	679	NA

Utah Regional Haze Second Planning Period SNCR and SCR Cost Analyses

SNCR COST EFFECTIVENESS	Unit 1 ($/ton)	Unit 2 ($/ton)	Unit 3 ($/ton)
Hunter	$5,752	$5,702	$4,906
Huntington	$5,673	$5,785	NA

SCR COST EFFECTIVENESS	Unit 1 ($/ton)	Unit 2 ($/ton)	Unit 3 ($/ton)
Hunter	$4,418	$4,423	[illegible]
Huntington	$4,077	$4,286	NA

INPUTS

Interest Rate (i)	3.250%	(Input SNCR and SCR Cost of Capital Interest Rate)		
SNCR Life (n) (years)	20	(Input SNCR Equipment Life)		
CRF (SNCR)	0.06878	(Calculated CRF for given SNCR equipment life and interest rate)	Capital Recovery Factor (CRF)	Capital Recovery Factor $i(1+i)^n / ((1+i)^n - 1)$
SNCR Auxiliary Power Cost	$30	(Input SNCR auxiliary power cost $/MWh)		
SNCR Removal Efficiency	20.0%	(Input SNCR Removal Efficiency)		
SCR Life (n) (years)	30	(Input SCR Equipment Life)		
CRF (SCR)	0.05268	(Calculated CRF for given SCR equipment life and interest rate)	Capital Recovery Factor (CRF)	Capital Recovery Factor $i(1+i)^n / ((1+i)^n - 1)$

SNCR COSTS	Unit 1 SNCR Capital Cost	Unit 2 SNCR Capital Cost	Unit 3 SNCR Capital Cost	Unit 1 SNCR Total Indirect Costs	Unit 2 SNCR Total Indirect Costs	Unit 3 SNCR Total Indirect Costs	Unit 1 SNCR Total Capital Investment (TCI)	Unit 2 SNCR Total Capital Investment (TCI)	Unit 3 SNCR Total Capital Investment (TCI)	Unit 1 SNCR Annualized Capital Cost	Unit 2 SNCR Annualized Capital Cost	Unit 3 SNCR Annualized Capital Cost	Unit 1 SNCR Annual O&M Cost	Unit 2 SNCR Annual O&M Cost	Unit 3 SNCR Annual O&M Cost	Unit 1 SNCR Total Annual Cost	Unit 2 SNCR Total Annual Cost	Unit 3 SNCR Total Annual Cost
Hunter	$7,574,000	$7,574,000	$7,574,000	$8,430,000	$8,430,000	$8,430,000	$16,004,000	$16,004,000	$16,004,000	$1,100,737	$1,100,737	$1,100,737	$2,168,400	$2,208,800	$3,176,600	$3,269,137	$3,309,537	$4,277,337
Huntington	$7,644,000	$7,644,000	NA	$8,508,000	$8,508,000	NA	$16,152,000	$16,152,000	NA	$1,110,917	$1,110,917	NA	$2,256,200	$2,256,000	NA	$3,367,117	$3,266,917	NA

SCR COSTS	Unit 1 SCR Capital Cost	Unit 2 SCR Capital Cost	Unit 3 SCR Capital Cost	Unit 1 SCR Total Indirect Costs	Unit 2 SCR Total Indirect Costs	Unit 3 SCR Total Indirect Costs	Unit 1 SCR Total Capital Investment (TCI)	Unit 2 SCR Total Capital Investment (TCI)	Unit 3 SCR Total Capital Investment (TCI)	Unit 1 SCR Annualized Capital Cost	Unit 2 SCR Annualized Capital Cost	Unit 3 SCR Annualized Capital Cost	Unit 1 SCR Annual O&M Cost	Unit 2 SCR Annual O&M Cost	Unit 3 SCR Annual O&M Cost	Unit 1 SCR Total Annual Cost	Unit 2 SCR Total Annual Cost	Unit 3 SCR Total Annual Cost
Hunter	$76,395,000	$76,395,000	$81,894,000	$69,797,000	$69,797,000	$77,538,000	$146,192,000	$146,192,000	$162,132,000	$7,701,646	$7,701,646	$8,557,197	$1,771,000	$1,807,000	$2,264,000	$9,472,646	$9,508,646	$10,821,197
Huntington	$75,707,120	$75,707,120	NA	$66,216,136	$66,216,136	NA	$141,923,256	$141,923,256	NA	$7,476,761	$7,476,761	NA	$1,763,000	$1,720,000	NA	$9,239,761	$9,196,761	NA

SNCR and SCR BASELINE EMISSIONS	Unit 1 Baseline Heat Input (MMBtu/year)	Unit 2 Baseline Heat Input (MMBtu/year)	Unit 3 Baseline Heat Input (MMBtu/year)	Unit 1 Baseline NOx Emission Rate (lb/MMBtu)	Unit 2 Baseline NOx Emission Rate (lb/MMBtu)	Unit 3 Baseline NOx Emission Rate (lb/MMBtu)	Unit 1 Baseline NOx Emissions (tons/year)	Unit 2 Baseline NOx Emissions (tons/year)	Unit 3 Baseline NOx Emissions (tons/year)
Hunter	28,482,643	30,101,030	31,182,279	0.200	0.193	0.280	2,842	2,902	4,359
Huntington	28,063,728	27,150,145	NA	0.212	0.208	NA	2,968	2,825	NA

SNCR EMISSIONS	Unit 1 Baseline Heat Input (MMBtu/year)	Unit 2 Baseline Heat Input (MMBtu/year)	Unit 3 Baseline Heat Input (MMBtu/year)	Unit 1 SNCR NOx Emission Rate (lb/MMBtu)	Unit 2 SNCR NOx Emission Rate (lb/MMBtu)	Unit 3 SNCR NOx Emission Rate (lb/MMBtu)	Unit 1 SNCR NOx Emissions (tons/year)	Unit 2 SNCR NOx Emissions (tons/year)	Unit 3 SNCR NOx Emissions (tons/year)
Hunter	28,482,643	30,101,030	31,182,279	0.160	0.154	0.224	2,273	2,322	3,487
Huntington	28,063,728	27,150,145	NA	0.169	0.166	NA	2,374	2,260	NA

SCR EMISSIONS	Unit 1 Baseline Heat Input (MMBtu/year)	Unit 2 Baseline Heat Input (MMBtu/year)	Unit 3 Baseline Heat Input (MMBtu/year)	Unit 1 SCR NOx Emission Rate (lb/MMBtu)	Unit 2 SCR NOx Emission Rate (lb/MMBtu)	Unit 3 SCR NOx Emission Rate (lb/MMBtu)	Unit 1 SCR NOx Emissions (tons/year)	Unit 2 SCR NOx Emissions (tons/year)	Unit 3 SCR NOx Emissions (tons/year)
Hunter	28,482,643	30,101,030	31,182,279	0.05	0.05	0.05	712	753	780
Huntington	28,063,728	27,150,145	NA	0.05	0.05	NA	702	679	NA

Attachment C

Differences Between Utah's and PacifiCorp's Calculations of SNCR Cost Effectiveness

One of the key sources of discrepancies between PacifiCorp's and UDAQ's SNCR cost effectiveness values is UDAQ's reliance on the SNCR Cost Calculation Spreadsheet which is included in the EPA Air Pollution Cost Control Manual (CCM). This results in a significant discrepancy in capital costs for SNCR between UDAQ's and PacifiCorp's analyses. For example, UDAQ's capital cost for Hunter Unit 1 is approximately $11M, while PacifiCorp's is approximately $16M. The large discrepancy is primarily the result of UDAQ's reliance on the generic estimate in EPA's CCM SNCR spreadsheet vs. S&L's site-specific engineering estimate. The CCM spreadsheet includes EPA's disclaimer that "*actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a* ***detailed engineering study and cost quotations from system suppliers***." EPA, Air Pollution Control Cost Estimation Spreadsheet For Selective Non-Catalytic Reduction (SNCR) Excel workbook, June 2019, Read Me tab. In other words, EPA's CCM SNCR guidance indicates that specific, detailed engineering and cost estimates, such as that developed by PacifiCorp, are preferable to the generic SNCR cost estimate based on the CCM.

The cost analysis provided by PacifiCorp and S&L is a detailed engineering study based on site-specific conditions and quotations from system suppliers as recommended by the CCM. PacifiCorp's cost estimate is a more accurate representation of the cost effectiveness of SNCR at the Hunter and Huntington units than the cost effectiveness values provided by using the CCM spreadsheet. The resulting differences are significant. For example, for Hunter Unit 1 the UDAQ analysis calculates a total capital investment (TCI) of $11,272,568 and a direct annual cost (O&M) of $1,705,334 per year. The PacifiCorp estimate calculates a TCI value of $16,004,000 and an annual O&M cost of $2,168,400. This is after adjusting PacifiCorp's costs by using UDAQ's 3.25% interest rate and $30/MWh electrical power cost.

Specific discrepancies between PacifiCorp's unit specific and UDAQ's more generalized analysis are outlined below.

1. **NOx Control Rate:** UDAQ and PacifiCorp used different NOx control efficiencies for SNCR. UDAQ used SNCR NOx control efficiencies ranging from 21.1% to 23.0%. PacifiCorp originally used its anticipated SNCR-controlled rates based on boiler firing configurations, baseline NOx rates and anticipated NOx emission limits following the implementation of SNCR. These rates are within the typical range for units of similar size and baseline NOx rates. However, PacifiCorp has subsequently revised its cost effectiveness determinations using a 20% NOx reduction rate, which is a typical manufacturer-guaranteed performance rate for similar boilers. Using this rate is more conservative and is consistent with the methodology used for the SCR cost effectiveness calculations.

2. **Heat Input:** UDAQ's estimated heat input values as calculated using the CCM methodology are much lower than PacifiCorp's actual boiler heat input values (excluding Hunter Unit 3). Further, the CCM spreadsheet is designed to utilize a ***net*** boiler heat input rate. UDAQ miscalculated the boiler heat input values by using annual Acid Rain ***gross*** generation data from CAMD (averaged from 2015-2020) to calculate unit heat rates. Net

and gross rates cannot be used interchangeably. These heat rate values were then multiplied by ***inaccurate net*** generation (in MW) values – instead of multiplying by the units' net ratings at full load capacity (net dependable capacity) – to determine boiler heat input.

Table 1 summarizes PacifiCorp's current net heat input rates and net dependable capacities for each unit. This is the data that should be used to calculate the correct boiler heat input values for use in the CCM spreadsheet.

Table 1: PacifiCorp Net Generation and Heat Rate Values

PacifiCorp Unit	Net Dependable Capacity (MW)	Net Heat Rate (Btu/kWh)	PacifiCorp Calculated Boiler Heat Input (MMBtu/hour)	UDAQ Calculated Boiler Heat Input (MMBtu/hour)
Hunter Unit 1	446	10,502	4,684	3,996
Hunter Unit 2	446	10,334	4,609	4,171
Hunter Unit 3	471	10,067	4,742	4,939
Huntington Unit 1	459	10,218	4,690	4,064
Huntington Unit 2	450	10,595	4,768	4,421

3. **Capacity Factor:** To calculate each unit's capacity factor, UDAQ used the Acid Rain ***gross*** generation and boiler heat input data to calculate gross unit heat rates. However, the CCM spreadsheet requires use of *net* heat rate values. Furthermore, UDAQ utilized incorrect unit-specific net MW ratings instead of current maximum dependable capacity net MW ratings. The use and application of these inaccurate values in the CCM spreadsheet resulted in calculations of incorrect unit capacity factors.

   Table 2 summarizes the Acid Rain average gross generation data (in MWh) and the inaccurate net generation values UDAQ used to calculate unit-specific capacity factors. Table 3 summarizes PacifiCorp's unit-specific annual capacity factors used to determine the average 2015-2019 values, which were calculated by actual heat input divided by rated heat input rate.

Table 2: UDAQ Calculated 2015-2019 Average Capacity Factors

	UDAQ			
	Average 2015-2019 CAMD Gross Generation (MWh)	Net Generation (MW)	Maximum Annual Generation (MWh)	Calculated Capacity Factor (%)
Hunter-1	3,062,197	430	3,766,800	81.3%
Hunter-2	3,103,568	430	3,766,800	82.4%
Hunter-3	3,217,127	510	4,467,600	72.0%
Huntington-1	3,043,166	440	3,854,400	79.0%
Huntington-2	2,796,838	455	3,985,800	70.2%

Table 3: PacifiCorp Actual 2015-2019 Capacity Factors

	PacifiCorp Actual Annual Capacity Factors					
	2015	2016	2017	2018	2019	Average
Hunter-1	82.3%	72.5%	51.2%	65.1%	76.7%	69.6%
Hunter-2	77.8%	70.8%	55.9%	72.0%	72.3%	69.8%
Hunter-3	81.8%	61.5%	58.1%	72.2%	70.4%	68.8%
Huntington-1	82.7%	63.9%	54.9%	60.6%	70.5%	66.5%
Huntington-2	67.6%	74.1%	49.9%	68.1%	52.3%	62.4%

4. **Operating and Maintenance Costs:** In general, UDAQ's use of generic CCM values resulted in O&M costs which were lower than the engineering estimates provided by S&L which were based on site-specific data (i.e. $1.7M vs. $2.2M O&M for Hunter Unit 1). PacifiCorp submits that the site-specific cost effectiveness determinations submitted for annualized capital and O&M costs are more accurate and 'real world' than the cost effectiveness values provided by the CCM.

Summary

PacifiCorp proposes UDAQ make the following adjustments to obtain a more representative cost effectiveness value for the installation of SNCR at the Hunter and Huntington plants:

- Utilize an SNCR NOx control efficiency of 20% for the Hunter and Huntington boilers, which is expected to be achievable based on unit size and firing configuration;
- Utilize capital and O&M costs provided by S&L which are site specific and more accurate than the generalized costs provided by the CCM model;
- Utilize PacifiCorp's actual weighted average cost of capital of 7.303% as the interest rate in the model instead of the 3.25% rate originally used by UDAQ;
- Utilize the current and accurate net MW generation rates and net unit heat rate provided in Table 1 to calculate boiler heat input; and lastly;
- Utilize the actual 2015-2019 average annual capacity factors in Table 3 instead of the rates included in Table 2, which are inaccurate.

PacifiCorp believes that use of the S&L capital and O&M cost data when combined with an SNCR 20% control efficiency and 7.303% interest rate will provide an accurate representation of unit-specific cost effectiveness. This is demonstrated by UDAQ's and PacifiCorp's SCR cost effectiveness determinations which provide essentially equivalent dollar-per-ton values.

The following tables provide a summary of PacifiCorp's revised SNCR cost effectiveness values for the Hunter and Huntington plants applying these adjustments. The estimates are based on a systemwide SNCR control efficiency of 20% and an interest rate of 7.303%. Note that the provided values do not incorporate minor changes in annualized capital and O&M costs which will occur when the April 9, 2020, S&L studies are updated to incorporate the current 7.303% interest rate and use of the 20% SNCR NOx control efficiency versus the studies' original use of a 7% interest rate and anticipated SNCR-controlled permit limit emission rates.

Table 4: PacifiCorp Updated Hunter SNCR Cost Effectiveness

COST EFFECTIVENESS	Hunter Unit 1	Hunter Unit 2	Hunter Unit 3
Baseline			
Baseline Heat Input (MMBtu/year)	28,482,643	30,101,030	31,182,279
Baseline NOx Emission Rate (lb/MMBtu)	0.200	0.193	0.280
Baseline NOx Emissions (tons/year)	2,842	2,902	4,359
NOx Emissions with SNCR (20% control efficiency)			
Controlled NOx Emission Rate (lb/MMBtu)	0.160	0.154	0.224
Controlled NOx Emissions (tons/year)	2,273	2,322	3,487
SNCR Annual NOx Removal (tons/year)	**568**	**580**	**872**
SNCR Cost Effectiveness (7.303% interest rate)			
Annualized Capital Costs (20-year life)	$1,546,424	$1,546,424	$1,546,424
Total Annual O&M Costs	$2,168,400	$2,208,800	$3,176,600
Total Annual Cost ($/year)	**$3,714,824**	**$3,755,224**	**$4,723,024**
COST EFFECTIVENESS ($/TON)	**$6,536**	**$6,469**	**$5,417**

Table 5: PacifiCorp Updated Huntington SNCR Cost Effectiveness

COST EFFECTIVENESS	Huntington Unit 1	Huntington Unit 2
Baseline		
Baseline Heat Input (MMBtu/year)	28,063,728	27,150,145
Baseline NOx Emission Rate (lb/MMBtu)	0.212	0.208
Baseline NOx Emissions (tons/year)	2,968	2,825
NOx Emissions with SNCR (20% control efficiency)		
Controlled NOx Emission Rate (lb/MMBtu)	0.169	0.166
Controlled NOx Emissions (tons/year)	2,374	2,260
SNCR Annual NOx Removal (tons/year)	**594**	**565**
SNCR Cost Effectiveness (7.303% interest rate)		
Annualized Capital Costs (20-year life)	$1,560,724	$1,560,724
Total Annual O&M Costs	$2,256,200	$2,156,000
Total Annual Cost ($/year)	**$3,816,924**	**$3,716,724**
COST EFFECTIVENESS ($/TON)	**$6,431**	**$6,579**

In conclusion, PacifiCorp submits that Tables 4 and 5 use of accurate annualized capital and O&M costs when combined with an appropriate SNCR NOx control efficiency of 20% provide reasonable SNCR cost effectiveness determinations for the Hunter and Huntington units. PacifiCorp has requested that S&L update their April 9, 2020, studies to utilize the current interest rate of 7.303% and the more conservative SNCR NOx control efficiency of 20% for all Hunter and Huntington units. These updates are currently being finalized and are not anticipated to materially impact the data provided here. PacifiCorp will notify UDAQ if any material changes occur.

APPENDIX C.4 – Sunnyside

APPENDIX C.4.A

Sunnyside Operations Associates L.P.

P.O. Box 10, East Carbon, Utah 84520 • (801) 888-4476 • Fax (801) 888-2538

April 9, 2020

Mr. Bryce Bird
Utah Division of Air Quality
195 North 1950 West
Salt Lake City, Utah 84116

RE: Four Factor Analysis - Regional Haze 2nd Implementation Period Sunnyside Cogeneration Associates, Title V Operating Permit Number #700030004

Dear Mr. Bird:

Attached is the Sunnyside Cogeneration Associates (Sunnyside) four factor analysis to meet the requirements of the U.S. Environmental Protection Agency's (EPA's) Regional Haze (RH) program. Sunnyside's analysis has been developed for review by the Utah Division of Air Quality (UDAQ) and Western Regional Air Partnership (WRAP), to complete its reasonable progress analysis as part of the second implementation period for the RH program.

This analysis has been developed using the four-factors addressed in Section 169A(g)(1) of the Clean Air Act (CAA), EPA's guidance, and the direction provided in UDAQ's letter dated October 21, 2019. Specifically, Sunnyside evaluated the sources generating NO_x and SO_2 for the four factors.

As you are aware, this analysis took longer than anticipated in light of the COVID-19 pandemic currently impacting our nation. In developing this analysis resources and vendor's availibity were limited requiring additional time to prepare a complete report.

If you have any questions regarding this submittal, please feel free to contact me or Rusty Netz at (435-888-4476 Ext. 107.

Thank You,

Gerald Hascall
Agent for
Sunnyside Cogeneration Associates

CC: Jay Baker, UDAQ jbaker@utah.gov
Jon Black, UDAQ jlblack@utah.gov
Brian Mensinger - Trinity Consultants, Inc.
Plant File

REGIONAL HAZE 2ND IMPLEMENTATION PERIOD FOUR-FACTOR ANALYSIS

Sunnyside Cogeneration Associates > Sunnyside, UT

Sunnyside Cogeneration Facility Four-Factor Analysis

Prepared For:

Rusty Netz – Sunnyside Cogeneration Associates

Sunnyside Cogeneration Facility

#1 Power Plant Road
Sunnyside, Utah 84539

Prepared By:

Brian Mensinger – Managing Consultant
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(801) 272-3000
April 8, 2020

Project 204502.0008

1. EXECUTIVE SUMMARY

Sunnyside Cogeneration Associates (Sunnyside) owns and operates a combustion boiler (EU #1), an emergency diesel engine (EU#5) and an emergency generator (EU#7), at its Cogeneration facility located at #1 Power Plant Road, Sunnyside, UT (The Facility). The boiler features a circulating fluidized bed, a baghouse and a limestone injection system. The facility operates under the jurisdiction of the Utah Department of Air Quality (UDAQ) Title V air operating permit (Permit # 700030004).

The following report represents Sunnyside's response to a request by UDAQ on October 21, 2019 that Sunnyside conduct a four-factor analysis of the plant's emission reduction options for visibility impairing pollutants. Per UDAQ, only sulfur dioxide (SO_2) and oxides of nitrogen (NO_X) need to be considered as visibility-impairing pollutants for this analysis.

The United States Environmental Protection Agency's (U.S. EPA's) guidelines in 40 CFR Part 51.308 are used to evaluate reduction measures for the emission units at the Sunnyside cogeneration facility. In establishing a reasonable progress goal for any mandatory Class I Federal area within the State, the State must consider the following four factors and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A):

1. The costs of compliance
2. The time necessary for compliance
3. The energy and non-air quality environmental impacts of compliance
4. The remaining useful life of any potentially affected sources

The purpose of this report is to provide information to UDAQ and the Western Regional Air Partnership (WRAP) regarding potential SO_2 and NO_X emission reduction measures for the Sunnyside cogeneration facility. Based on the Regional Haze Rule, associated U.S. EPA guidance, and UDAQ's request, Sunnyside understands that UDAQ will only move forward with requiring emission reductions from the Sunnyside Cogeneration Facility if UDAQ determines that the emission reductions are needed to show reasonable progress and provide the most cost-effective controls among all options available. In other words, control reductions should be imposed by the Regional Haze Rule only if these potential measures result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals. Sunnyside is submitting this report to provide results of the four-factor analysis and discuss the feasibility or infeasibility of these potential options. Table 1-1 below summarizes the SO_2 and NO_X emission reduction measures and the evaluation outcome.

Table 1-1. Summary of Findings

Pollutant	Emission Reduction Measure	Technically Feasible?	Cost Effective?	Appropriate for Emissions Reduction?	Notes
SO_2	Spray-Dry Absorbers	No	NA	No	Facility does not own sufficient water rights to implement technology.
	Dry Scrubbing	Yes	No	No	Implementation requires an additional baghouse, combined cost exceeds practical application.
	Wet Scrubbing	No	NA	No	Insufficient water available similar to spray-dry absorber. Therefore, technically infeasible.
	Hydrated Ash Reinjection (HAR)	No	NA	No	Impractical with current CaO levels available in the ash. Increasing ash or limestone feed to sufficient CaO levels is not technically feasible.
NO_X	Selective Catalytic Reduction (SCR)	Yes	No	No	Significant fouling and poisoning of catalyst. Therefore, technically infeasible. Cost also exceeds practical application.
	Selective Non-Catalytic Reduction (SNCR)	Yes	No	No	Insufficient residence time or temperatures to be effective. Cost also exceeds practical application.

As discussed in this four-factor analysis, Sunnyside concludes that the facility's existing control measures are the most suitable for SO_2 and NO_X emissions from the CFB boiler. The emissions reduction methods analyzed in this report are found to be either technically infeasible or cost ineffective. The boiler has existing NO_X emission limits in place based on the Title V permit, which are similar to existing boilers with PSD BACT limits. Likewise, actual SO_2 emissions from the boiler are comparable to PSD BACT limits for boilers that utilize waste (i.e., refuse) coal. As such, add-on NO_X and SO_2 control may provide minimal benefit to visibility.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to natural conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. In establishing a reasonable progress goal for a Class I area, the state must (40 CFR 51.308(d)(1)(i)):

(A) consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.

(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction.[1]

On October 21, 2019, UDAQ sent a letter to Sunnyside requesting "a four-factor analysis of its operations for nitrogen oxide and sulfur dioxide" for Sunnyside's Sunnyside Cogeneration Facility.[2] Sunnyside understands that the information provided in a four-factor review of control options will be used by UDAQ in their evaluation of reasonable progress goals for Utah. Based on the RHR, associated U.S. EPA guidance, and UDAQ's request, Sunnyside understands that UDAQ will only move forward with requiring emission reductions from the Sunnyside cogeneration facility if UDAQ determines that the emission reductions are needed to show reasonable progress and provide the most cost-effective controls among all options available. In other words, control reductions should be imposed by the RHR only if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals. The purpose of this report is to provide information to UDAQ and WRAP regarding SO_2 and NO_X emission reductions that could or could not be achieved for the Sunnyside Cogeneration Facility, if the emission reductions are determined by UDAQ to be necessary to meet the reasonable progress goals.

The information presented in this report considers the following four factors for the emission reductions:

1. Costs of compliance
2. Time necessary for compliance
3. Energy and non-air quality environmental impacts of compliance
4. Remaining useful life of the Emission Units

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[1] 40 CFR 51. 308(d)(1)(i)(B).

[2] Refer to letter from UDAQ to Sunnyside dated October 21, 2019.

The four-factor analysis is satisfied by conducting a stepwise review of emission reduction options in a top-down fashion. The steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Factor 4 is also addressed in the stepwise review of the emission reduction options, primarily in the context of the costing of emission reduction options, if any, and whether any capitalization of expenses would be impacted by limited equipment life. Once the stepwise review of reduction options was completed, a review of the timing of the emission reductions is provided to satisfy Factor 2 of the four factors.

A review of the four factors for SO_2 and NO_X can be found in Sections 5 and 6 of this report, respectively. Section 4 of this report includes information on the Sunnyside cogeneration facility's existing/baseline emissions.

In this analysis, various electricity generating technologies were reviewed to identify the technologies capable of burning refuse coal. It was concluded that the only technically feasible and commercially available technology capable of burning refuse coal is a circulating fluidized bed boiler. Pulverized coal (PC) boiler and integrating gasification combined cycle (IGCC) combustion units are not designed to operate with fuel that has a relatively low heating value as in the case for refuse coal. Therefore, these alternative boiler designs were not considered for this project.

3. SOURCE DESCRIPTION

The Sunnyside cogeneration facility is in Sunnyside, Carbon County, Utah (approximately 25 miles southeast of Price). The nearest Class I areas and their respective distance from the facility are Canyonlands National Park (91 miles), Capital Reef National Park (96 miles), Bryce Canyon National Park (171 miles) and Zion National Park (217 miles).

The Sunnyside power plant began operations in May of 1993. The electricity it produces is sold to PacifiCorp, operating as Utah Power and Light (UPLC). The plant qualifies as a small power production facility and qualifying cogeneration facility ("QF") under the Public Utility Regulatory Policy Act of 1997 ("PURPA").[3] The facility operates a coal-fired combustion boiler that features circulating fluidized bed (CFB), a baghouse and a limestone injection system. The facility also operates an emergency diesel engine and emergency generator. All process units are currently permitted in its UDAQ Title V air operating permit (Permit # 700030004) which was renewed on April 30, 2018. The CFB boiler is subject to the NESHAPS Part 63, Subpart UUUUU Mercury and Air Toxics Standards [MATS] Rule. As a result, Sunnyside is required to meet standard of 0.2 lb/MMBtu of an SO_2.[4] This standard requires continuous monitoring with a continuous emission monitor system (CEMS).

The plant's CFB boiler, designed by Tampella Power, produces steam that drives a Dresser-Rand turbine generator.[5] The CFB boiler and baghouse uses limestone injection. Historically, CFB boilers have been one of the primary low emission combustion technologies for commercial and small utility installations using low grade fuels. This trend continues with CFB technology being considered for smaller coal fired units as a means to effectively utilize lower quality fuels and meet environmental requirements.[6]

The current boiler produces emissions from one stack at Sunnyside's cogeneration facility. For the purposes of a control technology review, only the emissions from the boiler stack itself are considered as well as the operations from the emergency diesel engine and emergency generator.

3.1. PROCESS DESCRIPTION

The following subsections describe the processes and equipment used to generate power at the Sunnyside cogeneration facility. The process addressed in this four-factor analysis can be divided into two emission sources: CFB Boiler operations and emergency generators.

[3] Catalog of CHP Technologies, Section 4. Technology Characterization – Steam Turbines, U.S. EPA Combined Heat and Power Partnership, March 2015

https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_4._technology_characterization_-_steam_turbines.pdf

[4] Federal Register Vol. 81, No.66 Table2 to Subpart UUUUU of Part 63 Emission Limits for Existing EGUs

[5] https://www.aciinc.net/sunnyside

[6] Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units, U.S. EPA Office of Air and Radiation, October 2010

https://www.epa.gov/sites/production/files/2015-12/documents/electricgeneration.pdf

3.1.1. Boiler Operations

The Sunnyside Cogeneration Facility produces steam in a CFB boiler with a design maximum heat input capacity of 700 MMBtu/hr which feeds a steam turbine generator, producing a nominal 58 MW of power.[7] [8] Power produced by the steam generator is sold to the grid. The boiler runs on waste coal from two surrounding sub-bituminous waste-coal piles which are located on land owned or leased by Sunnyside. The waste-coal originates from a coal wash plant that previously removed the ash and sulfur out to the coal, leaving behind waste coal piles. Similar to other waste-coal burning facilities, Sunnyside has the added environmental benefit of utilizing a waste product, cleaning up old mining sites and generating an ash that is used as a beneficial back-fill material for reclamation of the old mining sites.

The CFB unit is equipped with air pollution control system to minimize emissions of air pollutants. Limestone is injected into the CFB with the coal feed stream to provide in-situ control of SO_2. The flue gas from the CFB is directed to a fabric filter baghouse for particulate matter ($PM/PM_{10}/PM_{2.5}$) control.

CFB combustion involves waste-coal and limestone being suspended through the action of primary combustion air distributed below the combustion floor. More specifically, in the CFB boiler, the crushed fuel is mixed with limestone in a highly turbulent, suspended (fluidized) state. The fluidized bed mixing facilitates inherent emission reductions in a number of ways. First, this turbulent mixing enhances the heat transfer efficiency and provides an optimized combustion environment for the use of low-grade fuels such as waste-coal. Second, with combustion temperatures ranging between 1,575 degrees (°) Fahrenheit (F) and 1,650 °F in the CFB coal-fired boiler, the formation of thermal NO_x and, to some extent, SO_3 is reduced, relative to older designs. Meanwhile, a PC boiler has combustion temperatures of 2,500 to 2,800°F and subsequently produces more NO_x.[9] Third, SO_2 leaving the combustion chamber (boiler) is significantly reduced due to the thermo-chemical reaction of the calcium/magnesium sorbent with fuel particles.

In summary, the Sunnyside facility supplies power using a CFB boiler that facilitates power generation with inherently low emissions through the consumption of waste coal that can have other impacts to the water and soil quality in the environment.

3.1.2. Emergency Diesel Engine and Emergency Generator

An emergency diesel engine rated at approximately 201 HP, is used to power the emergency backup fire-pump. A 500-kW emergency generator is on site to provide power to the plant's operations in the event of a power outage. While emissions are minor for the maintenance and testing of emergency generator engines, they have been addressed in this analysis for completeness.

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[7] UDAQ Inspection Report Dated August 9, 2016.

[8] Combined Heat and Power Technology Fact Sheet Series, U.S. Department of Energy, 2016, https://www.energy.gov/sites/prod/files/2017/12/f46/CHP%20Overview-120817_compliant_0.pdf

[9] U.S. EPA Clean Air Technology Center. Alternative Control Techniques Document – NOx Emissions from Utility Boiler. Research Triangle Park, North Carolina. -3-150, EPA-453/R-94-023, March 1997,

This section summarizes emission rates that are used as baseline rates in the four-factor analysis presented in Sections 5 and 6 of this report.

4.1. BASELINE EMISSION RATES

Baseline emission rates in tons per year are needed for both SO_2 and NO_X to complete the four-factor analysis. They are used in the control cost-effectiveness analysis to determine the annual dollars of control cost per ton of pollutant reduced, as well as in the scaling of operating costs for control equipment under consideration.

Sunnyside has provided the following emissions for this four-factor analysis which are based on actual emission rates. The projected annual emissions from the boiler for both NO_X and SO_2 are determined using CEMS data while the emergency generator and emergency diesel engine are based on the manufacturer specifications and past-actual usage. These same baseline rates are provided to UDAQ for use in the on-the-books/on-the-way basis for modeling because no changes to boiler and/or emergency generator operation are expected between now and 2028. The baseline annual emission rates for the purposes of this analysis are summarized in Table 4-1.

Table 4-1. Baseline Emission Rates (tons/yr)

Pollutant	Baseline Annual Emissions (tons/yr)		
	Boiler (EU #1)	Emergency Diesel Engine (EU #5)	Emergency Generator (EU #7)
SO_2	471	0.001	0.020
NO_X	431	0.020	0.310

The values for the CFB boiler are based on the facility's average annual emissions (tons/yr) for NO_X and SO_2 between 2016 and 2018, as recorded by the plant's CEMS. The three-year averaged values represent reasonable expected emissions for the coal-fired boiler, emergency engine, and emergency generator. The emergency generator and emergency diesel engine's emissions are calculated using manufacturer's specifications and yearly operating data, including the amount of diesel used and annual hours of operation. Using the baseline annual emissions, SO_2 and NO_X emissions from the boiler and emergency equipment were reviewed on a lb/MMBTU basis and a lb/HP-hr basis respectively, as shown in Table 4-2 below.

Table 4-2. Baseline Emission Rates

Pollutant	Baseline Annual Emissions		
	Boiler (EU #1)	Emergency Diesel Engine (EU #5)	Emergency Generator (EU #7)
	(lb/MMBTU)	(lb/HP-hr)	(lb/HP-hr)
SO_2	0.17	8.29E-4	2.71E-3
NO_X	0.15	1.66E-2	4.20E-2

When compared to Prevention of Significant Deterioration (PSD) permitting Best Available Control Technology (BACT) limits in the RACT/BACT/LAER Clearinghouse (RBLC) database, the boiler's SO_2 and NO_X emission levels on a lb/MMBTU basis are comparable to PSD BACT limits for CFB boilers that process refuse coal, and are significantly lower than emission limits provided in Sunnyside's Title V permit as shown in Table 4-3.[10]

Table 4-3. Permitted Emission Limits (lbs/MMBtu)

Pollutant	Boiler (EU #1) Emission Limits (lbs/MMBtu)	
	Normal Operations[11]	Startup, Shutdown, Maintenance/Planned Outage, or Malfunction
SO_2 Title V	0.42	1.2
SO_2 MATS	0.2	--
NO_X	0.25	0.60

[10] RBLC Search results are provided in Appendix C.

[11]

5. SO_2 FOUR FACTOR EVALUATION FOR CFB BOILERS

The four-factor analysis is satisfied by conducting a stepwise review of emission reduction options in a top-down fashion. The steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Cost (Factor 1) and energy / non-air quality impacts (Factor 3) are key factors determined in Step 4 of the stepwise review. However, timing for compliance (Factor 2) and remaining useful life (Factor 4) are also discussed in Step 4 to fully address all four factors as part of the discussion of impacts. Factor 4 is addressed further in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by a limited equipment life.

The baseline SO_2 emission rates that are used in the SO_2 four-factor analysis are summarized in Table 4-2. The basis of the emission rates is provided in Section 4 of this report. The CFB boiler is permitted to achieve a reduction of at least 70% SO_2 that would otherwise be emitted from the combustion process. In practice, Sunnyside the CFB boiler achieves greater than 90% reduction to meet NESHAPS, Subpart UUUUU (MATS Rule) of 0.2 lb/MMBTU of SO_2 for Electric Generating Units (EGUs).[12] More specifically, to control SO_2, the CFB process injects limestone to reduce sulfur compounds in the exhaust, including sulfuric acid (H_2SO_4) and SO_2. Within the combustion zone, calcium oxide (CaO) is formed by in-situ calcinination of the injected limestone. SO_2 formed during the combustion process combines with the in-situ limestone to form calcium sulfite ($CaSO_3$) and/or calcium sulfate ($CaSO_4$), $_{\text{particulate}}$, which is collected downstream in the fabric filter.

This CFB boiler configuration is also commonly instituted to achieve BACT for permitted CFB boilers.[13] When compared to the permitted emission rates for SO_2 found in the RBLC database,[14] Sunnyside's CFB boiler emits SO_2 at a rate comparable to CFB boiler installations around the country.

5.1. STEP 1: IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES

SO_2 is generated during fuel combustion in a boiler, as the sulfur in the fuel, specifically the waste-coal, is oxidized by oxygen in the combustion air.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for the Sunnyside CFB boiler are summarized in Table 5-1. Alternate fuels are not considered in this analysis based on the CFB boiler is not designed for other fuels; therefore, it exists as the base case. The retrofit controls predominantly include add-on controls that eliminate SO_2 after it is formed. Sunnyside

[12] Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs, Low Rank Virgin Coal, SO_2.

[13] Utah Division of Air Quality New Source Plan Review, Sevier Power Company's 270 MW Coal-Fired Power Plant, Dec. 2003

[14] RBLC Search results are located in Appendix C.

currently uses limestone injection to control SO_2 emissions. This top-down control review investigates whether installation of an additional SO_2 control device in series with the prior control technology is warranted.

Table 5-1. Available SO_2 Control Technologies and Measures for the Sunnyside CFB Boiler

SO_2 Control Technologies
Spray Dry Absorbers
Wet Scrubbing
Dry Scrubbing
Hydrated Ash Reinjection

5.1.1. Spray Dry Absorbers

Spray dry absorption involves spraying a high concentration, aqueous slurry sorbent, typically consists of lime, sodium bicarbonate, or trona,[15] into the wet flue gas stream. The sorbent interacts with acid gases (HCl, for example) or SO_2 and forms larger particles, while the evaporation of water from the slurry cools the flue gas stream. The cooling enhances precipitation of these particles from the flue gas stream, and the particles can be subsequently removed using an electrostatic precipitator or dry filter downstream.[16]

Spray dry absorbers require sufficient water to prepare the aqueous alkaline slurry. Water usage can vary greatly as injection rates of slurry and dilution water are controlled by signals from the in-stack CEMS and the stack temperature.[17]

5.1.2. Wet Scrubbing

A wet scrubber is a technology that may be installed downstream of the boiler. In a typical wet scrubber, the flue gas flows upward through a reactor vessel, while an aqueous slurry of alkaline reagent flows down from the top. The scrubber mixes the flue gas and alkaline reagent using a series of spray nozzles to maximize dissolution of SO_2 into the alkaline reagent by distributing the reagent across the scrubber vessel. The calcium (typically) in the aqueous reagent reacts with the SO_2 in the flue gas to form calcium sulfite ($CaSO_3$) and/or calcium sulfate ($CaSO_4$), which collects in the bottom of the reactor and is subsequently removed with the scrubber sludge.

5.1.3. Dry Scrubbing - Dry Sorbent

Dry scrubbers utilize powdered sorbents, such as dry limestone or lime, and pneumatically inject the powder downstream of the boiler. A dry scrubber would be an add-on control technology after the limestone injection already occurring in the CFB boiler. Dry sorbent injection involves a sorbent storage tank, feeding mechanism, transfer line, blower and injection device. An expansion chamber is located downstream of injection point to increase residence time and efficiency. SO_2 in the flue gas reacts directly with the powdered reagent to form waste particles which are subsequently carried in the flue gas through a particulate control device, such as a fabric filter or electrostatic precipitator, where the particles are collected from the cleaned flue gas. Dry

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[15] Trona is a sodium carbonate compound, which is processed into soda ash or baking soda. https://www.wyomingmining.org/minerals/trona/

[16] Rogoff et al., Waste to Energy 2nd Ed., Section 8.2.4.6 Spray dryers/dry scrubbers

[17] Ibid.

scrubbers are usually applied when lower removal efficiencies are required, or for smaller plants.[18] Effects on plant operation vary for the different sorbents. Some coal-fired boiler owners and operators select to use hydrated lime if possible, in order to avoid potential heavy metal leaching from the collected fly ash mixed with DSI by-product.[19]

5.1.4. Dry Scrubbing - Hydrated Ash Reinjection

Hydrated ash reinjection (HAR) effectively reduces SO_2 emissions by increasing the extent of reaction between SO_2 and hydrating sorbents in the CFB. The CFB recycles fly ash in the system for a specified period, after which the flue gas is sent to a particulate control device where the sulfur-rich particulates are collected. Design and efficiencies for HAR systems vary greatly based on vendor and sorbent type.[20] HAR also requires significant amounts of fly ash to maintain reaction rates that sustain desulfurization of the flue gas.

5.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible SO_2 control technologies that are identified as available in Step 1.

5.2.1. Spray Dry Absorbers

Installing an additional spray dry absorber in series with the current FGD system would further reduce SO_2 emissions at Sunnyside's facility. Despite the misleading name, spray dry absorbers (also known as semi-dry absorbers), require water to atomize the reactive sorbent into an aqueous solution.[21] [22]

Sunnyside's operation already requires a significant use of water, and the plant's current water rights are not sufficient enough to sustain the necessary water usage to operate an additional spray dry absorber. In 2018, Sunnyside exceeded their allotted water rights. Consequently, it had to purchase 44.5 million gallons of additional water from the city of East Carbon.[23] At times there is not sufficient water for purchase. The facility already uses the majority of its water rights and normal years for current operations and has to buy additional water to supply the necessary amount of water to the cooling towers. Any additional water consumption would result in the water rights being used much more rapidly and represents an undue burden on the facility to acquire the water for spray dry absorber operation. As additional water rights are not available in the quantity required for implementing water-intensive technology, installation of an additional spray dry absorber in series with Sunnyside's current limestone injection technology is considered infeasible and will not be evaluated further

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[18] See Air Pollution Control Technology Fact Sheet, Flue Gas Desulfurization, EPA-452/F-03-034, Pg. 4

[19] Power Engineering International – Dry sorbent injection for SOx emissions control, June 28, 2017

[20] Montana Department of Environmental Quality, Regional Haze Four Factor Analysis, Rosebud Power Plant, 2019

[21] See Air Pollution Control Technology Fact Sheet, Flue Gas Desulfurization, EPA-452/F-03-034, Pg. 4

[22] See description of spray dry absorber technology available from vendor : https://www.gea.com/en/products/spray-dryer-absorber.jsp

[23] According to email correspondence from Sunnyside Cogeneration on the water usage at the facility in 2018.

5.2.2. Wet Scrubbing

Similar to spray dry absorption, A wet scrubbing system utilizes a ground alkaline agent, such as lime or limestone, in slurry to remove SO_2 from stack gas. However, wet scrubbing uses more water than spray dry systems to generate the aqueous sorbent. The alkaline slurry is sprayed into the absorber tower and reacts with SO_2 in the flue gas to form insoluble $CaSO_3$ and $CaSO_4$ solids. A wet flue gas desulfurization (FGD) must be located downstream of the fabric filter baghouse. The spent slurry is dewatered using settling basins and filtration equipment. Recovered water is typically reused to blend new slurry for the wet scrubber. A significant amount of makeup water is required to produce enough slurry to maintain the scrubber's design removal efficiency. Water losses from the system occur from evaporation into the stack gas, evaporation from settling basins, and retained moisture in scrubber sludge. As the concentration of the SO_2 in the CFB gas is inherently low due to existing control technologies, it is not anticipated that a wet FGD system will provide a significant reduction in overall SO_2 emissions.

As mentioned previously, the plant's current water rights and water availability are not sufficient to operate a wet scrubber instead of limestone injection technology, or in series with the current limestone injection technology. Since any additional water consumption represents an undue burden on the facility to acquire the water for wet scrubber operation, this technology is considered infeasible and will not be evaluated further.

5.2.3. Dry Scrubbing

Dry scrubbing systems are mechanically simple systems and use less water than wet scrubbing and spray dry systems.[24] Due to limited water use and simple waste disposal, dry injection systems install easily and are good candidates for retrofit applications.[25].Therefore, dry scrubbing is considered technically feasible, and considered further.

5.2.4. Hydrated Ash Reinjection

Application of HAR results in higher particulate loading in the flue gas, and subsequently generates larger emissions particulate matter. Flue gas exiting the CFB at Sunnyside typically contains approximately 10% unreacted calcium oxide in the fly ash and even less in the bottom ash. [26] To enable HAR, either additional limestone loading to the CFB would needed or significant amounts of ash to effectively scrub SO_2. Therefore, large amounts of unreacted fly ash are required to implement HAR to be able to handle the additional loading. Additionally, a larger particulate control device would likely be required to handle the increased particulate matter in the flue gas.

HAR implementation would be impractical with 10% available CaO and even if adding reagent would be feasible it would likely require the installation of an enhanced baghouse with the addition of additional particulate in the flue gas of the CFB due to the significant amount of ash reagent that would be required. Due to the questionable technical feasibility of HAR, and the generation of PM emissions, the technology is considered technically infeasible, and no longer considered.

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[24] As limestone is injected into the CFB boiler and calcines in the combustion chamber, the addition of lime as a reagent in a scrubber is practical based on reactivity and temperature for further SO_2 removal in flue gas.

[25] See Air Pollution Control Technology Fact Sheet, Flue Gas Desulfurization, EPA-452/F-03-034, Pg. 4

[26] Based on fly ash characterization results conducted at Sunnyside Cogeneration Associates.

5.3. STEP 3: RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS

Step 3 of the top-down control review is to rank the technically feasible options by effectiveness. Table 5-2 below ranks feasible control technologies according to their respective control efficiency for SO_2 removal.

Table 5-2. SO_2 Control Efficiencies for Remaining Feasible Technologies

Control Technologies	Control Efficiency[27 28]
Dry Scrubbing	50-98%

Control efficiency is undetermined at this time because the most effective method to determine optimal performance and balance of plant effects is to conduct a DSI trial on the unit in question. These trials typically range from one week to three months in duration, using temporary equipment designed for this purpose.[29] For the purposes of evaluation the average of the range was used.

5.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS

Step 4 of the top-down control review is the impact analysis. Sunnyside's average emission rate of SO_2 between 2016 and 2018 was 471 tons per year or approximately 0.17 lbs of SO_2 per MMBTU with the utilization of limestone injection technology.

Installing dry scrubbing technology at Sunnyside also requires the installation of additional baghouse to remove particulates generated from dry scrubbing operation. Sunnyside's cost analysis of this technology shows that dry scrubbing provides an undue economic burden to the facility, costing approximately $10,372 per ton of SO_2 removed.

The boiler currently operated was determined to achieve BACT for SO_2 at the time of the boiler's New Source Review (NSR) permit.[30] It has further reduced its emissions to meet NESHAPS, Part 63 Subpart UUUUU (MATS).[31] When compared to the permitted emission rates for SO_2 found in the RBLC database, Sunnyside's CFB boiler emits SO_2 at a rate comparable to SO_2 BACT limits of CFB boiler installations around the country.[32] The Sunnyside CFB boiler is already equipped with limestone injection, which is currently installed primarily for SO_2 control on the CFB technology. Sunnyside is currently injecting limestone to manage SO_2 emissions as needed to meet the existing, appropriately low SO_2 limits set forth by BACT, NSPS Subpart Da, and NESHAPs Part 63,

[27] See cost analysis for hydrated ash reinjection performed by Colstrip Energy Limited Partnership's Rosebud Power Plant, for Regional Haze Four-Factor Analysis in 2019, Submitted to Montana DEQ, Bison Engineering.

[28] Ibid.

[29] Power Engineering International – Dry sorbent injection for SOx emissions control, June 28, 2017

[30] See Title V Operating Permit #700030004 Condition II.B.2.c

[31] Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs, Low Rank Virgin Coal, SO_2 require 0.2 lb/MMBtu.

[32] See RBLC Tables provided in Appendix C

Subpart UUUUU (MATS Rule).[33]

Since Sunnyside's emission rate maintains parity with NSPS and MATS emission limitations for similar processes and no technologies are available to reduce the emission rate further. The current process of a limestone injection technology to achieve a reduction in SO_2 emissions is considered BACT for the boiler. Furthermore, this emission rate is well below the established SO_2 limitation from NSPS Subpart Da, which is 0.6 lb/MMBTU and remains below NESHAPS, Part 63 Subpart UUUUU (MATS) of 0.2 lb/MMBTU. No technologies are available to reduce SO_2 emissions further. Therefore, the current process of using inherently low sulfur raw materials and natural scrubbing is considered BACT for the boiler.

5.4.1. Cost of Compliance

The currently installed and operating controls are assumed to be cost-effective. As stated previously, all cost calculations and cost effectiveness determinations are considered on the basis of the currently controlled emission levels. Detailed cost calculations for the SO_2 control technology is included in Appendix A.

5.4.1.1. Dry Scrubber Cost Calculations

Dry Scrubber cost calculations are determined using the U.S. EPA's Control Cost Manual methodology. A retrofit factor of 1.3 is used in determining the capital costs associated with the potential installation of dry scrubber technology.

5.4.1.2. Cost Effectiveness

The cost effectiveness is determined by dividing the annual control cost by the annual tons reduced. Table 5-3 summarizes the results. Based on the results of this analysis, the cost of dry scrubbing is not cost effective.

Table 5-3. SO_2 Cost of Compliance Based on Emissions Reduction

Control Option	Control Cost ($/yr)	Baseline Emission Level (tons)	SO_2 Reduction (%)	Emission Reduction (tons)[34]	Cost Effectiveness ($/ton removed)
Dry Scrubber	$3,253,696	471	74%	319	$10,202

5.4.2. Timing for Compliance

Sunnyside believes that reasonable progress compliant controls are already in place. However, if UDAQ and WRAP determine that one of the SO_2 control options analyzed in this report is necessary to achieve reasonable progress, it is anticipated that this change could be implemented during the period of the second

[33] BACT restricts SO_2 emissions to 0.42 lb/MMBTU, while NSPS Subpart Da restricts SO_2 emissions to 0.6 lb/MMBTU.

[34] Assumes that Sunnyside plant has a 91.5% uptime based on its baseline period. Therefore, emission reduction = baseline emissions * (1 – SO_2 reduction) * Uptime.

long-term strategy for regional haze (approximately ten years following WRAP's reasonable progress determination).

5.4.3. Energy Impacts

The cost of energy required to operate the control devices has been included in the cost analyses found in Appendix A. To operate any of these add-on control devices, overall plant efficiency would decrease due to the operation of the add-on controls. Additionally, this control equipment would consume additional power causing uses all or in excess of its parasitic load and Sunnyside would not meet its power purchase agreement obligation.

Emission reducing options that involve water also require significant energy to operate the wet scrubber and associated equipment (pumps, atomizers, etc.). However, water-intensive control technologies have been eliminated due to a lack of water availability.

The use of emissions reduction options involving the injection of lime for dry scrubbing and wet scrubbing also causes significant energy impacts. The production of lime is an energy-intensive process that can result in increases in NO_X, particulate matter, and SO_2 emissions, an effect directly counters to regional haze efforts. This lime production emissions increase would then be coupled with the energy and emissions impacts resulting from the transportation of the lime to the facility. The production and delivery of lime to the Sunnyside facility would require significant energy and would result in emission increases of pollutants that directly contribute to visibility impairment around the country.

5.4.4. Non-Air Quality Environmental Impacts

Technically feasible add-on SO_2 control options that have been considered in this analysis also have additional non-air quality impacts associated with them.

- A dry scrubbing control system will require additional particulate loading in the flue gas thereby increasing the volume to be handled, which will put a burden on the existing baghouse system and result a larger baghouse control system to capture PM emissions exiting from the stack.

5.4.5. Remaining Useful Life

The remaining useful life of the boiler will likely impact the annualized cost of an add-on control technology (dry scrubbing control) because the useful life is anticipated to be less than the capital cost recovery period of 20 years or less. Although, the cost analysis presented in this report is based on 20 years to be conservative.

5.5. SO_2 Conclusion

The CFB boiler, equipped with limestone injection, inherently removes the vast majority of SO_2 that is created from the process.[35] The limestone injection configuration, as currently used was determined to achieve BACT and MATS emission limitations. Furthermore, Sunnyside's current SO_2 control technology is commonly used to achieve BACT for CFB boilers.[36]

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[35] See Sunnyside's Title V Operating Permit, 700030004, Condition II.B.2.f

[36] BACT determinations provided in RBLC Search Results, Appendix C.

This analysis did not identify any technically feasible and cost-effective control options to reduce SO_2 beyond the low levels currently achieved by control options already permitted for the boiler.

As described in Section 2, the Factors of the four-factor analyses are considered by conducting a stepwise review of emission reduction options in a top-down fashion. The steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Cost (Factor 1) and energy / non-air quality impacts (Factor 3) are key impacts determined in Step 4 of the stepwise review. However, timing for compliance (Factor 2) and remaining useful life (Factor 4) are also discussed in Step 4 to fully address all four factors as part of the discussion of impacts. Factor 4 is primarily addressed in in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by a limited equipment life.

The baseline NO_X emission rates that are used in the NO_X four-factor analysis are summarized in Table 4-3. The basis of the emission rates is provided in Section 4 of this report. The boiler currently has CFB technology installed. The baseline NO_X emission rates for the Sunnyside CFB boiler are within the range of permitted Title V values on a lb/MMBtu basis.

6.1. STEP 1: IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

NO_X emissions are produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms "thermal" NO_X and "fuel" NO_X when describing NO_X emissions from the combustion of fuel. Thermal NO_X emissions are produced through high-temperature oxidation of nitrogen found in the combustion air. Fuel NO_X emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel. Many variables can affect the equilibrium in the boiler, which in turn affects the creation of NO_X.[37]

A circulating fluidized bed reduces the fuel required to achieve sufficient material temperatures, over traditional FBC units, limiting thermal NO_X production in the EGU's system. A CFB boiler uses staged combustion limiting the formation of NO_X.[38] This effect is combined with the benefits of combusting the fuel in stages, a method which allows for more fuel to be burned at a lower temperature rather than the higher peak flame temperature within the boiler, thereby reducing thermal NO_X formation.

Step 1 of the top-down control review is to identify available retrofit control options for NO_X. The available NO_X retrofit control technologies for the Sunnyside Boiler are summarized in Table 6-1.

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[37] C. B. Oland, Guide to Low-Emission Boiler and Combustion Equipment Selection, Oak Ridge National Laboratory, April 2002

[38] Technology Overview: Circulating Fluidized Bed Combustion, U.S. EPA Office of Air Quality Planning and Standards, June 1982

Table 6-1. Available NO_X Control Technologies for the Sunnyside Boiler

NO_X Control Technologies	
Combustion Controls	Circulating Fluidized Bed (CFB) (Base Case)
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

NO_X emissions controls, as listed in Table 6-1, can be categorized as combustion or post-combustion controls. Combustion controls reduce the peak flame temperature, which minimizes NO_X formation. Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) convert NO_X in the flue gas to molecular nitrogen and water.

6.1.1. Combustion Controls

6.1.1.1. Circulating Fluidized Bed

Circulating fluidized bed (CFB) combustion is a specific type of fluidized bed combustion (FBC). To begin, FBC combustion involves coal being crushed into fine particles then suspended in a fluidized bed by upward-blowing jets of air. This results in a turbulent mixing of combustion air with the coal particles. The coal is mixed with a sorbent, specifically limestone (for SO_2 emission control). The operating temperatures for FBC are in the range of 1,500°F to 1,670°F.

The CFB technology allows for operating at higher gas stream velocities and with finer-bed size particles. There is no defined bed surface but rather high-volume, hot cyclone separators to recirculate entrained solid particles in flue gas to maintain the bed and achieve high combustion efficiency. As noted, before, the lower peak combustion temperature reduces thermal NO_X while the staged combustion reduces fuel NO_X. Sunnyside meets their Title V permitted NO_X emission limits using the CFB technology. Therefore, the CFB technology will not be evaluated further.

6.1.2. Post Combustion Controls

6.1.2.1. Selective Catalytic Reduction

An SCR system is a process whereby NOx is reduced by spraying a reagent, such as urea or ammonia over a catalyst in the presence of oxygen. On the catalyst surface, NH_3 and nitric oxide (NO) or nitrogen dioxide (NO_2) react to form diatomic nitrogen and water. The overall chemical reactions can be expressed as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

6.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible NO_X control technologies that are identified in Step 1.

6.2.1. Post Combustion Controls

6.2.1.1. Selective Catalytic Reduction

The SCR process requires a reactor vessel, a catalyst, and an ammonia storage and injection system. The presence of the catalyst effectively reduces the ideal reaction temperature for NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NO_X into molecular nitrogen (N_2) and water vapor (H_2O).[44] The optimum operating temperature is dependent on the type of catalyst and the flue gas composition. Generally, the optimum temperature ranges from 480°F to 800°F.[45] The effectiveness of an SCR system is dependent of a variety of factors, including the inlet NO_x concentration, the exhaust temperature, and ammonia injection rate, the type of catalysts poisons, such as particulate matter and SO_2. In practice, SCR systems can operate at efficiencies in the range of 70% to 90%.[46] While SCR has been used for NOx control in pulverized coal applications, the nature of CFB makes it very impractical. Considering the high particulate loading rate and calcium oxide (CaO) concentration of the flue gas due to limestone injection in this section of the CFB boiler exhaust stream, and due to use of refuse coal fuel in the boiler with ash content as high as 60%, an SCR system installed upstream of particulate controls would experience rapid catalyst de-activation and fouling. These technical problems would make the operation of an SCR in the high-dust laden flue gas upstream of the particulate controls technically infeasible for a CFB boiler design.

Since low-temperature SCR is not technically feasible, another option would be to reheat the flue gas downstream of the baghouse to the temperature range known to be effective for SCR use at (650-750°F). This increase in exhaust temperature would require an additional combustion device, also increasing NO_X, SO_2, and $PM_{2.5}$ emissions.

The main drawback with SCR is the overall costs associated with running the system. SCR systems traditionally have high capital and operating costs as large volumes of catalyst required for the reduction reaction as well as replacement catalyst and ammonia reagent costs. Even with the increase in ammonia, $PM_{2.5}$, and SO_2 emissions, Sunnyside has considered this technology to be technically feasible for the CFB boiler and further evaluated the economic feasibility of this technology as detailed in Step 4.

6.2.1.2. Selective Non-Catalytic Reduction

Successful implementation of SNCR poses several technical challenges - most related to maintaining NH_3 injection within the optimal temperature range (approximately 1,600°F and 2,000°F).[47]

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[44] Ibid.

[45] OAQPS, *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA/424/B-02-001 (http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf); January 2002

[46] OAQPS, *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA/424/B-02-001 (http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf); January 2002

[47] Air Pollution Control Cost Manual, Section 4, Chapter 1, Selective Non-Catalytic Reduction, NOx Controls, EPA/452/B-02-001, Pages 1-5.

When operated within the optimum temperature range of 480°F to 800°F, the reaction can result in removal efficiencies between 70 and 90 percent.[39] The rate of NO_X removal increases with temperature up to a maximum removal rate at a temperature between 700°F and 750°F. As the temperature increases above the optimum temperature, the NO_X removal efficiency begins to decrease. SCR has been successfully installed and operated on many industrial boilers in the U.S. and therefore will be further evaluated.

6.1.2.2. Selective Non-Catalytic Reduction

In SNCR systems, a reagent is injected into the flue gas within an appropriate temperature window. The NO_X and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia and urea SNCR processes require three to four times as much reagent as SCR systems to achieve similar NO_X reductions.

Like SCR, SNCR uses ammonia or a solution of urea to reduce NO_X through a similar chemical reaction.

$$2NO+4NH_3+2O_2 \rightarrow 3N_2+6H_2O$$

SNCR residence time can vary between 0.001 seconds and 10 seconds.[40] However, increasing the residence time available for mass transfer and chemical reactions at the proper temperature generally increases the NO_X removal. There is a gain in performance for residence times greater than 0.5 seconds. The U.S. EPA Control Cost Manual indicates that SNCR requires a higher temperature range than SCR of between approximately 1,600°F and 2,000°F,[41] due to the lack of a catalyst to lower the activation energies of the reactions; however, the control efficiencies achieved by SNCR vary across that range of temperatures. At higher temperatures, NO_X reduction rates decrease.[42] In addition, a greater residence time is required for lower temperatures.

There are several complications that can occur when attempting to identify and successfully implement the necessary controls to obtain ideal temperature zones for NO_X reduction, resulting in significant variability among the reduction efficiencies achieved with SNCR in boilers .[43] In other words, SNCR in boilers have achieved varying and sometimes poor success, often due to the flue gas temperatures as well as varying combustion loads diverging from optimal values.

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[39] Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NOx Controls, EPA/452/B-02-001, Pages 2-9 and 2-10.

[40] Air Pollution Control Cost Manual, Section 4, Chapter 1, Selective Non-Catalytic Reduction, NOx Controls, EPA/452/B-02-001, Page 1-8

[41] Ibid, Page 1-6

[42] Ibid, Page 1-14.

[43] Ibid, Page 1-15.

Temperature, residence time, reagent injection rate, reagent distribution in the flue gas, uncontrolled NOx level, and CO and O_2 concentrations are important in determining the effectiveness of SNCR. In general, if NOx and reagent are in contact at the proper temperature for a long enough time, then SNCR will be successful at reducing the NOx level. SNCR is most effective within a specified temperature range or window (approximately 1,600°F and 2,000°F) At temperatures below the window, reaction kinetics are extremely slow, such that little or no NO_x reduction occurs. As the temperature within the window increases, the NO_x removal efficiency increases because reaction rates increase with temperature. However, the gain in performance for residence times greater than 0.5 seconds is generally minimal. NO_x generation is minimized between 1,600°F and 2,000°F because the reaction rate plateaus in this range.[48]

Sunnyside's temperatures in the combustor are approximately 1,620 °F and cyclone outlet at 1,670 °F. Plants of similar design have installed lances to inject ammonia at the exit of the cyclone. Within 100 ft of the potential lance injection location, would be the equivalent to 0.2 seconds of residence time, the temperature drops 600 °F; therefore, falling out of the SCNR temperature window. As a result, it is believed that the control efficiency at Sunnyside would be extremely low to the point where the controls would not be effective.

Additionally, at lower temperatures the reaction rate is slowed down, causing ammonia slip, which would result in the formation of ammonia salts, which themselves are condensable $PM_{2.5}$, a visibility impairing pollutant.

Despite the technical and adverse environmental impacts detailed above, the installation of SNCR is considered technically feasible for Sunnyside Cogeneration's boiler and will be considered further.

6.3. STEP 3: RANK OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS BY EFFECTIVENESS

Step 3 of the top-down control review is to rank the technically feasible options to effectiveness. Table 6-2 presents potential NO_X control technologies for the boiler and their associated control efficiencies.

Table 6-2. Ranking of NO_X Control Technologies by Effectiveness

Pollutant	Control Technology	Potential Control Efficiency (%)
NO_X	SCR	70-90
	SNCR	Varies Significantly

[a] Control efficiency for SNCR, per the U.S. EPA Control Cost Manual Chapter 1 Figures 1.3 and 1.4 document SNCR effects from temperature and residence time.

[48] See EPA 452/B-02-001 Chapter 1 Section 4: NO_X Controls, Figure 1.3

6.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step 4 of the top-down control review is the impact analysis. The impact analysis considers the:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

6.4.1. Cost of Compliance

The currently installed and operating controls are assumed to be cost-effective. As stated previously, all cost calculations and cost effectiveness determinations are considered on the basis of the currently controlled emission levels. Detailed cost calculations for each of the NO_X control technologies are included in Appendix B.

6.4.1.1. SNCR Cost Calculations

SNCR cost calculations are determined using the U.S. EPA's Control Cost Manual methodology. A retrofit factor of 1 is used in determining the capital costs associated with the potential installation of SNCR.

6.4.1.2. Cost Effectiveness

The cost effectiveness is determined by dividing the annual control cost by the annual tons reduced. Table 6-3 summarizes the results.

Table 6-3. NO_X Cost of Compliance Based on Emissions Reduction

Control Option	Control Cost ($/yr)	Baseline Emission Level (tons)	NO_X Reduction (%)[49]	Emission Reduction (tons)[50]	Cost Effectiveness ($/ton removed)
SCR	$5,199,098	432	90%	356	$12,039
SNCR	$678,005	432	15%[b]	59	$10,542

[a] Emission reduction assumes actual operating time of Sunnyside at 334 days per year.
[b] NOx reduction is based on evaluation of Figures 1.3 and 1.4 documenting NOx reduction percent control curves based on temperature and residence time in CFB boilers of similar design to Sunnyside.

6.4.2. Timing for Compliance

Sunnyside believes that reasonable progress compliant controls are already in place. However, if the UDAQ determines that one of the control methods analyzed in this report is necessary to achieve reasonable

[49] EPA's Cost Control Manual, EPA/452/B-02-001, Section 4.2 NOx Post Combustion Chapter 1 SNCR

[50] Assumes that Sunnyside plant has a 91.5% uptime based on its baseline period. Therefore, emission reduction = baseline emissions * (1 – NO_x reduction) * Uptime.

progress, it is anticipated that this change could be implemented during the period of the second long-term strategy for regional haze (approximately ten years following the reasonable progress determination for this second planning period).

6.4.3. Energy Impacts and Non-Air Quality Impacts

As with the addition of SO_2 controls, the introduction of either SNCR or SCR for NO_X control will result in an increase in the electricity demand and/or waste generated at the facility. Overall plant efficiency will decrease as a result of the use of this equipment. Additionally, this control equipment would consume additional power causing uses all or in excess of its parasitic load and Sunnyside would not meet its power purchase agreement obligation.

Environmental agencies around the country have acknowledged the significance of ammonia slip and the potential increases in condensable $PM_{2.5}$ that can result from the introduction of excess ammonia slip into the atmosphere.

For jurisdictions that struggle with meeting PM standards, the California Environmental Protection Agency Air Resources Board's guidance document[51] advises all air quality districts in California to not permit higher levels of ammonia slip:

> *"Air districts should consider the impact of ammonia slip on meeting and maintaining PM_{10} and $PM_{2.5}$ standards, particularly in regions where ammonia is the limiting factor in secondary particulate matter formation. Where a significant impact is identified, air districts could revise their respective New Source Review rules to regulate ammonia as a precursor to both PM_{10} and $PM_{2.5}$."*

The use of SNCR or SCR for NO_X control introduces the risk of excessive ammonia slip emissions, which contributes to visibility impairing compound formation of ammonia salts.

Additionally, there are safety concerns associated with the transport and storage of ammonia, including potential ammonia spills that can have serious adverse environmental and health impacts.

6.4.4. Remaining Useful Life

The remaining useful life of the boiler will likely impact the annualized cost of an add-on control technology SCR and SNCR) because the useful life is anticipated to be less than the capital cost recovery period of 20 years or less. Although, the cost analysis presented in this report is based on 20 years to be conservative.

6.5. NO_X CONCLUSION

The facility currently uses CFB technology to lower NO_X emissions and achieves Title V permitting NO_X limits as currently operated. SCR is a technically feasible control option for this boiler but is not cost effective as costing greater than $10,000 per ton of NO_X removed. While SNCR *may* represent a cost-effective option for NO_X

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[51] California Environmental Agency Air Resources Board's Report to the Legislature: Gas-Fired Power Plant NO_X Emission Controls and Related Environmental Impacts, May 2004. Page 29. https://ww3.arb.ca.gov/research/apr/reports/l2069.pdf

emissions reduction, the introduction of substantial ammonia slip has the potential to cause adverse environmental impacts. The ammonia and $PM_{2.5}$ emissions have the potential to cause direct health impacts for those in the area, and present additional safety concerns for the storage and transportation of ammonia. Despite not having SNCR or SCR installed, the Sunnyside boiler is achieving a NO_X emission rate on a lb/MMBtu basis that is comparable to PSD BACT levels set on CFB boilers.[52] Therefore, additional add-on controls for NO_X emissions reductions are not necessary on the Sunnyside CFB boiler.

[52] See RBLC search results in Appendix C.

7. SO_2 AND NO_X FOUR FACTOR EVAULATION FOR EMERGENCY GENERATOR

Sunnyside cogeneration facility has an emergency generator installed in the event of a loss of power or similar event requiring the plant and facility to maintain electric power. The emergency generator is powered by a 201 HP diesel engine. The emergency diesel engine operates in accordance with the standards set forth in 40 CFR Subpart ZZZZ, the NESHAP for Reciprocating Internal Combustion Engines (RICE) Maximum Available Control Technology (MACT) and is in adherence with the provisions set forth in its UDAQ Title V Permit. The 5000 Kw Emergency generator is subject to NSPS Subpart JJJJ.

Provisions include limiting operation to emergency procedures, emergency demand response, testing and maintenance, and operations in non-emergency settings to 50 hours per year. The emergency engine also follows best combustion practices which include changing the oil and filter after every 500 hours of operation or annually, inspect the air cleaner after every 1,000 hours of operation or annually, and inspect all hoses and belts every 500 hours of operation or annually. These will apply to whichever time provision comes first, either the hours of operation or annual mark. Sunnyside will also limit the engine's time spent at idle and minimize the engine's startup time to under 30 minutes in order to achieve appropriate and safe loading of the engine.

As noted in Table 4-1, the annual SO_2 and NO_X emissions for the emergency engine and generator are quite low and attribute to less than 1% of the Boiler's emissions. Any controls implemented to reduce the current emissions from the emergency generator and engine would result in insignificant emission reductions and only increase the financial burden for Sunnyside. Any emission reductions from the emergency engine and generator would have no statistically significant effect on the Regional Haze to the applicable Class 1 areas stated in Section 3. Sunnyside already follows the standards set forth in 40 CFR Subpart ZZZZ and its UDAQ Title V permit and will continue to follow best combustion practices in order to maintain low emissions.

APPENDIX A : SO_2 CONTROL COST CALCULATIONS

Sunnyside Cogeneration Associates
Four Factor Analysis - Dry Scrubber Cost Analysis

Dry Scrubber Cost Analysis
Table A-1: Dry Sorbent Injection Process Inputs

Variable		Value	Units
Baseline SO_2 Emissions		471	tons/year
SO_2 Removal Efficiency		74%	
Total SO_2 Removed		318.9141	tons/year
Lime Injection Rate		500	lb/hr
Annual Operating Time		8031	hours/year

[1] Assumes control technology uptime of 92% for maintenance and unexpected boiler and control technology downtime.

Table A-2: Dry Sorbent Injection Costs

Cost Item	Factor	Cost	Notes
Captial Costs[1]			
Equipment Cost	A	$2,900,000.00	Dry sorbent injection systems can cost between 40 and 50 USD per kW.
Instrumentation	0.1×A	$290,000.00	Per EPA Control Cost Manual
Sales Tax	0.03×A	$87,000.00	Per EPA Control Cost Manual
Freight	0.05×A	$145,000.00	Per EPA Control Cost Manual
Purchased equipment cost, PEC	B = 1.18×A	$3,422,000.00	Per EPA Control Cost Manual
Direct Installation Costs			
Foundation and Supports	0.12×B	$410,640.00	Per EPA Control Cost Manual
Handling and Erection	0.40×B	$1,368,800.00	Per EPA Control Cost Manual
Electrical	0.01×B	$34,220.00	Per EPA Control Cost Manual
Piping	0.3×B	$1,026,600.00	Per EPA Control Cost Manual
Installation for ductwork	0.01×B	$34,220.00	Per EPA Control Cost Manual
Painting	0.01×B	$34,220.00	Per EPA Control Cost Manual
Direct Installation Cost	0.85×B	$2,908,700.00	Per EPA Control Cost Manual
Retrofit Factor	1.3		
Direct Installation Costs Including Retrofit Factor		$3,781,310.00	
Site Preparation			As required, estimate
Buildings			As required, estimate
Total Direct Cost	1.30×B + SP + Bldg + Direct Costs	$7,203,310.00	Direct costs include foundation, handling, electrical, piping, ductwork, and painting
Indirect Costs (Installation)			
Engineering	0.10×B	$342,200.00	Per EPA Control Cost Manual
Construction and Field Expenses	0.10×B	$342,200.00	Per EPA Control Cost Manual
Contractor Fees	0.10×B	$342,200.00	Per EPA Control Cost Manual
Start-up	0.01×B	$34,220.00	Per EPA Control Cost Manual
Performance Test	0.01×B	$34,220.00	Per EPA Control Cost Manual
Contingencies	0.03×B	$102,660.00	Per EPA Control Cost Manual
Total Indirect Cost, IC	0.35×B	$1,197,700.00	Per EPA Control Cost Manual
Total Capital Investment (TCI)	TCI = DC + IC	$8,401,010.00	

Sunnyside Cogeneration Associates
Four Factor Analysis - Dry Scrubber Cost Analysis

Table A-3: Continued

Cost Item	Factor	Cost	Notes
Direct Annual Costs[1]			
Operating Labor			
Operator		$22,310.63	0.5 hr/shift, 3 shifts/day, 365 d/yr, $40.75/hr
Supervisor		$3,346.59	15% of Operator
Operating Materials			
SOx to be controlled (tpy)		471	Based on average annual SO_2 emissions from 2016 to 2018
Ratio of sorbent to Sox		3	Per Air Pollution Engineering Manual, 2nd Edition, p264
Lime required (tpy)		1413	Lime required (tpy) = SO_2 emissions (tpy) × 3
Limestone Cost ($/ton)		55.81	Current costs from Sunnyside's Limestone supplier
Limestone Cost ($/yr)		$78,859.53	Annual Cost ($/yr) = Limestone Cost ($/ton) × Annual Lime Required
Maintenance			
Maintenance Labor		$22,310.63	0.5 hr/shift, 3 shifts/day, 365 d/yr, $40.75/hr
Maintenance Materials		$22,310.63	100% of Maintenance Labor
Utilities			
Power Consumption		0.67% (% of electrical generation)	Chapter 5 Emission Control Technologies - EPA Base Case v5.13 Table 5-17 Illustrative DSI Cost for Representative sizes and heat rates. 1.7lb/MMBtu (uncontrolled Sunnyside)*2.0 lb/MMBtu (Base case v5.13) = 0.85 Table 5-17 Capacity Penalty%= 0.79%*.85=.67%
Rate		74.68 ($/MWh)	Current revenue from Sunnyide
Electricity	67% of Electrical Generati	$232,861.68	Cost conservatively represents lost revenue from electricity that could be sold to the grid, and does not include operating costs of boiler
Direct Annual Cost		$381,999.68	
Indirect Annual Costs, IC			
Overhead	60% sum of operating labor, maintenance labor, and associated materials	$42,167.08	
Administrative Charges	2% of TCI	$168,020.20	Where TCI is estimated as $8,401,010.00
Property Taxes	1% of TCI	$84,010.10	Where TCI is estimated as $8,401,010.00
Insurance	1% of TCI	$84,010.10	Where TCI is estimated as $8,401,010.00
Indirect Annual Cost		$378,207.48	Sum of overhead, administrative, taxes, and insurance
Capital Recovery2		$0.09	$ Annually/$ Capital Cost
Annualized Capital Cost		$792,995.91	Capital Recovery * Total Capital Investment
Total Annual Cost (Dry Scrubber)		$1,553,203.07	$/year
Total Annual Cost From Baghouse(s)		$1,700,493.62	$/year
Total Annual Cost From Dry Scrubber and Baghouse(s)		$3,253,696.69	$/year
Cost Effectiveness		$10,202.42	$/ton

[1] Capital recovery calculated based on the methodology provided in the EPA Control Cost Manual, Section 1 Chapter 2, Equation 2.8 and 2.8a on Page 2-22, where an interest rate of 7% is assumed.

Interest	7.00%
Equipment Life	20

Sunnyside Cogeneration Associates
Four Factor Analysis - Dry Scrubber Cost Analysis

Table A-4: Baghouse Operating Parameters

Parameter	Value	Unit
Stack Flowrate	311,000	ACFM
Stack flowrate	165,243	dscfm
Operating Hours	8,031	hr/yr
Pressure Drop	7.5	in. of H_2O

Table A-5: Electricity Costs

Parameter	Value	Unit	Notes
Power Required	1,801,488.52	kWh/yr	Power (kWh/yr = 0.000181(Q)(delta P)(hours per year), per EPA Cost Control Manual Eq 1.14
Energy Cost	0.07468	$/Kwh	
Cost of Electricity	$134,535.16		
Compressed Air Costs			
Flow needed (2scfm/1,000 acfm)	2		Per EPA Cost Control Manual, 1.5.1.8 Compressed Air
Cost (per 1,000 scfm)	$0.38	$/1,000 scfm	Per EPA Cost Control Manual, 1.5.1.8 Compressed Air, where inflation is accounted for using 2019 CEPCI of 602.9, and 2002 CEPCI of 395.6
Cost per min	$0.19	$/min	2 scfm/1,000acfm*(Q)*cost per 1,000 scfm
Cost per hour	$11.43	$/hr	2 scfm/1,000acfm*(Q)*cost per 1,000 scfm * 60 min/hr
Cost per year	$91,795	$/yr	2 scfm/1,000acfm*(Q)*cost per 1,000 scfm * 60 min/hr * 8031 hr/yr, per EPA Cost Control Manual
Cost of Bags	$273,318	$	Scaled on estimates used at Colstrip Energy Limited Partnership's Rosebud Power Plant, and scaled for inflation.

Table A-6: Baghouse Costs

Cost Component	Factor	Cost	Notes
Direct Costs			
Purchased Equipment Costs			
Baghouses Needed		1	
Capital Cost per SCFM:		16	$/SCFM
SCFM		165243	SCFM, engineering estimate
Cost per Baghouse (estimate)		$3,065,044	Scaled on estimates used at Colstrip Energy Limited Partnership's Rosebud Power Plant, and scaled for inflation.
Total Equipment Costs	A	$3,065,044	Per EPA Control Cost Manual
Instrumentation	0.1A	$306,504	Per EPA Control Cost Manual
Equipment Tax:	0.03A	$91,951	Per EPA Control Cost Manual
Freight	0.05A	$153,252	Per EPA Control Cost Manual
Purchased Equpment Cost (PEC)	B = 1.18 × A	$3,616,752	
Direct Installation Costs			
Foundation and Supports	0.04×B	$144,670	Per EPA Control Cost Manual
Handling and Erection	0.5×B	$1,808,376	Per EPA Control Cost Manual
Electrical	0.08×B	$289,340	Per EPA Control Cost Manual
Piping	0.01×B	$36,168	Per EPA Control Cost Manual
Insulation for Ductwork	0.07×B	$253,173	Per EPA Control Cost Manual
Painting	0.04×B	$144,670	Per EPA Control Cost Manual
Direct Installation Costs	0.74×B	$2,676,396	
Retrofit Factor	1.3		
Direct Installation Costs Including Retrofit Factor		$3,479,315	
Site Preparation		Not Included	
Facilities and Building		Not Included	
Total Direct Costs	1.74B + Retrofit	$7,096,067	
Indirect Costs			
Engineering	0.1×B	$361,675	Per EPA Control Cost Manual
Construction and Field Expenses	0.2×B	$723,350	Per EPA Control Cost Manual
Contractor Fees	0.1×B	$361,675	Per EPA Control Cost Manual
Start-up	0.01×B	$36,168	Per EPA Control Cost Manual
Performance Test	0.01×B	$36,168	Per EPA Control Cost Manual
Contingencies	0.03×B	$108,503	Per EPA Control Cost Manual
Total Indirect Costs	0.45×B	$1,627,538	Per EPA Control Cost Manual
Total Capital Investment	2.19×B + Retrofit	$8,723,605	

Table A-7: Continued

Cost Component	Factor	Cost	Notes
Direct Annual Costs			
Operating Labor			
Operator		$89,243	2hr/shift, 3 shifts/day, 365 days/yr, at $40.75/hr
Supervisor		$13,386	15% of operator
Operating Materials			
Maintenance Labor		$44,621	1hr/shift, 3 shifts/day, 365 days/yr, at $40.75/hr
Maintenance Materials		$44,621	100% of Maintenance Labor
Replacement Bags		$109,901	0.4021*cost of bags (accounts for future worth at 3 years and 10%)
Utilities			
Electricity		$134,535	Power (kWh/yr) = 0.000181(Q) (delta P)(hours per year), per EPA Cost Control Manual Eq 1.14
		$91,795	2 scfm/1,000acfm*(Q)*cost per 1,000 scfm * 60 min/hr * 8031 hr/yr, per EPA Cost Control Manual
Compressed Air			
Total Direct Annual Costs		$528,103	
Indirect Annual Costs			
Overhead	Operating Labor	$115,123	Does not include replacement bags
Administrative Charges	2% of TCI	$174,472	Where the TCI is estimated as $8,723,605.15
Property Tax	1% of TCI	$87,236	Where the TCI is estimated as $8,723,605.15
Insurance	1% of TCI	$87,236	Where the TCI is estimated as $8,723,605.15
Capital Recovery	$0.09		assumes 7% interest for 20 years
Total Indirect Annual Costs		$348,944	
Annualized Capital Cost		$823,447	
Total Annual Cost		$1,700,494	

Equipment cost obtained based on a vendor quote used by Bison engineering for cost analysis at Colstrip Energy Limited Partnership's Rosebud Power Plant in Colstrip Montana. Costs related to the construction and implementation of the equipment are obtained from the EPA control cost manual.

Capital recovery calculated based on the methodology provided in the EPA Control Cost Manual, Section 1 Chapter 2, Equation 2.8 and 2.8a on Page 2-22, where an interest rate of 7% is assumed.

Interest	7%
Equipment life	20

APPENDIX B : NO_X CONTROL COST CALCULATIONS

Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

What type of fuel does the unit burn?

Is the SCR for a new boiler or retrofit of an existing boiler?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.30

* NOTE: You must document why a retrofit factor of 1.3 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	700.00 MMBtu/hour
What is the higher heating value (HHV) of the fuel?	7,072 Btu/lb
What is the estimated actual annual fuel consumption?	883,413,174 lbs/Year
Enter the net plant heat input rate (NPHR)	12 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	6497 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned:

Enter the sulfur content (%S) = 0.71 percent by weight

[redacted]

Coal Type	[redacted]
Bituminous	
Sub-Bituminous	
Lignite	

[redacted]

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the *Cost Estimate* tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable

Enter the following design parameters for the proposed SCR:

Sunnyside Cogeneration Associates
Four Factor Analysis - SCR Cost Analysis

Number of days the SCR operates (t_{SCR})	334	days
Number of days the boiler operates (t_{plant})	334	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.15	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.015	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.05	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

*For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516.00	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used

Enter the cost data for the proposed SCR:

Desired dollar-year	2019	
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 [redacted] 2016 CEPCI
Annual Interest Rate (i)	4.75	Percent
Reagent ($Cost_{reag}$)	2.500	\$/gallon for 29% ammonia
Electricity ($Cost_{elect}$)	0.0821	\$/kWh
Catalyst cost ($CC_{replace}$)	227.00	\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst
Operator Labor Rate	40.75	\$/hour (including benefits)
Operator Hours/Day	4.00	hours/day*

CEPCI = Chemical Engineering Plant Cost Index

* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	700	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	867,081,448	lbs/Year
Actual Annual fuel consumption (Mactual) =		883,413,174	lbs/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.20	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.019	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8925	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	90.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	96.77	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	431.85	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.13	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	345,631	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	117.77	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.27	
Atmospheric pressure at sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)^*$ =	11.6	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.30	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1), where Y = $H_{catalyst}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	2,934.86	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	360	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	414	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	20.3	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	52	feet

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source.
Reagent Cost ($/gallon)	$2.50/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Site specific information. Used average cost of ammonia supplier costs
Electricity Cost ($/kWh)	[illegible]	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	https://www.eia.gov/electricity/state/utah/
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	Site Specific
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/	Site specific
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	Site specific
Interest Rate (Percent)	5.5	Default bank prime rate	https://www.federalreserve.gov/releases/h15/

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	38	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	130	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	17	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	5,900	gallons (storage needed to store a 14 day reagent supply rounded to th

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0786

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers	432.96	kW

Cost Estimate

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	\$30,630,645	in 2019 dollars
Reagent Preparation Cost (RPC) =	\$2,578,991	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	\$0	in 2019 dollars
Balance of Plant Costs (BPC) =	\$5,954,920	in 2019 dollars
Total Capital Investment (TCI) =	\$50,913,923.07	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) = \$30,630,645 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) = \$2,578,991 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) = \$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) = \$5,954,920 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,192,542	in 2019 dollars
Indirect Annual Costs (IDAC) =	$4,006,522	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$5,199,064	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$254,570	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$386,548	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$317,246	in 2019 dollars
Annual Catalyst Replacement Cost =		$234,177	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}/R_{layer}$) x FWF	* Calculation Method 2 selected.	
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
Method 2 (for coal-fired industrial boilers):	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
Direct Annual Cost =		$1,192,542	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,688	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$4,001,834	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$4,006,522	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$5,199,064	per year in 2019 dollars
NOx Removed =	432	tons/year
Cost Effectiveness =	$12,039	per ton of NOx removed in 2019 dollars

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

What type of fuel does the unit burn?

Is the SNCR for a new boiler or retrofit of an existing boiler?

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.30

* NOTE: You must document why a retrofit factor of 1.3 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	700.00 MMBtu/hour
What is the higher heating value (HHV) of the fuel?	7,072 Btu/lb
What is the estimated actual annual fuel consumption?	883,413,174 lbs/Year
Is the boiler a fluid-bed boiler?	
Enter the net plant heat input rate (NPHR)	12 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned:

Enter the sulfur content (%S) = 0.71 percent by weight

or

Select the appropriate SO_2 emission rate:

Ash content (%Ash): 41.425 percent by weight

[illegible]

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Bituminous	0	[illegible]	[illegible]	[illegible]	[illegible]
Sub-Bituminous	0	[illegible]	[illegible]	[illegible]	[illegible]
Lignite	0	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source .
Reagent Cost ($/gallon)	$2.50/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Site specific information. Used the average cost of ammonia supplier costs.
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	Site specific
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a	https://www.eia.gov/electricity/state/utah/
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	Site specific
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/	Site specific
Percent ash content for Coal (% weight)	5.84	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/	Site specific
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/	Site specific

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	334	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.15	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.11	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	0.50	
Concentration of reagent as stored (C_{stored})	29.4	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft³
Concentration of reagent injected (C_{inj})	19	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used		

Plant Elevation	6497	Feet above sea level

Densities of typical SNCR reagents:		
50% urea solution	71	lbs/ft³
29.4% aqueous NH_3	56	lbs/ft³

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019	
CEPCI for 2019	607.5	Enter the CEPCI value for 2019 [illegible] 2016 CEPCI
Annual Interest Rate (i)	4.75	Percent
Fuel ($Cost_{fuel}$)	1.89	\$/MMBtu*
Reagent ($Cost_{reag}$)	2.50	\$/gallon for a 29.4 percent solution of ammonia
Water ($Cost_{water}$)	0.004	\$/gallon
Electricity ($Cost_{elect}$)	0.0821	\$/kWh
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.8	\$/ton*

CEPCI = Chemical Engineering Plant Cost Index

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	700	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	867,081,448	lbs/Year
Actual Annual fuel consumption (Mactual) =		883,413,174	lbs/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.20	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.93	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8167	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	15	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	15.75	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	64.31	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*($1x10^6$)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.27	
Atmospheric pressure at 6497 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	11.6	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.30	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	19	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	66	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	8.8	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	3,000	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\,(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0786

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)$/NPHR =	2.1	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) $\times ((C_{stored}/C_{inj}) - 1)$ =	4	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.07	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	4.4	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,062,767 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,979,238 in 2019 dollars
Total Capital Investment (TCI) =	$5,254,607 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,062,767 in 2019 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$1,979,238 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$262,629 in 2019 dollars
Indirect Annual Costs (IDAC) =	$415,377 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$678,005 in 2019 dollars

Direct Annual Costs (DAC)
DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$78,819 in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$180,268 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$1,379 in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$142 in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$1,151 in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$870 in 2019 dollars
Direct Annual Cost =		$262,629 in 2019 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,365 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$413,012 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$415,377 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$678,005 per year in 2019 dollars
NOx Removed =	64 tons/year
Cost Effectiveness =	$10,542 per ton of NOx removed in 2019 dollars

APPENDIX C : RBLC SEARCH RESULTS

Sunnyside Cogeneration Associates
Four Factor Analysis - RBLC Search

Agency/Document Title	NO_X Emissions Requirement	Control	Reference
EPA, RBLC Search	0.1 lb/MMBtu 30-day rolling average	SNCR	RBLC ID: WV-0024. Western Greenbrier Co-Generation, LLC. 1,070 MMBtu/hr firing waste coal.
	0.088 lb/MMBtu 30-day rolling average	SNCR	RBLC ID: UT-0070. Deseret Power Electric Cooperative. 1,445 MMBtu/hr firing waste coal.
	0.155 lb/MMBtu	SNCR	RBLC ID: WI-0225. Manitowoc Public Utilities. 650 MMBtu/hr firing coal/pet coke.

Agency/Document Title	SO_2 Emissions Requirement	Control	Reference
EPA, RBLC Search	0.08 lb/MMBtu 8-hour average	Limeston Injection	RBLC ID: CA-1206. Stockton Cogen Company. 730 MMBtu/hr firing coal.
	0.08 lb/MMBtu 30-day rolling average	Limestone Injection and Flash Dryer Absorption with Fresh Lime	RBLC ID: KY-0100. J.K. Smith Generating Station. 3,000 MMBtu/hr firing waste coal and coal.
	0.10 lb/MMBtu 24-hour average	Spray Dry Absorber or Polishing Scrubber	RBLC ID: MI-0400. Wolvering Power. 3,030 MMBtu/hr firing petcoke and coal.

APPENDIX C.4.B – Sunnyside UDAQ Four-Factor Analysis Evaluation

State of Utah
SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of
Environmental Quality

Kimberly D. Shelley
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQP-064-21

July 27, 2021

Gerald Hascall
Sunnyside Cogeneration Associates
One Power Plant Road
Sunnyside, UT 84539
jhascall@sscogen.com

Rusty Netz
P.O. Box 10
East Carbon, Utah 84520
rnetz@sscogen.com

Dear Mr. Hascall and Mr. Netz,

The DAQ has received your four-factor analysis for the Sunnyside Cogeneration Power Plant prepared for the second planning period of Utah's Regional Haze State Implementation Plan. Enclosed is an engineering review of each analysis outlining some outstanding issues for you to be aware of. Please provide the DAQ with amendments or reasoning for these issues by **August 31st, 2021**. If you have any questions, please contact John Jenks at jjenks@utah.gov or (385) 306-6510.

Sincerely,

Chelsea Cancino
Environmental Scientist

RNC:CC:GS:jf

Regional Haze – Second Planning Period
SIP Evaluation Report:

Sunnyside Cogeneration Facility

Utah Division of Air Quality

July 30, 2021

SIP EVALUATION REPORT

Sunnyside Cogeneration Facility

1.0 Introduction

The following is part of the Technical Support Documentation for the Second Planning Period of the Reginal Haze SIP (aka the Visibility SIP). This document specifically serves as an evaluation of the Sunnyside Cogeneration Facility.

1.1 Facility Identification

Name: Sunnyside Cogeneration Facility
Address: State Road 123, #1 Power Plant Road, Sunnyside, Utah
Owner/Operator: Sunnyside Cogeneration Associates
UTM coordinates: 552,984 m Easting, 4,377,786 m Northing, UTM Zone 12

1.2 Facility Process Summary

The Sunnyside Cogeneration Facility (Sunnyside) is in Sunnyside, Carbon County, Utah (approximately 25 miles southeast of Price). The nearest Class I areas and their respective distance from the facility are Canyonlands National Park, (91 miles), Capitol Reef National Park (95 miles), Bryce Canyon National Park (171 miles) and Zion National Park (217 miles). The Sunnyside power plant began operations in May of 1993. The electricity it produces is sold to PacifiCorp, operating as Utah Power and Light [UPLC). The plant qualifies as a small power production facility and qualifying cogeneration facility ("QF") under the Public Utility Regulatory Policy Act of 1997 ('PURPA"). The facility operates a coal-fired combustion boiler that features circulating fluidized bed (CFB), a baghouse and a limestone injection system. The facility also operates an emergency diesel engine and emergency generator. All process units are currently permitted in its UDAQ Title V air operating permit (Permit # 700030004) which was renewed on April 30, 2018. The CFB boiler is subject to the NESHAPS Part 63, Subpart UUUUU Mercury and Air Toxics Standards [MATSI Rule. As a result Sunnyside is required to meet standard of 0.2 lb/MMBtu of SO2.

This standard requires continuous monitoring with a continuous emission monitor system (CEMS). The plant's CFB boiler, designed by Tampella Power, produces steam that drives a Dresser Rand turbine generator. The CFB boiler and baghouse uses limestone injection. Historically, CFB boilers have been one of the primary low emission combustion technologies for commercial and small utility installations using low grade fuels. This trend continues with CFB technology being considered for smaller coal fired units as a means to effectively utilize lower quality fuels and meet environmental requirements. The current boiler produces emissions from one stack at Sunnyside's cogeneration facility. For the purposes of a control technology review, only the emissions from the boiler stack itself are considered as well as the operations from the emergency diesel engine and emergency generator.

1.3 Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

- Circulating Fluidized Bed Combustion Boiler - Rated at 700 MMBtu/hr and fueled by coal, coal refuse or alternative fuels, and fueled by diesel fuel during startup, shutdown, upset condition and flame stabilization. This boiler is equipped with a limestone injection system to the fluidized bed and a baghouse. This boiler is subject to 40 CFR 60, Subpart Da and CAM.
- One diesel engine, approximately 201 HP, used to power the emergency backup fire pump, and various portable I/C engines to power air compressors, generators, welders and pumps.
- A 500 kW emergency standby diesel generator, used in the event of disruption of normal electrical power and testing/maintenance.

1.4 Facility Current Potential to Emit

The current PTE values for Sunnyside, as established by the most recent NSR permit issued to the source (DAQE-AN100960029-13) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
SO_2	1,289.26
NO_X	771.2

2.0 Four Factor Review Methodology

Each source reviewed in this second planning period submitted a report on the available control technologies for SO2 and NOx emission reductions and the application of each technology to that facility. The information on available controls should consider the following four factors when analyzing the possible emission reductions:

1. Factor 1 – The Costs of Compliance
2. Factor 2 – Time Necessary for Compliance
3. Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance
4. Factor 4 – Remaining Useful Life of the Source

Although not specifically required, the recommended approach was to follow a step-wise review of possible emission reduction options in a "top-down" fashion similar to U.S. EPA's guidelines for review of BART or Best Available Retrofit Technology (as found in 40 CFR 51, Section 308 amendments, pub. July 5, 2005). The steps involved are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document results

The process is inherently similar to that used in selecting BACT (Best Available Control Technology) under the NSR/PSD (Title I) permitting program. UDAQ evaluated the submissions from each source following the methodology outlined above. Where a particular submission may have differed from the recommended process, UDAQ will make note, and provide additional information as necessary.

3.0 Source Evaluation of Baseline Emission Rates

Sunnyside has provided the following emissions for this four-factor analysis which are based on actual emission rates. The projected annual emissions from the boiler for both NOx and SO2 are determined using CEMS data while the emergency generator and emergency diesel engine are based on the manufacturer specifications and past-actual usage. These same baseline rates are provided to UDAQ for use in the on-the-books/on-the-way basis for modeling because no changes to boiler and/or emergency generator operation are expected between now and 2028.

Pollutant	Baseline Annual Emissions (tons/yr)		
	Boiler	Emerg. Diesel Engines	Emergency Generator
SO2	471	0.001	0.020
NOx	431	0.020	0.310

The values for the CFB boiler are based on the facility's average annual emissions (tons/yr) for NOx and SO2 between 2016 and 2018, as recorded by the plant's CEMS. The three-year averaged values represent reasonable expected emissions for the coal-fired boiler, emergency engine, and emergency generator. The emergency generator and emergency diesel engine's emissions are calculated using manufacturer's specifications and yearly operating data, including the amount of diesel used and annual hours of operation. Using the baseline annual emissions, SO2 and NOx emissions from the boiler and emergency equipment were reviewed on a lb/MMBTU basis and a lb/HP-hr basis respectively.

Pollutant	Baseline Annual Emissions (tons/yr)		
	Boiler lb/MMBtu	Emerg. Diesel Engines lb/hp-hr	Emergency Generator lb/hp-hr
SO2	0.17	8.29E-4	2.71E-3
NOx	0.15	1.66E-2	4.20E-2

When compared to Prevention of Significant Deterioration (PSD) permitting Best Available Control Technology (BACT) limits in the RACT/BACT/LAER Clearinghouse (RBLC) database, the boiler's SO2 and NOx emission levels on a lb/MMBTU basis are comparable to PSD BACT limits for CFB boilers that process refuse coal, and are significantly lower than emission limits provided in Sunnyside's Title V permit (0.42 lb SO2/MMBtu and 0.25 lb NOx/MMBtu respectively).

4.0 Source Four Factor Analysis for Emission Reductions

4.1 SO2 Emissions - CFB Boilers

4.1.1 Step 1: Identification of Available Retrofit Control Technologies

SO2 is generated during fuel combustion in a boiler, as the sulfur in the fuel, specifically the waste-coal, is oxidized by oxygen in the combustion air. The available SO2 retrofit control technologies for the Sunnyside CFB boiler are summarized below. Alternate fuels are not considered in this analysis based on the CFB boiler is not designed for burning other fuels; therefore, it exists as the base case. The retrofit controls predominantly include add-on controls that eliminate SO2 after it is formed. Sunnyside currently uses limestone injection to control SO2 emissions. This top-down control review investigates whether installation of an additional SO2 control device in series with the prior control technology is warranted.

SO2 Control Technologies:
Spray Dry Absorbers
Wet Scrubbing
Dry Scrubbing
Hydrated Ash Reinjection

Spray Dry Absorbers
Spray dry absorption involves spraying a high concentration, aqueous slurry sorbent, typically consists of lime, sodium bicarbonate, or trona, into the wet flue gas stream. The sorbent interacts with acid gases (HCl, for example) or SO2 and forms larger particles, while the evaporation of water from the slurry cools the flue gas stream. The cooling enhances precipitation of these particles from the flue gas stream, and the particles can be subsequently removed using an electrostatic precipitator or dry filter downstream. Spray dry absorbers require sufficient water to prepare the aqueous alkaline slurry. Water usage can vary greatly as injection rates of slurry and dilution water are controlled by signals from the in-stack CEMS and the stack temperature.

Wet Scrubbing
A wet scrubber is a technology that may be installed downstream of the boiler. In a typical wet scrubber, the flue gas flows upward through a reactor vessel, while an aqueous slurry of alkaline reagent flows down from the top. The scrubber mixes the flue gas and alkaline reagent using a series of spray nozzles to maximize dissolution of SO2 into the alkaline reagent by distributing the reagent across the scrubber vessel. The calcium (typically) in the aqueous reagent reacts with the SO2 in the flue gas to form calcium sulfite (CaSO3) and/or calcium sulfate (CaSO4), which collects in the bottom of the reactor and is subsequently removed with the scrubber sludge.

Dry Scrubbing – Dry Sorbent
Dry scrubbers utilize powdered sorbents, such as dry limestone or lime, and pneumatically inject the powder downstream of the boiler. A dry scrubber would be an add-on control technology after the limestone injection already occurring in the CFB boiler. Dry sorbent injection involves a sorbent storage tank, feeding mechanism, transfer line, blower and injection device. An expansion chamber is located downstream of injection point to increase residence time and efficiency. SO2 in the flue gas reacts directly with the powdered reagent to form waste particles which are subsequently carried in the flue gas through a particulate control device, such as a fabric filter or electrostatic precipitator, where the particles are collected from the cleaned flue gas. Dry scrubbers are usually applied when lower removal efficiencies are required, or for smaller plants. Effects on plant operation vary for the different sorbents. Some coal-fired boiler owners and operators select to use hydrated lime if possible in order to avoid potential heavy metal leaching from the collected fly ash mixed with DSI byproduct.

Dry Scrubbing - Hydrated Ash Reinjection
Hydrated ash reinjection (HAR) effectively reduces SO2 emissions by increasing the extent of reaction between SO2 and hydrating sorbents in the CFB. The CFB recycles fly ash in the system for a specified period, after which the flue gas is sent to a particulate control device where the sulfur-rich particulates are collected. Design and efficiencies for HAR systems vary greatly based on vendor and sorbent type. HAR also requires significant amounts of fly ash to maintain reaction rates that sustain desulfurization of the flue gas.

4.1.2 Step 2: Eliminate Technically Infeasible Control Technologies

Spray Dry Absorbers

Installing an additional spray dry absorber in series with the current FGD system would further reduce SO2 emissions at Sunnyside's facility. Despite the misleading name, spray dry absorbers (also known as semi-dry absorbers), require water to atomize the reactive sorbent into an aqueous solution. Sunnyside's operation as a cogeneration facility already requires a significant use of water, and the plant's current water rights are not sufficient enough to sustain the necessary water usage to operate an additional spray dry absorber. In 2018, Sunnyside Cogeneration exceeded their allotted water rights. Consequently, it had to purchase 44.5 million gallons of additional water from the city of East Carbon. The facility already uses the majority of its water rights for current operations and has to buy additional water to supply the necessary amount of water to the cooling towers. Any additional water consumption would result in the water rights being used much more rapidly and represents an undue burden on the facility to acquire the water for spray dry absorber operation. As additional water rights are not available in the quantity required for implementing water-intensive technology, installation of an additional spray dry absorber in series with Sunnyside's current limestone injection technology is considered infeasible and will not be evaluated further.

Wet Scrubbing
Similar to spray dry absorption, A wet scrubbing system utilizes a ground alkaline agent, such as lime or limestone, in slurry to remove SO2 from stack gas. However, wet scrubbing uses more water than spray dry systems to generate the aqueous sorbent. The alkaline slurry is sprayed into the absorber tower and reacts with SO2 in the flue gas to form insoluble CaSO3 and CaSO4 solids. A wet flue gas desulfurization (FGD) must be located downstream of the fabric filter baghouse. The spent slurry is dewatered using settling basins and filtration equipment. Recovered water is typically reused to blend new slurry for the wet scrubber. A significant amount of makeup water is required to produce enough slurry to maintain the scrubber's design removal efficiency. Water losses from the system occur from evaporation into the stack gas, evaporation from settling basins, and retained moisture in scrubber sludge. As the concentration of the SO2 in the CFB gas is inherently low due to existing control technologies, it is not anticipated that a wet FGD system will provide a significant reduction in overall SO2 emissions. As mentioned previously, the plant's current water rights are not sufficient to operate a wet scrubber instead of limestone injection technology, or in series with the current limestone injection technology. Since any additional water consumption represents an undue burden on the facility to acquire the water for wet scrubber operation, this technology is considered infeasible and will not be evaluated further.

Dry Scrubbing
Dry scrubbing systems are mechanically simple systems and use less water than wet scrubbing and spray dry systems. Due to limited water use and simple waste disposal, dry injection systems install easily and are good candidates for retrofit applications. Therefore, dry scrubbing is considered technically feasible, and considered further.

Hydrated Ash Reinjection
Application of HAR results in higher particulate loading in the flue gas, and subsequently generates larger emissions particulate matter. Flue gas exiting the CFB at Sunnyside typically contains approximately 10% unreacted calcium oxide in the fly ash and even less in the bottom ash. To enable HAR, either additional limestone loading to the CFB would needed or significant amounts of ash to effectively scrub SO2. Therefore, large amounts of unreacted fly ash are required to implement HAR To be able to handle the additional loading. Additionally, a larger particulate control device would likely be required to handle the increased particulate matter in the flue gas. HAR implementation would be impractical with 10% available CaO and even if adding

reagent would be feasible it would likely require the installation of an enhanced baghouse with the addition of additional particulate in the flue gas of the CFB due to the significant amount of ash reagent that would be required. Due to the questionable technical feasibility of HAR, and the generation of PM emissions, the technology is considered technically infeasible, and no longer considered.

4.1.3 Step 3: Rank Technically Feasible Control Options by Control Effectiveness

Control efficiency is undetermined at this time because the most effective method to determine optimal performance and balance of plant effects is to conduct a DSI trial on the unit in question. These trials typically range from one week to three months in duration, using temporary equipment designed for this purpose. For the purposes of evaluation the average of the range was used. Thus, Dry Scrubbing, the only remaining option, has a control efficiency of 50-98%.

4.1.4 Step 4: Evaluation of Impacts for Feasible Controls

Sunnyside's average emission rate of SO2 between 2016 and 2018 was 471 tons per year or approximately 0.17 lbs of SO2 per MMBTU with the utilization of limestone injection technology. Installing dry scrubbing technology at Sunnyside also requires the installation of an additional baghouse to remove particulates generated from dry scrubbing operation. Sunnyside's cost analysis of this technology shows that dry scrubbing provides an undue economic burden to the facility, costing approximately $10,372 per ton of SO2 removed.

The boiler currently operated was determined to achieve BACT for SO2 at the time of the boiler's New Source Review (NSR) permit. It has further reduced its emissions to meet NESHAPS, Part 63 Subpart UUUUU (MATS). When compared to the permitted emission rates for SO2 found in the RBLC database, Sunnyside's CFB boiler emits SO2 at a rate comparable to SO2 BACT limits of CFB boiler installations around the country. The Sunnyside CFB boiler is already equipped with limestone injection, which is currently installed primarily for SO2 control on the CFB technology. Sunnyside is currently injecting limestone to manage SO2 emissions as needed to meet the existing, appropriately low SO2 limits set forth by BACT, NSPS Subpart Da, and NESHAPs Part 63, Subpart UUUUU (MATS Rule).

Since Sunnyside's emission rate maintains parity with NSPS and MATS emission limitations for similar processes and no technologies are available to reduce the emission rate further, the current process of a limestone injection technology to achieve a reduction in SO2 emissions is considered BACT for the boiler. Furthermore, this emission rate is well below the established SO2 limitation from NSPS Subpart Da, which is 0.6 lb/MMBTU and remains below NESHAPS, Part 63 Subpart UUUUU (MATS) of 0.2 lb/MMBTU. No technologies are available to reduce SO2 emissions further. Therefore, the current process of using inherently low sulfur raw materials and natural scrubbing is considered BACT for the boiler.

Cost of Compliance:
The currently installed and operating controls are assumed to be cost-effective. As stated previously, all cost calculations and cost effectiveness determinations are considered on the basis of the currently controlled emission levels.

Dry Scrubber Cost Calculations

Dry Scrubber cost calculations are determined using the U.S. EPA's Control Cost Manual methodology. A retrofit factor of 1.3 is used in determining the capital costs associated with the potential installation of dry scrubber technology.

Cost Effectiveness
The cost effectiveness is determined by dividing the annual control cost by the annual tons reduced. Based on the results of this analysis, the cost of dry scrubbing is not cost effective.

SO2 Cost of Compliance Based on Emissions Reduction

Control Option	Control Cost ($/yr)	Baseline Emissions	SO2 Reductions	Emission Reductions	Cost Effectiveness
Dry Scrubber	$3,253,696	471 tons	74%	212	$10,372

Timing for Compliance:
Sunnyside believes that reasonable progress compliant controls are already in place. However, if UDAQ and WRAP determine that one of the SO2 control options analyzed in this report is necessary to achieve reasonable progress, it is anticipated that this change could be implemented during the period of the second long-term strategy for regional haze (approximately ten years following WRAP's reasonable progress determination).

Energy Impacts:
The cost of energy required to operate the control devices has been included in the cost analyses found in Appendix A. To operate any of these add-on control devices, overall plant efficiency would decrease due to the operation of the add-on controls. At a minimum, decreased efficiency would result in increased electrical usage by the plant with an associated increase in indirect (secondary) emissions from nearby power stations.

Emission reducing options that involve water also require significant energy to operate the wet scrubber and associated equipment (pumps, atomizers, etc). However, water-intensive control technologies have been eliminated due to a lack of water availability.

The use of emissions reduction options involving the injection of lime for dry scrubbing and wet scrubbing also causes significant energy impacts. The production of lime is an energy-intensive process that can result in increases in NOx, particulate matter, and SO2 emissions, an effect directly counter to regional haze efforts.

This lime production emissions increase would then be coupled with the energy and emissions impacts resulting from the transportation of the lime to the facility. The production and delivery of lime to the Sunnyside facility would require significant energy and would result in emission increases of pollutants that directly contribute to visibility impairment around the country.

Non-Air Quality Environmental Impacts
Technically feasible add-on SO2 control options that have been considered in this analysis also have additional non-air quality impacts associated with them. A dry scrubbing control system will require additional particulate loading in the flue gas thereby increasing the volume to be handled, which will put a burden on the existing baghouse system and result a larger baghouse control system to capture PM emissions exiting from the stack.

Remaining Useful Life:

The remaining useful life of the boiler will likely impact the annualized cost of an add-on control technology (dry scrubbing control) because the useful life is anticipated to be less than the capital cost recovery period of 20 years or less. However, the cost analysis presented in this report is based on 20 years to be conservative.

4.1.5 SO2 Conclusion:

The CFB boiler, equipped with limestone injection, inherently removes the vast majority of SO2 that is created from the process. The limestone injection configuration, as currently used was determined to achieve BACT and MATS emission limitations. Furthermore, Sunnyside's current SO2 control technology is commonly used to achieve BACT for CFB boilers

This analysis did not identify any technically feasible and cost-effective control options to reduce SO2 beyond the low levels currently achieved by control options already permitted for the boiler.

4.2 NOx Emissions – CFB Boilers

NOx emissions are produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms "thermal" NOx and "fuel" NOx when describing NOx emissions from the combustion of fuel. Thermal NOx emissions are produced through high-temperature oxidation of nitrogen found in the combustion air. Fuel NOx emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel. Many variables can affect the equilibrium in the boiler, which in turn affects the creation of NOx.

A circulating fluidized bed reduces the fuel required to achieve sufficient material temperatures, over traditional FBC units, limiting thermal NOx production in the EGU's system. A CFB boiler uses staged combustion limiting the formation of NOx. This effect is combined with the benefits of combusting the fuel in stages, a method which allows for more fuel to be burned at a lower temperature rather than the higher peak flame temperature within the boiler, thereby reducing thermal NOx formation.

4.2.1 Step 1: Identification of Available Retrofit Control Technologies

NOx emissions controls can be categorized as combustion or post-combustion controls. Combustion controls reduce the peak flame temperature, which minimizes NOx formation. Post-combustion controls convert NOx in the flue gas to molecular nitrogen and water.

Combustion Controls: Circulating Fluidized Bed (CFB) (Base Case)
Post-Combustion Controls: Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR)

Circulating fluidized bed (CFB) combustion is a specific type of fluidized bed combustion (FBC). In FBC combustion, coal is crushed into fine particles then suspended in a fluidized bed by upward-blowing jets of air. This results in a turbulent mixing of combustion air with the coal particles. The coal is mixed with a sorbent, specifically limestone (for SO2 emission control). The operating temperatures for FBC are in the range of 1,500°F to 1,670°F. CFB technology allows for operating at higher gas stream velocities and with finer-bed size particles. There is no defined bed surface but rather high-volume, hot cyclone separators to recirculate entrained solid particles in flue gas to maintain the bed and achieve high combustion efficiency. As noted, before, the lower peak combustion temperature reduces thermal NOx while the staged combustion reduces fuel

NOx. Sunnyside meets their Title V permitted NOx emission limits using the CFB technology. Therefore, the CFB technology will not be evaluated further.

An SCR system is a process whereby NOx is reduced by spraying a reagent, such as urea or ammonia over a catalyst in the presence of oxygen. On the catalyst surface, NH3 and nitric oxide (NO) or nitrogen dioxide (NO2) react to form diatomic nitrogen and water. The overall chemical reactions can be expressed as follows:

$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$
$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$

When operated within the optimum temperature range of 480°F to 800°F, the reaction can result in removal efficiencies between 70 and 90 percent. The rate of NOx removal increases with temperature up to a maximum removal rate at a temperature between 700°F and 750°F. As the temperature increases above the optimum temperature, the NOx removal efficiency begins to decrease. SCR has been successfully installed and operated on many industrial boilers in the U.S. and therefore will be further evaluated.

In SNCR systems, a reagent is injected into the flue gas within an appropriate temperature window. The NOx and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia and urea SNCR processes require three to four times as much reagent as SCR systems to achieve similar NOx reductions. Like SCR, SNCR uses ammonia or a solution of urea to reduce NOx through a similar chemical reaction.

$2NO + 4NH_3 + 2O_2 \rightarrow 3N_2 + 6H_2O$

SNCR residence time can vary between 0.001 seconds and 10 seconds. However, increasing the residence time available for mass transfer and chemical reactions at the proper temperature generally increases the NOx removal. There is a gain in performance for residence times greater than 0.5 seconds. The U.S. EPA Control Cost Manual indicates that SNCR requires a higher temperature range than SCR of between approximately 1,600°F and 2,000°F, due to the lack of a catalyst to lower the activation energies of the reactions; however, the control efficiencies achieved by SNCR vary across that range of temperatures. At higher temperatures, NOx reduction rates decrease. In addition, a greater residence time is required for lower temperatures.
There are several complications that can occur when attempting to identify and successfully implement the necessary controls to obtain ideal temperature zones for NOx reduction, resulting in significant variability among the reduction efficiencies achieved with SNCR in boilers. In other words, SNCR in boilers have achieved varying and sometimes poor success, often due to the flue gas temperatures as well as varying combustion loads diverging from optimal values.

4.2.2 Step 2: Eliminate Technically Infeasible Control Technologies

Selective Catalytic Reduction:
The SCR process requires a reactor vessel, a catalyst, and an ammonia storage and injection system. The presence of the catalyst effectively reduces the ideal reaction temperature for NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx into molecular nitrogen (N2) and water vapor (H2O). The optimum operating temperature is dependent on the type of catalyst and the flue gas composition. Generally, the optimum

temperature ranges from 480°F to 800°F. The effectiveness of an SCR system is dependent of a variety of factors, including the inlet NOx concentration, the exhaust temperature, and ammonia injection rate, the type of catalysts poisons, such as particulate matter and SO2. In practice, SCR systems can operate at efficiencies in the range of 70% to 90%. While SCR has been used for NOx control in pulverized coal applications, the nature of CFB makes it very impractical. Considering the high particulate loading rate and calcium oxide (CaO) concentration of the flue gas due to limestone injection in this section of the CFB boiler exhaust stream, and due to use of refuse coal fuel in the boiler with ash content as high as 60%, an SCR system installed upstream of particulate controls would experience rapid catalyst de-activation and fouling. These technical problems would make the operation of an SCR in the high-dust laden flue gas upstream of the particulate controls technically infeasible for a CFB boiler design.

Since low-temperature SCR is not technically feasible, another option would be to reheat the flue gas downstream of the baghouse to the temperature range known to be effective for SCR use at (650-750°F). This increase in exhaust temperature would require an additional combustion device, also increasing NOx, SO2, and PM2.5 emissions.

The main drawback with SCR is the overall costs associated with running the system. SCR systems traditionally have high capital and operating costs as large volumes of catalyst required for the reduction reaction as well as replacement catalyst and ammonia reagent costs. Even with the increase in ammonia, PM2.5, and SO2 emissions, Sunnyside has considered this technology to be technically feasible for the CFB boiler and further evaluated the economic feasibility of this technology as detailed in Step 4.

Selective Non-Catalytic Reduction:
Successful implementation of SNCR poses several technical challenges - most related to maintaining NH3 injection within the optimal temperature range (approximately 1,600°F and 2,000°F).

Temperature, residence time, reagent injection rate, reagent distribution in the flue gas, uncontrolled NOx level, and CO and O2 concentrations are important in determining the effectiveness of SNCR. In general, if NOx and reagent are in contact at the proper temperature for a long enough time, then SNCR will be successful at reducing the NOx level. SNCR is most effective within a specified temperature range or window (approximately 1,600°F and 2,000°F) At temperatures below the window, reaction kinetics are extremely slow, such that little or no NOx reduction occurs. As the temperature within the window increases, the NOx removal efficiency increases because reaction rates increase with temperature. However, the gain in performance for residence times greater than 0.5 seconds is generally minimal. NOx generation is minimized between 1,600°F and 2,000°F because the reaction rate plateaus in this range.

Sunnyside's temperatures in the combustor are approximately 1,620 °F and cyclone outlet at 1,670 °F. Plants of similar design have installed lances to inject ammonia at the exit of the cyclone. Within 100 ft of the potential lance injection location, would be the equivalent to 0.2 seconds of residence time, the temperature drops 600 °F; therefore, falling out of the SCNR temperature window. As a result, it is believed that the control efficiency on the Sunnyside would be extremely low to the point where the controls would not be effective.

Additionally, at lower temperatures the reaction rate is slowed down, causing ammonia slip, which would result in the formation of ammonia salts, which themselves are condensable PM 2.5, a visibility impairing pollutant.

Despite the technical and adverse environmental impacts detailed above, the installation of SNCR is considered technically feasible for Sunnyside Cogeneration's boiler and will be considered further.

4.2.3 Step 3: Rank Technically Feasible Control Options by Control Effectiveness

Ranking of NOx Control Technologies by Effectiveness

Control Technique	Control Efficiency
SCR:	70-90
SNCR:	Varies Significantly [a]

[a] Control efficiency for SNCR, per the U.S. EPA Control Cost Manual Chapter 1 Figures 1.3 and 1.4 document SNCR effects from temperature and residence time.

4.2.4 Step 4: Evaluation of Impacts for Feasible Controls

Step 4 of the top-down control review is the impact analysis. The impact analysis considers the: cost of compliance, energy impacts, non-air quality impacts, and the remaining useful life of the source.

Cost of Compliance:
The currently installed and operating controls are assumed to be cost-effective. As stated previously, all cost calculations and cost effectiveness determinations are considered on the basis of the currently controlled emission levels.

SNCR cost calculations are determined using the U.S. EPA's Control Cost Manual methodology. A retrofit factor of 1 is used in determining the capital costs associated with the potential installation of SNCR.

Cost Effectiveness
The cost effectiveness is determined by dividing the annual control cost by the annual tons reduced.

NOx Cost of Compliance Based on Emissions Reduction

Control Option	**Control Cost (\$/yr)**	**Baseline Emission Level (tons)**	**NOx Reduction (%)**	**Emission Reduction (tons)[a]**	**Cost Effectiveness (\$/ton removed)**
SCR	\$5,199,098	432	90%	388.8	\$12,039
SNCR	\$678,005	432	15%[b]	367	\$10,542

[a] Emission reduction assumes actual operating time of Sunnyside at 334 days per year.
[b] NOx reduction is based on evaluation of Figures 1.3 and 1.4 documenting NOx reduction percent control curves based on temperature and residence time in CFB boilers of similar design to Sunnyside.

Timing for Compliance:
Sunnyside believes that reasonable progress compliant controls are already in place. However, if the UDAQ determines that one of the control methods analyzed in this report is necessary to achieve reasonable progress, it is anticipated that this change could be implemented during the

period of the second long-term strategy for regional haze (approximately ten years following the reasonable progress determination for this second planning period).

Energy Impacts and Non-Air Quality Impacts:
As with the addition of SO2 controls, the introduction of either SNCR or SCR for NOx control will result in an increase in the electricity demand and/or waste generated at the facility. Overall plant efficiency will decrease as a result of the use of this equipment, and the generation of the necessary electricity will contribute to the plant's overall emissions and environmental impact. Environmental agencies around the country have acknowledged the significance of ammonia slip and the potential increases in condensable PM2.5 that can result from the introduction of excess ammonia slip into the atmosphere.

For jurisdictions that struggle with meeting PM standards, the California Environmental Protection Agency Air Resources Board's guidance document advises all air quality districts in California to not permit higher levels of ammonia slip:

> *"Air districts should consider the impact of ammonia slip on meeting and maintaining PM10 and PM2.5 standards, particularly in regions where ammonia is the limiting factor in secondary particulate matter formation. Where a significant impact is identified, air districts could revise their respective New Source Review rules to regulate ammonia as a precursor to both PM10 and PM2.5."*

The use of SNCR or SCR for NOx control introduces the risk of excessive ammonia slip emissions, which contributes to visibility impairing compound formation of ammonia salts. Additionally, there are safety concerns associated with the transport and storage of ammonia, including potential ammonia spills that can have serious adverse environmental and health impacts.

Remaining Useful Life:
The remaining useful life of the boiler will likely impact the annualized cost of an add-on control technology SCR and SNCR) because the useful life is anticipated to be less than the capital cost recovery period of 20 years or less. Although, the cost analysis presented in this report is based on 20 years to be conservative.

4.2.5 NOx Conclusion:

The facility currently uses CFB technology to lower NOx emissions and achieves Title V permitting NOx limits as currently operated. SCR is a technically feasible control option for this boiler but is not cost effective with a control cost greater than $10,000 per ton of NOx removed. While SNCR may represent a cost-effective option for NOx emissions reduction, the introduction of substantial ammonia slip has the potential to cause adverse environmental impacts. The ammonia and PM2.5 emissions have the potential to cause direct health impacts for those in the area, and present additional safety concerns for the storage and transportation of ammonia. Despite not having SNCR or SCR installed, the Sunnyside boiler is achieving a NOx emission rate on a lb/MMBtu basis that is comparable to PSD BACT levels set on CFB boilers. Therefore, additional add-on controls for NOx emissions reductions are not necessary on the Sunnyside CFB boiler.

4.3 SO2 and NOx Emissions – Emergency Generator

Sunnyside cogeneration facility has an emergency generator installed in the event of a loss of power or similar event requiring the plant and facility to maintain electric power. The emergency generator is powered by a 201 HP diesel engine. The emergency diesel engine operates in accordance with the standards set forth in 40 CFR Subpart ZZZZ, the NESHAP for Reciprocating Internal Combustion Engines (RICE) Maximum Available Control Technology (MACT) and is in adherence with the provisions set forth in its UDAQ Title V Permit. The 5000 Kw Emergency generator is subject to NSPS Subpart JJJJ.

Provisions include limiting operation to emergency procedures, emergency demand response, testing and maintenance, and operations in non-emergency settings to 50 hours per year. The emergency engine also follows best combustion practices which include changing the oil and filter after every 500 hours of operation or annually, inspect the air cleaner after every 1,000 hours of operation or annually, and inspect all hoses and belts every 500 hours of operation or annually. These will apply to whichever time provision comes first, either the hours of operation or annual mark. Sunnyside will also limit the engine's time spent at idle and minimize the engine's startup time to under 30 minutes in order to achieve appropriate and safe loading of the engine.

The annual SO2 and NOx emissions for the emergency engine and generator are quite low and attribute to less than 1% of the Boiler's emissions. Any controls implemented to reduce the current emissions from the emergency generator and engine would result in insignificant emission reductions and only increase the financial burden for Sunnyside. Any emission reductions from the emergency engine and generator would have no statistically significant effect on the Regional Haze to the applicable Class 1 areas stated in Section 3. Sunnyside already follows the standards set forth in 40 CFR Subpart ZZZZ and its UDAQ Title V permit and will continue to follow best combustion practices in order to maintain low emissions.

5.0 UDAQ Analysis

UDAQ noted several potential errors in Sunnyside's analysis:

1. The Sunnyside four-factor analysis for SO2 eliminated both wet scrubbers and spray dry scrubbers from consideration as an SO2 control because it does not have the water rights that would be needed for operation of the wet scrubber or a spray dry absorber. The Sunnyside analysis failed to evaluate the use of a circulating dry scrubber which can achieve high SO2 removal efficiencies (as high as 98% control) with lower water use and waste compared to wet or dry scrubbers.

Sunnyside's four-factor analysis did include a cost effectiveness analysis for a "dry scrubber," by which they were referring to dry sorbent injection. The company's analysis found that dry sorbent injection would have a cost effectiveness of $10,202/ton of SO2 removed. More specifically, the company provided a cost analysis for a dry scrubber combined with its cost estimates for a new baghouse. A review of that cost analysis shows that there were several factors that improperly inflated the costs of a dry scrubber.

2. Sunnyside Cogen did not provide justification for including the cost for a new replacement baghouse with a dry scrubbing option.

The Sunnyside Cogen four-factor analysis of installing a dry scrubber included the costs of also installing a new baghouse, even though the CFB boiler already is equipped with a baghouse. The Sunnyside four factor analysis does not explain why a new baghouse would be required with dry scrubbing. The analysis does say that for hydrated ash reinjection, "a larger particulate control device would likely be required to handle the increased particulate matter in the flue gas." Yet, the company claimed that it did not consider hydrated ash reinjection as technically feasible for the Sunnyside CFB boiler, due to its claim that the fly ash at Sunnyside only contains 10% unreacted calcium oxide and that "even if adding reagent would be feasible it would likely require the installation of an enhanced baghouse…." However, nothing in the company's description of dry scrubbing in the four-factor analysis indicated or justified that a new baghouse would be necessary with dry scrubbing. Yet, in a subsequent section of the four-factor analysis, Sunnyside inexplicably stated that use of dry scrubbing technology at Sunnyside "also requires the installation of an additional baghouse to remove particulates generated from dry scrubbing operation." Other than this statement, there was no justification for a new baghouse for dry scrubbing provided.

Before one can determine whether an upgraded baghouse would be necessary for dry scrubbing, more information on the details of the existing baghouse and existing PM rates must be provided. It must be noted that the Sunnyside four-factor analysis indicates that the coal used at the CFB boiler has a very high ash content. This is not unusual for a CFB boilers which often burn waste coal. The existing baghouse thus had to be designed for a high level of ash content. There likely was some level of additional particulate loading built into the design of the existing baghouse. In addition, there is some evidence that a baghouse used in conjunction with sodium-based sorbents, rather than the more traditional lime-based sorbents, can achieve 70-90% SO2 control without any increase in particulate matter loading. This option was not evaluated.

3. Sunnyside's analysis was inconsistent regarding the amount of sorbent required and the possible resulting efficiency

The Sunnyside Cogen four-factor analysis assumed lime would be used at the reagent for the dry sorbent injection at a ratio of 3 tons of sorbent to 1 ton of SO2 emitted and assumed 74% SO2 control would be achieved. One table of the Sunnyside DSI cost list assumes a lime injection rate of 500 lb/hr, although the company's annual operational cost analysis assumed that 1,413 tons per year of lime would be required which, assuming the claimed baseline operating hours of 8,031 hours/year, equates to 352 lb/hr.

Using the Sargent & Lundy formula for estimating the amount of lime needed for the Sunnyside CFB boiler and assuming that use of lime could achieve Sunnyside's planned 74% SO2 reduction indicates that the lime injection rate would need to be 0.0921 tons per hour or 184 lb/hour, which is much lower than the 352 to 500 pounds of lime per hour assumed in the Sunnyside cost analysis for dry sorbent injection. Sunnyside should correct these inconsistencies, or at least explain which value is correct.

4. The Sunnyside dry sorbent injection analysis assumed too high of a cost for auxiliary power

The Sunnyside Cogen analysis assumed an auxiliary power demand of 0.67% of total electrical generation. Sunnyside used the uncontrolled SO2 emission rate for Sunnyside's CFB boiler of 1.7 lb/MMBtu rather than the currently controlled SO2 rate claimed by Sunnyside of 0.17 lb/MMBtu in its calculations of auxiliary power demand. The dry sorbent injection system will only need to reduce SO2 emissions from the current 0.17 lb/MMBtu rate exiting the CFB boiler, and not the uncontrolled SO2 rate of the coal. In addition, in calculating the costs of auxiliary power, Sunnyside used an electricity cost of $74.68/MWhr, which it said is the "current revenue" from Sunnyside. The Sunnyside dry sorbent injection cost analysis also states that "[c]ost conservatively represents lost revenue from electricity that could be sold to the grid, and does not include operating costs of the boiler." However, EPA's Control Cost Manual states that the cost for auxiliary power for electrical generating units should use the busbar cost for electricity. The busbar cost is the cost of producing the electricity, not the revenue made or sale price of the electricity.

Sunnyside's cost for electricity usage due to dry sorbent injection at its CFB boiler was a significant part of its annual operating costs. At an estimated \$232,862 for auxiliary power, Sunnyside's projected electricity cost was 59% of its total direct annual costs of dry sorbent injection. However, Sunnyside clearly overstated the costs for auxiliary power. Even at the Company's stated electricity cost of \$74.68/MWhr, the total cost for electricity should not have been any more than the following:

0.028% x 58.33 MW x 8031 hours/yr x \$74.68/MW-hr = \$9,795 per year.

Sunnyside's claimed cost of \$232,862 per year for electricity is almost 24 times higher than what the Sargent & Lundy IPM power formula calculates would be the auxiliary power needs using lime as the sorbent to achieve 74% SO2 control. Clearly, Sunnyside's operational expenses are overstated.

5. The Sunnyside dry scrubbing cost analysis improperly included annual costs for taxes and insurance and assumed unreasonably high annual costs for administrative charges.

The Sunnyside Cogen dry scrubbing analysis included annual costs for administrative charges, taxes and insurances that totaled 4% of the total capital investment. Utah has a tax exemption for air pollution controls in R307-120. There is no justification for including annual costs equating to 2% of the total capital investment for taxes. With respect to administrative costs, Sunnyside assumed annual costs of dry sorbent injection equating to 2% of the total capital investment per year which, based on the company's dry sorbent injection cost estimates, would equate to \$168,020 per year. EPA does not assume anywhere near that high of an administrative cost for SCR in its SCR cost spreadsheet. Specifically, EPA estimates annual administrative charges for SCR based on the formula 0.03 x Operator Cost + 0.4 x Annual Maintenance Cost. The administrative costs for operating dry sorbent injection should not be any higher than the administrative costs for operating SCR, and would likely be lower. For the dry sorbent injection system costs as presented by Sunnyside, EPA's administrative cost equation of its SCR spreadsheet would indicate the following annual administrative costs for dry sorbent injection:

0.03 x (\$22,310.63 + \$3,346.59) + 0.4 x (\$22,310.63+\$22,310.63) = \$18,741 per year

This estimated \$18,741 per year for administrative overhead is almost 9 times lower than the \$168,020 per year administrative cost estimate provided by Sunnyside Cogen. Thus, it appears that Sunnyside greatly overstated annual administrative costs of operating dry sorbent injection at the Sunnyside CFB boiler.

6. The Sunnyside dry scrubbing cost analysis improperly assumed a 30% increase in cost as a retrofit factor

The Sunnyside Cogen four-factor analysis assumed a 1.3 retrofit factor for the dry sorbent injection part of the evaluation of dry scrubbing. This same retrofit factor was also applied to the cost analysis for SCR and SNCR as well. Yet, the company did not provide any justification for application of a retrofit factor for any of these control options at the Sunnyside CFB boiler.

EPA's SCR and SNCR cost spreadsheets state that "[y]ou must document why a retrofit factor of 1.3 is appropriate for the proposed project." For SNCR systems, EPA has stated no additional retrofit factor is justified for its SNCR spreadsheet, because it already applies a retrofit factor for installation of SNCR at an existing facility compared to installation at a new source. For retrofitted SCR systems, it must be noted that EPA's SCR chapter in its Control Cost Manual already provides for a 25% increase above the cost of SCR at a new greenfield coal-fired boiler in its SCR cost spreadsheet, because EPA's spreadsheet calls for use of a 0.8 retrofit factor for an SCR installation at a new facility and a "1" retrofit factor for an average SCR retrofit. Further, given that most utility boilers that have retrofitted an SCR reactor likely were not planned or designed for an SCR reactor to be installed, the average retrofit costs that EPA's SCR cost spreadsheet calculates take into account some of the difficulties like lack of space and the need to elevate the SCR.

7. The Sunnyside dry sorbent injection cost analysis used too high of an interest rate and too short expected life when amortizing costs

The Sunnyside dry sorbent cost analysis assumed a 7% interest rate and a 20-year life in amortizing the capital cost of this control system. The current bank prime rate is 3.25%. The Federal Reserve has indicated that it expects interest rates to remain at these low levels at least through 2023. Thus, a much lower interest rate should have been used to amortize capital costs of dry sorbent injection. Sunnyside's use of a higher than realistic interest rate would overstate the annualized capital costs by amortizing the capital costs over the life of controls at an unreasonably high interest rate.

Sunnyside Cogen also only assumed a 20-year life for the dry sorbent injection system. EPA assumed a 30-year life of DSI in cost effectiveness calculations for this control at several Texas power plants. Sunnyside should have evaluated a 30-year life for the dry sorbent injection system.

8. Sunnyside assumed too high of an interest rate and too short of a life of controls in determining the annualized capital costs of SNCR and SCR

The Sunnyside SCR and SNCR cost effectiveness analyses assumed a 4.75% interest rate and a 20-year life of both SCR and SNCR. While the 4.75% interest rate used in the SCR and SNCR cost analysis is much lower than the 7% interest rate used in Sunnyside's dry sorbent injection cost analysis, a 4.75% interest rate is still an unreasonably high interest rate to assume in a cost effectiveness analysis. It is unclear why a different interest rate was chosen for this analysis – at the very least one would assume the interest rates to be the same. The current prime bank rate of 3.25% should be used or the source should provide a detailed justification for using a firm-specific interest rate.

With respect to the assumed 20-year life of SCR and SNCR, EPA has stated that the life of an SCR should be 30 years. In its SCR chapter of its Control Cost Manual, EPA included several sources for its assumed 30-year life of an SCR system at a power plant. Absent an enforceable retirement date on the remaining useful life of the Sunnyside CFB plant, it is reasonable to assume a 30-year life in estimating cost effectiveness of SCR, as EPA states in its Control Cost Manual.

9. Sunnyside assumed a very high cost for aqueous ammonia that was not justified.

In its SNCR and SCR cost analyses, Sunnyside Cogen assumed a cost for 29.4% aqueous ammonia of \$2.50 per gallon. EPA's SNCR and SCR cost spreadsheets assumes a significantly lower cost at \$0.293 per gallon for 29.4% aqueous ammonia, citing to the USGS Minerals Commodities

Summaries. Sunnyside provided no justification or basis for assuming a cost for aqueous ammonia that is 8.5 times higher than the cost of aqueous ammonia used in EPA's SNCR cost estimation spreadsheet, other than to put a note in the spreadsheet printouts that it was "[s]ite-specific information" and that they "[u]sed average cost of ammonia supplier costs."

10 Sunnyside assumed a higher cost for electricity than it assumed in its dry sorbent injection analysis

In its SCR and SNCR cost analysis, Sunnyside assumed a cost for electricity of $0.0821/kW. Yet, in its dry sorbent injection analysis, Sunnyside Cogen assumed a lower electricity cost of $0.07468/kWhr, which the Company said is the "current revenue" from Sunnyside. As previously stated, it does not appear that the electricity cost used in the dry sorbent injection cost analysis was the most appropriate to use for estimating the costs of auxiliary power, as the Sunnyside cost analysis stated that the electricity "[c]ost conservatively represents lost revenue from electricity that could be sold to the grid, and does not include operating costs of the boiler." EPA's Control Cost Manual states that the cost for auxiliary power for electrical generating units should use the busbar cost for electricity. The busbar cost is the cost of producing the electricity, not the revenue made or sale price of the electricity. The company is not justified in assuming any higher of a cost for electricity for an SNCR or an SCR system than what it assumed in its DSI cost analysis.

6.0 Conclusion

At this time, UDAQ is unable to proceed with its review and requests additional information as follows:

1. The source needs to resubmit the Four Factor analysis correcting the errors mentioned above.
2. Additional information must be provided regarding the infeasibility of SCR.
    a. This information can include additional details on economics as well as technical limitations.
3. Additional information must be provided regarding the infeasibility of SNCR.
    a. As with SCR, this information can include additional details on economics as well as technical limitations.
4. Any other pertinent information Sunnyside feels is warranted should also be provided in order to assist UDAQ in the review process.

APPENDIX C.4.C - Sunnyside Evaluation Response

Trinity Consultants

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October 15, 2021

Ms. Chelsea Cancino
Environmental Scientist
Utah Division of Air Quality
195 N 1950 W
Salt Lake City, UT 84116
ccancino@utah.gov

RE: Response to UDAQ questions on Sunnyside Cogeneration Associates Four Factor Analysis

Dear Ms. Cancino:

Sunnyside Cogeneration Associates (Sunnyside) has prepared this letter in response to Utah Division of Air Quality's (UDAQ's) questions dated July 30th, 2021 (DAQP-064-21), which were in reference to the Four Factor Analysis submitted on April 8th, 2020 prepared for the second planning period of Utah's Regional Haze State Implementation Plan (SIP). The UDAQ noted a total of ten (10) questions, requests, and/or potential errors and asked that Sunnyside resubmit the Four Factor Analysis correcting the analysis. The UDAQ's concerns are re-stated below, followed by Sunnyside's responses to replace, or supplement the prior submission. The enclosed responses have been provided for clarification, revisions, and/or references to the approach in originally submitted Four-Factor Analysis. In addition, Sunnyside has provided a revised cost analyses in Attachment A to replace the cost analyses submitted in Sunnyside's originally submitted Four-Factor Analysis.

If you have further questions about these responses, please reach out Trinity Consultants, Inc. (Trinity) or Sunnyside for further information or clarification.

UDAQ'S LIST OF POTENTIAL ERRORS

1. The Sunnyside four-factor analysis for SO_2 eliminated both wet scrubbers and spray dry scrubbers from consideration as an SO_2 control because it does not have the water rights that would be needed for operation of the wet scrubber or a spray dry absorber. The Sunnyside analysis failed to evaluate the use of a circulating dry scrubber which can achieve high SO_2 removal efficiencies (as high as 98% control) with lower water use and waste compared to wet or dry scrubbers.

   Sunnyside's four-factor analysis did include a cost effectiveness analysis for a "dry scrubber," by which they were referring to dry sorbent injection. The company's analysis found that dry sorbent injection would have a cost effectiveness of $10,202/ton of SO_2 removed. More specifically, the company provided a cost analysis for a dry scrubber combined with its cost estimates for a new baghouse. A review of that cost analysis shows that there were several factors that improperly inflated the costs of a dry scrubber.

2. Sunnyside Cogen did not provide justification for including the cost for a new replacement baghouse with a dry scrubbing option.

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Before one can determine whether an upgraded baghouse would be necessary for dry scrubbing, more information on the details of the existing baghouse and existing PM rates must be provided. It must be noted that the Sunnyside four-factor analysis indicates that the coal used at the CFB boiler has a very high ash content. This is not unusual for a CFB boilers which often burn waste coal. The existing baghouse thus had to be designed for a high level of ash content. There likely was some level of additional particulate loading built into the design of the existing baghouse. In addition, there is some evidence that a baghouse used in conjunction with sodium-based sorbents, rather than the more traditional lime-based sorbents, can achieve 70-90% SO_2 control without any increase in particulate matter loading. This option was not evaluated.

3. Sunnyside's analysis was inconsistent regarding the amount of sorbent required and the possible resulting efficiency

The Sunnyside Cogen four-factor analysis assumed lime would be used at the reagent for the dry sorbent injection at a ratio of 3 tons of sorbent to 1 ton of SO_2 emitted and assumed 74% SO_2 control would be achieved. One table of the Sunnyside DSI cost list assumes a lime injection rate of 500 lb/hr, although the company's annual operational cost analysis assumed that 1,413 tons per year of lime would be required which, assuming the claimed baseline operating hours of 8,031 hours/year, equates to 352 lb/hr.

Using the Sargent & Lundy formula for estimating the amount of lime needed for the Sunnyside CFB boiler and assuming that use of lime could achieve Sunnyside's planned 74% SO_2 reduction indicates that the lime injection rate would need to be 0.0921 tons per hour or 184 lb/hour, which is much lower than the 352 to 500 pounds of lime per hour assumed in the Sunnyside cost analysis for dry sorbent injection. Sunnyside should correct these inconsistencies, or at least explain which value is correct.

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The Sunnyside Cogen analysis assumed an auxiliary power demand of 0.67% of total electrical generation. Sunnyside used the uncontrolled SO_2 emission rate for Sunnyside's CFB boiler of 1.7 lb/MMBtu rather than the currently controlled SO_2 rate claimed by Sunnyside of 0.17 lb/MMBtu in its calculations of auxiliary power demand. The dry sorbent injection system will only need to reduce SO_2 emissions from the current 0.17 lb/MMBtu rate exiting the CFB boiler, and not the uncontrolled SO_2 rate of the coal. In addition, in calculating the costs of auxiliary power, Sunnyside used an electricity cost of $74.68/MWhr, which it said is the "current revenue" from Sunnyside. The Sunnyside dry sorbent injection cost analysis also states that "[c]ost conservatively represents lost revenue from electricity that could be sold to the grid and does not include operating costs of the boiler." However, EPA's Control

Cost Manual states that the cost for auxiliary power for electrical generating units should use the busbar cost for electricity. The busbar cost is the cost of producing the electricity, not the revenue made or sale price of the electricity.

Sunnyside's cost for electricity usage due to dry sorbent injection at its CFB boiler was a significant part of its annual operating costs. At an estimated $232,862 for auxiliary power, Sunnyside's projected electricity cost was 59% of its total direct annual costs of dry sorbent injection. However, Sunnyside clearly overstated the costs for auxiliary power. Even at the Company's stated electricity cost of $74.68/MWhr, the total cost for electricity should not have been any more than the following:

0.028% x 58.33 MW x 8031 hours/yr x $74.68/MW-hr = $9,795 per year.

Sunnyside's claimed cost of $232,862 per year for electricity is almost 24 times higher than what the Sargent & Lundy IPM power formula calculates would be the auxiliary power needs using lime as the sorbent to achieve 74% SO_2 control. Clearly, Sunnyside's operational expenses are overstated.

5. The Sunnyside dry scrubbing cost analysis improperly included annual costs for taxes and insurance and assumed unreasonably high annual costs for administrative charges.

   The Sunnyside Cogen dry scrubbing analysis included annual costs for administrative charges, taxes and insurances that totaled 4% of the total capital investment. Utah has a tax exemption for air pollution controls in R307-120. There is no justification for including annual costs equating to 2% of the total capital investment for taxes. With respect to administrative costs, Sunnyside assumed annual costs of dry sorbent injection equating to 2% of the total capital investment per year which, based on the company's dry sorbent injection cost estimates, would equate to $168,020 per year. EPA does not assume anywhere near that high of an administrative cost for SCR in its SCR cost spreadsheet. Specifically, EPA estimates annual administrative charges for SCR based on the formula 0.03 x Operator Cost + 0.4 x Annual Maintenance Cost. The administrative costs for operating dry sorbent injection should not be any higher than the administrative costs for operating SCR and would likely be lower. For the dry sorbent injection system costs as presented by Sunnyside, EPA's administrative cost equation of its SCR spreadsheet would indicate the following annual administrative costs for dry sorbent injection:

   0.03 x ($22,310.63 + $3,346.59) + 0.4 x ($22,310.63+$22,310.63) = $18,741 per year

   This estimated $18,741 per year for administrative overhead is almost 9 times lower than the $168,020 per year administrative cost estimate provided by Sunnyside Cogen. Thus, it appears that Sunnyside greatly overstated annual administrative costs of operating dry sorbent injection at the Sunnyside CFB boiler.

6. The Sunnyside dry scrubbing cost analysis improperly assumed a 30% increase in cost as a retrofit factor

   The Sunnyside Cogen four-factor analysis assumed a 1.3 retrofit factor for the dry sorbent injection part of the evaluation of dry scrubbing. This same retrofit factor was also applied to the cost analysis for SCR and SNCR as well. Yet, the company did not provide any justification for application of a retrofit factor for any of these control options at the Sunnyside CFB boiler. EPA's SCR and SNCR cost spreadsheets state that "[y]ou must document why a retrofit factor of 1.3 is appropriate for the proposed project." For SNCR systems, EPA has stated no additional retrofit factor is justified for its SNCR spreadsheet, because it already applies a retrofit factor for installation of SNCR at an existing facility compared to installation at a new source. For retrofitted SCR systems, it must be noted that EPA's SCR chapter in its Control Cost Manual already provides for a 25% increase above the cost of SCR at a new greenfield coal-fired boiler in its SCR cost spreadsheet, because EPA's spreadsheet calls for use of a 0.8 retrofit factor for an SCR installation at a new facility and a "1" retrofit factor for an average SCR retrofit. Further, given that most utility boilers that have retrofitted an SCR reactor likely were not planned or designed for an SCR reactor to be installed, the average retrofit costs that EPA's SCR cost spreadsheet calculates take into account some of the difficulties like lack of space and the need to elevate the SCR.

7. The Sunnyside dry sorbent injection cost analysis used too high of an interest rate and too short, expected life when amortizing costs

   The Sunnyside dry sorbent cost analysis assumed a 7% interest rate and a 20-year life in amortizing the capital cost of this control system. The current bank prime rate is 3.25%. The Federal Reserve has indicated that it expects interest rates to remain at these low levels at least through 2023. Thus, a much lower interest rate should have been used to amortize capital costs of dry sorbent injection. Sunnyside's use of a higher than realistic interest rate would overstate the annualized capital costs by amortizing the capital costs over the life of controls at an unreasonably high interest rate.

   Sunnyside Cogen also only assumed a 20-year life for the dry sorbent injection system. EPA assumed a 30-year life of DSI in cost effectiveness calculations for this control at several Texas power plants. Sunnyside should have evaluated a 30-year life for the dry sorbent injection system.

8. Sunnyside assumed too high of an interest rate and too short of a life of controls in determining the annualized capital costs of SNCR and SCR

   The Sunnyside SCR and SNCR cost effectiveness analyses assumed a 4.75% interest rate and a 20-year life of both SCR and SNCR. While the 4.75% interest rate used in the SCR and SNCR cost analysis is much lower than the 7% interest rate used in Sunnyside's dry sorbent injection cost analysis, a 4.75% interest rate is still an unreasonably high interest rate to assume in a cost effectiveness analysis. It is unclear why a different interest rate was chosen for this analysis – at the very least one would assume the interest rates to be the same. The current prime bank rate of 3.25% should be used or the source should provide a detailed justification for using a firm-specific interest rate.

   With respect to the assumed 20-year life of SCR and SNCR, EPA has stated that the life of an SCR should be 30 years. In its SCR chapter of its Control Cost Manual, EPA included several sources for its assumed 30-year life of an SCR system at a power plant. Absent an enforceable retirement date on the remaining useful life of the Sunnyside CFB plant, it is reasonable to assume a 30-year life in estimating cost effectiveness of SCR, as EPA states in its Control Cost Manual.

9. Sunnyside assumed a very high cost for aqueous ammonia that was not justified.

   In its SNCR and SCR cost analyses, Sunnyside Cogen assumed a cost for 29.4% aqueous ammonia of $2.50 per gallon. EPA's SNCR and SCR cost spreadsheets assumes a significantly lower cost at $0.293 per gallon for 29.4% aqueous ammonia, citing to the USGS Minerals Commodities Summaries. Sunnyside provided no justification or basis for assuming a cost for aqueous ammonia that is 8.5 times higher than the cost of aqueous ammonia used in EPA's SNCR cost estimation spreadsheet, other than to put a note in the spreadsheet printouts that it was "[s]ite-specific information" and that they "[u]sed average cost of ammonia supplier costs."

10. Sunnyside assumed a higher cost for electricity than it assumed in its dry sorbent injection analysis

    In its SCR and SNCR cost analysis, Sunnyside assumed a cost for electricity of $0.0821/kW. Yet, in its dry sorbent injection analysis, Sunnyside Cogen assumed a lower electricity cost of $0.07468/kWhr, which the Company said is the "current revenue" from Sunnyside. As previously stated, it does not appear that the electricity cost used in the dry sorbent injection cost analysis was the most appropriate to use for estimating the costs of auxiliary power, as the Sunnyside cost analysis stated that the electricity "[c]ost conservatively represents lost revenue from electricity that could be sold to the grid, and does not include operating costs of the boiler." EPA's Control Cost Manual states that the cost for auxiliary power for electrical generating units should use the busbar cost for electricity. The busbar cost is the cost of producing the electricity, not the revenue made or sale price of the electricity. The company is not justified in assuming any higher of a cost for electricity for an SNCR or an SCR system than what it assumed in its DSI cost analysis.

SUNNYSIDE'S RESPONSES

Question 1

Control Technology Clarification

The UDAQ's question indicates confusion regarding the current design and available technologies due to the generic nomenclature used in the original Four Factor Analysis. Sunnyside would like to further clarify the reviewed technologies. While all of the technologies discussed utilize absorption to remove pollutants from the process gas stream, the method by which this absorption is achieved varies. These technologies can be broadly divided into two categories: wet scrubbing and dry scrubbing. As wet scrubbing, referred to as wet flue gas desulfurization (WFGD), has already been eliminated as technically infeasible due to water shortages and long-term availability, this group of technologies will not be further discussed.

Dry scrubbers, or dry sorbent injection (DSI), generically refers to the interaction of acid gas compounds, such as hydrogen chloride (HCl), SO_2, and hydgrogen sulfide (H_2SO_4), with sorbents, such as hydrated lime, sodium bicarbonate, or trona.[1] There are several methods which facilitate interaction of the acid gases and reagents including, Hydrated Ash Reinjection (HAR), Spray Dryer Absorber (SDA), and Circulating Dry Scrubber (CDS)/ Circulating Fluidized Bed Scrubber (CFBS). To provide clarification, a revised summary of these technologies and evaluation of feasibility have been provided in the following paragraphs.

Hydrated ash reinjection effectively reduces SO_2 emissions by increasing the extent of reaction between SO_2 and hydrating sorbents. This control device recycles fly ash in the system for a specified period, after which the flue gas is sent to a particulate control device where the sulfur-rich particulates are collected. Design and efficiencies for HAR systems vary greatly based on vendor and sorbent type.[2]

Specifically, the circulating fluidized bed (CFB) boiler technology at Sunnyside suspends small pieces of solid fuel during the combustion process using upward blowing jets of hot air. Hot gases, carrying the coal fragments and fly ash, are recirculated through cyclones and back into the boiler chamber through the jets. In addition to coal fragments, limestone is added to the boiler. As the coal fragments and injected limestone recirculate between the boiler and the cyclones the extent of reaction between SO_2 and limestone is increased. Similarly, ash in the fuel (i.e., waste coal) has the opportunity to react with these coal fragments.

The addition of further HAR technology is not feasible as flue gas exiting the CFB boiler at Sunnyside typically contains approximately 10% unreacted calcium oxide in the fly ash and even less in the bottom ash.[3] This low amount of unreacted calcium oxide would necessitate the addition of a significant amount of

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[1] Trona is a sodium carbonate compound, which is processed into soda ash or baking soda. https://www.wyomingmining.org/minerals/trona/

[2] Montana Department of Environmental Quality, Regional Haze Four Factor Analysis, Rosebud Power Plant, 2019

[3] Based on fly ash characterization results conducted at Sunnyside Cogeneration Associates.

fly ash and would generate an even larger amount of additional particulate matter (PM). Additionally, there is a significant amount of ash already entrained in the CFB Boiler which would make additional ash infeasible. As a result, HAR is not considered further.

Spray Dryer Absorber technology sprays atomized lime slurry droplets into the flue gas. Acid gases are absorbed by the atomized slurry droplets while simultaneously evaporating into a solid particulate. The flue gas and solid particulate are then directed to a fabric filter where the solid materials are collected from the flue gas. This technology is not utilized in the current design as the addition of a slurry would inhibit combustion by increasing water content within the firebox and cyclone system. The CFB boiler design and its recirculating flue gas would alter the combustion dynamics significantly enough that the system would need to be re-engineered to accommodate this technology.

Installing an additional SDA in series with Sunnyside's current system could further reduce SO_2 emissions at Sunnyside's facility. However, despite the misleading name, SDA, requires a considerable amount of water to atomize the reactive sorbent into an aqueous solution.

Sunnyside's operation already requires a significant use of water, and not only are the plant's current water rights limited but the availability of water has reduced and is not sufficient enough to sustain the necessary water usage to operate an additional SDA. Any additional water consumption would result in the available water being used much more rapidly and represents an undue burden on the facility to acquire the water that is also limited in supply for SDA operation. As a result, installation of an additional spray dry absorber in series with Sunnyside's current limestone injection technology is considered infeasible and will not be evaluated further.

Circulating dry scrubber (CDS)/Circulating fluidized bed scrubber (CFBS) is a control technique in which the waste gas stream passes through an absorber vessel containing a fluidized bed of hydrated lime and recycled byproduct.[4] Boiler flue gas enters the device at the bottom of the up-flow vessel, causing turbulent flow.[5] The turbulent flow increases mixing of the flue gas, solids, and small amounts of water to achieve a high capture efficiency of the vapor phase acid gases contained within the flue gas. The gas and solids mixture then leaves the top of the scrubber and the fabric filter removes the solid material. These controls have been documented to achieve 98% reduction of SO_2, which is consistent with what the UDAQ had stated in their potential concerns with Sunnyside's four factor analysis.

Given the configuration of existing units, there is not enough space between the CFB boiler and existing baghouse for the addition of a further CDS/CFBS unit without significant reconfiguration of existing equipment. Of all the add on control technologies considered, CDS/CFBS is the only potentially feasible option.

Existing controls for SO_2 as defined in Sunnyside's Title V air operation permit (#700030004) Condition II.A.2 currently provide SO_2 controls to the circulating fluidized bed (CFB) boiler, which involves limestone injection. Hereafter, control strategies currently implemented within the Sunnyside's CFB Boiler will be referred to as DSI using limestone. Since 1993, when the boiler was installed, Sunnyside has refined operation, limestone injection rate, and other key performance indicators to reduce SO_2 emissions.

The analysis provided under Question 1 should replace information found in Table 1-1, and Sections 5.1, 5.2, and 5.3, as applicable.

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[4] EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control
[5] Power Engineering Article, Circulating Fluidized Bed Scrubber vs Spray Dryer Absorber, Circulating Fluidized Bed Scrubber vs. Spray Dryer Absorber - Power Engineering (power-eng.com)

CDS/CFBS Cost Analysis

In the original Four Factor Analysis, Sunnyside provided a cost analysis for the addition of a separate DSI unit (dry scrubber) and baghouse to ensure a comprehensive analysis of multiple options was provided. After further evaluation, a dry scrubbing unit cannot be retrofitted between the CFB boiler and the existing baghouse due to space limitations requiring significant reconfiguration of existing equipment. Accordingly, a CDS/CFBS is the only add on unit that is potentially technically feasible. Based on the additional detail provided above, and in response to the UDAQ request, a cost analysis has been completed for a CDS/CFBS to replace the DSI cost analysis.

Based on the EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, the average estimated cost for a CDS /CFBS that is able to achieve 90% or higher was $81 million with the highest being $400 million. Thus, the total capital investment has been revised. A revised cost analysis has been provided in Attachment A. Sunnyside requests that this cost for CDS/CFBS replace the cost analysis for SO_2 control in the original Four Factor Analysis.

Additionally, because the flow pathways in this control device are essential to pollutant control, this system typically includes a baghouse within the design. The current baghouse was made operational in January 1993 and is in marginal condition based on its age, requiring periodic repair to tubesheets, seals, and shell of the baghouse. This further justifies the need for replacement if alternative technologies are considered. Total cost of the baghouse replacement is estimated at $1.7 million and is insignificant compared to the total capital investment for the CDS/CFBS system as a whole. For further information please see Sunnyside's response to Question 2. Based on the revised calculations, provided in Attachment A, a CDS/CFBS device is not considered economically feasible.

Question 2

Inclusion of Baghouse in Cost Analysis

In the event that Sunnyside were to proceed with the design and installation of an additional control device, the only potentially feasible control method is the use of a CDS /CFBS as discussed in Question 1. CDS/CFBS is a control technique in which the waste gas stream passes through an absorber vessel containing a fluidized bed of hydrated lime and recycled byproduct.[6] This control device would be in addition to DSI with limestone already occurring within the CFB boiler.

Boiler flue gas enters the device at the bottom of the up-flow vessel, causing turbulent flow.[7] The turbulent flow increases mixing of the flue gas, solids, and small amounts of water to achieve a high capture efficiency of the vapor phase acid gases contained within the flue gas. The gas and solids mixture then leaves the top of the scrubber and enters the baghouse. In many cases the solids entrained in the flue gas are captured and recycled back to the scrubber to capture additional pollutants.[8] A portion of the recycled solids is removed from the baghouse in order to maintain the right quantity of material in the circulating loop. As a result, the baghouse is essential to the design and effectiveness of the a CDS/CFBS unit.

As previously mentioned, the current baghouse was made operational in January 1993, and is in marginal condition based on its age. CDS/CFBS design requires integration of the baghouse into the mixing chamber,

[6] EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control
[7] Power Engineering Article, Circulating Fluidized Bed Scrubber vs Spray Dryer Absorber, Circulating Fluidized Bed Scrubber vs. Spray Dryer Absorber - Power Engineering (power-eng.com)
[8] Power Engineering Article, Circulating Fluidized Bed Scrubber vs Spray Dryer Absorber, Circulating Fluidized Bed Scrubber vs. Spray Dryer Absorber - Power Engineering (power-eng.com)

this connection is not likely to be reliable on the existing equipment given the age of the unit. Furthermore, the addition of a CDS/CFBS would increase the amount of PM processed because it represents a secondary addition of hydrated lime to further react with pollutants.

Additionally, there is insufficient space to install a CDS/CFBS between the boiler and existing baghouse. To alter the design and re-direct the ducting into the existing baghouse from the boiler and the CDS/CFBS would require custom design plans and detailed computational fluid dynamic engineering. Even if a re-engineering of the duct work allowed the existing baghouse to be used, it is likely that the flow patterns produced by the CDS/CFBS would disrupt the flow through the plenum of the baghouse thereby redirecting air flow and eliminating the distribution of air evenly across the compartments.

These design considerations led to the conclusion that, regardless of capacity or current emission rate, inclusion of a replacement baghouse within the cost analysis was warranted. Additionally, upon utilization of a CDS/CFBS specific capital investment cost of $81 million, at a minimum, the included $1.7 million for a new baghouse becomes negligible.

Sorbent Chemistry

The UDAQ also requested that Sunnyside address the use of a sodium-based sorbent, such as sodium bicarbonate or trona, rather than the traditional lime. While "there is some evidence that a baghouse used in conjunction with sodium-based sorbents, ..., can achieve 70-90% SO_2 control without any increase in particulate matter loading," changing the sorbent chemistry will not address the integration of the baghouse with the CDS/CFBS control device, the need for computational fluid dynamic engineering to ensure proper operation of the CDS/CFBS, nor the existing space requirements.

Additionally, Sunnyside did not consider the switch from a traditional lime sorbent to a sodium-based sorbent because sodium-based sorbents have not been considered best industry practice for at least the last 20 years. This is demonstrated by a review of the RBLC, section 1.11, which identifies only lime-based sorbents. Moreover, the control efficiency of any sorbent is dependent on the flue gas properties, sorbent size, mixing of sorbent and pollutants, as well as various other control system configurations. Sunnyside has optimized these parameters within its current DSI limestone system to maximize control efficiency while maintaining CFB boiler operation. Therefore, consideration of absorbents is eliminated from further evaluation.

Question 3

Sunnyside has updated this formula in the revised cost analysis to utilize the Sargent & Lundy formula for estimating the amount of lime needed for the Sunnyside CFB boiler. This formula now assumes that use of lime could achieve 74% SO_2 reduction resulting in a lime injection rate of 0.0921 tons per hour or 184 lb/hour.

Question 4

Sunnyside has revised the cost for auxiliary power to be consistent with the UDAQ comments. Specifically, the busbar cost for electricity has now been calculated based on 2018 operating data. The resulting rate is $49.45 per MW.

Additionally, the electrical usage rate has been updated to match the UDAQ comments and as displayed below:

0.028% x 58.33 MW x 8031 hours/yr x $49.45/MW-hr = $6,486 per year.

The analysis provided under Question 2, 3, and 4 along with the attached cost analysis should replace information found in Sections 5.4 and 5.5 of the Four Factor Analysis.

Question 5

Tax Rate

The UDAQ suggested that there are tax exemptions in Utah for control equipment. UAC R307-120 exempts the purchase of control equipment from sales/use tax. As a result, sales tax is no longer included in CDS/CFBS cost analysis provided.

Property taxes are still assessed for control equipment and are not addressed under UAC R307-120, therefore this tax rate has been taken from the EPA Cost Control Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, Subsection 2.6.5.8 Property Taxes, Insurance, Administrative Charges and Permitting Costs.

Sales tax rates and property taxes are not used in either the SCR or SNCR cost analyses due to the equation format provided by EPA.

Insurance

Insurance rate was based on a 1% of the Total capital investment (TCI) which is documented in the EPA Cost Control Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, Subsection 2.6.5.8 Property Taxes, Insurance, Administrative Charges and Permitting Costs.

Administrative Costs

The administrative cost calculation has been updated to be consistent with SCR as suggested by the UDAQ. Specifically, the following formula was used: 0.03 x Operator Cost + 0.4 x Annual Maintenance Cost.

Question 6

The UDAQ questioned the retrofit factor (RF) of 1.3 used all cost analyses, as a result Sunnyside re-evaluated the use of this factor on a technology specific basis.

CDS/CFBS

The estimated cost provided in EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, represents the estimated cost for a CDS /CFBS that is able to achieve 90% or higher. This cost includes contingency for a simple retrofit. EPA states that for retrofits that are more complicated than average, a retrofit factor of greater than 1 can be used to estimate capital costs, provided the reasons for using a higher retrofit factor are appropriate and fully documented.[9] The bounds given for the RF on a dry system are 0.8 to 1.5. [10] EPA further documents that the retrofit factor should

[9] EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, Subsection 1.2.3.5

[10] EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, Subsection 1.2.3.5

account for site congestion, site access, and capacity of existing infrastructure. The amount of space available near the utility boiler can significantly impact the costs.[11]

In order to install a CDS/CFBS system the site would need to decommission the existing baghouse and utilize architectural and mechanical experts to fit both the CDS/CFBS and a new baghouse within the currently allocated space. Additionally, because the flow mechanics, namely turbulence, are key to the control efficiency, an outside contractor would need to ensure fluid mechanics were compatible. Sunnyside anticipates that these considerations would likely lead to a custom design and would justify the 1.3 retrofit factor.

SCR

The procedures for estimating costs presented in EPA's Cost Control Manual, Section 4 NOx Controls, Chapter 2 Selective Catalytic Reduction are based on cost data for SCR retrofits on existing coal-, oil-, and gas-fired boilers for electric generating units larger than 25 MWe (approximately 250 MMBtu/hr). Thus, this report's procedure estimates costs for typical retrofits of such boilers.

As mentioned in the original Four Factor Analysis, since low-temperature SCR is not technically feasible, implementation of SCR can only be implemented if the flue gas is reheated downstream of the baghouse. This heating is necessary to ensure an operable temperature range. The installation of an additional combustion device, including additional engineering and capital investment, is not standard for the retrofit of this technology. As a result, a 1.3 retrofit factor has been utilized. A revised cost analysis has been provided in Attachment A to replace the cost analysis submitted in the Sunnyside Four-Factor Analysis. It should be noted that this cost analysis represents estimates based on information available at the time.

SNCR

The costing algorithms in presented in EPA's Cost Control Manual, Section 4 NOx Controls, Chapter 1 Selective Non-Catalytic Reduction are based on retrofit applications of SNCR to existing coal-fired utility boilers. EPA stated that over the years, SNCR has begun to be applied to existing sites that are more difficult to retrofit, which means the gap between average retrofit and new installation costs may be greater than it used to be, but it is not expected to be substantial.

Because this technology could be implemented within the boiler, rather than as a stand-alone control device the flue gas path, Sunnyside anticipates that should this application be installed it would likely be considered a standard retrofit project. As a result, the 1.3 retrofit factor has been replaced by a 1.0 retrofit factor. A revised cost analysis has been provided in Attachment A to replace the cost analysis submitted in the Sunnyside Four-Factor Analysis. It should be noted that this cost analysis represents estimates based on information available at the time and further investigation may be required.

Question 7

Equipment Life

While EPA generally recommends a 30 year equipment life, the EPA Cost Control Manual states that for retrofits on older combustion units, the remaining life of the controlled combustion unit may be an important factor for determining the expected lifetime for a dry scrubber.[12] Additionally, the EPA issued

[11] EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, Subsection 1.2.3.5

[12] EPA Cost Control Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, Indirect Annual Costs (pg. 1-35)

Reasonable Progress Source Identification and Analysis Protocol (WRAP) for Second 10-year Regional Haze State Implementation Plans, which further supports this statement by adding "States should combine and annualize these costs over the expected life of the source or the control equipment, whichever is shorter." The document then goes on to state:

> *"Generally, the remaining useful life of the source itself will be longer than the useful life of the emission control measure under consideration unless there is an enforceable requirement for the source to cease operation sooner. Thus, states should normally use the useful life of the control measure to calculate emission reductions, amortized costs, and cost per ton. However, if there is an enforceable requirement for the source to cease operation by a date before the end of what would otherwise be the useful life of the control measure under consideration, then states should use the enforceable shutdown date to calculate remaining useful life"*

The Sunnyside Plant was originally commissioned in the early 1990s, thus the plant has already been running for approximately 30 years. Due to equipment aging, it is estimated that CFB boiler will not be operating beyond an additional 20 years. Thus a 20-year life span has been applied to the cost control analyses provided.

Interest Rate

The EPA cost manual states that "when performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, the correct interest rate to use is the nominal interest rate, which is the rate firms actually face."[13]

For this analysis, which evaluates equipment costs that may take place more than 5 years into the future, it is important to ensure that the selected interest rate represents a longer-term view of corporate borrowing rates. The cost manual cites the bank prime rate as one indicator of the cost of borrowing as an option for use when the specific nominal interest rate is not available.

Over the past 20 years, the annual average prime rate has varied from 3.25% to 9.23%, with an overall average of 4.86% over the 20-year period.[14] But the cost manual also adds the caution that the "base rates used by banks do not reflect entity and project specific characteristics and risks including the length of the project, and credit risks of the borrowers."[15] For this reason, the prime rate should be considered the low end of the range for estimating capital cost recovery.

Actual borrowing costs experienced by firms are typically higher. For economic evaluations of the impact of federal regulations, the Office of Management and Budget (OMB) uses an interest rate of 7%.

> *"As a default position, OMB Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost*

[13] EPA Cost Control Manual, Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology
[14] Board of Governors of the Federal Reserve System Data Download Program, "H.15 Selected Interest Rates," accessed April 16, 2020.
https://www.federalreserve.gov/datadownload/Download.aspx?rel=H15&series=8193c94824192497563a23e3787878ec&filetype=spreadsheetml&label=include&layout=seriescolumn&from=01/01/2000&to=12/31/2020
[15] EPA Cost Control Manual, Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology

> *of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector."*[16]

Based on this guidance, Sunnyside now uses a 7% interest rate in all cost analyses provided.

Question 8

The equipment life and interest rate explanations provided in Question 7 are not control technology specific. Thus, the same conclusions are applicable, namely, a 20-year life span and 7% interest rate are appropriate for the cost analyses provided.

Question 9

In response to the UDAQ's request, Sunnyside obtained a cost estimate for 19% aqua ammonia from Thatcher Group, Inc (Thatcher). Thatcher quoted $0.18 per lb. of solution. Based on this value, if we assume a density of 19% ammonia is estimated to be 7.46 lbs/gal to 7.99 lbs/gal. This results in a cost per gallon ranges from 1.34 $/gal to 1.438 $/gal. This cost is significantly higher than the EPA estimate of $0.293, which is acceptable as it states, "User should enter actual value if known". Furthermore, it should be noted that the cost for ammonia based on the most recent U.S. Geological Survey, Minerals Commodity Summaries, which was quoted in the original Four Factor Analysis is also significantly higher and based on a density of 29% ammonia. Since the $1.438 is still less than the originally used $2.5 per gallon, these calculations have been updated to include the vendor quote.

Question 10

As discussed in Question 4, Sunnyside has revised the cost for auxiliary power to be consistent with the UDAQ's comments. Please see section 4 for additional information.

A revised cost analysis for SCR and SNCR have been provided in Attachment A to replace the cost analysis in the original Four Factor Analysis.

[16] OMB Circular A-4, https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf

Attachment A - Revised Cost Analyses

Dry Scrubber Cost Analysis

Table A-1: CDS/CFBS

Variable		Value	Units
Baseline SO_2 Emissions		471	tons/year
SO_2 Removal Efficiency		74%	
Total SO_2 Removed		318.91	tons/year
Lime Injection Rate		184	lb/hr (Sargent & Lundy)
Annual Operating Time		8031	hours/year

[1] Assumes control technology uptime of 92% for maintenance and unexpected boiler and control technology downtime

Table A-2: Dry Sorbent Injection Costs

Cost Item	Factor	Cost	Notes
Captial Costs[1]			
Equipment Cost	A	$66,600,000.00	EPA Cost Control Manual, Section 5 SO2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubber for Acid Gas Control, with a ratio applied to be consistent with the 74% control orginally estimated
Instrumentation	0.1×A	$6,660,000.00	Per EPA Control Cost Manual
Sales Tax		$0.00	Assume tax exempt per UDAQ Rules
Freight	0.05×A	$3,330,000.00	Per EPA Control Cost Manual
Purchased equipment cost, PEC	B = 1.18×A	$76,590,000.00	Per EPA Control Cost Manual
Direct Installation Costs			
Foundation and Supports	0.12×B	$9,190,800.00	Per EPA Control Cost Manual
Handling and Erection	0.40×B	$30,636,000.00	Per EPA Control Cost Manual
Electrical	0.01×B	$765,900.00	Per EPA Control Cost Manual
Piping	0.3×B	$22,977,000.00	Per EPA Control Cost Manual
Installation for ductwork	0.01×B	$765,900.00	Per EPA Control Cost Manual
Painting	0.01×B	$765,900.00	Per EPA Control Cost Manual
Direct Installation Cost	0.85×B	$65,101,500.00	Per EPA Control Cost Manual
Retrofit Factor	1.3		Per EPA Control Cost Manual
Direct Installation Costs Including Retrofit Factor		$84,631,950.00	
Site Preparation			As required, estimate
Buildings			As required, estimate
Total Direct Cost	1.30×B + SP + Bldg + Direct Costs	$161,221,950.00	Direct costs include foundation, handling, electrical, piping, ductwork, and painting
Indirect Costs (Installation)			
Engineering	0.10×B	$7,659,000.00	Per EPA Control Cost Manual
Construction and Field Expenses	0.10×B	$7,659,000.00	Per EPA Control Cost Manual
Contractor Fees	0.10×B	$7,659,000.00	Per EPA Control Cost Manual
Start-up	0.01×B	$765,900.00	Per EPA Control Cost Manual
Performance Test	0.01×B	$765,900.00	Per EPA Control Cost Manual
Contingencies	0.03×B	$2,297,700.00	Per EPA Control Cost Manual
Total Indirect Cost, IC	0.35×B	$26,806,500.00	Per EPA Control Cost Manual
Total Capital Investment (TCI)	TCI = DC + IC	$188,028,450.00	

Table A-3: Continued

Cost Item	Factor	Cost	Notes
Direct Annual Costs[1]			
Operating Labor			
Operator		$22,310.63	0.5 hr/shift, 3 shifts/day, 365 d/yr, $40.75/hr
Supervisor		$3,346.59	15% of Operator
Operating Materials			
Lime required (tpy)		739	Lime required (tpy) = SO_2 emissions (tpy) × 3
Limestone Cost ($/ton)		55.81	Current costs from Sunnyside's Limestone supplier
Limestone Cost ($/yr)		$41,235.33	Annual Cost ($/yr) = Limestone Cost ($/ton) × Annual Lime Required
Maintenance			
Maintenance Labor		$22,310.63	0.5 hr/shift, 3 shifts/day, 365 d/yr, $40.75/hr
Maintenance Materials		$22,310.63	100% of Maintenance Labor
Utilities			
Rate		$49.45	($/MW) Total annual Busbar cost divided by MW produced from Sunnyside
Electricity		$6,485.54	Cost conservatively represents lost revenue from electricity that could be sold to the grid, and does not include operating costs of boiler
Direct Annual Cost		$117,999.34	
Indirect Annual Costs, IC			
Overhead	60% sum of operating labor, maintenance labor, and associated materials	$42,167.08	
Administrative Charges	= 0.03 x Operator Cost + 0.4 x Annual Maintenance Cost.	$25,545.67	Where the TCI is estimated as $666000000
Property Taxes	1% of TCI	$1,880,284.50	Where the TCI is estimated as $666000000
Insurance	1% of TCI	$1,880,284.50	Where the TCI is estimated as $666000000
Indirect Annual Cost		$3,828,281.75	Sum of overhead, administrative, taxes, and insurance
Capital Recovery[2]		$0.09	$ Annually/$ Capital Cost
Annualized Capital Cost		$17,748,555.52	Capital Recovery * Total Capital Investment
Total Annual Cost (Dry Scrubber)		$21,694,836.60	$/year
Cost Effectiveness		$68,027.21	$/ton

[1] Capital recovery calculated based on the methodology provided in the EPA Control Cost Manual, Section 1 Chapter 2, Equation 2.8 and 2.8a on Page 2-22, where an interest rate of 7% is assumed.

[2] Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, 2.6.5.8 Property Taxes, Insurance, Administrative Charges and Permitting Costs

Interest	7.00%
Based on CPE Boiler Equipment Life (Life of the Unit)	20

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.30

* NOTE: You must document why a retrofit factor of 1.3 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	700.00	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	7,072	Btu/lb
What is the estimated actual annual fuel consumption?	883,419,174	lbs/Year
Enter the net plant heat input rate (NPHR)	12	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	6497	Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.71 percent by weight

For units burning coal blends:

Note: The table below is prepopulated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ● Method 2
- ○ Not applicable

Enter the following design parameters for the proposed SCR:

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Number of days the SCR operates (t_{SCR})	334 days
Number of days the boiler operates (t_{plant})	334 days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.15 lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.015 lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.05

*The SRF value of 1.05 is a default value. Users should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1
Number of catalyst layers (R_{layer})	3
Number of empty catalyst layers (R_{empty})	1
Ammonia Slip (Slip) provided by vendor	2 ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours
Estimated SCR equipment life	20 Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	[illegible] °F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516.00 ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	19 percent
Density of reagent as stored (ρ_{stored})	57.788 lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14 days

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2019	
CEPCI for 2019	607.5 Enter the CEPCI value for 2019 / 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7 Percent	
Reagent ($Cost_{reag}$)	1.380 \$/gallon for 19% ammonia	
Electricity ($Cost_{elect}$)	0.0495 \$/kWh	
Catalyst cost ($CC_{replace}$)	227.00 \$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* \$227/ft3 is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	40.75 \$/hour (including benefits)	
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	Revised Cost: $1.38/gallon Initial Cost: ~~$2.50/gallon of 29% Ammonia~~	Revised cost analysis: Quotation from Thatcher (Average cost based on density range.) Initial cost analysis: ~~U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf~~	Site specific information. Used average cost of ammonia supplier costs.
Electricity Cost ($/kWh)		U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	Busbar cost and production rate for 2018 used
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	Site Specific
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	Site specific
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	Site specific
Interest Rate (Percent)	7	See explanation in summary	[illegible]

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	700	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	867,031,448	lbs/Year
Actual Annual fuel consumption (Mactual) =		883,413,174	lbs/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.20	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.019	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8925	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	90.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	96.77	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	431.85	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.12	
Volumetric flue gas flow rate ($q_{flue gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	345,631	acfm
Space velocity (V_{space}) =	$q_{flue gas}$/$Vol_{catalyst}$ =	117.77	/hour
Residence Time	1/V_{space}	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10[6])/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.27	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.6	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.30	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1), where Y = $H_{catalyst}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3111	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	2,934.86	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue gas}$ /(16ft/sec x 60 sec/min)	360	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	414	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	20.3	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	52	feet

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Four Factor Analysis - SCR Cost Analysis

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole
Density = 57.788 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	38	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/Csol$ =	198	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density	26	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24)$/Reagent Density =	8,700	gallons (storage needed to store a 14 day reagent supply rounded to th

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0944

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	$A \times 1{,}000 \times 0.0056 \times (CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	432.96	kW

Cost Estimate

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$30,630,645	in 2019 dollars
Reagent Preparation Cost (RPC) =	$2,578,991	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$5,954,920	in 2019 dollars
Total Capital Investment (TCI) =	$50,913,923.07	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$30,630,645 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$2,578,991 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42} ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$5,954,920 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$995,457 in 2019 dollars
Indirect Annual Costs (IDAC) =	$4,810,962 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$5,806,419 in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$254,570 in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$315,628 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$191,082 in 2019 dollars
Annual Catalyst Replacement Cost =		$234,177 in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	* Calculation Method 2 selected.
Method 2 (for coal-fired utility boilers):	$B_{MW} \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
Method 2 (for coal-fired industrial boilers):	$(Q_B/NPHR) \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
Direct Annual Cost =		$995,457 in 2019 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Operator Cost + 0.4 x Annual Maintenance Cost =	$4,688 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$4,806,274 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$4,810,962 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$5,806,419 per year in 2019 dollars
NOx Removed =	432 tons/year
Cost Effectiveness =	$13,445 per ton of NOx removed in 2019 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? [illegible]

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.00

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 700.00 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 7,072 Btu/lb

What is the estimated actual annual fuel consumption? 889,413,174 lbs/Year

Is the boiler a fluid-bed boiler? Yes

Enter the net plant heat input rate (NPHR) 12 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Sub-Bituminous

Enter the sulfur content (%S) = 0.71 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 41.425 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	[illegible]
Sub-Bituminous	0	0.41	5.84	[illegible]	1.89
Lignite	0	0.82	13.6	[illegible]	1.74

Please click the calculate button to calculate weighted [illegible] values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	334 days	Plant Elevation	6497 Feet above sea level
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.15 lb/MMBtu		
Outlet NO_x Emissions (NOx_{out}) from SNCR	0.13 lb/MMBtu		
Estimated Normalized Stoichiometric Ratio (NSR)	0.50		
Concentration of reagent as stored (C_{stored})	19 Percent		
Density of reagent as stored (ρ_{stored})	57.703 lb/ft^3		
Concentration of reagent injected (C_{inj})	19 percent		
Number of days reagent is stored ($t_{storage}$)	14 days		
Estimated equipment life	20 Years		
Select the reagent used	Ammonia		

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2019	
CEPCI for 2019	607.5 Enter the CEPCI value for 2019	541.7 2016 CEPCI
Annual Interest Rate (i)	7 Percent	
Fuel ($Cost_{fuel}$)	1.89 \$/MMBtu*	
Reagent ($Cost_{reag}$)	1.38 \$/gallon for a 19 percent solution of ammonia	
Water ($Cost_{water}$)	0.004 \$/gallon	
Electricity ($Cost_{elect}$)	0.0495 \$/kWh	
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.8 \$/ton*	

CEPCI = Chemical Engineering Plant Cost Index

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

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Four Factor Analysis - SNCR Cost Analysis

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	Revised Cost: $1.38/gallon Initial Cost: ~~$1.50/gallon of 29% Ammonia~~	Revised cost analysis: Quotation from Thatcher (Average cost based on density) Initial cost analysis: ~~U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf~~	Site specific information. Used the average cost of ammonia supplier costs
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf	Site specific
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a	Sunnyside cost and energy production rate from 2018 used
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	Site specific
Ash Disposal Cost ($/ton)	40.6	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	Site specific
Percent ash content for Coal (% weight)	5.84	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	Site specific
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	Site specific
Interest Rate (%)	7	See attached summary	Federal Bank Prime Loan Rate

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	700	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	867,081,448	lbs/Year
Actual Annual fuel consumption (Mactual) =		883,413,174	lbs/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.20	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.93	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	8167	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	15	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	15.75	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	64.31	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.27	
Atmospheric pressure at 6497 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	11.6	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole
Density = 57.783 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	19	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	102	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	13.2	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	4,500	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i = Interest Rate	0.0944

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	2.1	kW/hour
Water Usage: Water consumption (q_w) =	$(m_{sol}$/Density of water$) \times ((C_{stored}/C_{inj}) - 1)$ =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.07	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	4.4	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,586,744 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,522,491 in 2019 dollars
Total Capital Investment (TCI) =	$4,042,005 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$1,586,744 in 2019 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$1,522,491 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$212,706	in 2019 dollars
Indirect Annual Costs (IDAC) =	$383,384	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$596,090	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$60,630	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$149,224	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$830	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$1,151	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$870	in 2019 dollars
Direct Annual Cost =		$212,706	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,819	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$381,565	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$383,384	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$596,090	per year in 2019 dollars
NOx Removed =	64	tons/year
Cost Effectiveness =	$9,268	per ton of NOx removed in 2019 dollars

APPENDIX C.5 - US Magnesium

APPENDIX C.5.A

REGIONAL HAZE 2ND IMPLEMENTATION PERIOD FOUR-FACTOR ANALYSIS

US Magnesium LLC, Rowley Plant - Tooele County

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1. EXECUTIVE SUMMARY

US Magnesium, LLC (USM) owns and operates the Rowley Plant, a primary magnesium production facility located in Toole County, Utah. In a letter dated October 21, 2019[1] sent to USM by UDAQ it requested a four-factor Best Available Retrofit Technology (BART) analysis of USM's Rowley Plant as part of the second planning period for Regional Haze.

The letter determined that PM_{10} is not a significant contributor to visibility, and so no BART analysis was performed for PM_{10}. The letter also stated that USM is a significant source of SO_2 and NO_X. During a follow-up meeting in October of 2019, as well as phone calls in June of 2020, UDAQ determined, with the help of USM's actual annual inventory, that SO_2 emissions from the magnesium plant are not a contributing factor to visibility impairment and as a result no BART analysis was required or performed for SO_2.

The U.S. EPA has issued guidelines in 40 CFR 51.308 that are to be used to evaluate the reduction measures for the emission units at USM's facility. The State must consider the following four factors[2], and include a demonstration showing how these factors were taken into consideration when selecting the goal:

1. The costs of compliance
2. The time necessary for compliance
3. The energy and non-air quality environmental impacts of compliance
4. The remaining useful life of any potentially effected sources

This report documents the results of a four-factor BART analysis for NO_X emissions facility wide. It is intended to provide information to UDAQ and the Western Regional Air Partnership (WRAP) for the purposes of the second planning period of the Regional Haze SIP.

USM has multiple NO_X emitting units on site, all a result of fuel combustion, that UDAQ has identified as contributing to regional haze. The results of the four-factor BART analysis determined that one retrofit control option is feasible for installation at USM's facility, a flue gas recirculation (FGR) system on their Riley Boiler. The estimated NO_X reduction from the FGR system is 22.6 tons annually. The installation of the control device could potentially be performed prior to the end of the second planning phase for regional haze, 2028, although additional evaluation will be necessary.

A summary of the NO_X emission reduction measures and findings can be found below in Table 1-1.

[1] Refer to UDAQ letter DAQP-183-19

[2] 40 CFR 51.308

Table 1-1: Summary of Findings

Emission Source	Emission Reduction Measure	Technically Feasible?	Cost Effective?	Appropriate for Emissions Reductions?	Notes
Turbines & Duct Burners	Water or Steam Injection	No	NA	No	USM utilizes the exhaust from the Turbines, amplifying the temperature using the duct burners, in their spray dryers to create dry magnesium chloride the starting material for magnesium production at their plant. Any modifications to combustion or post combustion temperature directly impact product development and are therefore not feasible.
	Dry Low-NO_X	No	NA	No	
	Selective Catalytic Reduction (SCR)	No	NA	No	
Chlorine Reduction Burner	NA	NA	NA	NA	The CRB is a control device for chlorine emissions and is required to operate within a specific temperature range for efficient destruction of chlorine. No control techniques or devices exist to control NO_X emissions from this source.
Riley Boiler	Flue Gas Recirculation (FGR)	Yes	Yes	Yes	A potentially viable option for controlling an estimated 22.6 tons of NO_X annually. Installation of an FGR may be feasible by the end of 2028.
	Low NO_X Burners	No	NA	No	Limited space constraints for the current setup at USM make this option not feasible.
	Ultra-Low NO_X Burners	No	NA	No	Limited space constraints for the current setup at USM make this option not feasible.
	Selective Catalytic Reduction (SCR)	Yes	No	No	The costs associated with this control device made this option not cost effective.
	Selective Non-Catalytic Reduction (SNCR)	No	NA	No	The 1972 boiler currently installed at USM does not reach and maintain the temperatures required for an SNCR device.
Diesel Engines	Exhaust Gas Recirculation (EGR)	Yes	No	No	The cost to implement EGR on the 31 diesel engines does not justify the reduction in emissions associated with each engine.

Emission Source	Emission Reduction Measure	Technically Feasible?	Cost Effective?	Appropriate for Emissions Reductions?	Notes
	Selective Catalytic Reduction (SCR)	Yes	No	No	The cost to retrofit each engine with an SCR unit and the accompanying space required is not economically feasible.
	Lean NO_X Catalysts	No	NA	No	Lean NO_X catalysts are relatively new emission control devices, a thorough search of the available databases found no instances where they are in use.
HCl Plant	Water or Steam Injection	No	NA	No	The reduction in peak flame temperature associated with water or steam injection would impede the production of HCl, and alter the function of the HCl Plant, it is therefore not technically feasible.
	Dry Low-NO_X	No	NA	No	The reduction in peak flame temperature associated staged combustion or by modifying fuel-air ratios would impede the production of HCl, and alter the function of the HCl Plant, it is therefore not technically feasible.
	Selective Catalytic Reduction (SCR)	No	NA	No	A RBLC search found one facility that has implemented SCR on a HCl plant as LAER. The variable run times and associated operating temperatures make operating a SCR unit a challenge as the HCl Plant and its operation was not designed for one, a retrofit option was determined to not be technically feasible.
Casting House	NA	NA	NA	NA	No retrofit control strategies or devices were identified for the small burners utilized in the casting house at USM.
Lithium Plant	Low NO_X Burners	Yes	Yes	Yes	Currently equipped on the evaporative burners at USM. They were determined to be BACT in 2020 as part of their most recent permit modification.
	Ultra-Low NO_X Burners	Yes	Yes	Yes	Currently equipped on the new boilers at USM. They were determined to be BACT in 2020 as part of their most recent permit modification.

2. INTRODUCTION AND BACKGROUND

The Clean Air Act (CAA) has made it a national goal to restore national parks and wilderness areas back to natural conditions by reducing and correcting visibility impairments from man-made sources that result in pollution called regional haze. The EPA defines "regional haze" in 40 CFR 51.301 as "visibility impairment that is caused by the emission of air pollutants from numerous anthropogenic sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources." The pollutants responsible for the decrease in visibility are particulate and gaseous emissions from sources, they absorb light and as a result negatively impact visibility.

The 1977 amendments to the CAA established Class I areas under the Prevention of Significant Deterioration (PSD) program, and defined them as, "national wilderness areas, and national memorial parks that exceed 5,000 acres, and all national parks that exceed 6,000 acres." Five National Parks located in Utah are listed as Class I areas Arches, Bryce Canyon, Canyonlands, Capitol Reef, and Zion. In 1999 the EPA promulgated the Regional Haze Rule (RHR). The RHR established guidelines that would work to restore visibility to the 156 Class I areas nationwide.

The RHR requires States to establish reasonable progress goals towards achieving natural visibility conditions for the Class I areas located within the State. The State is required to meet the specific requirements listed in 40 CFR 51.308(d)(i):

(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.

(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction measures needed to achieve it for the period covered by the implementation plan.

With this being the second implementation period, the State and the EPA will attempt to distinguish between natural and anthropogenic sources. This will be done utilizing modelling to establish what background concentrations are, both episodic and routine in nature and compare those background levels against the man-made source contributions.

UDAQ has requested that US Magnesium conduct a four-factor analysis for second phase of the regional haze program for its Rowley Plant. US Magnesium understands that the information provided within this document will be used by UDAQ in their evaluation of reasonable progress goals. Similarly, US Magnesium assumes that emission reductions will only be required if the reductions demonstrate reasonable progress towards improved visibility in one or more of the Class I areas located within the state within the period covered by the implementation plan.

The purpose of this report is to provide UDAQ with information on available retrofit technologies for NOx emission reductions at US Magnesium's Rowley Plant.

The four-factors that are evaluated in this report for emission reductions are:

1. Cost of compliance
2. Time necessary for compliance
3. Energy and non-air quality environmental impacts of compliance
4. Remaining useful life of the Emission Units

This report summarizes a top down BART analysis for all applicable emission units, following the provisions published in 40 CFR Part 51, Section 308 in July of 2005. The top down BART analysis consists of the following steps:

Step 1 – Identify all potentially available retrofit control technologies
Step 2 – Eliminate technically infeasible options
Step 3 – Rank remaining control technologies by control effectiveness
Step 4 – Evaluate most effective controls and document conclusions

This four-step process will satisfy the requirements of the four-factor analysis, as factor 4 and similarly factor 2 will be addressed in the cost of emission reduction options.

3. SOURCE DESCRIPTION

US Magnesium's (USM) Rowley Plant is located within Tooele County, Utah. The five Class I areas are located the following distances from their facility:

Arches National Park – 225 miles
Bryce Canyon National Park – 230 miles
Canyonlands National Park – 235 miles
Capitol Reef National Park – 193 miles
Zion National Park – 250 miles

USM operates a primary magnesium production facility that began operation in 1972. They produce magnesium metal from the waters of the Great Salt Lake. Some of the water is evaporated in a system of solar evaporation ponds to increase the magnesium concentration and the resulting brine solution is then purified and dried to a powder in one of three natural gas fired spray dryers. The powder is then melted and further purified in the melt reactor before going through an electrolytic process to separate magnesium metal from chlorine. The metal is then refined or alloyed and cast into molds. The chlorine from the melt reactor is combusted with natural gas in the chlorine reduction burner (CRB) and converted into hydrochloric acid (HCl). The HCl is removed from the gas stream through a scrubber train. The chlorine that is generated at the electrolytic cells is collected and piped to the chlorine plant where it is liquefied for reuse or sale. USM also produces other minerals and chemicals for sale as a byproduct of magnesium production, lithium carbonate and food grade HCl acid.

USM operates a wide array of equipment that produces PM, NO_X, and SO_2. This equipment ranges from diesel-fueled engines to natural gas fired equipment such as boilers, burners, furnaces, turbines. The PM producing equipment includes the spray dryers and emergency off-gas stack. The equipment that can be found in the subsequent section is the relevant equipment that emits pollutants of concern for the purposes of this four-factor analysis.

USM also operates mobile equipment that facilitate various operations on site and movement of material. These emissions will not be included in this four-factor analysis as they constitute a very small portion of the overall NO_X emissions and USM maximizes efficiencies on product loads and vehicle miles traveled to reduce operating costs.

3.1. EQUIPMENT DESCRIPTION

The following subsections describe the equipment utilized by USM to generate their final products for sale.

3.1.1. Natural Gas Turbines | Duct Burners - (Spray Dryers)

Three 12,700 KW natural gas fired turbines are utilized for onsite electrical generation. The exhaust stream of each turbine is equipped with an additional 15.3 MMBtu/hr duct burner to increase the temperature of the exhaust gas from the turbines for use in the spray dryers. The spray dryers utilize the heated exhaust to dry the concentrated brine solution into a magnesium chloride powder utilizing one of three identical spray dryers.

3.1.2. Emergency Off-gas Stack

The emergency off-gas (EOG) scrubber stack is a pollutant source for PM_{10}. The EOG system is primarily operated to collect fugitive emissions within the melt/reactor building as part of USM's industrial hygiene/worker safety program.

3.1.3. Chlorine Reduction Burner

The chlorine reduction burner (CRB) is the control device that reduces (reacts) chlorine gas from the melt/reactor process with natural gas (CH4) to produce hydrogen chloride gas which is recovered as hydrochloric acid (liquid) for use in other areas of USM's production processes. The CRB has a minimum firing rating of 1 MMBtu/hr and a maximum fire rating of 42 MMBtu/hr. The CRB controls most of the chlorine emissions from the facility and utilizes only natural gas as a fuel source. An operating temperature of 1,650 to 2,000 degrees Fahrenheit is maintained to achieve the necessary reaction of chlorine gas within the combustion zone, the typical fire rating for the required temperature is 20 MMBtu/hr.

3.1.4. Riley Boiler

The Riley Boiler is a 60 MMBtu/hr boiler that was installed when the plant was first constructed in 1972. The boiler provides heat through the production of steam for operations throughout the site.

3.1.5. Diesel-fired Engines

USM utilizes two main sizes of diesel-fired engines to power the direct drive pumps. These pumps move water around the solar evaporation pond system to increase the magnesium chloride concentration in the brine until the brine is eventually pumped to the processing facility. USM utilizes the following engines onsite, all of which are compliant with NESHAP 40 CFR 63 Subpart ZZZZ:

- 14 - Caterpillar 3406 (420 hp)
- 13 – Caterpillar 3208 (225 hp)
- 1 – Cummings C-9 (285 hp)
- 1 – Caterpillar 3306 (225 hp)
- 1 – Caterpillar 3304 (90 hp)
- 1 – 292 hp fire pump engine

All engines are retrofit with an EST Oxidation Converter, a packed catalyst system, for the reduction of CO and PM emissions.

3.1.6. Hydrochloric Acid Plant

The plant produces food grade hydrochloric acid by reducing purified chlorine in a natural gas flame to produce hydrogen chloride gas. The gas passes through a series of absorbers to produce the food grade hydrochloric acid.

3.1.7. Cast House

USM operates eleven natural gas fired crucible furnaces, each crucible furnace contains six individual 1 MMBtu/hr burners, in the cast house. The cast house also utilizes bayonet burners in tool heating boxes, the heating boxes are necessary for site safety. The tools are heated to remove any water condensation from the tools and bring them up to a working temperature to eliminate the risk of explosion when working with magnesium metal. The cast house is also equipped with a natural gas fired anode oven for magnesium purification.

3.1.8. Lithium Carbonate Plant

The lithium carbonate plant separates lithium from electrolytic process sludge (also referred to as "smut") in a series of digester units, soda ash contact ("demag") units, filter presses, a dryer/classifier and packaging system. Emission units consist of several natural gas fired pieces of equipment. Two natural gas fired ultra-low NO_x boilers, a 63 MMBtu/hr and 84 MMBtu/hr unit and two low-NO_x natural gas fired evaporator burners, a 50 MMBtu/hr and 100 MMBtu/hr unit.

3.1.9. Other Sources

A small propane heater is utilized at the south pumping station. It does not operate full time and has a minimal impact on overall NO_x emissions. This emission source is included here and the emissions tables, but no analysis was performed.

3.1.10. Mobile Sources

Emissions from mobile sources on site come from diesel and propane consumption. The mobile sources include equipment like trucks, track hoes, bulldozers, cranes, skid loaders, and forklifts. The sources are responsible for product development, product handling, and various other site operations. These emission sources were included in the equipment and emission sections for completeness, but as they are not stationary sources no further analysis was performed.

4. BASELINE EMISSIONS

This section summarizes the baseline emission rates that are used as a starting point for the accompanying four-factor analysis presented in section 5. Specifically, they are used in the cost effectiveness analysis to determine the annual cost per ton of pollutant removed for a specific control device or strategy.

4.1. PM_{10} EMISSIONS

USM has provided the following emissions information for PM_{10}. The emissions represent actual emissions at their facility for the 2018 calendar year and are based on a combination of actual fuel use, stack testing, operational hours, or production rates. The Lithium Plant was permitted in 2020 and actual emissions are not yet available, for this reason potential to emit totals were included in the table below for this plant's emissions instead of actuals. The baseline annual emission rates that will be used for the purposes of this analysis are summarized below in Table 4-1.

Table 4-1: Annual PM_{10} Baseline Actual Emission Rates (tons/yr)

Equipment	PM10 Baseline Emissions (tons/yr)
Turbines | Duct Burners	921.06
Emergency Off-gas Stack	43.42
Chlorine Reduction Burner	3.29
Riley Boiler	1.81
Diesel Engines	1.28
HCl Plant	0.33
Cast House	1.12
Lithium Plant	11.64*
Other Sources	4.42
Mobile Sources	4.83
Total	993.21

*Lithium Plant emissions are listed as PTE emissions, as it was not in operation in 2018.

UDAQ has made the decision that the deciview impacts at the five National Parks within Utah are not significantly impacted by point source particulate matter emissions. USM acknowledges that they are a major source for PM_{10} but agrees with UDAQ's assessment, the low dispersion rate for particulate matter makes its negative impact on visibility at the national parks the least likely contributor. As a result, no further analysis or discussion was performed for PM_{10} emissions within this document.

4.2. SO_2 EMISSIONS

USM has provided the following emissions information for SO_2. The emissions represent actual emissions at their facility for the 2018 calendar year and are based on a combination of actual fuel use, stack testing, operational hours, or production rates. The Lithium Plant was permitted in 2020 and actual emissions are not yet available, for this reason potential to emit totals were included in the table below for this plant's emissions instead of actuals. The baseline annual emission rates that will be used for the purposes of this analysis are summarized below in Table 4-2.

Table 4-2: Annual SO_2 Baseline Actual Emission Rates (tons/yr)

Equipment	SO2 Baseline Emissions (tons/yr)
Turbines | Duct Burners	1.66
Chlorine Reduction Burner	0.07
Riley Boiler	0.14
Diesel Engines	0.03
HCl Plant	0.03
Cast House	7.29
Lithium Plant	0.75*
Other Sources	0.06
Mobile Sources	0.05
Total	10.08

*Lithium Plant emissions are listed as PTE emissions, as it was not in operation in 2018.

Due to the insignificant amount of sulfur dioxide emissions coming from USM, a decision was made in the fall of 2019 during a meeting with UDAQ to omit sulfur dioxide from the upcoming BART analysis. Any reductions in SO_2 would not result in any reasonable progress goals and would also likely be cost prohibitive given the minimal impacts of additional controls. No further discussion or analysis was performed for SO_2.

4.3. NO_X EMISSIONS

USM has provided the following emissions information for NO_X. The emissions represent actual emissions at their facility for the 2018 calendar year and are based on a combination of actual fuel use, stack testing, operational hours, or production rates. The Lithium Plant was permitted in 2020 and actual emissions are not yet available, for this reason potential to emit totals were included in the table below for this plant's emissions instead of actuals. The baseline annual emission rates that will be used for the purposes of this analysis are summarized below in Table 4-3.

Table 4-3: Annual NO_X Baseline Actual Emission Rates (tons/yr)

Equipment	NO_X Baseline Emissions (tons/yr)
Turbines | Duct Burners	813.58
Chlorine Reduction Burner	11.66
Riley Boiler	45.25
Diesel Engines	71.65
HCl Plant	4.32
Casting House	14.70
Lithium Plant	26.61*
Other Sources	0.02
Mobile Sources	73.01
Total	1,060.79

*Lithium Plant emissions are listed as PTE emissions, as it was not in operation in 2018.

The values listed above will be utilized in determining actual reductions to emissions because of any additional retrofit control technology. The same assumptions of operation that were employed to calculate annual emissions in 2018 will be employed to determine any reductions from add-on equipment because of the ensuing BART analysis.

5. NO_X FOUR-FACTOR ANALYSIS

The four-factor analysis was completed using a top-down approach, using the following four steps:

Step 1 – Identify all potentially available retrofit control technologies
Step 2 – Eliminate technically infeasible options
Step 3 – Rank remaining control technologies by control effectiveness
Step 4 – Evaluate most effective controls and document conclusions

All four factors of the analysis will be touched on in step four of the above approach. The most effective controls will be represented in a cost per ton removed evaluation, satisfying factor 1, (costs of compliance) and factor 4 (remaining useful life of equipment). Factor 2, (time necessary for compliance) will be included in the conclusions section. Factor 3 (energy and non-air quality environmental impacts of compliance) will be satisfied in steps 2 and 3 of the above approach.

The following four-factor analysis was performed for the NO_X emission units listed in Table 4.3 and utilizing the emission rates included within.

All the NO_X generated at USM is a result of the fuel combustion process. Two primary formation mechanisms are responsible, thermal NO_X, when atmospheric nitrogen and oxygen disassociate in the combustion zone and form NO_X, or fuel NO_X when nitrogen present in the fuel interacts with atmospheric oxygen in the combustion zone. USM utilizes natural gas as a fuel source except during times of curtailment, natural gas and diesel have little to no nitrogen content resulting in the majority of NO_X formation being thermal in origin.

Control strategies for NO_X formation fall into one of two categories, combustion controls or post-combustion controls. Combustion control technologies focus on reducing the peak flame temperature and excess air in the combustion zone resulting in reduced NO_X formation. Post-combustion controls focus on reducing NO_X after it has formed in the exhaust stream usually by utilizing a catalyst.

5.1. TURBINES AND DUCT BURNERS

5.1.1. Step 1: Identify All Potentially Available Retrofit NO_X Control Technologies

The turbines at USM are utilized for electrical generation as an integrated part of the production process. The exhaust from the turbines is routed to a duct burner to increase the temperature before being routed to a spray dryer. The heated exhaust is used to dry the magnesium chloride slurry into a magnesium chloride powder. For the spray dryer to work properly the inlet temperature of the exhaust steam needs to reach 1,000 °F. The exhaust temperature from the turbines is 900 °F, and the duct burners boost the temperature to 1,000 °F.

The duct burners take the exhaust from the turbines and continue to heat it to the desired temperature. NO_X control strategies for this type of equipment does not exist, inlet temperatures and exit temperatures prohibit the use of combustion controls, and post combustion controls are similarly prohibitive, as exhaust temperatures need to reach 1,000 °F. The duct burners emissions are incorporated with the turbines emissions and were included here for completeness. However, since no NO_X control strategies exist for the duct burners at USM, given their utilization, no further analysis was performed for them.

Common control technologies for reduction of NO_X emissions in natural gas turbines, identified by the EPA[3], are listed in Table 5-1 below.

Table 5-1: Available Retrofit NO_X Control Technologies for Combustion Turbines

Combustion Turbines NO_X Control Technologies	
Combustion Controls	Water or Steam Injection
	Dry Low-NO_X
Post-Combustion Controls	Selective Catalytic Reduction (SCR)

5.1.1.1. Combustion Controls

5.1.1.1.1. Water or Steam Injection

Water and or steam injection is commonly termed wet control for gas turbines. Steam or water injection controls the formation of NO_X emissions by decreasing the peak flame temperature. It is an effective tool for reducing the formation of thermal NO_X in all but regenerative cycle combustors.

Evaporation of the water reduces the cycle efficiency of a few percent but increases power output by double that reduction. This is caused by the steam formed or injected in the combustor raising the mass flow rate through the turbine therefore increasing power.

NO_X emission reductions of generally 60-70% can be achieved using water or steam injection at water-to-fuel ratios of 0.2:1 to 1:1. It is important to utilize water or steam free of contaminants, so a water treatment system is an integral component of a wet control system.

Several mechanical limits exist when it comes to water or steam injection systems. Some examples of this are combustion operating instabilities, increased CO, heat rate penalties, combustion flame blow-off or flame-out. These limitations can decrease the efficiency of the water or steam injection system and increase the maintenance required on the turbine.

5.1.1.1.2. Dry Low-NO_X

NO_X emission control techniques that are performed in without the injection of water or steam are referred to as dry controls, but the method for emissions reductions is the same, reducing the peak flame temperature. This is generally accomplished by lean combustion or staged combustion.

Lean combustion refers to a technique that reduces the air/fuel ratio beyond that of normal stoichiometric operation (equivalence ratio = 1) to an air/fuel equivalence ratio of 2, i.e. very lean. This reduces the combustion temperature by reducing the air required for combustion below

[3] U.S. Environmental Protection Agency. (1993). *Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines.* North Carolina: Office of Air Quality Planning and Standards.

stoichiometric levels. This method is only achievable under normal load range, during periods of startup or low load a transition program with higher air/fuel ratios is required. This results in increased NO_X emissions during periods of startup or low load situations.

Staged combustion is another technique to lower NO_X emissions, this strategy utilizes multiple combustion zones, usually two. The first zone operates lean or rich, but the second zone always operates lean. The incomplete combustion that results in the first combustions zone is further combusted in the lean second combustion zone resulting in reduced NO_X formation.

5.1.1.2. Post-Combustion Controls

5.1.1.2.1. Selective Catalytic Reduction (SCR)

In the SCR process, ammonia is injected in the gas turbines exhaust gas stream reacting with NO_X in the presence of a catalyst to form molecular nitrogen and water. SCR works best in base loaded combined cycle gas turbine applications where the turbine is fueled with natural gas. SCR is capable of NO_X removal efficiencies between 70% and 90%. The catalytic NO_X-ammonia reaction takes place over a limited temperature range, 600-750 °F, anything about ~850 °F and the catalyst is damaged irreversibly. Ammonia slip is also a concern when utilizing an SCR for NO_X emission reductions, as well as ammonia storage, and costs of disposal of spent catalysts.

5.1.2. Step 2: Eliminate Technically Infeasible Options

To evaluate if the above NO_X controls are technically feasible it is important to understand the role of the turbines at USM. The turbines are utilized for electrical generation and are integral to the production process. The exhaust coupled with a duct burner is used in a spray dryer to dry the magnesium chloride slurry into a magnesium chloride powder. For the spray dryer to work properly the exhaust temperature of turbines needs to reach 1,000 °F. This is achieved by utilizing an inline duct burner to boost the temperature from 900 °F to 1,000 °F. The magnesium chloride powder is then sent to the melt reactor for further processing.

Taking these operational constraints into consideration, step 2 of the top-down review can be completed.

5.1.2.1. Combustion Controls

Combustion controls focus on reducing the peak flame temperature in the combustion zone of the turbine, therefore reducing thermal NO_X formation. Given that the parameters required for drying the magnesium chloride brine both options are directly conflict with the need for 1,000 °F exhaust temperatures.

5.1.2.1.1. Water or Steam Injection

This control technology given its strategy for reducing peak flame temperature is adding water to the combustion zone directly conflicts with the magnesium chloride powder production. Moisture in the exhaust stream will most definitely affect the ability of the spray dryers to operate as designed. This method is considered technically infeasible given the operational requirements of the spray dryers and will not be considered further.

5.1.2.1.2. Dry Low-NOx

Reducing peak flame temperatures and lowering the temperature of the exhaust gas would require a larger duct burner be installed. A larger duct burner would create just as much NOx as the reduction, possibly more. For this reason both the lean combustion and staged combustion methods are considered technically infeasible, as the operational requirements for the spray dryers would be negatively impacted to a point where they would conflict with the production of magnesium product, as a result this will not be considered further.

5.1.2.2. Post Combustion Controls

5.1.2.2.1. Selective Catalytic Reduction (SCR)

An SCR system requires a specific operating temperature to be effective at NOx removal, that temperature hovers around 750 °F. The duct burners take the exhaust from the turbines at roughly 900 °F and heat it to 1,000 °F. An SCR system is not technically feasible at these operating temperatures and will not be considered further in this analysis.

5.1.3. Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 of the review process is to rank the technically feasible options by how effective they are at removing NOx emissions. As no control technologies are technically feasible for the specific operations at USM, no ranking is possible.

5.1.4. Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance
- Timing for compliance
- Energy and other impacts not related to air quality
- The remaining useful life of the source

As no remaining retrofit control technologies are technically feasible, analysis of the above list is not possible.

5.1.4.1. Summary and Conclusions

USM requires specific temperatures from their exhaust stream for their proper operation of the spray dryers, any changes to the turbine or duct burners would require significant alterations to the spray dryers. The turbines and duct burners, in 2018, emitted 813.58 tons of NOx emissions. Although this is a significant source of NOx emissions, no technically feasible retrofit technologies were found during the BART analysis. USM will continue to operate the turbines and duct burners as they are currently configured.

5.2. CHLORINE REDUCTION BURNER

5.2.1. Step 1: Identify All Potentially Available Retrofit NO_X Control Technologies

USM operates the only primary magnesium metal production facility in the United States. As such it is the only facility that operates a chlorine reduction burner (CRB) in the United States. The CRB is a control device for chlorine gas emissions. It is designed to take the chlorine gas that is generated in the melt reactor process and as tail-gas from the chlorine (purification) plant, and in the presence of heat and methane, produce CO2 and hydrochloric acid (HCl). The HCl is scrubbed and recovered as hydrochloric acid liquid prior to the exhaust stream being further scrubbed and then vented to the atmosphere.

Combustion techniques that lower the formation of thermal NO_X by lowering the peak flame temperature are not a viable option for control as they would impact the CRB's main function of reducing the chlorine emissions that are emitted to the atmosphere. The CRB requires an operating temperature of no less than 1,650 °F and no more than 2,000 °F for proper operation and has strict monitoring requirements listed in their Title V operating permit[4].

Post-combustion techniques involving a catalyst would foul the packed scrubbers that remove the HCl acid from the exhaust stream, which could violate the emission requirements found in 40 CFR 63 Subpart TTTTT[5].

Given the unique operating parameters involved in the CRB no control technologies exist for the reduction of NO_X emissions. Therefore, no additional analysis was performed for the CRB.

5.2.2. Step 2: Eliminate Technically Infeasible Options

No NO_X emission reduction retrofit controls are available for the CRB.

5.2.3. Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 of the review process is to rank the technically feasible options by how effective they are at removing NO_X emissions. As no control technologies are technically feasible for the specific operations at USM, no ranking is possible.

5.2.4. Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance
- Timing for compliance
- Energy and other impacts not related to air quality

[4] See UDAQ Title V Operating Permit #4500030003 dated December 12, 2018.
[5] 40 CFR 63 Appendix Table 1 to Subpart TTTTT of Part 63 – Emission Limits

- The remaining useful life of the source

As no remaining retrofit control technologies are technically feasible, analysis of the above list is not possible.

5.1.4.1. Summary and Conclusions

The CRB at USM is required to maintain an operating temperature of 1,650 to 2,000 °F, and as such combustion controls are not a viable option for controlling the formation of thermal NO_X. Post-combustion controls are similarly disadvantageous, and the exhaust stream from the CRB passes through an absorber to recover HCL as hydrochloric acid liquid and then several packed bed scrubbers to remove PM. The addition of any catalyst to remove NO_X emissions could interfere with the scrubber's operation and result in emissions that violate the emissions standards that are listed in the appliable MACT, Subpart TTTTT. The CRB at USM currently emits 11.66 tons of NO_X annually. USM will continue to operate the CRB as it is currently configured.

5.3. RILEY BOILER

5.3.1. Step 1: Identify All Potentially Available Retrofit NO_X Control Technologies

USM utilizes a 60 MMBtu/hr boiler, referred to as the Riley boiler that was first installed prior to the plant beginning operation in 1972. The boiler utilizes natural gas as a combustion source and provides heat throughout the plant via the production of steam. The boiler is located in the middle of their facility, nestled between scrubbers, spray dryers, and various other equipment.

Common NO_X control strategies for a natural gas boiler are listed below in Table 5-2. The RBLC of the EPA Clean Air Technology Center as well as EPA's, "Nitrogen Oxides (NO_X), Why and How They are Controlled"[6] were utilized in determining control technologies for evaluation.

Table 5-2: Available Retrofit NO_X Control Technologies for Combustion Turbines

Boiler NO_X Control Technologies	
Combustion Controls	Flue Gas Recirculation (FGR)
	Low NO_X Burners
	Ultra-Low NO_X Burners
Post-Combustion Controls	Selective Catalytic Reduction (SCR)
	Selective Non-Catalytic Reduction (SNCR)

5.3.1.1. Combustion Controls

5.3.1.1.1. Flue Gas Recirculation (FGR)

Flue gas recirculation consists of recirculating a portion of the flue gas to the combustion zone to lower the peak flame temperature and lowers the percentage of oxygen in the combustion zone, thereby reducing thermal NO_X formation. FGR is one of the main NO_X reduction strategies for

[6] U.S. EPA. (1999). *Nitrogen Oxides (NOx), Why and How They Are Controlled.* North Carolina: U.S. Environmental Protection Agency.

low NO_X and ultra-low NO_X burners. Standalone FGR systems can achieve up to 50% NO_X reductions.[7]

5.3.1.1.2. Low NO_X burners

Low NO_X burners reduce the formation of thermal NO_X by utilizing multiple technologies coupled with staged combustion. Many variations of a low NO_X burner exist, almost all of them utilizing staged combustion for controlling fuel to air ratios to limit the peak flame temperature. Controlling fuel and air mixing at the burner creates larger and more branching flames, making low NO_X burners have a larger footprint than a standard boiler like the one installed at USM. Low NO_X burners can reduce NO_X emissions by up to 80% from a standard combustion unit and are considered common place and often the starting point of new boiler installations.

5.3.1.1.3. Ultra-Low NO_X burners

Ultra-Low NO_X burners improve upon the design of a low NO_X burner usually by lowering combustion temperatures even more by modifying the burners further. The lower temperatures require larger volumes of fuel as the combustion process is not complete, this also increases CO emissions while reducing NO_X emissions. Depending on the provider of the ultra-low unit, technology varies but they are generally capable of meeting NO_X emission limits of 9 ppm.

<u>5.3.1.2. Post-Combustion Controls</u>

5.3.1.2.1. Selective Catalytic Reduction (SCR)

In the SCR process, ammonia is injected into the exhaust stream reacting with NO_X in the presence of a catalyst to form molecular nitrogen and water. SCR works best in stable conditions, units that fluctuate in operation and therefore temperature do not achieve optimal NO_X reduction rates. SCR is capable of NO_X removal efficiencies between 80% and 90%[8]. The catalytic NO_X-ammonia reaction takes place over a limited temperature range, 600-750 °F, anything about ~850 °F and the catalyst is damaged irreversibly. Ammonia slip is also a concern when utilizing an SCR for NO_X emission reductions, as well as ammonia storage, and costs of disposal of spent catalysts.

5.3.1.2.2. Selective Non-Catalytic Reduction (SNCR)

SNCR is a similar process to SCR in that it utilizes ammonia as a reductant to reduce NO_X compounds to molecular N_2 and water, however the technology does not utilize a catalyst. The ammonia in injected directly into the primary combustion zone where temperatures reach 1,400-2,000 °F. NO_X reduction in SNCR is only effective at high temperatures (1,600-2,100 °F), so additional heating of the emissions stream may be required to meet optimal operating temperatures. SNCR NO_X removal efficiencies vary between 30% and 50%.

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[7] CDP. (2020, July 27). *ICIBSE Journal.* Retrieved from Module 106: Natural gas boiler flue gas recirculation to reduce NOx emissions: https://www.cibsejournal.com/cpd/modules/2016-12-nox/

[8] Ron D. Bell. (2020, July 22). *An Overview of Technologies for Reduction of Oxides of Nitrogen From Combustion Furnaces.* Retrieved from MPR: https://www.mpr.com/uploads/news/nox-reduction-coal-fired.pdf

5.3.2. Step 2: Eliminate Technically Infeasible Options

5.3.2.1. Combustion Controls

5.3.2.1.1. Flue Gas Recirculation (FGR)

FGR increases the maintenance required and can result in fouled air intake systems, combustion chamber deposits, and increased wear rates, but it is technically feasible as a retrofit option.

5.3.2.1.2. Low NOx Burners

To convert the standard burners currently installed in the Riley boiler, to low NOx burners would require substantial modifications and would not really fit the definition of a retrofit. The additional space requirement due to the staged combustion a low NOx unit requires would be challenging to fit into the existing space. This would require modifications to other systems to accommodate the additional size, and as a result has been ruled out as a technically feasible option. The low NOx burners have been ruled out as a retrofit option and was not evaluated further.

5.3.2.1.3. Ultra-Low NOx Burners

An ultra-low NOx burner was similarly ruled out as technically feasible as a retrofit option as it would require a near complete replacement of the existing boiler. Additionally, the space requirements would require the same modifications as installing low NOx burners. The ultra-low NOx burners have been ruled out as a retrofit option and was not evaluated further.

5.3.2.2. Post-Combustion Controls

5.3.2.2.1. Selective Catalytic Reduction (SCR)

An SCR system is an effective way at reducing NOx formation in a stationary combustion unit like the boiler utilized at USM. They do present additional safety concerns with the use of ammonia and ammonia storage. An SCR system is considered a technically feasible retrofit option for the boiler.

5.3.2.2.2. Selective Non-Catalytic Reduction (SNCR)

The boiler at USM was built in the 1970's and has had general maintenance and replacement of some of the burner units and housing as it has aged but is largely unchanged. The required operating temperatures for an SNCR system to work properly (1,600 – 2,000 °F) are not within the boilers operating range. As a result, a SNCR system has been ruled out as a retrofit option for the Riley boiler, and was not evaluated further.

5.3.3. Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 is the ranking of the remaining commonly available retrofit control technologies by control effectiveness. Table 5-3 below ranks those remaining retrofit control technologies by their respective control effectiveness at reducing NOx emissions.

Table 5-3: Remaining Retrofit NO_X Control Technologies by Control Effectiveness

NO_X Control Technologies	NO_X Control Reductions
Selective Catalytic Reduction (SCR)	Up to 90%
Flue Gas Recirculation (FGR)	Up to 50%

5.3.4. Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance
- Timing for compliance
- Energy and other impacts not related to air quality
- The remaining useful life of the source

5.3.4.1. Cost of Compliance

The Riley boiler operating at USM was installed in 1972 and has no addon equipment. The cost analysis below is based on the baseline emissions calculated using AP-42 and a full-time operating schedule, generating 45.25 tons of NOx annually.

5.3.4.1.1. Selective Catalytic Reduction (SCR)

Evaluating the costs for an SCR unit on an existing boiler of this small size is challenging. The EPA's Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction (SCR) was used to estimate the costs of retrofitting the boiler[9]; the cost values are based on the 2018 annual average Chemical Engineering Plant Cost Index (CEPCI) value of 603.1. The summary of the results are listed below in Table 5-4, with the detailed cost results found in Appendix A.

[9] The detailed inputs and outputs of the EPA cost estimation tool can be found in Appendix A.

Table 5-4: Summary SCR Retrofit Costs for Riley Boiler

CAPITAL COSTS				
Direct Costs			**Indirect Annual Costs**	
SCR System	$86,684		Administrative Charges	$2,716
			Capital Recovery Costs	$279,930
Total	$86,684		**Total**	$282,646
ANNUAL COSTS			**Totals**	
Direct Costs			Interest rate	7.00%
Maintenance	$16,311		CRF	0.0858
Annual Reagent Cost	$48,399		Life of Control (yrs)	25
Annual Electricity Cost	$17,910		Total Capital Investments	$3,262,190
Annual Catalyst Replacement Cost	$4,064		Total Annual Costs	$369,330
Total	$70,373		Total Annual Cost	**$369,330.00***

*Reported in 2018 dollars

EPA's cost estimating tool, based on the default parameters of an SCR unit, determined that a unit would reduce NO_X emissions by an estimated 38 tons annually. The cost effectiveness based on 2018 dollars is listed in Table 5-5 below.

Table 5-5: SCR Retrofit Cost Effectiveness for Riley Boiler

	Total Annual Cost ($/yr)	Control Efficiency	NO_X Emissions Reduction	Cost Effectiveness ($/ton removed)
SCR Costs	$369,330	90%	38	$9,726*

*Reported in 2018 dollars

The costs associated with installing an SCR system on a boiler of this age would be not be considered economically feasible. As a result, the use of an SCR system for NO_X control has been ruled out as a viable retrofit option for NO_X control.

5.3.4.1.2. Flue Gas Recirculation (FGR)

The cost analysis for a FGR system on an existing boiler needs to be done by specific vendors and engineered for the specific boiler, especially for older units like the one at USM's facility. However, general cost guidelines can be used to estimate the costs for an appropriate FGR system. A general cost for an FGR system is somewhere in the range of $8-35/kW, in specific cases some can be as low as $3/kW.[10] This would put the cost range of an addon FGR for the 60 MMBtu/hr Riley boiler somewhere between $52,740 and $615,300.

[10] Frederick, N., Agrawal, R. K., & Wood, S. C. (2020, August 3). *NOx control on a Budget: Induced Flue Gas Recirculation.* Retrieved from Power Engineering: https://www.power-eng.com/2003/07/01/nosubx-sub-control-on-a-budget-induced-flue-gas-recirculation/#gref

It is important to note that these cost estimates were from EPA studies done in the 1990's, and as such the cost per ton removed analysis was performed using the high end of the range, $615,300. The cost analysis results can be found below in Table 5-6.

Table 5-6: FGR Retrofit Costs for the Riley Boiler

CAPITAL COSTS				
Direct Costs				
FGR System (all inclusive)				$615,300
			Total	$615,300
ANNUAL COSTS			Totals	
Direct Costs			Interest rate	7.00%
Maintenance (hrs @ $)	52 @ $60		CRF	0.0944
Cost of Maintenance hours	$3,120		Life of Control (yrs)	20
			Total Capital Costs	$615,300
			Annualized Capital	$58,080
			Annual Maintenance Cost	$3,120
Total	$3,120.00		Total Annual Cost	**$61,200**

Assuming a 50% NO_X emissions control efficiency from a FGR system, a reduction of 22.6 tons of NO_X annually would result from the installation. The cost effectiveness based on dollars per ton of NO_X removed is listed below in table 5-7.

Table 5-7: FGR Retrofit Cost Effectiveness for Riley Boiler

	Total Annual Cost ($/yr)	Control Efficiency	NO_X Emissions Reduction	Cost Effectiveness ($/ton removed)
FGR System	$61,200	50%	22.6	$2,708

Based on the factored cost estimate evaluated, an FGR system may be reasonable given the amount of NO_X control achieved, and the estimated cost per ton removed of $2,708.

5.4.4.2. Timing for Compliance

Although additional evaluation will be necessary, installation of an FGR system on the Riley boiler may be feasible before the end of 2028, the end of the second long-term strategy for regional haze.

5.4.4.3. Energy and Other Impact Not Related to Air Quality

The biggest concern related to the installation of a FGR system would be the increase in CO that is associated with the decrease in burner efficiency because of incomplete combustion. No other negative impacts are related to energy or other environmental issues.

5.4.4.4. Remaining Useful Life of the Source

The boiler has been well maintained and parts have been replaced over the years. It is reasonable to assume that the boiler will continue to operate for the foreseeable future. Given that the boiler was built and installed in 1972, it is approximately 48 years old, the remaining useful life is speculative, but given proper maintenance and replacement of worn out parts of the boiler its anticipated the boiler will last another 10 to 20 years.

5.4.4.5. Summary and Conclusions

USM has determined that a potentially viable retrofit control technology for NOx control of the Riley boiler is the installation of an FGR system. The system would reduce NOx emissions by approximately 22.6 tons, with an estimated cost per ton removed of $2,708. Although additional evaluation will be necessary, USM incorporating this control strategy into the Riley boilers current layout may be feasible before the end of 2028.

5.4. DIESEL ENGINES

5.4.1. Step 1: Identify All Potentially Available Retrofit NO_X Control Technologies

The diesel engines used onsite at USM are mostly comprised of modified Caterpillar engines that run direct drive water pumps for movement of fluids from one evaporation cell to another through various channels and trenches. The diesel engines are the second largest point source category for NOx emissions, this is due to the number of engines, 31, that are utilized onsite. Of the 31 engines, one is a 292 hp fire pump engine that charges their fire suppression system under emergency conditions (e.g., a plant fire during a power outage). Control technologies for that engine have not been analyzed as part of this analysis, as it is an emergency fire water pump engine that has very minimal run times.

The remaining 30 engines are all equipped with aftermarket catalytic oxidizers to comply with the emission standards listed in 40 CFR 63 Subpart ZZZZ. The engines make and models are listed below:

- 14 - Caterpillar 3406 (420 hp)
- 13 – Caterpillar 3208 (225 hp)
- 1 – Cummings C-9 (285 hp)
- 1 – Caterpillar 3306 (225 hp)
- 1 – Caterpillar 3304 (90 hp)

Although the engines utilized at USM facility consist of different sized motors, the control technologies for NOx are similar. The following control technologies applicability to the engines was evaluated regardless of engine size, as the only difference will be evaluated in Step 4 when looking at the implementation costs.

Common control technologies for reduction of NO_X emissions in diesel engines have been identified by EPA's Control Techniques Guidelines[11,12] and manufacturers[13,14], and are listed below in Table 5-8.

Table 5-8: Available Retrofit NO_X Control Technologies for Diesel Engine

NO_X Control Technologies	
Combustion Controls	Exhaust Gas Recirculation (EGR)
Post-Combustion Controls	Selective Catalytic Reduction (SCR)
	Lean NO_X Catalysts

5.4.1.1. Combustion Controls

5.4.1.1.1. Exhaust Gas Recirculation (EGR)

Utilizing EGR is an effective method for reducing NO_X emissions from a diesel engine. Low-pressure and high-pressure EGR systems exist but for retrofitting purposes a low-pressure system is almost always utilized as it does not require extensive engine modifications.

EGR recirculates a portion of the engine's exhaust back to the intake manifold, in most cases an intercooler lowers the temperature of the recirculated gases. The cooled recirculated gases, which have a higher heat capacity than air and contain less oxygen than air, lower the combustion temperature of the engine, resulting in less thermal NO_X forming. Diesel particulate filters are required when utilizing a low-pressure EGR system to ensure that large amounts of particulates are not recirculated to the engine. An EGR system can reduce NO_X emissions, by lowering the combustion temperature of the engine, by up to 40%.

5.4.1.2. Post-Combustion Controls

5.4.1.2.1. Selective Catalytic Reduction (SCR)

SCR is an established method for controlling NO_X emissions from stationary sources. A SCR system uses a catalyst and a chemical reductant to convert NO_X emissions to molecular nitrogen and oxygen in oxygen-rich exhaust streams common to diesel engines.

The chemical reductant of choice is generally ammonia and it is injected based on the amount of NO_X present in the exhaust stream that is calculated via algorithm. As the exhaust air and the ammonia pass over the SCR catalyst, a chemical reaction occurs that reduces NO_X emissions to nitrogen and oxygen. SCR systems on stationary sources can control 95% of NO_X emissions.

[11] United States Environmental Protection Agency. (1993, July). Alternative Control Techniques Document - NOx Emissions from Stationary Reciprocating Internal Combustion Engines.

[12] *Verified Technologies List for Clean Diesel*. (2017, January 19). Retrieved from United States Environmental Protection Agency: https://www.epa.gov/verified-diesel-tech/verified-technologies-list-clean-diesel

[13] CleanAIR Systems. (2009, December). Emissions Guidebook. Retrieved from: http://www.intermountainelectronics.com/uploads/media/Media_633964831354073381.pdf

[14] *What is Retrofit*. (2020). Retrieved from Manufacturers of Emission Controls Association: http://www.meca.org/diesel-retrofit/what-is-retrofit

5.4.1.2.2. Lean NOx Catalysts

Diesel engines are designed to run lean, which makes controlling NOx emissions challenging. Reducing NOx to molecular nitrogen in the oxygen-rich diesel exhaust environment requires a reductant (typically a hydrocarbon or carbon monoxide) and under normal operating conditions reductants are generally not present.

Lean NOx catalyst systems typically inject a small amount of diesel fuel or other reductant into the exhaust upstream of the catalyst. The reductant serves as the reducing agent for the catalytic conversion of NOx to N_2. Some systems operate passively without added reductant reduced NOx conversion rates. A lean NOx catalyst consists of a porous material with a highly ordered channel structure, along with either a precious metal or base metal catalyst. The added fuel and the catalyst are capable of peak NOx control efficiencies ranging from 10 to 30 percent, which the higher control percent correlating to increased fuel injection rates.

5.4.2. Step 2: Eliminate Technically Infeasible Options

<u>5.4.2.1. Combustion Controls</u>

5.4.2.1.1. Exhaust Gas Recirculation (EGR)

Although EGR increases engine maintenance and can result in fouled air intake systems, combustion chamber deposits, and increased engine wear rates, it is technically feasible as a retrofit option.

<u>5.4.2.2. Post-Combustion Controls</u>

5.4.2.2.1. Selective Catalytic Reduction (SCR)

SCR systems are an effective way at reducing NOx formation, they do present additional safety concerns with the use of ammonia or urea, and ammonia or urea storage. Additionally, the physical footprint of the SCR which can range from 50% to 60% the size of the engine is a real concern. It would likely mean extensive modifications to some of the existing pump stations to accommodate their size. However, given these concerns they remain a technically feasible retrofit option.

5.4.2.2.2. Lean NOx Catalysts

Lean NOx Catalysts are a relatively new addition to controlling NOx emissions. Although in theory they do appear to be technically feasible an extensive search through the RBL Clearinghouse and California's CARB database we were unable to find any stationary engines that utilized this control equipment. Therefore, this will not be considered a technically feasible control option for the diesel engines and will not be evaluated further.

5.4.3. Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 is the ranking of the remaining commonly available retrofit control technologies by control effectiveness. Table 5-9 below ranks those remaining retrofit control technologies by their respective control effectiveness at reducing NOx emissions.

Table 5-9: Remaining Retrofit NO_X Control Technologies by Control Effectiveness

NO_X Control Technologies	NO_X Control Reductions
Selective Catalytic Reduction (SCR)	Up to 95%
Exhaust Gas Recirculation (EGR)	Up to 40%

5.4.4. Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance
- Timing for compliance
- Energy and other impacts not related to air quality
- The remaining useful life of the source

5.4.4.1. Cost of Compliance

Currently USM has installed catalytic oxidizers on all the diesel engines to meet the requirements in 40 CFR 63 Subpart ZZZZ, these controls are cost-effective. All additional costs calculation and cost evaluations are considered in addition to the currently controlled emission levels.

5.4.4.1.1. Selective Catalytic Reduction Cost Effectiveness

To simplify the costs associated with the SCR systems, the engines are treated as identical units, although this is a slight oversimplification the engines do fall within a similar size rating. Also the efficiency of an SCR system drops off the smaller the engine rating due to mixing in the exhaust stream, so although the SCR system may be slightly over priced for the smaller engines the increased urea consumption will make up for the bias.

The pumping stations where the engines are housed consist of platforms built over water canals at over one dozen different remote locations within the overall approximately 75,000 acre the solar pond system. Ammonia presented too many safety concerns to be considered a viable option, the following cost analysis will look only at the use of urea as the chemical reagent.

An SCR system equipped with a 4,000-gallon urea storage tank fitted with a heating system to prevent urea freezing was analyzed. The costs provided in Table 5-10 below are estimates by Caterpillar based on systems they have in place for other engines of a similar size.

Table 5-10: SCR Retrofit Costs for Diesel Engines

CAPITAL COSTS			
Direct Costs		**Installation Costs**	
SCR System	$20,000	Surface Equipment	$5,000
Urea Tank	$3,500	Startup	$250
Urea Tank Heating System	$4,500	Contractor Fee	$1,500
Taxes	$2,030	Contingency	$800
		Testing	$250
Total	$30,030	**Total**	$7,800
ANNUAL COSTS		**Totals**	
Direct Costs		Interest rate	7.00%
Maintenance (hrs @ $)	52 @ $20	CRF	0.0944
Cost of Maintenance hours	$1,040	Life of Control (yrs)	20
Maintenance Parts	$2,500	Total Capital Costs	$37,830
Urea Cost ($1.00/gal @ 5 gal/hr @ 4,000 hr/yr)	$20,000	Annualized Capital	$3,571
Catalyst Module (20,000 hr life, $20,000 cost to replace)	$5,000	Annual Maintenance Cost	$28,540
Total	$28,540.00	Total Annual Cost	**$32,111**

Continuing with the simplified model if each of the 30 engines play an equal role in 71.65 tons of NOx emitted annually from the diesel engines on site, then each engine would emit 2.39 tons. A summary of the cost breakdown per engine and as an entire facility can be found in Table 5-11.

Table 5-11: Summary of SCR Cost Analysis

	Total Annual Cost ($/yr)	Control Efficiency	NO_X Emissions Reduction	Cost Effectiveness ($/ton removed)
Per Engine Basis	$32,111	95%	2.27	$14,146
All Engines	$963,326	95%	68.10	

The costs associated with the SCR exceed that which would be considered economically feasible. As a result, the use of SCR systems for NOx control has been ruled out as a viable retrofit option for NOx control.

5.4.4.1.2. Exhaust Gas Recirculation Cost Effectiveness

The estimated cost for a low-pressure exhaust gas recirculation system including a diesel particulate filter is somewhere in the range of $18,000 to $20,000[15]. A detailed cost breakdown

[15] *Diesel Retrofit*. (2020, July 22). Retrieved from Manufacturers of Emission Controls Association: http://www.meca.org/galleries/files/DieselRetrofitFAQ_0106.pdf

was not performed for an EGR system, the simple cost of the unit alone coupled with the increased ware on the engines regardless of maintenance makes these units not economical. A Summary of the EGR Cost Analysis can be found in Table 5-12.

Table 5-12: Summary of EGR Cost Analysis

	Total Annual Cost ($/yr)	Control Efficiency	NO_X Emissions Reduction	Cost Effectiveness ($/ton removed)
Per Engine Basis	$20,000.00	40%	0.96	$20,833.33
All Engines	$600,00.00	40%	28.80	

The emissions reductions from this unit cannot make up the costs to purchase the units, not even considering the costs to install or maintain the engines once installed. The EGR units have been ruled out as a viable option for NO_X control.

5.4.4.2. Timing for Compliance

USM believes that reasonable progress compliant controls are already in place, and any additional controls are unnecessary. However, if UDAQ determines that one of the control methods analyzed in this report is required to achieve reasonable progress, it is anticipated that this change would be implemented during the period of the second long-term strategy for regional haze (approximately ten years following the reasonable progress determination for this second planning period).

5.4.4.3. Energy and Other Impact Not Related to Air Quality

The biggest concern related to NO_X control that lies outside of air quality impacts would be that of ammonia storage. Ammonia is a caustic substance that is harmful to organic life, storing large quantities of it has the potential safety issues for personnel and for spills that can cause adverse environmental and health impacts.

The associated ammonia slip can also increase condensable $PM_{2.5}$ which contributes directly to visibility impairments.

5.4.4.4. Remaining Useful Life of the Source

The engines remaining life varies, but with proper maintenance and overhaul the engines are expected to last at least an additional 20 years, a similar lifetime to that of the control equipment being considered in this analysis.

5.4.4.5. Summary and Conclusions

USM has determined that the available retrofit control technologies are too costly for consideration of use at their facility. The diesel engines will continue to emit roughly 71.65 tons of NO_X annually. USM will continue to operate the diesel engines as they are currently configured.

5.5. HYDROCHLORIC ACID PLANT

5.5.1. Step 1: Identify All Potentially Available Retrofit NO_X Control Technologies

USM produces a pure food grade hydrochloric acid (HCl) at their acid plant. The concentration of HCl is roughly ~36% and is generated in a similar fashion to how the chlorine reduction burner works, by combusting natural gas in the presence of purified chlorine gas. The chemical reaction below demonstrates HCl formation using the combustion process.

$$CH_4 + O_2 + 2Cl_2 \rightarrow CO_2 + 4HCl$$

The average annual usage for the HCl plant is assumed to be 4,380 hours annually, exactly half of the calendar year. The HCl plant operates only when USM has suppliers in need of food grade HCl. To date in 2020, the HCl plant has not been utilized onsite, but is anticipated to resume production in the fall of 2020.

NO_X emissions associated with the HCl plant is generated through natural gas combustion in the burner. The unit is rated for less than 10 MMBtu/hr and generated 4.32 tons in 2018.

Potentially available retrofit controls for the combustion unit are the same controls typically available to other natural gas combustion units. Common retrofit controls are listed in Table 5-13 below.

Table 5-13: Available Retrofit NO_X Control Technologies for HCl Plant

NO_X Control Technologies	
Combustion Controls	Water or Steam Injection
	Dry Low-NO_X
Post-Combustion Controls	Selective Catalytic Reduction (SCR)

5.5.1.1. Combustion Controls

5.5.1.1.1. Water or Steam Injection

Steam or water injection controls the formation of NO_X emissions by decreasing the peak flame temperature. It is an effective tool for reducing the formation of thermal NO_X in all but regenerative cycle combustors.

NO_X emission reductions of generally 60-70% can be achieved using water or steam injection at water-to-fuel ratios of 0.2:1 to 1:1. It is important to utilize water or steam free of contaminants, so a water treatment system is an integral component of a wet control system.

Several mechanical limits exist when it comes to water or steam injection systems, things like combustion operating instabilities, increased CO, heat rate penalties, combustion flame blow-off or flame-out. These limitations can decrease the efficiency of the water or steam injection system and increase the maintenance required.

5.5.1.1.2. Dry Low-NOx

NOx emission control techniques that are performed in without the injection of water or steam are referred to as dry controls, but the method for emissions reductions is the same, reducing the peak flame temperature. This is generally accomplished by lean combustion or staged combustion.

Lean combustion refers to a technique that reduces the air/fuel ratio beyond that of normal stoichiometric operation (equivalence ratio = 1) to an air/fuel equivalence ratio of 2, i.e. very lean. This reduces the combustion temperature by reducing the air required for combustion below stoichiometric levels. This method is only achievable under normal load range, during periods of startup or low load a transition program with higher air/fuel ratios is required. This results in increased NOx emissions during periods of startup or low load situations.

Staged combustion is another technique to lower NOx emissions, this strategy utilizes multiple combustion zones, usually two. The first zone operates lean or rich, but the second zone always operates lean. The incomplete combustion that results in the first combustions zone is further combusted in the lean second combustion zone resulting in reduced NOx formation.

5.5.1.2. Post-Combustion Controls

5.1.1.2.1. Selective Catalytic Reduction (SCR)

In the SCR process, ammonia or urea is injected in the exhaust gas stream reacting with NOx in the presence of a catalyst to form molecular nitrogen and water. A SCR system can achieve a 95% reduction of NOx emissions.

The catalytic NOx-ammonia reaction takes place over a limited temperature range, 600-750 °F, anything about ~850 °F and the catalyst is damaged irreversibly. Ammonia slip is also a concern when utilizing an SCR for NOx emission reductions, as well as ammonia or urea storage, and costs of disposal of spent catalysts can also be a concern.

5.5.2. Step 2: Eliminate Technically Infeasible Options

The combustion unit at the HCl plant is the primary generator of the HCl product, as a result the plants operation must be taken into consideration when talking about NOx controls for the combustion unit.

5.5.2.1. Combustion Controls

Both water or steam injection and dry low-NOx combustion controls are technically infeasible for the HCl plant. Both controls reduce the formation of thermal NOx by reducing peak flame temperatures, this reduction in peak flame temperature would alter the performance of the HCl plant and as a result neither option will not be evaluated further.

5.5.2.2. Post-Combustion Controls

5.5.2.2.1. Selective Catalytic Reduction (SCR)

Although an SCR system is a feasible option retrofitting the HCl plant sizing, installation space, and operating the unit would be so challenging it is not technically feasible. The RBLC lists a facility in Louisiana that has installed an SCR unit onto a HCl plant[16], but provided no cost verification, and listed the emission type as LAER, which exceeds the requirements of this BART analysis many times over.

Sizing the SCR unit is challenging because the burner rate is not static, and the run times can be quite short. USM only operates the HCl plant when they have a supplier in need of the product. Depending on the economy and availability this can be quite infrequent. The minimal operating schedule would also make operating the unit a challenge. Historically there have been operation times that vary from half a day to several weeks. Downtime of the plant can be up to 8 months or more, requiring additional maintenance to get the unit operational upon startup.

The installation space required for an SCR unit is not extremely large, however, the exhaust stack on the HCl plant sits inside the racking and piping for the plant itself, and although it is probably feasible it would be a challenging retrofit.

For the reasons listed above this control technology is not considered technically feasible as a retrofit option for the hydrochloric acid plant and was not evaluated further.

5.5.3. Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 of the review process is to rank the technically feasible options by how effective they are at removing NOx emissions. As no control technologies are technically feasible for this specific operations at USM, no ranking is possible.

5.5.4. Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance
- Timing for compliance
- Energy and other impacts not related to air quality
- The remaining useful life of the source

As no remaining retrofit control technologies are technically feasible analysis of the above list is not possible.

5.1.4.1. Summary and Conclusions

The HCl plant at USM operates infrequently and has a minimal impact on the overall NOx emissions associated with the plant. In 2018, the HCl plant was responsible for 4.32 tons of NOx. No retrofit control options were technically feasible for the operations at USM. USM will continue to operate the HCl plant as it currently configured on an as needed basis.

[16] See Appendix B for RBLC search Results

5.6. CASTING HOUSE

5.6.1. Step 1: Identify All Potentially Available Retrofit NO_X Control Technologies

The cast house at USM operates eleven natural gas fired crucible furnaces. Each crucible furnace is equipped with six 1 MMBtu/hr burners, three in an upper horizontal angled array and three in a lower horizontal angled array, for a total heating rating of 6 MMBtu/hr per crucible furnace, for a total of 66 burners. After an extensive search of the RBLC database only two entries were found for crucible furnaces, both employing smaller burners in numerous quantities like operations at USM. Both the entries in the RBLC utilized AP-42 emission factors and operated with no emission controls[17]. Given the smaller size of these natural gas burners, and their array and installation it is unlikely that any control technologies exist, it is even less likely that a retrofit control technology would exist. No additional analysis was performed for the burners associated with the crucible furnaces USM operates.

The cast house also utilizes tool heating boxes, they are top and open-faced boxes with four small bayonet style burners, these burners typically range from 0.1 to 0.25 MMBtu/hr. The tool heating boxes sole purpose is safety. The tools used in USM casting house are heated up to remove any potential for water vapor or condensation forming on the metal when it contacts the heated magnesium metal. Water and magnesium can result in the formation of hydrogen gas, which is very explosive. These tool heating boxes are an integral part of the process and perform mandatory safety tasks. Given their low burner rating no retrofit controls exist that would still allow the heating boxes to function as needed. No additional analysis was performed for the tool heating boxes at USM.

5.6.2. Step 2: Eliminate Technically Infeasible Options

No retrofit controls were identified for the 1 MMBtu/hr burners utilized in the casting house at USM. Similarly, no retrofit controls were identified for the tool heating boxes that utilize 0.1 to 0.25 MMBtu/hr burners.

5.6.3. Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 of the review process is to rank the technically feasible options by how effective they are at removing NO_X emissions. As no control technologies are technically feasible for the specific operations at USM, no ranking is possible.

5.6.4. Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance

[17] See Appendix B for RBLC search Results

- Timing for compliance
- Energy and other impacts not related to air quality
- The remaining useful life of the source

As no remaining retrofit control technologies are technically feasible analysis of the above list is not possible.

5.6.4.1. Summary and Conclusions

USM operates eleven crucible furnaces for the purposes of maintaining magnesium metal in a molten state and casting that molten magnesium into ingots. Each furnace utilizes six smaller burners rated at 1 MMBtu/hr each. Additionally, there are multiple tool heating racks placed strategically around the casting house that are used to heat tools that will be in contact with heated magnesium ore. The combination of these burner units combusting natural gas emit 14.70 tons of NO_X emission annually. Given that there is a total of ~80 burners in the casting house, each contributing a minimal amount of NO_X emissions. Controls for these small combustion devices are not readily available, and none were found during the BART analysis. USM will continue to operate the casting house as it is currently configured.

5.7. LITHIUM PLANT

USM has recently constructed the lithium plant, which finished the permitting process on April 20, 2020. The lithium plant digests existing waste coupled with current waste streams to extract the available lithium ore. The NO_X emissions from the plant come from natural gas combustion units. The plant consists of two boilers, a 63 and an 84 MMBtu/hr; and two evaporative burners, a 50 and a 100 MMBtu/hr. The analysis for the lithium plant was broken into two sections, a natural gas fired boiler section and an evaporative burner section.

5.7.1. Natural Gas Fired Boilers

The natural gas fired boilers were installed in early 2020 and went through a BACT analysis earlier this year. They are ultra-low-NO_X units capable of meeting a concentration limit of 9 ppm NO_X or less[18]. As BACT is more inclusive than BART performing a BART analysis on these boilers would be redundant and would yield no results. No additional analysis was performed on the 62 MMBtu/hr or 84 MMBtu/hr natural gas fired boilers installed in 2020, however the NO_X BACT analysis that was completed for USM's AO is included below.

5.7.1.1. Boiler BACT Analysis from AO dated April 20, 2020

Two boilers are proposed for the Lithium Carbonate Production Plant: a 63 MMBtu/hr unit and an 84 MMBtu/hr unit. Both boilers will be fueled by natural gas and will operate 8,760 hours per year. NO_X emissions from both boilers combined will be 6.04 tons annually.

NO_X

NO_X emissions are generated from the natural gas combustion process.

[18] Per UDAQ Approval Order DAQE-AN107160050-20 dated April 20, 2020.

Available Control Technologies

Technically feasible options for NO_X control include selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), low NO_X burners, ultra-low NO_X burners, flue gas recirculation (FGR), and good combustion practices.

SCR is an add-on technology that chemically reduces NO_X compounds from the stack flue gas to N_2 and water. Ammonia is injected into the flue gas upstream of the catalyst chamber. The ammonia-air mixture then passes through a thermal catalytic reactor where the catalytic reaction is completed. NO_X reduction in SCR is only effective at high temperatures (480 F to 800 F), so additional heating of the emission stream may be required to meet optimal operating temperatures. SCR NO_X removal efficiencies are between 70% and 90%.

SNCR is similar to SCR in the use of ammonia as a reductant to reduce NO_X compounds to molecular N_2 and water but the technology does not utilize a catalyst. The ammonia is injected directly into the primary combustion zone where temperatures reach 1,400 to 2,000 F. NO_X reduction in SNCR is only effective at high temperatures (1600 F to 2100 F), so additional heating of the emission stream may be required to meet optimal operating temperatures. SNCR NO_X removal efficiencies vary between 30% and 50%.

Low and ultra-low NO_X burners are commonly used to reduce NO_X emissions from natural gas combustion equipment. Low NO_X burners can achieve NO_X emissions rates of 30 ppmvd and ultra-low NO_X burners will achieve NO_X emission rates of 9 ppmvd.

FGR consists of recirculating a portion of the flue gas to the combustion zone in order to lower the peak flame temperature and results in reduced thermal NO_X production. FGR is one of the main reduction methods for low-NO_X or ultra-low NO_X burners.

Good combustion practices and use of clean fuel includes the use of gaseous fuels and combustion practices to minimize the formation of NO_X emissions from the combustion process.

Technical and Economic Feasibility

All control technologies identified are technically feasible. USM has proposed to install boilers with ultra-low NO_X burners rated at 9 ppmvd.

The proposed boilers with ultra-low NO_X burners will generate relatively low NO_X emissions (6.04 tpy for both boilers). The addition of SCR and SNCR would reduce these emissions by 50 to 80% from an ultra-low NO_X burner, or 3 to 5 ton reduction. Due to the high costs of SCR and SNCR systems, this reduction would not be considered cost effective. Furthermore, there are several considerations with SCR and SNCRs that make these controls not technically feasible for boilers like the units proposed for the Lithium Carbonate Plant.

1) Due to the costs of SCR and SNCR systems, these technologies are usually applied to large combustion units (>100 MMBtu/hr).
2) High operating temperature requirements may require additional heating of the exhaust stream.
3) Health and safety considerations since SCR and SNCR require storage and handling of ammonia, a hazardous chemical.

4) Ammonia slip (i.e. ammonia emissions from unreacted ammonia) pose additional environmental and safety concerns

Given these technical difficulties, environmental concerns, and the relatively low NO_X emissions from the boilers with ultra-low NO_X burners, SCR and SNCR are not considered a feasible option.

Select BACT

DAQ considers BACT for NO_X from the boilers as the use of an ultra-low NO_X burners rated at 9 ppm, good combustion practices, and limiting visible emissions to 10% opacity from each boiler.

5.7.2. Evaporative Burners

The natural gas fired evaporative burners were similarly installed in early 2020 and went through a BACT analysis earlier this year. They are low-NO_X units capable of meeting a concentration limit of 30 ppm NO_X or less[19]. As BACT is more inclusive than BART performing a BART analysis on these evaporative burners would be redundant and would yield no results. No additional analysis was performed on the 50 MMBtu/hr or 100 MMBtu/hr evaporative burners installed in 2020, however the NO_X BACT analysis that was completed for USM's AO is included below.

5.7.2.1. Evaporative Burner BACT Analysis from AO dated April 20, 2020

USM has proposed to install two evaporator burners to supply hot exhaust gases for evaporating water from process liquors. One evaporator burner will have a heat input rating of 100 MMBtu/hr and the other evaporator burner will have a heat input rating of 50 MMBtu/hr. Both evaporator burners will be fueled by natural gas and will operate 8,760 hours per year. NO_X emissions from both evaporator burners combined are 20.57 tons annually.

NO_X

NO_X emissions will be generated from the natural gas combustion process.

Available Control Technologies

Technically feasible options for NO_X control include SCR, SNCR, low NO_X burners, ultra-low NO_X burners, FGR, and good combustion practices. These technologies were described above in the Boilers NO_X section.

Technical and Economic Feasibility

All control technologies identified are technically feasible. USM considered three burner options: uncontrolled at 130 ppmvd NO_X, low NO_X at 30 ppmvd, and ultra-low NO_X at 9-15 ppmvd.

According to the manufacturer of the burners, ultra-low NO_X burners are not technically feasible for the operating requirements of the Lithium Carbonate Plant.

[19] Per UDAQ Approval Order DAQE-AN107160050-20 dated April 20, 2020.

The first operating requirement is the process temperature. The process requires a temperature of 1,500 degrees F. According to burner manufacturer, ultra-low NO_X burners are limited to a maximum temperature of 1,000 degrees F at the site elevation (4,220 feet above sea level).

The second operating requirement is the turndown ratio. Ultra-low NO_X burners are limited to a turndown ratio of 5:1, while a low NO_X burner is capable of 13:1 turndown ratio. Turndown is a ratio of capacity at full fire to its lowest firing point before shut-down and indicates the number of on/off cycles. At each cycle, air is purged through the unit to remove any explosive gases. The lower the turndown ratio, the more sensitive the burner is to low firing points, and more purge cycles are required. Purge cycles removes heat from the burner and increases the number of startups. A low turndown ratio increases the number of on/off cycles, which can in turn deteriorate burner components and increase maintenance costs. The higher turndown ratio makes the burner more responsive to variable loads and is more suitable for the anticipated fluctuations in daily operations. The low NO_X burner with a higher turndown ratio is more suitable for the operations at the Lithium Carbonate Plant.

The third operating requirement is system reliability. The proposed burner will be fired in a combustion chamber which is attached to a spray tower. The spray tower will deliver the brine to be heated by the burner. Brine will be delivered at variable flows and distribution which will affect the back pressure on the burner. An ultra-low NO_X burner would be more sensitive to fluctuations in back pressure in the spray towers and would not be suitable for the planned process of the Lithium Carbonate Plant.

Given these operational considerations, an ultra-low NO_X burner is not considered technically feasible for operations at the Lithium Carbonate Plant.

USM conducted a cost analysis to determine the economic feasibility of the low NO_X burners (30 ppm). For the 100 MMBtu/hr burner, the capital cost of a low NO_X burner was estimated at $163,451 and would reduce NO_X emissions by 24.91 tpy. This would result in a cost efficiency of $6,536 per ton of NO_X removed. For the 50 MMBtu/hr burner, the capital cost of a low NO_X burner was estimated at $122,499 and would reduce NO_X emissions by 13.64 tpy. This would result in a cost efficiency of $8,373 per ton of NO_X removed. Therefore, low NO_X burners were determined to be economically feasible for both burners.

SCR and SNCR are not technically or economically feasible options for the same reasons previously discussed in the Boiler section.

Select BACT

BACT for these burners is a 10% opacity limitation and installation of low-NO_X burners, that will be certified by the manufacture to meet 30 ppm NO_X emissions.

6. CONCLUSION

This report outlines USM's evaluation of possible retrofit options for all NO_X emitting units onsite at their Rowley Plant located in Tooele County, Utah, in an attempt at reducing their NO_X emissions facility wide and reducing their impact on visibility impairment issues. The results of this report found that it is potentially technologically and economically feasible to install a flue gas recirculation unit on the Riley boiler, reducing their NO_X emissions by an estimated 22.6 tons annually. Aside from this change, there were currently no other technically or economically feasible options available for USM's Rowley Plant.

Pending further technological and cost refinement, the implementation schedule for the installation of the FGR unit may be installed prior to the end of 2028. Therefore, the emissions for the 2028 modeling scenario could be an estimated 22.6 tons less than the 2018 baseline year NO_X emissions.

APPENDIX A: RILEY BOILER SCR COST ESTIMATE

Cost Estimate		
USM Riley Boiler SCR Cost Analysis using EPA's SCR Cost Manual		
Total Capital Investment (TCI)		
TCI for Oil and Natural Gas Boilers		
For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW: $TCI = 80{,}000 \times (200/B_{MW})^{0.35} \times BMW \times ELEVF \times RF$		
Total Capital Investment (TCI) =	$3,262,190	in 2018 dollars

Annual Costs		
Total Annual Cost (TAC) TAC = Direct Annual Costs + Indirect Annual Costs		
Direct Annual Costs (DAC) =	$86,684	in 2018 dollars
Indirect Annual Costs (IDAC) =	$282,646	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$369,330	in 2018 dollars

Direct Annual Costs (DAC)
DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$16,311	in 2018 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$48,399	in 2018 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$17,910	in 2018 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$4,064	in 2018 dollars
Direct Annual Cost =		$86,684	in 2018 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,716	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$279,930	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$282,646	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$369,330	per year in 2018 dollars
NOx Removed =	38	tons/year
Cost Effectiveness =	$9,726	per ton of NOx removed in 2018 dollars

Table B-1: RBLC Search Results

USM EQUIPMENT	RBLC ID	FACILITY NAME	COMPANY NAME	OPERATING STATE	PERMIT ISSUE DATE	PROCESS NAME	FUEL SOURCE	THROUGHPUT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	BASIS
Casting House	MI-0301	Alchem Aluminum	Alchem Aluminum, Inc.	Michigan	5/2/2000	Crucible Heaters/Stations	Natural Gas	2.00 MMBtu/hr	NO_X	None, AP-42	0.14 lb/MMBtu	
HCl Plant	LA-0242	Hydrochloric Acid Production Furnace	Shintech Louisiana, LLC	Louisiana	6/29/2010	Hydrochloric Acid Production Furnace	Natural Gas	39.00 MMBtu/hr	NO_X	SCR	0.0146 lb/MMBtu	
Riley Boiler	PA-0319	Renaissance Energy Center	APV Renaissance Partners	Pennsylvania	8/27/2018	Auxiliary Boiler	Natural Gas	88.00 MMBtu/hr	NO_X	Low NOX Burners, FGR	0.02 lb/MMBtu	LAER
Riley Boiler	WV-0032	Brooke County Power Plant	ESC Brooke County Power I, LLC	West Virginia	9/18/2018	Auxiliary Boiler	Natural Gas	111.6 MMBtu/hr	NO_X	Low NoX burner	0.011 lb/MMBtu	BACT - PSD
Riley Boiler	MI-0433	MEC North, LLC & MEC South, LLC	Marshall Energy Center LLC	Michigan	6/29/2018	Auxiliary Boiler	Natural Gas	61.5 MMBtu/hr	NO_X	Low NOX burners, FGR	0.04 lb/MMBtu	BACT - PSD
Riley Boiler	FL-0367	Shady Hills Combined Cycle Facility	Shady Hills Energy Center, LLC	Florida	7/27/2018	Auxiliary Boiler	Natural Gas	60.00 MMBtu/hr	NO_X	Low NOX burner	0.05 lb/MMBtu	BACT - PSD
Riley Boiler	WY-0011	CIG	CIG	Wyoming	8/25/1976	Boiler, Gas, 2	Natural Gas	48.40 MMBtu/hr	NO_X	Design	0.2 lb/MMBtu	Other
Riley Boiler	TX-0079A	Shintech, Inc.	Shintech, Inc.	Texas	1/5/1981	Boiler, Steam	Natural Gas	55.00 MMBtu/hr	NO_X	Low Nox Burners	0.13 lb/MMBtu	BACT - PSD
Riley Boiler	IL-0020	Archer Daniels Midland	Archer Daniels Midland	Illinois	5/28/1982	Boiler	Natural Gas	90.00 MMBtu/hr	NO_X	Design	0.17 lb/MMBtu	BACT - PSD

APPENDIX C.5.B – US Magnesium UDAQ Four-Factor Analysis Evaluation

State of Utah
SPENCER J. COX
Governor
DEIDRE HENDERSON
Lieutenant Governor

Department of
Environmental Quality
Kimberly D. Shelley
Executive Director
DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQP-061-21

July 27, 2021

Rob Hartman
US Magnesium, LLC
238 North 2200 West
Salt Lake City, Utah 84116
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Todd Wetzel
14425 South Center Point Way
Bluffdale, Utah 84065
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Dear Mr. Hartman and Mr. Wetzel,

The DAQ has received your four-factor analyses for the US Magnesium Rowley Power Plant prepared for the second planning period of Utah's Regional Haze State Implementation Plan. Enclosed is an engineering review of each analysis outlining some outstanding issues for you to be aware of. Please provide the DAQ with amendments or reasoning for these issues by **August 31st, 2021**. If you have any questions please contact John Jenks at jjenks@utah.gov or (385) 306-6510.

Sincerely,

Chelsea Cancino

Chelsea Cancino
Environmental Scientist

RNC:CC:GS:jf

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Regional Haze – Second Planning Period
SIP Evaluation Report:

US Magnesium LLC - Rowley Plant

Utah Division of Air Quality

July 30, 2021

SIP EVALUATION REPORT

US Magnesium LLC - Rowley Plant

1.0 Introduction

The following is part of the Technical Support Documentation for the Second Planning Period of the Regional Haze SIP (aka the Visibility SIP). This document specifically serves as an evaluation of the US Magnesium LLC - Rowley Plant facility.

1.1 Facility Identification

Name: Rowley Plant
Address: 12819 North Skull Valley Road 15 Miles North Exit 77, I-80, Rowley, Utah
Owner/Operator: US Magnesium LLC
UTM coordinates: 4,530,490 m Northing, 354,141 m Easting, Zone 12

1.2 Facility Process Summary

US Magnesium LLC (USM) operates a primary magnesium production facility at its Rowley Plant, located in Tooele County, Utah. USM produces magnesium metal from the waters of the Great Salt Lake. Some of the water is evaporated in a system of solar evaporation ponds and the resulting brine solution is purified and dried to a powder in spray dryers. The powder is then melted and further purified in the melt reactor before going through an electrolytic process to separate magnesium metal from chlorine. The metal is then refined and/or alloyed and cast into molds. The chlorine from the melt reactor is combusted with natural gas in the chlorine reduction burner (CRB) and converted into hydrochloric acid (HCl). The HCl is removed from the gas stream through a scrubber train. The chlorine that is generated at the electrolytic cells is collected and piped to the chlorine plant where it is liquefied for reuse or sale.

USM Rowley Plant is a PSD source for CO, NO_X, PM10, PM2.5, and VOCs.

1.3 Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

- Three (3) gas turbines/generators and duct/process burners (natural gas/fuel oil)
- Chlorine reduction burner (CRB), and associated equipment
- Riley Boiler, 60 MMBtu/hr (natural gas)
- Solar pond diesel engines, 30 engines rated between 90 and 420 hp
- Fire pump engine, one additional diesel engine rated at 292 hp

1.4 Facility Current Potential to Emit

The current PTE values for the Rowley Plant, as established by the most recent NSR permit issued to the source (DAQE-AN107160050-20) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
SO2	24.10
NO_X	1,260.99

2.0 Four Factor Review Methodology

Each source reviewed in this second planning period submitted a report on the available control technologies for SO2 and NO_X emission reductions and the application of each technology to that facility. The information on available controls should consider the following four factors when analyzing the possible emission reductions:

1. Factor 1 – The Costs of Compliance
2. Factor 2 – Time Necessary for Compliance
3. Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance
4. Factor 4 – Remaining Useful Life of the Source

Although not specifically required, the recommended approach was to follow a step-wise review of possible emission reduction options in a "top-down" fashion similar to U.S. EPA's guidelines for review of BART or Best Available Retrofit Technology (as found in 40 CFR 51, Section 308 amendments, pub. July 5, 2005). The steps involved are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document results

The process is inherently similar to that used in selecting BACT (Best Available Control Technology) under the NSR/PSD (Title I) permitting program. DAQ evaluated the submissions from each source following the methodology outlined above. Where a particular submission may have differed from the recommended process, DAQ will make note, and provide additional information as necessary.

3.0 Analysis for SO2 Emission Reductions

USM has provided the following emissions information for SO2. The emissions represent actual emissions at their facility for the 2018 calendar year and are based on a combination of actual fuel use, stack testing, operational hours, or production rates. The Lithium Plant was permitted in 2020 and actual emissions are not yet available, for this reason potential to emit totals were included in the table below for this plant's emissions instead of actuals.

Annual SO2 Baseline Actual Emission Rates (tons/yr)

Equipment	SO2 Baseline Emissions (tons/yr)
Turbines | Duct Burners	1.66
Chlorine Reduction Burner	0.07
Riley Boiler	0.14
Diesel Engines	0.03
HCl Plant	0.03
Cast House	7.29

Lithium Plant	0.75*
Other Sources	0.06
Mobile Sources	0.05
Total	10.08

*Lithium Plant emissions are listed as PTE emissions, as it was not in operation in 2018.

Due to the insignificant amount of sulfur dioxide emissions coming from USM, a decision was made in the fall of 2019 during a meeting with DAQ to omit sulfur dioxide from the upcoming BART analysis. Any reductions in SO2 would not result in any reasonable progress goals and would also likely be cost prohibitive given the minimal impacts of additional controls. No further discussion or analysis was performed for SO2.

DAQ agrees with this analysis as stated above. No further review of SO2 emissions is necessary.

4.0 Analysis for NO_X Emission Reductions

USM has provided the following emissions information for NO_X. The emissions represent actual emissions at their facility for the 2018 calendar year and are based on a combination of actual fuel use, stack testing, operational hours, or production rates. The Lithium Plant was permitted in 2020 and actual emissions are not yet available, for this reason potential to emit totals were included in the table below for this plant's emissions instead of actuals.

Annual NO_X Baseline Actual Emission Rates (tons/yr)

Equipment	NO_X Baseline Emissions (tons/yr)
Turbines | Duct Burners	813.58
Chlorine Reduction Burner	11.66
Riley Boiler	45.25
Diesel Engines	71.65
HCl Plant	4.32
Cast House	14.70
Lithium Plant	26.61*
Other Sources	0.02
Mobile Sources	73.01
Total	1,060.79

*Lithium Plant emissions are listed as PTE emissions, as it was not in operation in 2018.

The values listed above will be utilized in determining actual reductions to emissions because of any additional retrofit control technology. The same assumptions of operation that were employed to calculate annual emissions in 2018 will be employed to determine any reductions from add-on equipment because of the ensuing BART analysis.

All the NO_X generated at USM is a result of the fuel combustion process. Two primary formation mechanisms are responsible, thermal NO_X, when atmospheric nitrogen and oxygen disassociate in the combustion zone and form NO_X, or fuel NO_X when nitrogen present in the fuel interacts with atmospheric oxygen in the combustion zone. USM utilizes natural gas as a fuel source except during times of curtailment, natural gas and diesel have little to no nitrogen content resulting in the majority of NO_X formation being thermal in origin.

Control strategies for NO_X formation fall into one of two categories, combustion controls or post-combustion controls. Combustion control technologies focus on reducing the peak flame temperature and excess air in the combustion zone resulting in reduced NO_X formation. Post-combustion controls focus on reducing NO_X after it has formed in the exhaust stream – usually by utilizing a catalyst.

4.1 Turbines and Duct Burners

Step 1: Identify All Potentially Available Retrofit NO_X Control Technologies

The turbines at USM are utilized for electrical generation as an integrated part of the production process. The exhaust from the turbines is routed to a duct burner to increase the temperature before being routed to a spray dryer. The heated exhaust is used to dry the magnesium chloride slurry into a magnesium chloride powder. For the spray dryer to work properly the inlet temperature of the exhaust steam needs to reach 1,000 °F. The exhaust temperature from the turbines is 900 °F, and the duct burners boost the temperature to 1,000 °F.

The duct burners take the exhaust from the turbines and continue to heat it to the desired temperature. NO_X control strategies for this type of equipment does not exist, inlet temperatures and exit temperatures prohibit the use of combustion controls, and post combustion controls are similarly prohibitive, as exhaust temperatures need to reach 1,000 °F. The duct burners emissions are incorporated with the turbines emissions and were included here for completeness.

Common control technologies for reduction of NO_X emissions in natural gas turbines, identified by the EPA are: Water or Steam Injection, Dry Low-NO_X, Selective Catalytic Reduction (SCR).

Water or Steam Injection
Water and or steam injection is commonly termed wet control for gas turbines. Steam or water injection controls the formation of NO_X emissions by decreasing the peak flame temperature. It is an effective tool for reducing the formation of thermal NO_X in all but regenerative cycle combustors. Evaporation of the water reduces the cycle efficiency of a few percent but increases power output by double that reduction. This is caused by the steam formed or injected in the combustor raising the mass flow rate through the turbine therefore increasing power. NO_X emission reductions of generally 60-70% can be achieved using water or steam injection at water-to-fuel ratios of 0.2:1 to 1:1. It is important to utilize water or steam free of contaminants, so a water treatment system is an integral component of a wet control system.

Several mechanical limits exist when it comes to water or steam injection systems. Some examples of this are combustion operating instabilities, increased CO, heat rate penalties, combustion flame blow-off or flame-out. These limitations can decrease the efficiency of the water or steam injection system and increase the maintenance required on the turbine.

Dry Low-NO_X
NO_X emission control techniques that are performed without the injection of water or steam are referred to as dry controls, but the method for emissions reductions is the same, reducing the peak flame temperature. This is generally accomplished by lean combustion or staged combustion. Lean combustion refers to a technique that reduces the air/fuel ratio beyond that of normal stoichiometric operation (equivalence ratio = 1) to an air/fuel equivalence ratio of 2, i.e. very lean. This reduces the combustion temperature by reducing the air required for combustion below stoichiometric levels. This method is only achievable under normal load range, during periods of startup or low load a transition program with higher air/fuel ratios is required. This results in

increased NOx emissions during periods of startup or low load situations. Staged combustion is another technique to lower NOx emissions, this strategy utilizes multiple combustion zones, usually two. The first zone operates lean or rich, but the second zone always operates lean. The incomplete combustion that results in the first combustion zone is further combusted in the lean second combustion zone resulting in reduced NOx formation.

Selective Catalytic Reduction (SCR)
In the SCR process, ammonia is injected in the gas turbines exhaust gas stream reacting with NOx in the presence of a catalyst to form molecular nitrogen and water. SCR works best in base loaded combined cycle gas turbine applications where the turbine is fueled with natural gas. SCR is capable of NOx removal efficiencies between 70% and 90%. The catalytic NOx-ammonia reaction takes place over a limited temperature range, 600-750 °F, anything above ~850 °F and the catalyst is damaged irreversibly. Ammonia slip is also a concern when utilizing an SCR for NOx emission reductions, as well as ammonia storage, and costs of disposal of spent catalysts.

Step 2: Eliminate Technically Infeasible Options

To evaluate if the above NOx controls are technically feasible it is important to understand the role of the turbines at USM. The turbines are utilized for electrical generation and are integral to the production process. The exhaust coupled with a duct burner is used in a spray dryer to dry the magnesium chloride slurry into a magnesium chloride powder. For the spray dryer to work properly the exhaust temperature of turbines needs to reach 1,000 °F. This is achieved by utilizing an inline duct burner to boost the temperature from 900 °F to 1,000 °F. The magnesium chloride powder is then sent to the melt reactor for further processing.

Water or Steam Injection
This control technology given its strategy for reducing peak flame temperature is adding water to the combustion zone directly conflicts with the magnesium chloride powder production. Moisture in the exhaust stream will most definitely affect the ability of the spray dryers to operate as designed. This method is considered technically infeasible given the operational requirements of the spray dryers and will not be considered further.

Dry Low-NOx
Reducing peak flame temperatures and lowering the temperature of the exhaust gas would require a larger duct burner be installed. A larger duct burner would create just as much NOx as the reduction, possibly more. For this reason both the lean combustion and staged combustion methods are considered technically infeasible, as the operational requirements for the spray dryers would be negatively impacted to a point where they would conflict with the production of magnesium product, as a result this will not be considered further.

Selective Catalytic Reduction (SCR)
An SCR system requires a specific operating temperature to be effective at NOx removal, that temperature hovers around 750 °F. The duct burners take the exhaust from the turbines at roughly 900 °F and heat it to 1,000 °F. An SCR system is not technically feasible at these operating temperatures and will not be considered further in this analysis.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 of the review process is to rank the technically feasible options by how effective they are at removing NOx emissions. As no control technologies are technically feasible for the specific operations at USM, no ranking is possible.

Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance
- Timing for compliance
- Energy and other impacts not related to air quality
- The remaining useful life of the source

As no remaining retrofit control technologies are technically feasible, analysis of the above list is not possible.

Summary and Conclusions
USM requires specific temperatures from their exhaust stream for their proper operation of the spray dryers, any changes to the turbine or duct burners would require significant alterations to the spray dryers. The turbines and duct burners, in 2018, emitted 813.58 tons of NOx emissions. Although this is a significant source of NOx emissions, no technically feasible retrofit technologies were found during the BART analysis. USM will continue to operate the turbines and duct burners as they are currently configured.

4.2 Chlorine Reduction Burner

Step 1: Identify All Potentially Available Retrofit NOx Control Technologies

USM operates the only primary magnesium metal production facility in the United States. As such it is the only facility that operates a chlorine reduction burner (CRB) in the United States. The CRB is a control device for chlorine gas emissions. It is designed to take the chlorine gas that is generated in the melt reactor process and as tail-gas from the chlorine (purification) plant, and in the presence of heat and methane, produce CO_2 and hydrochloric acid (HCl). The HCl is scrubbed and recovered as hydrochloric acid liquid prior to the exhaust stream being further scrubbed and then vented to the atmosphere.

Combustion techniques that lower the formation of thermal NOx by lowering the peak flame temperature are not a viable option for control as they would impact the CRB's main function of reducing the chlorine emissions that are emitted to the atmosphere. The CRB requires an operating temperature of no less than 1,650 °F and no more than 2,000 °F for proper operation and has strict monitoring requirements listed in their Title V operating permit. Post-combustion techniques involving a catalyst would foul the packed scrubbers that remove the HCl acid from the exhaust stream, which could violate the emission requirements found in 40 CFR 63 Subpart TTTTT.

Given the unique operating parameters involved in the CRB no control technologies exist for the reduction of NOx emissions. Therefore, no additional analysis was performed for the CRB.

Step 2: Eliminate Technically Infeasible Options

No NOx emission reduction retrofit controls are available for the CRB.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 of the review process is to rank the technically feasible options by how effective they are at removing NOX emissions. As no control technologies are technically feasible for the specific operations at USM, no ranking is possible.

Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance
- Timing for compliance
- Energy and other impacts not related to air quality
- The remaining useful life of the source

As no remaining retrofit control technologies are technically feasible, analysis of the above list is not possible.

Summary and Conclusions
The CRB at USM is required to maintain an operating temperature of 1,650 to 2,000 °F, and as such combustion controls are not a viable option for controlling the formation of thermal NOx. Post-combustion controls are similarly disadvantageous, and the exhaust stream from the CRB passes through an absorber to recover HCL as hydrochloric acid liquid and then several packed bed scrubbers to remove PM. The addition of any catalyst to remove NOx emissions could interfere with the scrubber's operation and result in emissions that violate the emissions standards that are listed in the applicable MACT, Subpart TTTTT. The CRB at USM currently emits 11.66 tons of NOx annually. USM will continue to operate the CRB as it is currently configured.

4.3 Riley Boiler

Step 1: Identify All Potentially Available Retrofit NOx Control Technologies

USM utilizes a 60 MMBtu/hr boiler, referred to as the Riley boiler that was first installed prior to the plant beginning operation in 1972. The boiler utilizes natural gas as a combustion source and provides heat throughout the plant via the production of steam. The boiler is located in the middle of their facility, nestled between scrubbers, spray dryers, and various other equipment. Common NOx control strategies for a natural gas boiler are listed below:

Combustion Controls:
Flue Gas Recirculation (FGR)
Low NOx Burners
Ultra-Low NOx Burners

Post-Combustion Controls:
Selective Catalytic Reduction (SCR)
Selective Non-Catalytic Reduction (SNCR)

The RBLC of the EPA Clean Air Technology Center as well as EPA's, "Nitrogen Oxides (NOx), Why and How They are Controlled" were utilized in determining control technologies for evaluation.

Flue Gas Recirculation (FGR)
Flue gas recirculation consists of recirculating a portion of the flue gas to the combustion zone to lower the peak flame temperature and lowers the percentage of oxygen in the combustion zone, thereby reducing thermal NOx formation. FGR is one of the main NOx reduction strategies for low NOx and ultra-low NOx burners. Standalone FGR systems can achieve up to 50% NOx reductions.

Low NOx burners (LNB)
LNB reduce the formation of thermal NOx by utilizing multiple technologies coupled with staged combustion. Many variations of a low NOx burner exist, almost all of them utilizing staged combustion for controlling fuel to air ratios to limit the peak flame temperature. Controlling fuel and air mixing at the burner creates larger and more branching flames, making LNB have a larger footprint than a standard boiler like the one installed at USM. LNB can reduce NOx emissions by up to 80% from a standard combustion unit and are considered common place and often the starting point of new boiler installations.

Ultra-Low NOx burners (ULNB)
ULNB improve upon the design of a low NOx burner usually by lowering combustion temperatures even more by modifying the burners further. The lower temperatures require larger volumes of fuel as the combustion process is not complete, this also increases CO emissions while reducing NOx emissions. Depending on the provider of the ultra-low unit, technology varies but they are generally capable of meeting NOx emission limits of 9 ppm.

Post-Combustion Controls
Selective Catalytic Reduction (SCR)
In the SCR process, ammonia is injected into the exhaust stream reacting with NOx in the presence of a catalyst to form molecular nitrogen and water. SCR works best in stable conditions, units that fluctuate in operation and therefore temperature do not achieve optimal NOx reduction rates. SCR is capable of NOx removal efficiencies between 80% and 90%8. The catalytic NOx-ammonia reaction takes place over a limited temperature range, 600-750 °F, anything about ~850 °F and the catalyst is damaged irreversibly. Ammonia slip is also a concern when utilizing an SCR for NOx emission reductions, as well as ammonia storage, and costs of disposal of spent catalysts.

Selective Non-Catalytic Reduction (SNCR)
SNCR is a similar process to SCR in that it utilizes ammonia as a reductant to reduce NOx compounds to molecular N2 and water, however the technology does not utilize a catalyst. The ammonia in injected directly into the primary combustion zone where temperatures reach 1,400-2,000 °F. NOx reduction in SNCR is only effective at high temperatures (1,600-2,100 °F), so additional heating of the emissions stream may be required to meet optimal operating temperatures. SNCR NOx removal efficiencies vary between 30% and 50%.

Step 2: Eliminate Technically Infeasible Options

Flue Gas Recirculation (FGR)
FGR increases the maintenance required and can result in fouled air intake systems, combustion chamber deposits, and increased wear rates, but it is technically feasible as a retrofit option.

Low NOx Burners (LNB)
To convert the standard burners currently installed in the Riley boiler to LNB would require substantial modifications and would not really fit the definition of a retrofit. The additional space requirement due to the staged combustion a low NOx unit requires would be challenging to fit into the existing space. This would require modifications to other systems to accommodate the additional size, and as a result has been ruled out as a technically feasible option. LNB have been ruled out as a retrofit option and not evaluated further.

Ultra-Low NOX Burners (ULNB)
An ULNB was similarly ruled out as technically feasible as a retrofit option as it would require a near complete replacement of the existing boiler. Additionally, the space requirements would require the same modifications as installing LNB. The ULNB have been ruled out as a retrofit option and were not evaluated further.

Selective Catalytic Reduction (SCR)
An SCR system is an effective way at reducing NOx formation in a stationary combustion unit like the boiler utilized at USM. They do present additional safety concerns with the use of ammonia and ammonia storage. An SCR system is considered a technically feasible retrofit option for the boiler.

Selective Non-Catalytic Reduction (SNCR)
This boiler at USM was built in the 1970's and has had general maintenance and replacement of some of the burner units and housing as it has aged but is largely unchanged. The required operating temperatures for an SNCR system to work properly (1,600 – 2,000 °F) are not within the boilers operating range. As a result, a SNCR system has been ruled out as a retrofit option for the Riley boiler, and was not evaluated further.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 is the ranking of the remaining commonly available retrofit control technologies by control effectiveness.

Selective Catalytic Reduction (SCR): Up to 90%
Flue Gas Recirculation (FGR): Up to 50%

Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance
- Timing for compliance
- Energy and other impacts not related to air quality
- The remaining useful life of the source

Cost of Compliance
The Riley boiler operating at USM was installed in 1972 and has no add-on equipment. The cost analysis below is based on the baseline emissions calculated using AP-42 and a full-time operating schedule, generating 45.25 tons of NOx annually.

Selective Catalytic Reduction (SCR)
Evaluating the costs for an SCR unit on an existing boiler of this small size is challenging. The EPA's Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction (SCR) was used to estimate the costs of retrofitting the boiler; the cost values are based on the 2018 annual average Chemical Engineering Plant Cost Index (CEPCI) value of 603.1. The detailed inputs and outputs of the EPA cost estimation tool can be found in Appendix A of USM's submission. The cost effectiveness based on 2018 dollars is $9,726/ton of NOx removed. The costs associated with installing an SCR system on a boiler of this age would be not be considered economically feasible. As a result, the use of an SCR system for NOx control has been ruled out as a viable retrofit option for NOx control.

The costs associated with installing an SCR system on a boiler of this age would not be considered economically feasible. As a result, the use of an SCR system for NOx control has been ruled out as a viable retrofit option for NOx control.

Flue Gas Recirculation (FGR)
The cost analysis for a FGR system on an existing boiler needs to be done by specific vendors and engineered for the specific boiler, especially for older units like the one at USM's facility. However, general cost guidelines can be used to estimate the costs for an appropriate FGR system. A general cost for an FGR system is somewhere in the range of $8-35/kW, in specific cases some can be as low as $3/kW.10 This would put the cost range of an addon FGR for the 60 MMBtu/hr Riley boiler somewhere between $52,740 and $615,300. It is important to note that these cost estimates were from EPA studies done in the 1990's, and as such the cost per ton removed analysis was performed using the high end of the range, $615,300.

Assuming a 50% NOx emissions control efficiency from a FGR system, a reduction of 22.6 tons of NOx annually would result from the installation. Based on the factored cost estimate evaluated, an FGR system may be reasonable given the amount of NOx control achieved, and the estimated cost per ton removed of $2,708.

Timing for Compliance
Although additional evaluation will be necessary, installation of an FGR system on the Riley boiler may be feasible before the end of 2028, the end of the second long-term strategy for regional haze.

Energy and Other Impact Not Related to Air Quality
The biggest concern related to the installation of a FGR system would be the increase in CO that is associated with the decrease in burner efficiency because of incomplete combustion. No other negative impacts are related to energy or other environmental issues.

Remaining Useful Life of the Source
The boiler has been well maintained and parts have been replaced over the years. It is reasonable to assume that the boiler will continue to operate for the foreseeable future. Given that the boiler was built and installed in 1972, it is approximately 48 years old, the remaining useful life is speculative, but given proper maintenance and replacement of worn out parts of the boiler its anticipated the boiler will last another 10 to 20 years.

Summary and Conclusions
USM has determined that a potentially viable retrofit control technology for NOx control of the Riley boiler is the installation of an FGR system. The system would reduce NOx emissions by approximately 22.6 tons, with an estimated cost per ton removed of $2,708. Although additional

evaluation will be necessary, USM incorporating this control strategy into the Riley boilers current layout may be feasible before the end of 2028.

4.4 Diesel Engines

Step 1: Identify All Potentially Available Retrofit NOX Control Technologies

The diesel engines used onsite at USM are mostly comprised of modified Caterpillar engines that run direct drive water pumps for movement of fluids from one evaporation cell to another through various channels and trenches. The diesel engines are the second largest point source category for NOx emissions, this is due to the number of engines, 31, that are utilized onsite. Of these 31 engines, one is a 292 hp fire pump engine that charges their fire suppression system under emergency conditions (e.g., a plant fire during a power outage). Control technologies for that engine have not been analyzed as part of this analysis, as it is an emergency fire water pump engine that has very minimal run times. The remaining 30 engines are all equipped with aftermarket catalytic oxidizers to comply with the emission standards listed in 40 CFR 63 Subpart ZZZZ.

Although the engines utilized at USM facility consist of different sized motors, the control technologies for NOx are similar. The following control technologies applicability to the engines was evaluated regardless of engine size, as the only difference will be evaluated in Step 4 when looking at the implementation costs. Common control technologies for reduction of NOx emissions in diesel engines have been identified by EPA's Control Techniques Guidelines and manufacturers, and are listed below:

Combustion Controls: Exhaust Gas Recirculation (EGR)
Post-Combustion Controls: Selective Catalytic Reduction (SCR), Lean NOx Catalysts

Exhaust Gas Recirculation (EGR)

Utilizing EGR is an effective method for reducing NOx emissions from a diesel engine. Low-pressure and high-pressure EGR systems exist but for retrofitting purposes a low-pressure system is almost always utilized as it does not require extensive engine modifications. EGR recirculates a portion of the engine's exhaust back to the intake manifold, in most cases an intercooler lowers the temperature of the recirculated gases. The cooled recirculated gases, which have a higher heat capacity than air and contain less oxygen than air, lower the combustion temperature of the engine, resulting in less thermal NOx forming. Diesel particulate filters are required when utilizing a low-pressure EGR system to ensure that large amounts of particulates are not recirculated to the engine. An EGR system can reduce NOx emissions, by lowering the combustion temperature of the engine, by up to 40%.

Selective Catalytic Reduction (SCR)

SCR is an established method for controlling NOx emissions from stationary sources. A SCR system uses a catalyst and a chemical reductant to convert NOx emissions to molecular nitrogen and oxygen in oxygen-rich exhaust streams common to diesel engines. The chemical reductant of choice is generally ammonia and it is injected based on the amount of NOx present in the exhaust stream that is calculated via algorithm. As the exhaust air and the ammonia pass over the SCR catalyst, a chemical reaction occurs that reduces NOx emissions to nitrogen and oxygen. SCR systems on stationary sources can control 95% of NOx emissions.

Lean NOx Catalysts

Diesel engines are designed to run lean, which makes controlling NOx emissions challenging. Reducing NOx to molecular nitrogen in the oxygen-rich diesel exhaust environment requires a reductant (typically a hydrocarbon or carbon moNOxide) and under normal operating conditions reductants are generally not present. Lean NOx catalyst systems typically inject a small amount of diesel fuel or other reductant into the exhaust upstream of the catalyst. The reductant serves as the reducing agent for the catalytic conversion of NOx to N2. Some systems operate passively without added reductant reduced NOx conversion rates. A lean NOx catalyst consists of a porous material with a highly ordered channel structure, along with either a precious metal or base metal catalyst. The added fuel and the catalyst are capable of peak NOx control efficiencies ranging from 10 to 30 percent, which the higher control percent correlating to increased fuel injection rates.

Step 2: Eliminate Technically Infeasible Options

Exhaust Gas Recirculation (EGR)
Although EGR increases engine maintenance and can result in fouled air intake systems, combustion chamber deposits, and increased engine wear rates, it is technically feasible as a retrofit option.

Selective Catalytic Reduction (SCR)
SCR systems are an effective way at reducing NOx formation, they do present additional safety concerns with the use of ammonia or urea, and ammonia or urea storage. Additionally, the physical footprint of the SCR which can range from 50% to 60% the size of the engine is a real concern. It would likely mean extensive modifications to some of the existing pump stations to accommodate their size. However, given these concerns they remain a technically feasible retrofit option.

Lean NOx Catalysts
Lean NOx Catalysts are a relatively new addition to controlling NOx emissions. Although in theory they do appear to be technically feasible an extensive search through the RBL Clearinghouse and California's CARB database we were unable to find any stationary engines that utilized this control equipment. Therefore, this will not be considered a technically feasible control option for the diesel engines and will not be evaluated further.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 is the ranking of the remaining commonly available retrofit control technologies by control effectiveness.

Selective Catalytic Reduction (SCR): Up to 95%
Exhaust Gas Recirculation (EGR): Up to 40%

Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance
- Timing for compliance
- Energy and other impacts not related to air quality
- The remaining useful life of the source

Cost of Compliance
Currently USM has installed catalytic oxidizers on all the diesel engines to meet the requirements in 40 CFR 63 Subpart ZZZZ, these controls are cost-effective. All additional costs calculation and cost evaluations are considered in addition to the currently controlled emission levels.

Selective Catalytic Reduction Cost Effectiveness
To simplify the costs associated with the SCR systems, the engines are treated as identical units, although this is a slight oversimplification the engines do fall within a similar size rating. Also the efficiency of an SCR system drops off the smaller the engine rating due to mixing in the exhaust stream, so although the SCR system may be slightly over priced for the smaller engines the increased urea consumption will make up for the bias.

The pumping stations where the engines are housed consist of platforms built over water canals at over one dozen different remote locations within the overall approximately 75,000 acre solar pond system. As ammonia presented too many safety concerns to be considered a viable option, the following cost analysis will look only at the use of urea as the chemical reagent.

An SCR system equipped with a 4,000-gallon urea storage tank fitted with a heating system to prevent urea freezing was analyzed. The costs provided in Table 5-10 below are estimates by Caterpillar based on systems they have in place for other engines of a similar size.

Continuing with the simplified model if each of the 30 engines play an equal role in 71.65 tons of NOx emitted annually from the diesel engines on site, then each engine would emit 2.39 tons. This leads to a cost effectiveness of $14,146/ton of NOx removed. The costs associated with the SCR exceed that which would be considered economically feasible. As a result, the use of SCR systems for NOx control has been ruled out as a viable retrofit option for NOx control.

Exhaust Gas Recirculation Cost Effectiveness
The estimated cost for a low-pressure exhaust gas recirculation system including a diesel particulate filter is somewhere in the range of $18,000 to $20,000. A detailed cost breakdown was not performed for an EGR system, the simple cost of the unit alone coupled with the increased ware on the engines regardless of maintenance makes these units not economical. The emissions reductions from this unit cannot make up the costs to purchase the units, not even considering the costs to install or maintain the engines once installed. The EGR units have been ruled out as a viable option for NOx control.

Timing for Compliance
USM believes that reasonable progress compliant controls are already in place, and any additional controls are unnecessary. However, if UDAQ determines that one of the control methods analyzed in this report is required to achieve reasonable progress, it is anticipated that this change would be implemented during the period of the second long-term strategy for regional haze (approximately ten years following the reasonable progress determination for this second planning period).

Energy and Other Impact Not Related to Air Quality
The biggest concern related to NOx control that lies outside of air quality impacts would be that of ammonia storage. Ammonia is a caustic substance that is harmful to organic life, storing large quantities of it has the potential safety issues for personnel and for spills that can cause adverse environmental and health impacts. The associated ammonia slip can also increase condensable PM2.5 which contributes directly to visibility impairments.

Remaining Useful Life of the Source
The engines remaining life varies, but with proper maintenance and overhaul the engines are expected to last at least an additional 20 years, a similar lifetime to that of the control equipment being considered in this analysis.

Summary and Conclusions
USM has determined that the available retrofit control technologies are too costly for consideration of use at their facility. The diesel engines will continue to emit roughly 71.65 tons of NOx annually. USM will continue to operate the diesel engines as they are currently configured.

4.5 Hydrochloric Acid Plant

Step 1: Identify All Potentially Available Retrofit NOx Control Technologies

USM produces a pure food grade hydrochloric acid (HCl) at their acid plant. The concentration of HCl is roughly ~36% and is generated in a similar fashion to how the chlorine reduction burner works, by combusting natural gas in the presence of purified chlorine gas. The chemical reaction below demonstrates HCl formation using the combustion process.

$CH_4 + O_2 + 2Cl_2 \rightarrow CO_2 + 4HCl$

The average annual usage for the HCl plant is assumed to be 4,380 hours annually, exactly half of the calendar year. The HCl plant operates only when USM has suppliers in need of food grade HCl. To date in 2020, the HCl plant has not been utilized onsite, but is anticipated to resume production in the fall of 2020.

NOx emissions associated with the HCl plant are generated through natural gas combustion in the burner. The unit is rated for less than 10 MMBtu/hr and generated 4.32 tons in 2018. Potentially available retrofit controls for the combustion unit are the same controls typically available to other natural gas combustion units.

Combustion Controls: Water or Steam Injection, Dry Low-NOx
Post-Combustion Controls: Selective Catalytic Reduction (SCR)

Water or Steam Injection
Steam or water injection controls the formation of NOx emissions by decreasing the peak flame temperature. It is an effective tool for reducing the formation of thermal NOx in all but regenerative cycle combustors. NOx emission reductions of generally 60-70% can be achieved using water or steam injection at water-to-fuel ratios of 0.2:1 to 1:1. It is important to utilize water or steam free of contaminants, so a water treatment system is an integral component of a wet control system. Several mechanical limits exist when it comes to water or steam injection systems, things like combustion operating instabilities, increased CO, heat rate penalties, combustion flame blow-off or flame-out. These limitations can decrease the efficiency of the water or steam injection system and increase the maintenance required.

Dry Low-NOx
NOx emission control techniques that are performed without the injection of water or steam are referred to as dry controls, but the method for emissions reductions is the same, reducing the peak flame temperature. This is generally accomplished by lean combustion or staged combustion. Lean

combustion refers to a technique that reduces the air/fuel ratio beyond that of normal stoichiometric operation (equivalence ratio = 1) to an air/fuel equivalence ratio of 2, i.e. very lean.

This reduces the combustion temperature by reducing the air required for combustion below stoichiometric levels. This method is only achievable under normal load range, during periods of startup or low load a transition program with higher air/fuel ratios is required. This results in increased NOx emissions during periods of startup or low load situations.

Staged combustion is another technique to lower NOx emissions, this strategy utilizes multiple combustion zones, usually two. The first zone operates lean or rich, but the second zone always operates lean. The incomplete combustion that results in the first combustions zone is further combusted in the lean second combustion zone resulting in reduced NOx formation.

Selective Catalytic Reduction (SCR)
In the SCR process, ammonia or urea is injected in the exhaust gas stream reacting with NOx in the presence of a catalyst to form molecular nitrogen and water. A SCR system can achieve a 95% reduction of NOx emissions.

The catalytic NOx-ammonia reaction takes place over a limited temperature range, 600-750 °F, anything about ~850 °F and the catalyst is damaged irreversibly. Ammonia slip is also a concern when utilizing an SCR for NOx emission reductions, as well as ammonia or urea storage, and costs of disposal of spent catalysts can also be a concern.

Step 2: Eliminate Technically Infeasible Options

The combustion unit at the HCl plant is the primary generator of the HCl product, as a result the plants operation must be taken into consideration when talking about NOx controls for the combustion unit.

Combustion Controls
Both water or steam injection and dry low-NOx combustion controls are technically infeasible for the HCl plant. Both controls reduce the formation of thermal NOx by reducing peak flame temperatures, this reduction in peak flame temperature would alter the performance of the HCl plant and as a result neither option will not be evaluated further.

Selective Catalytic Reduction (SCR)
Although a SCR system is a feasible option, retrofitting the HCl plant sizing, installation space, and operating the unit would be so challenging it is not technically feasible. The RBLC lists a facility in Louisiana that has installed an SCR unit onto a HCl plant, but provided no cost verification, and listed the emission type as LAER, which exceeds the requirements of this BART analysis many times over.

Sizing the SCR unit is challenging because the burner rate is not static, and the run times can be quite short. USM only operates the HCl plant when they have a supplier in need of the product. Depending on the economy and availability this can be quite infrequent. The minimal operating schedule would also make operating the unit a challenge. Historically there have been operation times that vary from half a day to several weeks. Downtime of the plant can be up to 8 months or more, requiring additional maintenance to get the unit operational upon startup.

The installation space required for an SCR unit is not extremely large, however, the exhaust stack on the HCl plant sits inside the racking and piping for the plant itself, and although it is probably feasible it would be a challenging retrofit.

For the reasons listed above this control technology is not considered technically feasible as a retrofit option for the hydrochloric acid plant and was not evaluated further.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
Step 3 of the review process is to rank the technically feasible options by how effective they are at removing NOx emissions. As no control technologies are technically feasible for the specific operations at USM, no ranking is possible.

Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance
- Timing for compliance
- Energy and other impacts not related to air quality
- The remaining useful life of the source

As no remaining retrofit control technologies are technically feasible analysis of the above list is not possible.

Summary and Conclusions
The HCl plant at USM operates infrequently and has a minimal impact on the overall NOx emissions associated with the plant. In 2018, the HCl plant was responsible for 4.32 tons of NOx. No retrofit control options were technically feasible for the operations at USM. USM will continue to operate the HCl plant as it currently configured on an as needed basis.

4.6 Casting House

Step 1: Identify All Potentially Available Retrofit NOx Control Technologies

The cast house at USM operates eleven natural gas fired crucible furnaces. Each crucible furnace is equipped with six 1 MMBtu/hr burners, three in an upper horizontal angled array and three in a lower horizontal angled array, for a total heating rating of 6 MMBtu/hr per crucible furnace, for a total of 66 burners. After an extensive search of the RBLC database only two entries were found for crucible furnaces, both employing smaller burners in numerous quantities like operations at USM. Both the entries in the RBLC utilized AP-42 emission factors and operated with no emission controls. Given the smaller size of these natural gas burners, and their array and installation it is unlikely that any control technologies exist, it is even less likely that a retrofit control technology would exist. No additional analysis was performed for the burners associated with the crucible furnaces USM operates.

The cast house also utilizes tool heating boxes, they are top and open-faced boxes with four small bayonet style burners, these burners typically range from 0.1 to 0.25 MMBtu/hr. The tool heating boxes sole purpose is safety. The tools used in USM casting house are heated up to remove any potential for water vapor or condensation forming on the metal when it contacts the heated magnesium metal. Water and magnesium can result in the formation of hydrogen gas, which is very explosive. These tool heating boxes are an integral part of the process and perform mandatory safety tasks. Given their low burner rating no retrofit controls exist that would still allow the heating boxes to function as needed. No additional analysis was performed for the tool heating boxes at USM.

Step 2: Eliminate Technically Infeasible Options

No retrofit controls were identified for the 1 MMBtu/hr burners utilized in the casting house at USM. Similarly, no retrofit controls were identified for the tool heating boxes that utilize 0.1 to 0.25 MMBtu/hr burners.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Step 3 of the review process is to rank the technically feasible options by how effective they are at removing NOx emissions. As no control technologies are technically feasible for the specific operations at USM, no ranking is possible.

Step 4: Evaluate Most Effective Controls and Document Conclusions

Step 4 of the review process is to evaluate the most effective controls and document conclusions; this is completed by considering the following:

- Cost of compliance
- Timing for compliance
- Energy and other impacts not related to air quality
- The remaining useful life of the source

As no remaining retrofit control technologies are technically feasible analysis of the above list is not possible.

Summary and Conclusions
USM operates eleven crucible furnaces for the purposes of maintaining magnesium metal in a molten state and casting that molten magnesium into ingots. Each furnace utilizes six smaller burners rated at 1 MMBtu/hr each. Additionally, there are multiple tool heating racks placed strategically around the casting house that are used to heat tools that will be in contact with heated magnesium ore. The combination of these burner units combusting natural gas emit 14.70 tons of NOx emission annually. Given that there is a total of ~80 burners in the casting house, each contributing a minimal amount of NOx emissions. Controls for these small combustion devices are not readily available, and none were found during the BART analysis. USM will continue to operate the casting house as it is currently configured.

4.7 Lithium Plant

USM has recently constructed the lithium plant, which finished the permitting process on April 20, 2020. The lithium plant digests existing waste coupled with current waste streams to extract the available lithium ore. The NOX emissions from the plant come from natural gas combustion units. The plant consists of two boilers, a 63 and an 84 MMBtu/hr; and two evaporative burners, a 50 and a 100 MMBtu/hr. The analysis for the lithium plant was broken into two sections, a natural gas fired boiler section and an evaporative burner section.

Natural Gas Fired Boilers
The natural gas fired boilers were installed in early 2020 and went through a BACT analysis earlier this year. They are ultra-low-NOx units capable of meeting a concentration limit of 9 ppm NOx or less. As BACT is more inclusive than BART performing a BART analysis on these boilers would be redundant and would yield no results. No additional analysis was performed on the 62 MMBtu/hr or 84 MMBtu/hr natural gas fired boilers installed in 2020, however the NOx BACT analysis that was completed for USM's AO was included as additional information.

Evaporative Burners
The natural gas fired evaporative burners were similarly installed in early 2020 and went through a BACT analysis earlier this year. They are low-NOx units capable of meeting a concentration limit of 30 ppm NOx or less19. As BACT is more inclusive than BART performing a BART analysis on these evaporative burners would be redundant and would yield no results. No additional analysis was performed on the 50 MMBtu/hr or 100 MMBtu/hr evaporative burners installed in 2020. As with the natural gas fired boilers, the BACT analysis from USM's AO was included as additional information.

4.8 Conclusion

This outlines USM's evaluation of possible retrofit options for all NOx emitting units onsite at their Rowley Plant located in Tooele County, Utah, in an attempt at reducing their NOx emissions facility wide and reducing their impact on visibility impairment issues. The results of this report found that it is potentially technologically and economically feasible to install a flue gas recirculation unit on the Riley boiler, reducing their NOx emissions by an estimated 22.6 tons annually. Aside from this change, there were currently no other technically or economically feasible options available for USM's Rowley Plant. Pending further technological and cost refinement, the implementation schedule for the installation of the FGR unit may be installed prior to the end of 2028. Therefore, the emissions for the 2028 modeling scenario could be an estimated 22.6 tons less than the 2018 baseline year NOx emissions.

5.0 DAQ Conclusion

Several errors were made during the analysis of the various control options outlined in this document. While the errors ultimately do not change the outcome or results of the analysis, they should be corrected prior to final acceptance by DAQ. The following lists the errors noticed by DAQ and the resulting effect each error leads to in the final result:

Incorrect interest rate used for control cost calculation – rather than using the current bank prime rate of 3.25%, the source calculated all control costs with either an interest rate of 7% (used as the default in the control cost manual) or 5.5% (used as the default in the SCR control cost spreadsheet). Both calculations result in a higher control cost in $/ton.

Second, the source used only a 20-year expected life for application of an SCR, which is lower than the standard 30-year lifespan. Again, this would artificially inflate the control cost by increasing the annualized cost.

However, the overall cost of the SCR system as estimated by the source was lower than expected, with an initial cost of just $87,000. The low initial cost serves to lower the resulting control cost.

DAQ reanalyzed the use of SCR on the Riley Boiler under two different scenarios. Under PTE, assuming full load, the application of SCR might be expected to remove as much as 188 tons of NOx at a control cost of \$4,073/ton of NOx removed – assuming the same 90% removal efficiency as did the source. However, the Riley Boiler did not operate at that high an output level – reporting just 45.25 tons of actual emissions in 2018. Adjusting the emission reduction for 90% of the actual emissions gives a removal of 40.7 tons of NOx (as opposed to the 38 tons suggested by the source), at a control cost of \$18,800/ton of NOx removed.

Similar errors were made with respect to the FGR calculations on the Riley Boiler. The incorrect interest rate was used – 7% vs 3.25%. FGR systems typically have a potential lifespan of 15 years rather than the 20 years suggested by the source. DAQ recalculated the control costs correcting for these errors and obtained a modified value of 22.5 tons of NOx removed at a control cost of \$1,880/ton of NOx removed.

None of the other equipment requires additional evaluation, as each is currently well controlled. While the same types of errors were made in the source's analysis, the resulting outcomes and conclusions remain unchanged.

DAQ recommends that FGR be considered for retrofit control application on the Riley boiler. Should the source increase utilization of the Riley boiler, then the application of SCR should be considered.

APPENDIX C.5.C - US Magnesium Evaluation Response

Chelsea Cancino <ccancino@utah.gov>

4-Factor Analysis Evaluation Response

Rob Hartman <rhartman@usmagnesium.com> Fri, Sep 17, 2021 at 8:32 AM
To: Chelsea Cancino <ccancino@utah.gov>
Cc: "gsowards@utah.gov" <gsowards@utah.gov>

Todd Wetzel resigned from GeoStrata, accepted a management position with an industrial production operation in the mid-west and moved out of Utah in mid-August. Mr. Wetzel is no longer available to advise on the DAQ comments or conclusions.

US Magnesium has re-evaluated the status of the Riley boiler (RILEY BOILER ENERGY ASSESSMENT - US Magnesium LLC, Rowley Plant - Tooele County, GeoStrata, March 2021: Submitted to the Utah Division of Air Quality on March 12, 2021) and the Riley boiler NOx emission factor utilized in US Magnesium's 2018 air emission inventory (AEI) that was the basis for the 4-factor analysis of that unit. In summary, the US Magnesium 2018 AEI grossly overstated the NOx emissions associated with the Riley boiler in two ways: 1) the Riley boiler is a 60 MMBTU boiler but the AP42 emission factor in the 2018 AEI is for a >100 MMBTU boiler, and 2) the Riley boiler, from the time of its installation, is outfitted with a low NOx burner, but the AP42 emission factor in the 2018 AEI is for an "uncontrolled burner." The implications are summarized below:

Riley Boiler 2018	NOx emission factor	AP 42 Table1.4-1. Emission Factors for NOx and CO from Natural Gas Combustion		Estimated NOx emissions (TPY)
AEI as submitted	190 lbs/MMscf	>100MMBTU (Large)	Uncontrolled	45.2499
AEI corrected for actual status of Riley boiler	50 lbs/MMscf	<100MMBTU (Small)	Controlled - Low NOx burner	**11.9074**

Corrected 2018 NOx emissions for the Riley boiler, implications on the 4-factor analysis:

Using the same reductions assumed for FGR (up to 50% NOx), the estimated reduction would be about 6 tons/year.

Using the same reductions assumed for SCR (up to 90% NOx), the estimated reduction would be about 10.7 tons/year.

Using DAQ's modified calculation for FGR: $1,880/ton * 22.5 tons = $42,000/yr. Correcting to 6 ton / yr reduction = $7,050/ton.

Using DAQ's modified calculation for SCR: $18,800/ton * 40.7 tons = $765,160/yr. Correcting to 11.9 ton / yr reduction = $64,300/ton.

US Magnesium submits this information to correct the record and as an addendum to the 4-factor analysis. US Magnesium concurs with DAQ's overall assessment that "None of the other equipment requires additional evaluation, as each is currently well controlled."

Rob Hartman, P.G.

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APPENDIX D – FLM Review

APPENDIX D.1 – National Parks Service Comments

National Park Service (NPS) Regional Haze SIP feedback for the Utah, Division of Air Quality

February 14, 2022

Contents

1 Executive Summary

The National Park Service (NPS) appreciates the opportunity to review the draft *Utah Regional Haze State Implementation Plan (SIP), Second Planning Period*. On February 9, 2022, staff from the NPS Air Resources Division (ARD) and NPS Interior Regions 6, 7, and 8 hosted a regional haze SIP review consultation meeting with Utah Division of Air Quality (UDAQ) staff to discuss NPS input on the draft Utah Regional Haze SIP. We provide the following recommendations to strengthen the Utah SIP, which were discussed during our consultation meeting and are detailed in this document.

This technical feedback document provides:

- Overarching feedback on reasonable progress source selection, cost-effectiveness thresholds, the significance of Utah emissions to NPS Class I areas, and responses to SIP questions and editorial notes (Section 2)
- Discussion of several reasonable progress facilities exempted from analysis (Section 3)
- Facility-specific feedback, analyses, and recommendations (Section 4)
- Oil and gas area source recommendations (Section 5)

Utah is home to five NPS-managed Class I areas: Arches, Bryce Canyon, Capitol Reef, Canyonlands, and Zion National Parks. Emissions from sources in the state also affect visibility at NPS-managed Class I areas in the surrounding region including Bandelier National Monument in New Mexico, Craters of the Moon National Monument in Idaho, Grand Canyon and Petrified Forest National Parks in Arizona, Grand Teton and Yellowstone National Parks in Wyoming, and Mesa Verde National Park in Colorado. These areas are the focus of our review–we do not speak for or represent non-NPS Class I areas.

In summary, we request that Utah improve the draft SIP by:

- Requiring actual emission reductions from selected sources.
    - Proposed RP emission limits for the Hunter and Huntington Power Plants would not reduce emissions below current levels.
- Identifying and justifying a reasonable cost-effectiveness threshold.
- Basing control decisions on the four-factors.
- Addressing permitted NO_x and SO_2 emission limits for specific sources to prevent backsliding.
- Evaluating area source emission reduction opportunities in the oil and gas sector.
- Providing additional information and/or improved control analyses and emission testing requirements.

In order to achieve reasonable progress in this round of SIP development, we request that UDAQ take this opportunity to improve visibility by requiring implementation of the technically feasible and cost-effective emission control improvements identified for the Hunter and Huntington Power Plants as well as other sources evaluated. Visibility improvement in Class I areas depends on the cumulative effects of regional emission reductions.

2 Overarching feedback

2.1 Source Selection

As discussed in section 7.A.1 of the SIP, the UDAQ used an emissions over distance (Q/d > 6) approach in the initial screening step for selecting facilities for four-factor reasonable progress analyses. This resulted in the selection of ten sources for consideration in the control technology analyses. After subsequent review, Utah removed four sources from this original list based on source closures or actual emissions—our comments on these specific sources can be found in sections 3 and 4 of this document. In general, we agree that Utah's source selection process resulted in a reasonable subset of sources to evaluate in the draft SIP. Utah's recommendation to use a lower emissions over distance threshold of six versus ten—as recommended by the WRAP—is more rigorous and resulted in a reasonable selection of facilities for evaluation.

2.2 Cost-effectiveness thresholds

While UDAQ has completed the technical work necessary to fulfill the state's analytical obligations under the regional haze provisions, the SIP does not identify the criteria relied upon to make the final reasonable progress (RP) determinations, as required under the regional haze (RH) regulations.[1]

For instance, the Utah SIP evaluated the four statutory factors for six sources but has not identified a cost threshold under which the evaluated controls would be considered reasonable. Many of the controls identified in the four-factor analyses for Utah sources are cost-effective based on cost criteria/thresholds identified by other states. For example, other states have set the following cost-effectiveness thresholds in their draft proposals:

- $5,000/ton in Arkansas (EGUs) and Texas
- $6,100/ton in Idaho
- $10,000/ton in Colorado and Oregon
- A range between $5,000 to $10,000/ton in Nevada
- A range between $4,000 to $6,500/ton in Arizona

The SIP should document the full rationale upon which the reasonable progress decisions are based. We recommend that UDAQ require all technically feasible, cost-effective controls identified through four-factor analysis in this planning period.

2.3 Significance of Utah Emissions to NPS Class I areas

[1] 40 CFR § 51.308 (f)(2)(i): 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. [Emphasis added]

In the draft SIP UDAQ writes that "Utah has analyzed the WRAP photochemical modeling for OTB 2028 and found that emissions from Utah do not significantly impact visibility at CIAs in other states." While it does not appear that this conclusion impacted the source selection process, it is not clear how Utah used this conclusion or whether it influenced their control technology determinations.

UDAQ's conclusion is not compatible with our findings regarding the impact of Utah sources in Class I areas of neighboring states, and we recommend that UDAQ revise this section of the draft SIP. We have several concerns with this statement in the draft SIP.

First, UDAQ's proposed threshold of 10% of total US Anthropogenic Impact for determining what constitutes a "significant impact" is quite high. For comparison, in their Cross State Air Pollution Rule (CSAPR), EPA established a "one percent of the ozone NAAQS" screening threshold to determine whether a state's contribution to ozone in a "downwind" state is significant:

> *The Agency also provides . . . interstate contributions that are at or above the one percent of the NAAQS screening threshold.*

Not only is this 1% value much lower than the 10% threshold that UDAQ is using, but it is also a fixed, absolute value based upon a fraction of a constant value for the ozone NAAQS. An analogous approach would be to use 1% of the value (in Mm^{-1}) for natural visibility conditions on the most-impaired days (MID) at a given CIA as a threshold for a significant contribution to visibility impairment.

Second, we have fundamental concern with using percentages of current (or 2028) impact to characterize significance. This is because the threshold is dependent on the haze levels in the given class I area. The more-impacted a given Class I area is, the greater the absolute value of the impact will need to be to "trigger" the threshold. This could lead to an underestimation of the impact of a given facility on a heavily-impacted Class I area. (A percentage of a big number is a big number, whereas the same percentage of a smaller number is much smaller.) For example, in 2016 we modeled the impacts of the BART Alternative using CALPUFF and estimated a 1.39 dv impact at Mesa Verde National Park, which indicates that Hunter and Huntington cause visibility impairment there. However, the WEP percentages and rankings downplay the importance of these facilities at Mesa Verde National Park.

Finally, this conclusion is not compatible with our understanding of previous modeling studies. As part of our 2016 comments to EPA on the BART Alternative for PacifiCorp's Hunter and Huntington power plants, the NPS conducted long range transport CALPUFF modeling analyses to evaluate the impacts from the different alternatives on visibility at eight NPS Class I areas. This analysis found that Hunter and Huntington were significant contributors to visibility impairment at all eight Class I areas, including the Utah national parks as well as Black Canyon of the Gunnison, Grand Canyon, and Mesa Verde National Parks in neighboring states. Further, in its 2019 BART Alternative proposal, PacifiCorp modeled impacts at 15 Class I areas, ten in neighboring states.

There are 25 mandatory federal Class I areas (11 administered by NPS) within 500 km of the Hunter and Huntington facilities that all exceed UDAQ's selection threshold of Q/d > 6. The 11 NPS Class I areas are Arches, Bryce Canyon, Capitol Reef, Canyonlands, and Zion National Parks in Utah, as well as Bandelier National Monument in New Mexico, Craters of the Moon National Monument in Idaho, Grand Canyon and Petrified Forest National Parks in Arizona, Grand Teton National Park in Wyoming, and Mesa Verde National Park in Colorado (Figures 1 and 2).

2.4 SIP Questions & Editorial Notes

2.4.1 Reasonably Attributable Visibility Impairment (RAVI)

On page 76 of the draft SIP Utah requested more information regarding where Utah stands in terms of RAVI for Class I areas.

RAVI is a separate process from periodic SIP revisions. This avenue is rarely used by the FLMs to address specific sources causing visibility impairment at Class I areas. The NPS will not likely pursue RAVI certification unless the approaches identified in the periodic SIP revisions do not adequately address documented impairment.

2.4.2 Prescribed Fire and International Contribution Glidepath Adjustments

On page 60 of the draft SIP UDAQ asked for feedback on using prescribed fire data from USFS to adjust projections.

NPS does not take a position on the adjustment of glidepath end points for prescribed fire. We support UDAQ's determination to not use glidepath adjustments for estimated contributions from international emissions.

2.4.3 Suggested Non-Technical Edits

In Table 27 *Sources initially selected to perform a Four-Factor analysis* in draft SIP, section 7.A.1, we recommend identifying the nearest Class I area referenced in the "distance to nearest Class I area" column.

In section 8.D.6 there appears to be a typographical error listing Intermountain Generation Station closing in 2017.

3 Sources Exempted from Four-Factor Analysis

Utah source selection criteria originally identified ten facilities for evaluation of emission control opportunities based on the four statutory factors identified in §7491 (g)(1) of the Clean Air Act. Based on updated 2018 emissions data and preliminary evaluations, four facilities were exempted from four-factor analyses including the Lisbon Natural Gas Processing Plant, Intermountain Generation Station, and Kennecott Utah Copper.

3.1 Lisbon Natural Gas Processing Plant (CCI Paradox Midstream, LLC)

We recommend that UDAQ revise the permit limits for this facility to reflect actual emission assumptions used to exclude this facility from four-factor analysis. This facility is located 35.8 km from Canyonlands National Park and is of interest to the NPS given the proximity to the park and significant potential emissions (the current SO_2 limits in the permit are quite high at 1,593 tons/year). The WRAP SO_2 WEP analyses ranks the Lisbon plant as the third most-most impacting facility in Canyonlands National Park. However, UDAQ excluded this source from analysis based on recent (2018) actual emissions. In Section 7.A.2, UDAQ states:

> *"In 2009 the plant received a permit modification to lower the SO_2 emissions from 1,593 tons down to 111 tons. The plant requested a reduction in emissions as it had installed both primary and secondary control systems to limit emissions of SO_2. Unfortunately, in 2010 the plant requested a new modification and mistakenly restored the original 1,593 tons of SO_2 emissions without explanation. While that PTE value has been carried forward in more recent permitting actions, actual emissions have never reached the 1,593-ton value. Rather, the actual emissions from the facility are more in line with the proper 2009 PTE of 111 tons."*

The SIP does not report recent actual emissions for this facility. We recommend including this information in the SIP. The conclusion presented in the UT SIP indicates that the plant has been complying with the 2009 requested reduction in potential to emit (PTE). However, the actual emissions reported in the 2014 NEI are nearly seven times this level at 189 tons/year of NO_x, 500 tons/year of SO_2 and 59 tons/year of PM_{10}, with a Q/d of 20.9 for Canyonlands NP. We recognize that in general, 2014 was a high production year in the oil and gas industry. Given that this industry is prone to periodic swings in production (and associated processing requirements), we recommend that the permit limitations discussed in the SIP as the basis for excluding the Lisbon Natural Gas Processing Plant from four-factor analysis are reinstated. This will ensure the facility continues to comply with the emission levels used to exclude it from four-factor analysis.

This is important given the proximity of this facility to the NPS Class I area, Canyonlands National Park, and is consistent with 2021 EPA guidance on this issue. Section 4.5 of the EPA 2021 Clarification Memorandum states:

> *"[F]or the purpose of a four-factor analysis for a particular source, a state may have assumed significantly lower baseline emissions (total emissions by mass) due to a projected reduction in utilization or production. This issue has*

come up in some SIPs and has implications for both new and existing measures. As explained in the August 2019 Guidance, reasonable bases for projecting that future emissions will be significantly different than past emissions are enforceable requirements and energy efficiency, renewable energy, or other similar programs, where there is a documented commitment to participate and a verifiable basis for quantifying changes in future emissions. However, in some cases states may have projected significantly lower total emissions due to unenforceable utilization or production assumptions and those projections are dispositive of the four-factor analysis. For example, a state that rejected new controls solely based on cost-effectiveness values that were higher due to low utilization assumptions. In this circumstance, an emission limit that requires compliance with only an emission rate may not be able to reasonably ensure that the source's future emissions will be consistent with the assumptions relied upon for the reasonable progress determination."

3.2 Intermountain Generation Station (Intermountain Power)

We recommend that UDAQ conduct or require four-factor analyses exploring opportunities to improve the efficiency of the existing SO_2 scrubbers consider NO_x emissions for the remaining useful life of the facility.

In the draft SIP UDAQ states that:

> *Though the coal-fired units are expected to cease operation by mid-2025, Utah is establishing a firm closure date of no later than December 31, 2027, to ensure that the coal-fired units at IGS will not continue to operate beyond the end of the second planning period. This date allows flexibility for closing the plant and the rescinding of the permit and approval order.*

The planned closure of a facility often affects the cost-effectiveness of controlling emissions by shortening the useful life in control cost calculations. UDAQ has properly required a federally enforceable closure date of December 31, 2027, to ensure that future emissions reflect SIP assumptions and conclusions.

A quick review indicates that upgrades to the existing SO_2 scrubbers may be a cost-effective way to reduce haze causing emissions in the remaining years prior to facility closure. We estimate that the scrubbers at the Intermountain Generation Station are 94% effective, while a modern wet limestone scrubber should be able to achieve at least 98% control (see attached calculation spreadsheet: IGS CAMD & EIA.xlsx). SO_2 scrubber upgrades of this nature are often very cost-effective and quick to implement. Although it is unlikely that NO_x can be reduced in a cost-effective manner over such a short remaining useful life, that possibility should also be investigated.

3.3 Kennecott Utah Copper–Mine & Copperton Concentrator

In the draft SIP, UDAQ states that the Kennecott Mine and Copperton Concentrator recently underwent BACT analysis as part of the Salt Lake $PM_{2.5}$ SIP. As a result, there are no additional controls that can be applied at this time. The predominant visibility impairing pollutant from this facility is NO_x, the vast majority of which comes from mine haul trucks and other non-road equipment. Section 209 of the Clean Air Act preempts the State from setting standards for non-road vehicles or engines. Though Part H of the $PM_{2.5}$ SIP does include in-use requirements for this equipment, UDAQ does not anticipate additional emissions reductions from this equipment until such time as the fleet turns over to more recent Tier 4 standards.

We request that UDAQ provide a breakdown of emissions from emission units it can regulate versus those it cannot regulate. UDAQ should explain how its $PM_{2.5}$ SIP includes in-use requirements for this equipment.

4 Specific Review of Four-Factor Analyses

4.1 PacifiCorp – Overarching Hunter & Huntington Feedback

Several aspects of our feedback for the PacifiCorp Hunter and Huntington power plants are common to both facilities and are addressed here. Plant-specific feedback on each individual facility four-factor analysis are presented in the following sections (4.2 and 4.3).

4.1.1 Class I Areas impacted by Hunter and Huntington

The scale of emissions from the Hunter and Huntington power plants and the proximity of these facilities to numerous Class I areas in Utah and neighboring states make them especially important for addressing regional haze in this planning period. As highlighted in our overarching feedback (Section 2.3) these two facilities affect visibility in 25 Class I areas including 11 managed by the NPS (Figures 1 and 2).

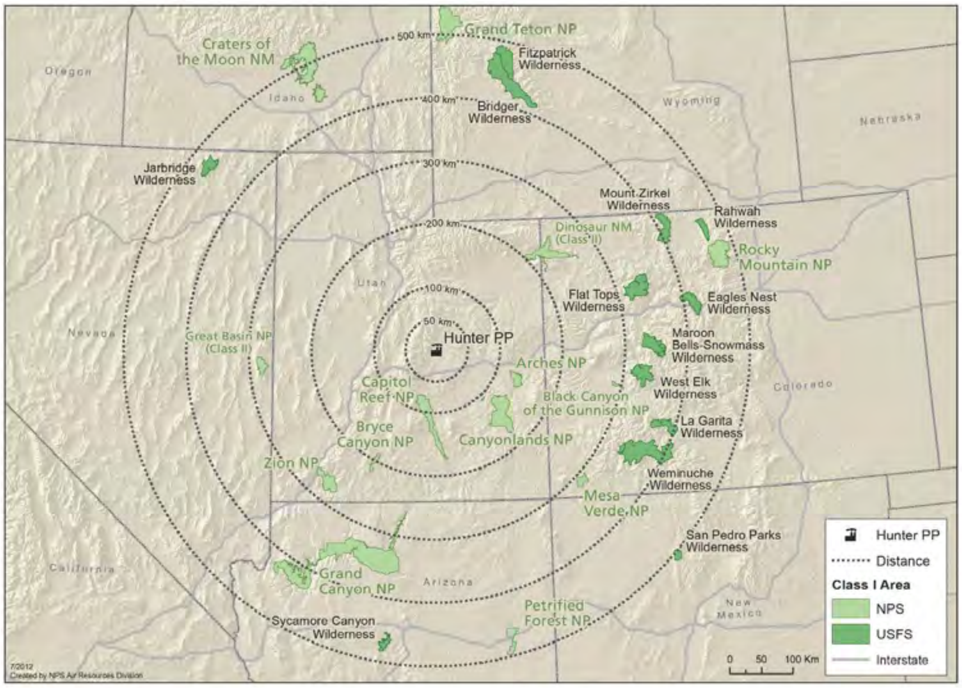

Figure 1. Map of Class I areas within 500km of the Hunter Power Plant. Note, Dinosaur National Monument and Great Basin National Park—both Class II parks—are also shown.

Figure 2. Map of Class I areas within 500km of the Huntington Power Plant. Note, Dinosaur National Monument and Utah and Great Basin National Park—both Class II parks—are also shown.

4.1.2 Need to Evaluate SO_2 Control Efficiency Improvements for Hunter and Huntington

PacifiCorp and UDAQ did not conduct a four-factor analysis to explore potential SO_2 emission reduction opportunities for the Hunter and Huntington facilities. PacifiCorp contends that the facilities are already effectively controlled for SO with the existing wet scrubbers and that no analysis is needed.

Regarding effective controls, EPA recently addresses the need to consider potential upgrades to existing controls through four-factor analysis in a clarification memorandum.[2]

[2] The EPA Memorandum, *Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period*, released July 8th, 2021 Sections 2.3 and 3.2:

"Similarly, in some cases, states may be able to achieve greater control efficiencies, and, therefore, lower emission rates, using their existing measures. Considering efficiency improvements for an existing control (e.g., using additional reagent to increase the efficiency of an existing scrubber) as a potential measure is generally reasonable since in many cases such improvements may only involve additional operation and maintenance costs. States should generally include efficiency improvements for sources' existing measures as control options in their four-factor analyses in addition to other types of emission reduction measures." (Section 3.2)

This was also recently emphasized in EPA comments on the draft Wyoming regional haze SIP:

> *Similarly, we recommend Wyoming consider whether it is possible to achieve a lower emission rate using the source's existing SO_2 controls, as well whether scrubber upgrades might be reasonable. If either is a potentially reasonable control option, we recommend the State either conduct a four-factor analysis for SO_2 control or explain why it is reasonable to forgo doing so.*

The wet scrubbers at Hunter and Huntington should be capable of achieving at least 95% control. Based upon 2020 Energy Information Administration (EIA) fuels data and the most-recent five years of Clean Air Markets Division (CAMD) data, the Hunter and Huntington scrubbers are achieving only 90% - 92% SO_2 control. Furthermore, PacifiCorp provided information indicating that upgrading the existing scrubbers could remove over 3,000 tons/year of additional SO_2 for less than $1,000/ton.

We recommend that UDAQ reduce haze causing SO_2 emissions from Hunter and Huntington facilities by requiring an evaluation of SO_2 scrubber optimization and potential efficiency improvements and implement any technically feasible and cost-effective options identified.

4.1.3 NO_x Control Analysis for Hunter and Huntington

Statutory Factor 1: Cost of Compliance

UDAQ revised the initial NO_x control cost analyses to address several analysis concerns. PacifiCorp raised technical objections to UDAQ's revised cost analyses for potential NO_x controls, including:

- interest rate,
- use of site-specific values,
- heat-input and capacity factors,
- air pre-heater costs, and
- operating and maintenance costs.

Given these concerns raised by PacifiCorp, we would like to underscore that in general, we agree with UDAQs revisions to the NO_x control technology cost analyses and made similar revisions in our assessment of NO_x control costs.

EPA's Control Cost Manual (CCM) recommends use of site-specific values where they are available. PacifiCorp objected to the use of a standard 3.25% interest rate and has provided

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"The underlying rationale for the "effective controls" flexibility is that if a source's emissions are already well controlled, it is unlikely that further cost-effective reductions are available. A state relying on an "effective control" to avoid performing a four-factor analysis for a source should demonstrate why, for that source specifically, a four-factor analysis would not result in new controls and would, therefore, be a futile exercise. States should first assess whether the source in question already operates an "effective control" as described in the August 2019 Guidance. *They should further consider information specific to the source, including recent actual and projected emission rates, to determine if the source could reasonably attain a lower rate.*" (Section 2.3) Based on CAMD data for existing similar sources, we recommend that the TVA facilities may be able to "reasonably attain a lower rate."

information demonstrating that an interest rate of 7.303% is appropriate for their cost analyses. We agree with UDAQ that this demonstration is sufficient and that the 7.303% is appropriate for use in PacifiCorp four-factor analyses. In each of the other areas where PacifiCorp cited concerns, we find that UDAQ methods are in line with those recommended by the EPA CCM and are well justified. We also rely on CCM methodology for our calculations

–Baseline emissions

For the cost-effectiveness evaluation of SNCR and SCR, PacifiCorp used the five-year average baseline NO_x emissions and heat input (2015-2019) as current conditions. PacifiCorp also completed a cost analysis for the Reasonable Progress Emission Limits (RPELs) using the facility's current Plantwide Applicability Limit (PAL) as the baseline.

We generally evaluate potential control strategies versus the most-likely future emission scenario—a continuation of current operations. However, for the sake of evaluating PacifiCorp's RPEL argument, we also evaluated potential control strategies versus PAL emission levels. Likewise, we evaluated potential control strategies versus the new NO_x limits proposed by UDAQ (RP Emissions). Using the CCM workbooks, we set "Inlet NO_x Emissions (NO_xin)" to the appropriate permit limit and adjusted the "actual annual MWhs output" to produce uncontrolled NO_x emissions approximating the appropriate PAL or limit proposed by UDAQ. Our analysis used 2016-2020 emissions as current. See analysis results in Tables 2, 3, 5, and 6 below.

–NO_x removal efficiency

One of the factors affecting SNCR efficiency is the boiler NO_x rate. PacifiCorp/S&L assumed that SNCR could achieve 20% NO_x reduction regardless of the differing NO_x emission rates from these boilers. Instead, we applied the relation provided by CCM Figure 1.1c to estimate boiler-specific NO_x reduction.

PacifiCorp/S&L cites NO_x control determinations from more than five years ago as evidence that SCR cannot be assumed to reduce NO_x emissions from these boilers below 0.05 lb/mmBtu on an annual basis. According to the CCM, this is no longer the case:

> *Typically, the annual average outlet NO_x should not be less than 0.04 lb/MMBtu, or at a level that results in a removal efficiency greater than 90 percent, unless a guarantee has been obtained from a vendor.*

EPA assumed in 2014 that SCR could achieve the 0.04 lb/mmBtu annual emissions proposed by Basin Electric at its coal-fired Laramie River Station in WY. 2020 CAMD data contains 11 coal-fired EGUs with SCR at 0.04 lb/mmBtu annual average. Based on this, we assumed that SCR could achieve 0.04 lb/mmBtu on an annual average basis, but not exceed 90% efficiency.

–Affordability

PacifiCorp references to affordability considerations are from the BART regulations and are not addressed in any EPA guidance related to Reasonable Progress.

4.1.4 UDAQ Conclusions

We share UDAQ's concerns with PacifiCorp's RPEL recommendation and support UDAQ's rejection of this proposal. RPEL would essentially be a "paper" reduction in emissions that would not reduce haze-causing emissions affecting visibility in Utah's Class I national parks. The intent of the Regional Haze Rule is to reduce emissions from facilities affecting Class I areas to the maximum extent that reasonably meets the four statutory factors.

With respect to potential NO_x emission controls, UDAQ concludes that "due to the relatively high $/ton estimates for SNCR, that control was deemed not to be cost-effective." UDAQ considers potential application of SCR at one or more units at the Hunter and Huntington power plants (particularly for Hunter unit 3) before concluding that given "… uncertainty and the wide variability in cost-effectiveness estimates at various utilization levels, UDAQ finds installation of SCR not to be cost-effective at any of the five units at Hunter and Huntington at this time."

UDAQ finds that enforceable mass-based NO_x emission limits at the Hunter and Huntington facilities will ensure that the EGU nitrate contribution to light extinction at Utah (and other states) CIAs does not exceed modeled or recent actual emissions levels. These proposed emission limits are referred to as "Reasonable Progress" (RP) emission limits.

Our analyses (detailed below) of the costs of applying SNCR or SCR to these EGUs show that PacifiCorp's cost-effectiveness values are overestimated. Furthermore, UDAQ has not presented its criteria and justification for determining that these options are not cost-effective (see section 2.2 Cost-effectiveness thresholds above).

Visibility impairment is a short-term problem. Any emission limit that does not limit short-term emissions effectively allows fluctuations that could adversely impact a visitor's experience. Haze causing emissions should be controlled to the maximum reasonable extent at all times.

Although the RP NO_x limits proposed by UDAQ represent significant reductions versus the current PAL NO_x limits for Hunter and Huntington, they would allow NO_x emissions to increase (4% at Hunter and 12% at Huntington) versus the most recent five-year average. Emissions data show that since 2015 NO_x emissions at Hunter have only exceeded the proposed RP limit of 10,001 tons/year once (in 2019).

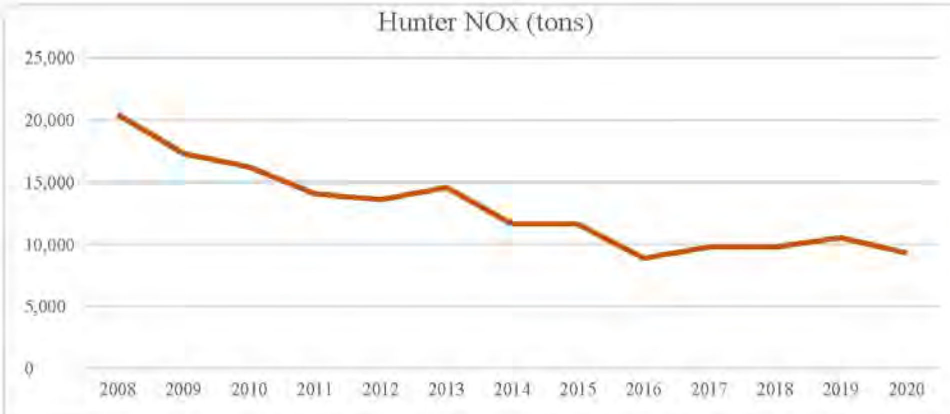

Figure 3. Annual facility wide NO_x emissions from PacifiCorp's Hunter Power Plant, 2008-2020 (CAMD 2020)

Likewise, NO_x emissions at Huntington have not exceeded the proposed RP limit of 6,091 tons/year (by 2028) since 2016.

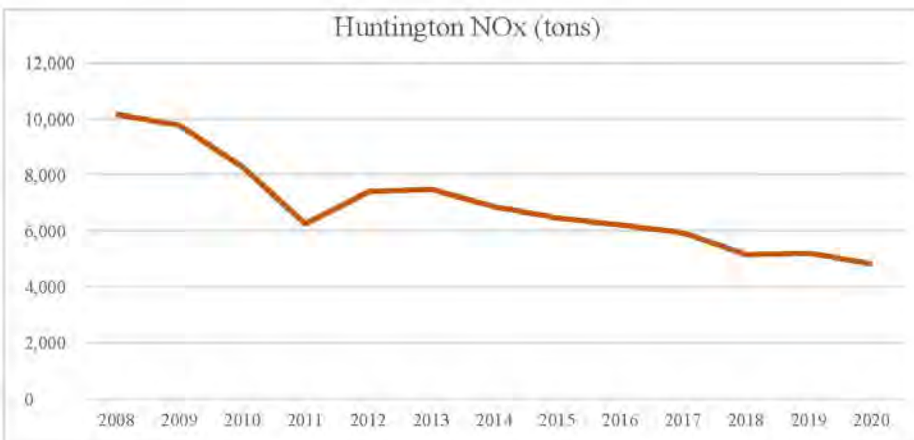

Figure 4. Annual facility wide NO_x emissions from PacifiCorp's Huntington Power Plant, 2008-2020 (CAMD 2020)

UDAQ RP emission limits, while adequate to prevent backsliding, fall well short of the NO_x emission reduction potential that requirement of SCR or SNCR controls at Hunter and Huntington EGUs could achieve. We recommend that UDAQ reconsider opportunities to make real NO_x emission reductions at the Hunter and Huntington power plants by requiring technically feasible, cost-effective controls in this planning period. Facility-specific findings and recommendations are detailed in Sections 4.2 and 4.3.

4.2 Hunter Power Plant (PacifiCorp)

4.2.1 Summary of NPS Recommendations and Requests for the Hunter Power Plant

NPS review of the four-factor analysis conducted for the Hunter Power Plant (Hunter) finds that there are technically feasible and cost-effective opportunities available to further control SO_2 and NO_x emissions from Units 1, 2, and 3. In fact, we find that the cost of control is more economical than estimated when analyses are adjusted in accordance with the EPA Control Cost Manual.

Although UDAQ has not established a cost threshold for this round of regional haze planning, we can advise that other states have set cost-effectiveness thresholds of \$4,000–\$6,500/ton in Arizona, \$5,000/ton in Arkansas (for EGUs) and Texas, \$5,000–\$10,000/ton in Nevada, \$6,100/ton in Idaho, and \$10,000/ton in Colorado and Oregon.

Four-factor analyses focused on upgrading or optimizing FGDs to reduce SO_2 emissions are warranted in this planning period. PacifiCorp analysis reveals that modifying the existing scrubbers at Hunter would be highly cost-effective and could reduce SO_2 emissions by over 1,800 tons/year compared to current emission levels. Additionally, we recommend that UDAQ address the increasing SO_2 emission rates from Hunter Unit 3.

We find that SNCR and SCR are both cost-effective opportunities for reducing NO_x emissions at Hunter Units 1, 2, and 3 under each of the emissions scenarios evaluated. SNCR could reduce current NO_x emissions by almost 2,100 tons/year compared to existing controls, almost 2,300 tons/year compared to proposed RP limits, and by over 3,400 tons/year compared to PAL limits. SCR could reduce current NO_x emissions by over 7,900 tons/year compared to existing controls, over 8,600 tons/year compared to proposed RP limits, and by over 12,900 tons/year compared to PAL limits. Average cost-effectiveness associated with the more rigorous SCR controls are \$6,000/ton or less and would be considered cost-effective in the context of the thresholds used by Colorado, Idaho, and Oregon in this round of regional haze planning.

We agree with the UDAQ decision to reject Hunter RPELs as a control option. This approach would not significantly reduce total annual NO_x or SO_2 emissions from current levels. We request that Utah require the most effective control measures found to be technically feasible and cost-effective through analysis of the four factors specified in the Regional Haze Rule. Those control measures include improved SO_2 scrubbing and addition of SCR to address NO_x emissions on all three Hunter units.

We recommend that Utah take every opportunity to reduce SO_2 and NO_x emissions from the Hunter Power Plant in this planning period. By requiring implementation of identified controls Utah will be reducing haze causing emissions and advancing incremental improvement of visibility in Utah's Class I areas as well as other Class I areas in the region.

4.2.2 Plant Characteristics

Hunter Power Plant (Hunter) is a 1,577-megawatt (MW) coal-fired power station operated by MidAmerican Energy (owned by Berkshire Hathaway) near Castle Dale, Utah.

- Unit 1: Ownership—PacifiCorp 93.75%, Provo City 6.25%
    - 480 MW capacity, tangentially-fired boiler in service since 1978
- Unit 2: Ownership—PacifiCorp 60.31%, Deseret Power Electric Cooperative 25.11%, Utah Associated Municipal Power Systems 14.58%
    - 480 MW capacity, tangentially-fired boiler in service since 1980
- Unit 3: Ownership—PacifiCorp 100%
    - 495 MW capacity, dry-bottom boiler in service since 1983

These subcritical boilers fire bituminous coals from the Sufco Mine (Wolverine Fuels) and Emery Mine (Bronco Utah). All EGUs are equipped with a low-NO_x burner/separated overfire air system (LNB/SOFA), baghouse, and SO Wet FGD (WFGD) scrubber with no scrubber bypass. Hunter Units 1 & 2 were subject to Best Available Retrofit Technology (BART) in the first Regional Haze planning period. (Hunter Unit 3 was constructed after the BART applicability period.) Hunter currently has NO_x, SO_2, and PM emission control technologies in place, including:

- Hunter Unit 1
    - LNB and SOFA (2014);
    - FGD (scrubber) system upgrade installed and operates year-round (2014);
    - Baghouse retrofit for PM control (2014);
- Hunter Unit 2
    - LNB and SOFA (2011);
    - FGD (scrubber) system installed and operates year-round (2011);
    - Baghouse retrofit for PM control (2011).
- Hunter Unit 3
    - Constructed with: FGD (scrubber) system upgrade that operates year-round; and baghouse for PM control (1983).
    - LNB and SOFA (2007).

4.2.3 Recent Emissions

Based upon recent emissions of SO_2 and NO_x, and distances of facilities from NPS Class I areas within 1,000 km, the Hunter Power Plant ranked #1 in the U.S. for cumulative impacts on those Class I areas. EPA's Clean Air Markets Database (CAMD) for 2020 shows Hunter's NO_x emissions at 9,287 tons which ranks it #6 among the 1,167 facilities in CAMD. Hunter's 2020 SO_2 emissions in CAMD were 2,957 tons and ranked #67. Hunter's carbon dioxide emissions of 8,715,743 tons rank #23 in the U.S. Hunter also ranked #340 for EGU mercury emissions with 3.4 lb in 2017.

The table below provides a breakdown *by unit* of 2020 SO_2 and NO_x emissions and how they rank versus the 3,317 EGUs in CAMD.

Table 1. 2020 Hunter EGU emissions and rank compared to other U.S. EGUs in CAMD

Unit ID	SO_2 (tons)	SO_2 (tons) Rank	Avg. SO_2 Rate (lb/MMBtu)	Avg. SO_2 Rate (lb/MMBtu) Rank	NO_x (tons)	NO_x (tons) Rank	Avg. NO_x Rate (lb/MMBtu)	Avg. NO_x Rate (lb/MMBtu) Rank
1	1,041	191	0.070	384	2,996	39	0.20	281
2	1,047	187	0.068	389	2,955	41	0.19	293
3	869	218	0.071	382	3,336	28	0.26	141

4.2.4 Reasonable Progress Emission Limit (RPEL)

We agree with UDAQ's rejection of the plantwide combined NO_x + SO emission limit of 17,000 tons/year proposed by PacifiCorp for Hunter as a control measure (RPEL). This measure would not constitute actual emission reductions. As our review illustrates, the sum of Hunter's $SO_2 + NO_x$ emissions has not exceeded the proposed RPEL of 17,000 tons/year since 2014 (see Figure XX). The most-recent five-year averages are 3,269 tons SO_2 and 9,643 tons NO_x and 12,912 tons combined.

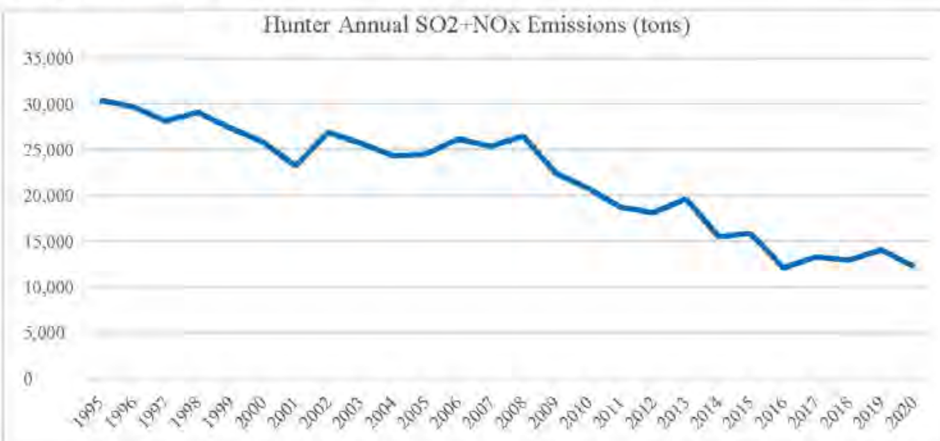

Figure 5. Hunter facility-wide annual $SO_2 + NO_x$ emissions (1995-2020) (CAMD 2020)

4.2.5 SO_2 Analysis

As discussed above (Section 4.1) we find that Hunter is not effectively-controlled for SO_2 emissions and that a four-factor analysis focused on efficiency improvements is warranted. Specifically, the wet scrubbers at Hunter should be capable of achieving at least 95% control. Our review of EIA 2020 fuels data indicates that uncontrolled SO_2 emissions at Hunter should be about 0.87 lb/mmBtu.[3] Based upon the most-recent five years of CAMD data, the Hunter

[3] We applied the AP-42 emission factor = 38S for bituminous coal as burned at Hunter.

scrubbers are achieving 90% - 92% SO_2 control. Further, the scrubber on Hunter Unit 3 has shown a trend of increasing SO_2 emission rates since 2009 as shown below. It is reasonable to expect that the scrubber optimization would minimally return the emission rate to levels that have been demonstrated in the recent past.

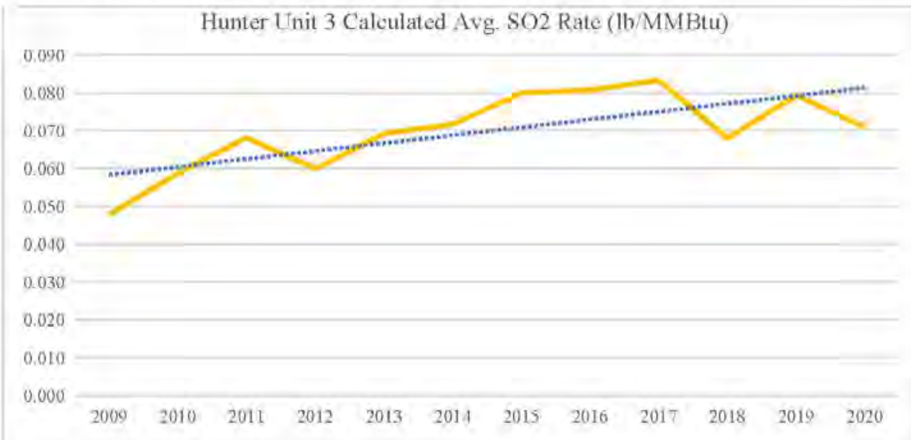

Figure 6. The Hunter Unit 3 calculated average SO_2 emission rate (2009-2020) is increasing. (CAMD 2020) (CAMD 2020)

PacifiCorp estimated that meeting it's suggested RPEL would require scrubbing to a SO emission rate of 0.032 lb./MMBtu on Units 1, 2, and 3 costing $301,000/year in O&M costs for a total annualized cost of $301,000/year for Units 1 and 2 and $311,000/year in O&M costs for a total annualized cost of $311,000/year for Unit 3. This suggests that scrubber upgrades and efficiencies are both known and achievable. Further, PacifiCorp estimates reveal that SO_2 emissions could be reduced by:

- Unit 1: over 500 tons/year at $600/ton.
- Unit 2: almost 700 tons/year at less than $500/ton
- Unit 3: over 600 tons/year at less than $500/ton

4.2.6 NO_x Analysis

Statutory Factor 1: Cost of Compliance

–Unit 1

The 2016 – 2020 sum of the average annual SO_2 and NO_x emissions from Hunter Unit 1 is 3,753 tons/year. The sum of Hunter Unit 1's SO_2 + NO_x emissions has not exceeded the proposed RPEL 4,824 tons/year threshold for this unit since 2013 as shown below.

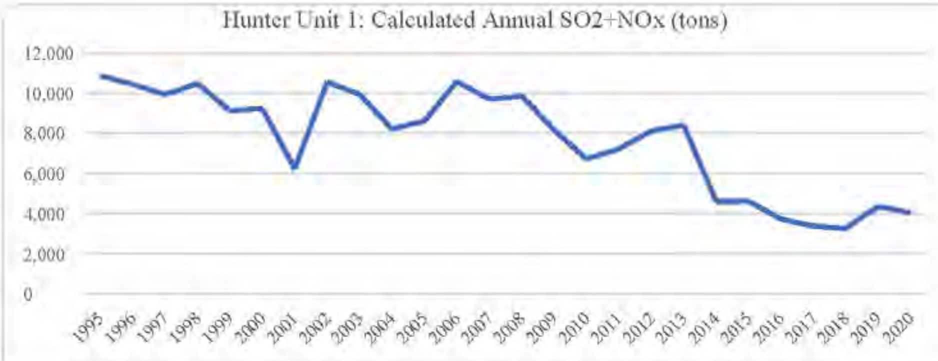

Figure 7. Hunter Unit 1, calculated annual SO_2 + NO_x emissions (CAMD 2020)

We find that 74% of recent Total SO_2 + NO_x emissions from Hunter Unit 1 have been NO_x. 74% of the Hunter Unit 1 PAL is 4,711 tons. Based upon Hunter Unit 1's 0.26 lb/mmBtu NO_x limit, we adjusted Hunter Unit 1 heat input to yield approximately 4,711 tons of NO_x; this formed the baseline for our analysis of the cost-effectiveness of adding SNCR or SCR versus the existing PAL.

PacifiCorp found that 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. Our estimates are shown in the table below.

–Unit 2

The 2016 – 2020 sum of the average annual SO_2 and NO_x emissions from Hunter Unit 2 is 4,047 tons/year. The sum of Hunter Unit 2's SO_2 + NO_x emissions has not exceeded the proposed RPEL 4,824 tons/year threshold since 2014 as shown below.

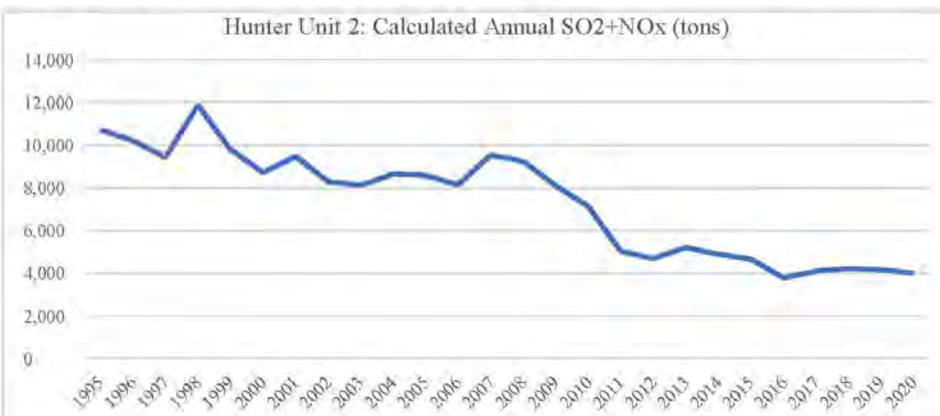

Figure 8. Hunter Unit 2, calculated annual SO_2 + NO_x emissions (CAMD 2020)

We find that 70% of recent Total SO_2 + NO_x emissions from Hunter Unit 2 have been NO_x. 70% of the Hunter Unit 2 PAL is 4,471 tons. Based upon Hunter Unit 2's 0.26 lb/mmBtu NO_x limit, we adjusted Hunter Unit 2 heat input to yield approximately 4,471 tons of NO_x; this formed the baseline for our analysis of the cost-effectiveness of adding SNCR or SCR versus the existing PAL.

PacifiCorp found 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. Our estimates are shown in the table below.

–Unit 3

The 2016 – 2020 sum of the average annual SO_2 and NO_x emissions from Hunter Unit 3 is 5,112 tons/year. The sum of Hunter Unit 2's SO_2 + NO_x emissions has not exceeded the proposed RPEL 7,352 tons/year threshold since 2008 as shown below.

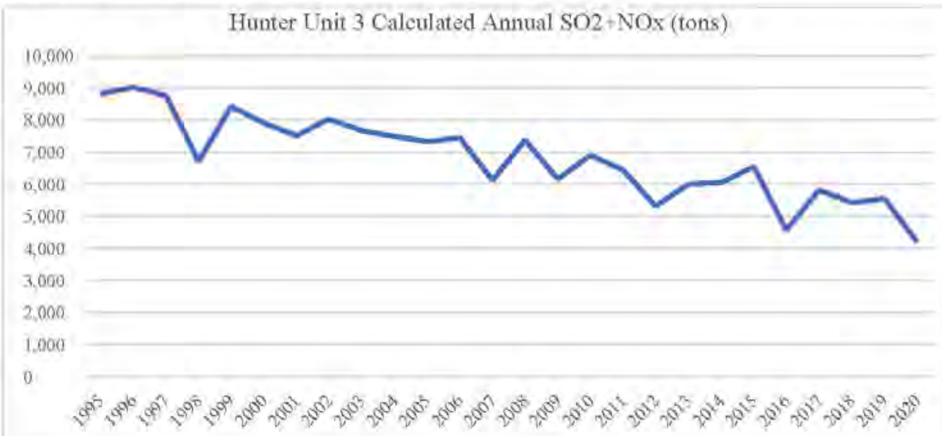

Figure 9. Hunter Unit 3, calculated annual SO_2 + NO_x emissions (CAMD 2020)

We find that 78% of recent Total SO_2 + NO_x emissions from Hunter Unit 3 have been NO_x. 78% of the Hunter Unit 3 PAL is 4,972 tons. Based upon Hunter Unit 3's 0.34 lb/mmBtu NO_x limit, we adjusted Hunter Unit 3 heat input to yield approximately 4,972 tons of NO_x; this formed the baseline for our analysis of the cost-effectiveness of adding SNCR or SCR versus the existing PAL.

PacifiCorp found 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. Our estimates are shown in the table below.

–Summary

Table 2. Hunter Cost Analyses for Current, PAL, and RP NO_x Emissions

Emission Unit and Baseline	Control Technology	Capital Cost	Indirect Cost	Direct Cost	Total Annual Cost	Tons Removed	Average Cost-effectiveness ($/ton)	Incremental Cost-effectiveness ($/ton)
Hunter **Unit 1** (current emissions)	SCR	$ 145,199,000	$ 12,070,598	$ 1,141,463	$13,212,061	2,228	$ 5,930	$ 6,173
	SNCR	$ 12,126,313	$ 1,176,859	$ 1,851,741	$ 3,028,599	578	$ 5,238	
Hunter **Unit 1** (PAL emissions)	SCR	$ 145,199,000	$ 12,070,598	$ 1,410,705	$13,481,303	3,697	$ 3,647	$ 3,557
	SNCR	$ 12,402,132	$ 1,203,627	$ 2,563,837	$ 3,767,464	966	$ 3,899	
Hunter **Unit 1** (RP emissions)	SCR	$ 145,199,000	$ 12,070,598	$ 1,082,996	$13,153,594	2,454	$ 5,359	$ 5,618
	SNCR	$ 12,402,132	$ 1,203,627	$ 1,764,630	$ 2,968,257	641	$ 4,628	
Hunter **Unit 2** (current emissions)	SCR	$ 145,199,000	$ 12,070,706	$ 1,164,238	$13,234,944	2,253	$ 5,873	$ 6,087
	SNCR	$ 11,991,127	$ 1,163,739	$ 1,922,186	$ 3,085,924	586	$ 5,266	
Hunter **Unit 2** (PAL emissions)	SCR	$ 145,199,000	$ 12,070,706	$ 1,397,827	$13,468,533	3,698	$ 3,642	$ 3,555
	SNCR	$ 12,308,220	$ 1,194,513	$ 2,562,820	$ 3,757,333	967	$ 3,887	
Hunter **Unit 2** (RP emissions)	SCR	$ 145,199,000	$ 12,070,706	$ 1,089,168	$13,159,874	2,512	$ 5,239	$ 5,479
	SNCR	$ 12,308,220	$ 1,194,513	$ 1,799,873	$ 2,994,386	656	$ 4,561	
Hunter **Unit 3** (current emissions)	SCR	$ 161,328,000	$ 13,411,189	$ 1,322,551	$14,733,740	3,427	$ 4,299	$ 4,429
	SNCR	$ 12,569,421	$ 1,219,862	$ 2,327,075	$ 3,546,937	901	$ 3,936	
Hunter **Unit 3** (PAL emissions)	SCR	$ 161,328,000	$ 13,411,189	$ 1,433,740	$14,844,929	4,352	$ 3,411	$ 3,364
	SNCR	$ 12,803,780	$ 1,242,607	$ 2,309,601	$ 3,552,208	995	$ 3,570	
Hunter **Unit 3** (RP emissions)	SCR	$ 161,328,000	$ 13,411,189	$ 1,284,380	$14,695,569	3,670	$ 4,004	$ 4,165
	SNCR	$ 12,803,780	$ 1,242,607	$ 2,309,601	$ 3,552,208	995	$ 3,570	

For calculations see workbooks identified by Unit# and emissions baseline condition in the PacifiCorp/HunterSCR and PacifiCorp/HunterSNCR folders in the attached NPS-UT_RH-SIP_FFA-AnalysisWorksheets.zip

Table 3. Hunter Facility-wide Totals for Control-Cost Analyses.

Emission Baseline	Control Technology	Capital Cost	Indirect Cost	Direct Cost	Total Annual Cost	Tons Removed	Average Cost-effectiveness ($/ton)	Incremental Cost-effectiveness ($/ton)
Hunter (current emissions)	SCR	$ 451,726,000	$ 37,552,493	$ 3,628,252	$41,180,744	7,908	$ 5,207	$ 5,394
	SNCR	$ 36,686,861	$ 3,560,460	$	$ 9,661,461	2,065	$ 4,678	$ -

				6,101,001				
Hunter (PAL emissions)	SCR	$ 451,726,000	$ 37,552,493	$ 4,242,272	$41,794,765	11,747	$ 3,558	$ 3,483
	SNCR	$ 37,514,132	$ 3,640,746	$ 7,436,258	$11,077,004	2,928	$ 3,784	$ -
Hunter (RP emissions)	SCR	$ 451,726,000	$ 37,552,493	$ 3,456,543	$41,009,036	8,636	$ 4,748	$ 4,965
	SNCR	$ 37,514,132	$ 3,640,746	$ 5,874,104	$ 9,514,850	2,293	$ 4,150	$ -

Statutory Factor 2: Time Necessary for Compliance

In consideration of time necessary for new NO_x controls, PacifiCorp writes that "…the installation of SNCR on the units would be less (time) 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." Based on analyses presented by Sargent & Lundy elsewhere, we expect that about five years would be necessary for SCR and two years for SNCR. It is unclear why more time is necessary in this case.

Statutory Factor 3: Energy and Non-Air Environmental Impacts

PacifiCorp raises several potential concerns with respect to Statutory factor 3 including the energy use, water use, carbon dioxide generation, and waste material generation as a result of operating pollution control equipment. Energy impacts are considered in the costs of compliance calculation and none of the other issues raised are unique to the Hunter facility. Utilities (including PacifiCorp at its Jim Bridger power plant in Wyoming) have shown that they can handle these materials with proper operation and maintenances practices.

We suggest that UDAQ could consider environmental co-benefits of NO_x emission reduction as part of this factor. NO_x is an ozone pre-cursor emission and ozone is known to affect both human and ecosystem health. Further, nitrogen deposition can be harmful to sensitive ecosystems including high alpine lakes and desert environments protected by national parks in the Utah region.

Statutory Factor 4: Remaining Useful Life

Unless a federally-enforceable shut-down date for a facility is in place, cost-effectiveness estimates are appropriately calculated using the EPA-mandated 20-year depreciable life for SNCR and 30-year depreciable life for SCR. Uncertainty and/or unenforceable commitments regarding facility lifetime are not part of the four-factor analysis.

4.2.7 Conclusions & Recommendations

- We agree with the UDAQ decision to reject Hunter RPELs as a control option. This approach would not significantly reduce total annual NO_x or SO_2 emissions from current levels.
- SO_2 four-factor analyses focused on upgrading or optimizing FGDs are warranted. Additionally, we recommend that UDAQ address the increasing SO_2 emission rates from Hunter Unit 3. Modifying the existing scrubbers at Hunter would be highly cost-effective and could reduce SO_2 emissions by over 1,800 tons/year compared to existing controls.
- The Cost of Compliance for adding NO_x controls is consistent with values accepted by other states in this round of planning (Section 2.2). The exceptionally large number of mandatory federal Class I areas affected by haze causing emissions from Hunter suggest consideration of higher cost thresholds.
- The annual average cost-effectiveness of adding SNCR would be acceptable in the context of the thresholds used by Colorado, Idaho, and Oregon. This strategy could reduce current NO_x emissions by almost 2,100 tons/year compared to existing controls,

almost 2,300 tons/year compared to proposed RP limits, and by over 3,400 tons/year compared to PAL limits.

- The annual average cost-effectiveness of adding SCR would also be acceptable in the context of the thresholds used by Colorado, Idaho, and Oregon. This strategy could reduce current NO_x emissions by over 7,900 tons/year compared to existing controls, over 8,600 tons/year compared to proposed RP limits, and by over 12,900 tons/year compared to PAL limits.
  - Using the PAL as baseline, as proposed by PacifiCorp, the cost-effectiveness of adding SCR never exceeds $3,700/ton.
  - Compared to the RP limits proposed by UDAQ, the cost-effectiveness of adding SCR never exceeds $5,400/ton.
  - Compared to current NO_x emissions, the cost-effectiveness of adding SCR never exceeds $6,000/ton.
  - The incremental cost-effectiveness of adding SCR is very reasonable.
- We request that Utah require the most effective control measures found to be technically feasible and cost-effective through analysis of the four factors specified in the Regional Haze Rule. Those control measures include improved SO_2 scrubbing and addition of SCR on all three Hunter units.

4.3 Huntington Power Plant (PacifiCorp)

4.3.1 Summary of NPS Recommendations and Requests for the Huntington Power Plant

NPS review of the four-factor analysis conducted for the Huntington Power Plant (Huntington) finds that there are technically-feasible and cost-effective opportunities available to further control SO_2 and NO_x emissions from Units 1 and 2. In fact, we find that the cost of control is more economical than estimated when analyses are adjusted in accordance with the EPA Control Cost Manual.

Although UDAQ has not established a cost threshold for this round of regional haze planning, we can advise that other states have set cost-effectiveness thresholds of: $4,000–$6,500/ton in Arizona, $5,000/ton for EGUs in Arkansas and Texas, $5,000–$10,000/ton in Nevada, $6,100/ton in Idaho, and $10,000/ton in Colorado and Oregon.

Four-factor analyses focused on upgrading or optimizing FGDs to reduce SO_2 emissions are warranted in this planning period. PacifiCorp analysis reveals that modifying the existing scrubbers at Huntington would be highly cost-effective and could reduce SO_2 emissions by over 1,300 tons/year compared to current emission levels.

We find that SNCR and SCR are both cost-effective opportunities for reducing NO_x emissions at Huntington Units 1 and 2 under each of the emissions scenarios evaluated. SNCR could reduce current NO_x emissions by over 1,100 tons/year compared to existing controls, over 1,300 tons/year compared to proposed RP limits, and by 1,750 tons/year compared to PAL limits. SCR could reduce current NO_x emissions by over 4,400 tons/year compared to existing controls, over

5,200 tons/year compared to proposed RP limits, and by over 8,500 tons/year compared to PAL limits. Average cost-effectiveness associated with the more rigorous SCR controls are $5,900/ton or less and would be considered cost-effective in the context of the thresholds used by Colorado, Idaho, and Oregon in this round of regional haze planning.

We agree with the UDAQ decision to reject Huntington RPELs as a control option. This approach would not significantly reduce total annual NO_x or SO_2 emissions from current levels. We request that Utah require the most-effective control measures found to be technically feasible and cost-effective through analysis of the four factors specified in the Regional Haze Rule. Those control measures include improved SO_2 scrubbing and addition of SCR to address NO_x emissions on both Huntington units.

We recommend that Utah take every opportunity to reduce SO_2 and NO_x emissions from the Huntington Power Plant in this planning period. By requiring implementation of identified controls Utah will be reducing haze causing emissions and advancing incremental improvement of visibility at Utah's Class I areas as well as other Class I areas in the region.

4.3.2 Plant Characteristics

The Huntington Power Plant (Huntington) is a 1,037.3-megawatt (MW) coal-fired power station operated by PacifiCorp (owned by Berkshire Hathaway) near Huntington, Utah.

- Unit 1: 541.3 MW capacity, tangentially-fired boiler in service since 1977
- Unit 2: 496.0 MW capacity, tangentially-fired boiler in service since 1974

These subcritical boilers fire bituminous coals from the Sufco (Wolverine Fuels), Bear Canyon 4 (Rhino Energy), Skyline Complex (Wolverine Fuels), Lila Canyon (Emery County Coal) mines. Each boiler is equipped with a low-NO_x burner/separated overfire air system (LNB/SOFA), baghouse, and SO Wet FGD (WFGD) scrubber with no scrubber bypass. Huntington Units 1 & 2 were subject to Best Available Retrofit Technology (BART) in the first Regional Haze planning period. PacifiCorp's Huntington facility currently has NO_x, SO_2, and PM emission control technologies in place, including:

- Huntington Unit 1
  - LNB and SOFA (2010);
  - FGD (scrubber) system upgrade installed and operates year-round (2010);
  - Baghouse retrofit for PM control (2010);
- Huntington Unit 2
  - LNB and SOFA (2005);
  - FGD (scrubber) system installed and operates year-round (2005);
  - Baghouse retrofit for PM control (2005).

4.3.3 Recent Emissions

Based upon recent emissions of SO_2 and NO_x, and distances of facilities from NPS Class I areas within 1,000 km, the Huntington Power Plant ranked #6 in the U.S. for cumulative impacts on those Class I areas.[4] EPA's Clean Air Markets Database (CAMD) for 2020 shows Huntington's NO_x emissions at 4,814 tons which ranks it #39 among the 1,167 facilities in CAMD. Huntington's 2020 SO_2 emissions in CAMD were 1,626 tons and ranked #111. Huntington's carbon dioxide emissions of 4,907,865 tons rank #78 in the US. Huntington also ranked #484 for EGU mercury emissions with 0.4 lb in 2017.

The table below provides a breakdown by unit of 2020 SO_2 and NO_x emissions and how they rank versus the 3,317 EGUs in CAMD.

Table 4. 2020 Huntington EGU emissions and rank compared to other US EGUs in CAMD

Unit ID	SO_2 (tons)	SO_2 (tons) Rank	Avg. SO_2 Rate (lb/MMBtu)	Avg. SO_2 Rate (lb/MMBtu) Rank	NO_x (tons)	NO_x (tons) Rank	Avg. NO_x Rate (lb/MMBtu)	Avg. NO_x Rate (lb/MMBtu) Rank
1	947	208	0.076	370	2,476	59	0.20	279
2	679	260	0.059	419	2,337	69	0.20	278

4.3.4 Reasonable Progress Emission Limit (RPEL)

We agree with UDAQ's rejection of the plantwide combined NO_x + SO emission limit of 10,000 tons/year proposed by PacifiCorp for Huntington as a control measure (RPEL). This measure would not constitute actual emission reductions. As our review illustrates, the sum of Huntington's SO_2 + NO_x emissions has not exceeded the proposed 10,000 tons/year limit since 2010 as shown below. The most-recent five-year averages are 2,124 tons SO_2 and 5,463 tons NO_x and 7,586 tons combined.

[4] EGU SO_2 and NO_x emissions were obtained from CAMD for 2018. Other stationary point source emissions were obtained from the 2014 National Emissions inventory. The sums of the SO_2 + NO_x emissions (Q) were divided by the distances (d) to generate a Q/d value for each facility relative to each Class I area within 1000 km. The total Q/d for Huntington was 461.

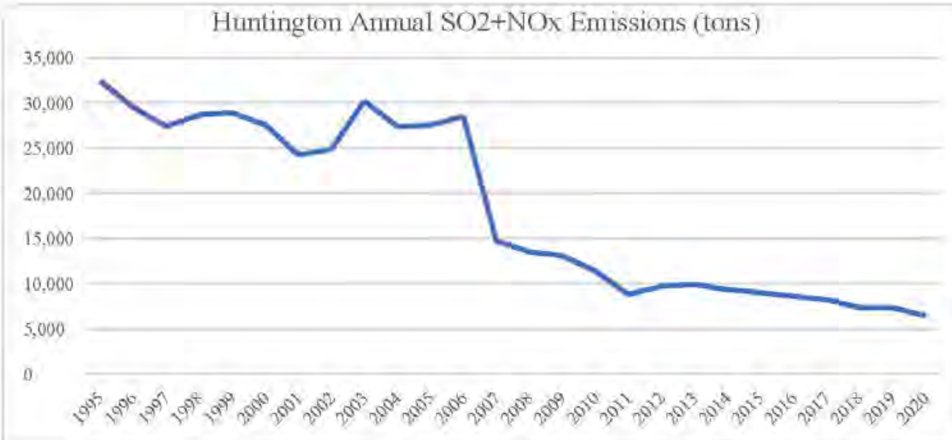

Figure 10. Huntington facility wide annual SO_2 + NO_x emissions (1995-2020) (CAMD 2020)

4.3.5 SO_2 Analysis

As discussed above (Section 4.1) we find that Huntington is not effectively-controlled for SO_2 emissions and that a four-factor analysis focused on efficiency improvements is warranted. Specifically, the wet scrubbers Huntington should be capable of achieving at least 95% control. Our review of EIA 2020 fuels data indicates that uncontrolled SO_2 emissions at Huntington should be about 0.88 lb/mmBtu.[5] Based upon the most-recent five years of CAMD data, the Huntington scrubbers are achieving only 91% - 92% SO_2 control.

PacifiCorp estimated that meeting it's suggested RPEL would require scrubbing to a SO emission rate of 0.030 lb./MMBtu on Units 1 and 2. Unit 1 costs to meet this rate are estimated by PacifiCorp to require $207,000/year in capital upgrades and $253,000/year in O&M costs for a total annualized cost of $460,000/year. Unit 2 costs to meet this rate are estimated by PacifiCorp to require $256,000/year in capital upgrades and $615,000/year in O&M costs for a total annualized cost of $871,000/year per unit. This suggests that scrubber upgrades and efficiencies are both known and achievable. Further, PacifiCorp estimates reveal that annual SO_2 emissions could be reduced from:

- Unit 1 by almost 800 tons/year at less than $600/ton and
- Unit 2 by almost 550 tons/year at $1,600/ton.

4.3.6 NO_x Analysis

Statutory Factor 1: Cost of Compliance

–Unit 1

[5] We applied the AP-42 emission factor = 38S for bituminous coal as burned at Hunter.

The 2016 – 2020 sum of the average annual SO_2 and NO_x emissions from Huntington Unit 1 is 3,939 tons/year. The sum of Huntington Unit 1's SO_2 + NO_x emissions has not exceeded the proposed 5,000 tons/year threshold since 2011 as shown below.

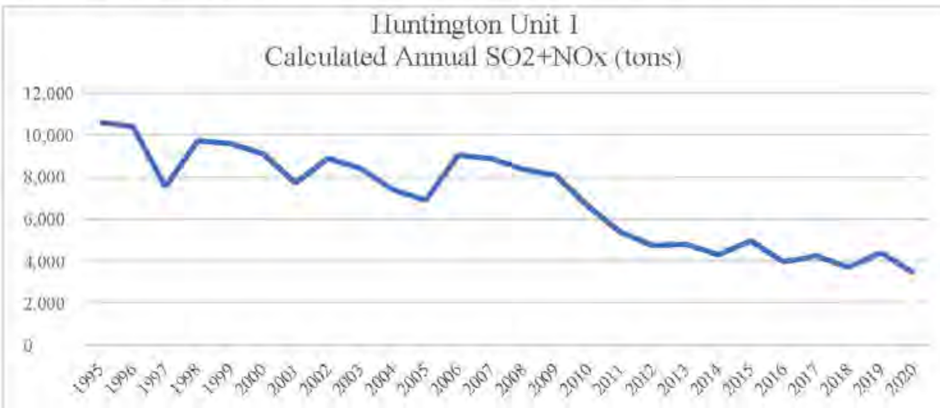

Figure 11. Huntington Unit 1, calculated annual SO_2 + NO_x emissions (CAMD 2020)

We find that 70% of recent Total SO_2 + NO_x emissions from Huntington Unit 1 have been NO_x. 70% of the Huntington Unit 1 PAL is 3,867 tons. Based upon Huntington Unit 1's 0.26 lb/mmBtu NO_x limit, we adjusted Huntington Unit 1 heat input to yield approximately 3,867 tons of NO_x; this formed the baseline for our analysis of the cost-effectiveness of adding SNCR or SCR versus the existing PAL.

PacifiCorp found that 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. Our estimates are shown in the table below.

–Unit 2

The 2016 – 2020 sum of the average annual SO_2 and NO_x emissions from Huntington Unit 2 is 3,648 tons/year. The sum of Huntington Unit 2's SO_2 + NO_x emissions has not exceeded the proposed 5,000 tons/year threshold since 2014 as shown below.

Figure 12. Huntington Unit 2, calculated annual SO_2 + NO_x emissions (CAMD 2020)

We find that 74% of recent Total SO_2 + NO_x emissions from Huntington Unit 2 have been NO_x. 74% of the Huntington Unit 2 PAL is 4,118 tons. Based upon Huntington Unit 2's 0.26 lb/mmBtu NO_x limit, we adjusted Huntington Unit 2 heat input to yield approximately 4,118 tons of NO_x; this formed the baseline for our analysis of the cost-effectiveness of adding SNCR or SCR versus the existing PAL.

PacifiCorp found that 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. Our estimates are shown in the table below.

–Summary

Table 5. Huntington Cost Analyses for Current, RP, and PAL NO_x Emissions

Emission Unit and Baseline	Control Technology	Capital Cost	Indirect Cost	Direct Cost	Total Annual Cost	Tons Removed	Average Cost-effectiveness ($/ton)	Incremental Cost-effectiveness ($/ton)
Huntington Unit 1 (current emissions)	SCR	$ 140,939,255	$ 11,716,578	$ 1,122,806	$12,839,384	2,218	$ 5,790	$ 5,999
	SNCR	$ 12,137,341	$ 1,177,929	$ 1,806,907	$ 2,984,836	575	$ 5,191	
Huntington Unit 1 (PAL emissions)	SCR	$ 140,939,255	$ 11,716,578	$ 1,287,019	$13,003,598	3,216	$ 4,043	$ 4,019
	SNCR	$ 12,377,967	$ 1,201,282	$ 2,253,711	$ 3,454,992	841	$ 4,110	
Huntington Unit 1 (RP emissions)	SCR	$ 140,939,255	$ 11,716,578	$ 1,123,420	$13,003,598	2,594	$ 4,950	$ 5,193
	SNCR	$ 12,377,967	$ 1,201,282	$ 1,853,445	$ 3,054,726	678	$ 4,506	
Huntington Unit 2 (current emissions)	SCR	$ 140,939,255	$ 11,716,643	$ 1,107,031	$12,823,674	2,188	$ 5,860	$ 6,088
	SNCR	$ 12,092,464	$ 1,173,574	$ 1,782,099	$ 2,955,673	567	$ 5,209	
Huntington Unit 2 (PAL emissions)	SCR	$ 140,939,255	$ 11,716,643	$ 1,354,011	$13,070,654	3,496	$ 3,739	$ 3,656
	SNCR	$ 12,329,007	$ 1,196,530	$ 2,432,600	$ 3,629,130	914	$ 3,972	
Huntington Unit 2 (RP emissions)	SCR	$ 140,939,255	$ 11,716,643	$ 1,109,361	$12,826,004	2,558	$ 5,013	$ 5,186
	SNCR	$ 12,329,007	$ 1,196,530	$ 1,829,817	$ 3,026,347	669	$ 4,526	

For calculations see workbooks identified by Unit# and emissions baseline condition in the PacifiCorp/HuntingtonSCR and PacifiCorp/HuntingtonSNCR folders in the attached NPS-UT_RH-SIP_FFA-AnalysisWorksheets.zip

Table 6. Huntington Facility-wide Totals for Control-Cost Analyses

Emission Unit and Baseline	Control Technology	Capital Cost	Indirect Cost	Direct Cost	Total Annual Cost	Tons Removed	Average Cost-effectiveness ($/ton)	Incremental Cost-effectiveness ($/ton)
Huntington (current emissions)	SCR	$ 281,878,510	$ 23,433,221	$ 2,229,837	$25,663,058	4,406	$ 5,824	$ 6,043
	SNCR	$ 24,229,804	$ 2,351,503	$ 3,589,006	$ 5,940,508	1,142	$ 5,200	
Huntington (PAL emissions)	SCR	$ 281,878,510	$ 23,433,221	$ 2,641,030	$26,074,252	6,712	$ 3,885	$ 3,830
	SNCR	$ 24,706,974	$ 2,397,812	$ 4,686,311	$ 7,084,122	1,754	$ 4,038	
Huntington (RP emissions)	SCR	$ 281,878,510	$ 23,433,221	$ 2,232,780	$25,829,601	5,152	$ 5,013	$ 5,189
	SNCR	$ 24,706,974	$ 2,397,812	$ 3,683,262	$ 6,081,074	1,347	$ 4,516	

Statutory Factor 2: Time Necessary for Compliance

In consideration of time necessary for new NO_x controls, PacifiCorp writes that "…the installation of SNCR on the units would be less (time) 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." Based on analyses presented by Sargent & Lundy elsewhere, we expect that about five years would be necessary for SCR and two years for SNCR. It is unclear why more time is necessary in this case.

Statutory Factor 3: Energy and Non-Air Environmental Impacts

PacifiCorp raises several potential concerns with respect to Statutory factor 3 including the energy use, water use, carbon dioxide generation, and waste material generation as a result of operating pollution control equipment. Energy impacts are considered in the costs of compliance calculation and none of the other issues raised are unique to the Huntington facility. Utilities (including PacifiCorp at its Jim Bridger power plant in Wyoming) have shown that they can handle these materials with proper operation and maintenances practices.

We suggest that UDAQ could consider environmental co-benefits of NO_x emission reduction as part of this factor. NO_x is an ozone pre-cursor emission and ozone is known to affect both human and ecosystem health. Further, nitrogen deposition can be harmful to sensitive ecosystems including high alpine lakes and desert environments protected by national parks in the Utah region.

Statutory Factor 4: Remaining Useful Life

Unless a federally enforceable shut-down date for a facility is in place, cost-effectiveness estimates are appropriately calculated using the EPA-mandated 20-year depreciable life for SNCR and 30-year depreciable life for SCR. Uncertainty and/or unenforceable commitments regarding facility lifetime are not part of the four-factor analysis.

4.3.7 Conclusions & Recommendations

- We agree with the UDAQ decision to reject Huntington RPELs as a control option. This approach would not significantly reduce total annual NO_x or SO_2 emissions from current levels.
- SO_2 four-factor analyses focused on upgrading or optimizing FGDs are warranted. Modifying the existing scrubbers at Huntington would be highly cost-effective and could reduce SO_2 emissions by over 1,300 tons/year compared to existing controls.
- The Cost of Compliance for adding NO_x controls is consistent with values accepted by other states in this round of planning (Section 2.2). The exceptionally large number of mandatory federal Class I areas affected by haze causing emissions from Huntington suggest consideration of higher cost thresholds.
- The annual average cost-effectiveness of adding SNCR would be acceptable in the context of the thresholds used by Colorado, Idaho, and Oregon. This strategy could reduce current NO_x emissions by over 1,100 tons/year compared to existing controls, over 1,300 tons/year compared to proposed RP limits, and by 1,750 tons/year compared to PAL limits.
- The annual average cost-effectiveness of adding SCR would also be acceptable in the context of the thresholds used by Colorado, and Oregon. This strategy could reduce current NO_x emissions by over 4,400 tons/year compared to existing controls, over 5,200

tons/year compared to proposed RP limits, and by over 8,500 tons/year compared to PAL limits.

  - Using the PAL as baseline, as proposed by PacifiCorp, the cost-effectiveness of adding SCR never exceeds $4,100/ton.
  - Compared to the RP limits proposed by UDAQ, the cost-effectiveness of adding SCR never exceeds $5,100/ton.
  - Compared to current NO_x emissions, the cost-effectiveness of adding SCR never exceeds $5,900/ton.
  - The incremental cost-effectiveness of adding SCR is very reasonable.

- We request that Utah require the most effective control measures found to be technically feasible and cost-effective through analysis of the four factors specified in the Regional Haze Rule. Those control measures include improved SO_2 scrubbing and addition of SCR on both Huntington units.

4.4 Sunnyside Cogeneration Facility

4.4.1 Summary of NPS Recommendations and Requests for Sunnyside Cogeneration

NPS review of the four-factor analysis conducted for the Sunnyside Cogeneration Facility (Sunnyside) finds that for the boiler there may be technically-feasible and cost-effective opportunities available to further control SO_2 emissions and that there are technically-feasible and cost-effective opportunities available to further control NO_x emissions. We find that the cost of control is more economical than the company's estimate when analyses are adjusted in accordance with the EPA Control Cost Manual (CCM).

Our review finds that Sunnyside has not provided sufficient justification to exclude dry sorbent injection (DSI) technology as technically feasible. We estimate DSI could remove almost 380 tons/year of SO_2 at around $6,900/ton.

Selective catalytic reduction (SCR) was the most cost-effective NO_x emission control analyzed. We estimate that SCR could remove 379 tons/year of NO_x for less than $7,200/ton. This suggests that SCR may be cost-effective and should be considered for this facility.

Although UDAQ has not established a cost threshold for this round of regional haze planning, we can advise that other states have set cost-effectiveness thresholds of $4,000–$6,500/ton in Arizona, $5,000/ton for EGUs in Arkansas and Texas, $5,000–$10,000/ton in Nevada, $6,100/ton in Idaho, and $10,000/ton in Colorado and Oregon.

We recommend that Utah take every opportunity to reduce SO_2 and NO_x emissions from the Sunnyside Cogeneration Facility in this planning period. By requiring implementation of identified controls, Utah will be reducing haze causing emissions and advancing incremental improvement of visibility at Canyonlands, Capitol Reef, Bryce Canyon, and Zion National Parks as well as other Class I areas in the region.

4.4.2 Sunnyside Cogeneration Facility Characteristics

Sunnyside Cogeneration Associates (Sunnyside) owns and operates a combustion boiler (EU #1), an emergency diesel engine (EU#S) and an emergency generator (EU#7) at its cogeneration facility located at #1 Power Plant Road, Sunnyside, UT. The facility is in Sunnyside, Carbon County, Utah (approximately 25 miles southeast of Price). The nearest Class I areas and their respective distance from the facility are Arches National Park (60 miles), Canyonlands National Park (75 miles), Capitol Reef National Park (85 miles), Bryce Canyon National Park (157 miles), and Zion National Park (204 miles).

The Sunnyside facility produces steam in a circulating fluid bed (CFB) boiler with a design maximum heat input capacity of 700 MMBtu/hr that feeds a steam turbine generator, producing a nominal 58 MW of power. The boiler features a circulating fluidized bed, a baghouse, and a limestone injection system. The boiler burns refuse coal.

According to the four-factor analysis, baseline emissions are:

Table 7. Baseline Emission Rates (tons/yr)

Pollutant	Baseline Annual Emissions (tons/yr)		
	Boiler (EU #1)	**Emergency Diesel Engine (EU #5)**	**Emergency Generator (EU #7)**
S02	471	0.001	0.020
NO_x	431	0.020	0.310

Table 8. Baseline Emission Rates

Pollutant	Baseline Annual Emissions		
	Boiler (EU #1)	**Emergency Diesel Engine (EU #5)**	**Emergency Generator (EU #7)**
	(lb/MMBTU)	**(lb/HP-hr)**	**(lb/HP-hr)**
S02	0.17	8.29E-4	2.71E-3
NO_x	0.15	1.66E-2	4.20E-2

The emission limits provided in Sunnyside's Title V permit are shown below.

Table 9. Permitted Emission Limits (lbs/MMBtu)

Pollutant	Boiler (EU #1) Emission Limits (lbs/MM Btu)	
	Normal Operations11	**Startup, Shutdown, Maintenance/Planned Outage, or Malfunction**
SO_2 Title V	0.42	1.2
SO_2 MATS	0.2	--
NO_x	0.25	0.60

4.4.3 SO_2 control cost analysis

The initial four-factor analysis concluded that of the add-on SO_2 controls considered only dry sorbent injection (DSI) was technically feasible, in part due to a lack of water needed for spray dryer absorbing or wet scrubbing technology. The analysis concluded that DSI would cost $10,202/ton.

After receiving comments from Utah on its four-factor analysis, the company updated its analysis of potential additional SO_2 controls. The company apparently decided that DSI is not technically feasible due to a lack of space, but a circulating dry scrubbing (CDS) system would be feasible. However, it is unclear from the updated analysis as to which system the company concluded would be technically feasible. According to the company's response to UDAQ:

> *"Given the configuration of existing units, there is not enough space between the CFB boiler and existing baghouse for the addition of a further CDS/CFBS unit without significant reconfiguration of existing equipment. Of all the add on control technologies considered, CDS/CFBS is the only potentially feasible option... After further evaluation, a dry scrubbing unit cannot be retrofitted between the CFB boiler and the existing baghouse due to space limitations requiring significant reconfiguration of existing equipment. Accordingly, a CDS/CFBS is the only add on unit that is potentially technically feasible. Based on the additional detail provided above, and in response to the UDAQ request, a cost analysis has been completed for a CDS/CFBS to replace the DSI cost analysis."*

The analysis does not clearly explain why there would be insufficient space for a DSI system but not for a CDS system. We therefore estimated costs for a DSI system with an Excel workbook that uses the cost estimation methods in the Integrated Planning Model (IPM) developed by Sargent and Lundy for EPA (Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology (epa.gov)). The IPM model is the basis for the cost estimation methods in the 7th edition of the CCM. This resulted in an estimate of $6,863/ton of SO_2 removed, assuming a 30-

year lifetime, 3.25% interest rate, and 90% SO_2 removal rate. Our estimate is documented in the worksheet titled Sunnyside_IPM_DSI_with_Trona_NPS.xlsx.

The company's revised SO_2 control cost estimate for a CDS system used Section 5 of EPA's Control Cost Manual (CCM), which resulted in an estimated cost of \$68,000/ton of SO_2 removed. EPA updated this section in April 2021 as part of the 7th edition of the CCM. The company stated that they would need to include the cost of a baghouse in their estimate for a CDS system, and that they would need to do additional design work to fit the CDS into the existing space. For these reasons they chose a retrofit factor of 1.3. They also chose an expected lifetime of 20 years as the existing system is 30 years old and isn't expected to last more than 20 years. However, the analysis does not mention any enforceable condition that would limit the lifespan. The updated analysis used a 7% interest rate, citing OMB Circular A-94.

> *"As a default position, OMB Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector."*

We disagree with the use of a 7% interest rate. The Circular also says:

> *"OMB revised Circular A-94 in 1992 after extensive internal review and public comment. In a recent analysis, OMB found that the average rate of return to capital remains near the 7 percent rate estimated in 1992. Circular A-94 also recommends using other discount rates to show the sensitivity of the estimates to the discount rate assumption."*

This suggests that the 7 percent estimate was based upon information that was current as of 2003. The Circular was last updated in 1993 but includes an appendix (Appendix C, DISCOUNT RATES FOR COST-EFFECTIVENESS, LEASE PURCHASE, AND RELATED ANALYSES) that is updated annually.

In addition, the CCM states that there is a distinction between private costs and societal costs, and the intent of the manual is to provide guidance on assessing private costs.

> *"When performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, the correct interest rate to use is the nominal interest rate, which is the rate firms actually face. Accounting for inflation should be done separately rather than using the real interest rate.*

For input to analysis of rulemakings, assessments of private cost should be prepared using firm-specific nominal interest rates if possible, or the bank prime rate if firm-specific interest rates cannot be estimated or verified."

As the four-factor analysis is assessing the private cost faced by a specific firm and not the societal costs associated with a proposed rulemaking, the OMB Circular's direction to use 7% as a "default" value is not applicable here. Since the analysis provided by the company does not provide additional justification for a higher nominal interest rate, it is more appropriate to use the bank prime rate for this cost estimation.

The four-factor analysis uses a 20-year lifetime, which is not consistent with EPA guidance for acid gas scrubbers. Section 5, SO_2 and Acid Gas Controls, of the 7th edition of the CCM for SO_2 controls, Chapter 1, paragraph 1.1.6, has this to say regarding equipment life:

"Acid gas scrubbers are relatively reliable systems that have been demonstrated to be exceedingly durable. In the past, the EPA has generally used equipment life estimates of 20 to 30 years for analyses involving acid gas scrubbers, although these estimates are recognized to be low for many installations. Many FGD systems installed in the 1970s and 1980s have operated for more than 30 years (e.g., Coyote Station; H.L. Spurlock Unit 2 in Maysville, KY; East Bend Unit 2 in Union, KY; and Laramie River Unit 3 in Wheatland, WY) and some scrubbers may have lifetimes that are much longer. Manufacturers reportedly design scrubbers to be as durable as boilers, which are generally designed to operate for more than 60 years."

As there is no enforceable shutdown date for the boiler it is more appropriate to use a 30-year lifetime for a CDS system.

The four-factor analysis used a retrofit factor of 1.3 but does not provide a detailed justification for this choice. A retrofit factor of 1 already incorporates additional costs beyond that of a greenfield installation to account for the cost of a retrofit of average difficulty and is more appropriate for this analysis.

To estimate costs for a CDS system, we used the guidance from the latest update to the CCM (7th edition) Section 5 and the accompanying cost worksheet (https://www.epa.gov/sites/default/files/2021-05/wetanddryscrubbers_controlcostmanualspreadsheet_may_2021.xlsm) for a spray dry absorber (SDA) system. This updated worksheet was made available in May 2021. According to the CCM, the capital costs for a CDS system are similar to the SDA system for a combustion unit of the same size and sulfur emission rate. In addition, the total capital investment costs for an SDA system include the costs for a baghouse, as well as the absorber island, reagent preparation equipment, waste recycling/handling facilities, and additional costs associated with installation. We used a retrofit factor of 1, interest rate of 3.25%, and expected lifetime of 30 years. In addition, we noted that the four-factor analysis assumed annual fuel consumption of 883,413,714 lbs, but with a maximum heat input rate of 700 MMBtu/hour, energy content of 7,072 btu/lb, and an average 8,031 hours of operation per year the maximum possible fuel consumption is

794,923,643 lbs. Using the EPA worksheet, and assuming a 3.25% interest rate, lifetime of 30 years, and an 88% removal efficiency (=0.02 lb/MMBtu rate) resulted in an estimated cost for an SDA/CDS system of $14,300/ton of SO_2 removed. This would reduce emissions by an estimated 422 tons. Our estimate is located in the accompanying worksheet wetanddryscrubbers_may_2021_Sunnyside.xlsm.

4.4.4 NO_x control cost analysis

The company's revised four-factor analysis also included cost estimates for an SCR and SNCR system to reduce NO_x emissions. The estimates used the EPA cost estimations worksheets, and assumed a 20-year lifetime, a 7% interest rate, and a retrofit factor of 1.3 for SCR and 1 for SNCR. Control efficiency was assumed to be 90% for SCR (resulting in an outlet NO_x rate of 0.015 lb/MMBtu) and 15% for SNCR (resulting in an outlet NO_x rate of 0.13 lb/MMBtu) for SNCR. Using these assumptions, the estimated cost efficiencies were $13,445/ton of NO_x removed for SCR (resulting in a reduction of 432 tons NO_x/year) and $9,268/ ton of NO_x removed for SNCR (resulting in a reduction of 64 tons NO_x/year).

We estimated SCR and SNCR costs using the most recent EPA cost estimation worksheets. For the SCR cost analysis, we used the latest cost worksheet from June 2019 provided with the 7th edition Section 4 (https://www.epa.gov/sites/default/files/2019-06/scrcostmanualspreadsheet_june-2019vf.xlsm).

As was the case for our SO_2 control cost estimates, we assumed a retrofit factor of 1 and interest rate of 3.25%. We assumed an equipment lifetime of 30 years for SCR as recommended by the CCM and 20 for SNCR. We also chose the option for a utility boiler rather than an industrial boiler in the data inputs tab. The resulting cost estimates were $9,943/ton for SNCR (resulting in a reduction of 63 tons NO_x/year), and $7,139/ton NO_x removed for SCR (resulting in a reduction of 379 tons/year). This suggests that SCR may be cost-effective and should be considered for this facility. Our cost estimate for SCR is located in the Excel workbook Sunnyside SCR cost worksheet_NPS.xlsm.

4.5 Leamington Cement Plant (Ash Grove Cement Company)

4.5.1 Summary of NPS Recommendations and Requests for the Leamington Cement Plant

Our review suggests that potential improvements may be available for the SNCR system at the Leamington Cement Plant. We recommend that UDAQ request further evaluation of this opportunity to reduce NO_x emissions from the facility.

4.5.2 Leamington Cement Plant Review

The Ash Grove Cement Company operates a single kiln at a facility near Leamington, Utah. At the Leamington cement plant, cement is produced when inorganic raw materials, primarily limestone (quarried on site), are ground, mixed, and then fed into a rotating kiln. The kiln alters the materials and recombines them into small stones called cement clinker. The clinker is cooled and ground with gypsum and additional limestone into a fine powdered cement. The final product is stored on site for later shipping. The major sources of air emissions are from the combustion of fuels for the kiln operation, from the kiln, and from the clinker cooling process.

The Leamington facility operates a low-NO_x burner on the kiln and has demonstrated compliance with a federally enforceable NO_x emission rate of 2.8 lbs/ton clinker (30-day rolling average). Annual baseline emissions rates are given in the four-factor analysis as:

Table 10. Annual Baseline Emission Rates

Pollutant	Kiln
NO_x	1,198 tons/year
SO_2	8.0 tons/year

The Leamington facility also operates a SNCR system on the kiln and has demonstrated compliance with a federally enforceable NO_x emission rate of 2.8 lbs/ton clinker (30 day rolling average).

In response to a request from UDAQ for information on potential improvements to efficiency of the existing SNCR system, the company stated that they were not aware of any changes that could be made to the system that would achieve greater NO_x control. We are aware of at least one older cement facility, the CEMEX Lyons facility in Lyons, Colorado, that was retrofitted with SNCR and is currently achieving a NO_x emissions rate of approximately 1.6 lbs NO_x/ton of clinker. UDAQ should request that the company reconsider whether there are potential improvements available for the SNCR system at the Leamington facility.

4.6 Cricket Mountain Plant (Graymont Western US Inc.)

4.6.1 Summary of NPS Recommendations and Requests for the Cricket Mountain Plant

NPS review of the four-factor analysis conducted for Graymont Western US Inc. (Graymont) finds that permitted emission limits are significantly higher than recent emissions levels. The costs of controls would be more cost-effective if emissions increased to permitted levels. We recommend that UDAQ consider tightening permitted emissions limits for NO_x and SO_2 to reasonably reflect future potential emissions from the Graymont Cricket Mountain Lime Plant and to prevent backsliding.

4.6.2 Cricket Mountain Plant Review

Graymont Western US Inc. (Graymont) operates the Cricket Mountain Lime Plant in Millard County. The Cricket Mountain Lime Plant consists of quarries and a lime processing plant, which includes five rotary lime kilns (Kilns 1 through 5) with preheaters. The rotary kilns are used to convert crushed limestone ore into quicklime. The products produced for resale are lime, limestone, and kiln dust. The kilns operate on pet coke and coal. Sources of emissions at this source include mining, limestone processing, rotary lime kilns, post-kiln lime handling, and truck and loadout facilities.

According to the original four-factor analysis supplied by the company the facility's potential to emit (PTE) is:

Table 11. Cricket Mountain Lime Plant Emission Limits

Pollutant	Potential to Emit (tons/year)
SO_2	760.29
NO_x	3,883.85

Although the facility's SO_2 potential to emit is permitted at 760 tons/year, the most recent inventory for the Cricket Mountain Plant showed SO_2 emissions of only 40.8 tons/year. For this reason, Graymont did not perform an analysis of control options for SO_2 emissions.

Graymont provided baseline NO_x emissions for each of the five kilns. The baseline emissions are the average NO_x emissions for years 2014-2018, based on stack test data and annual production rates. The baseline emissions are as follows:

- Kiln 1: 85.5 tons/year
- Kiln 2: 60.3 tons year
- Kiln 3: 50.0 tons/year
- Kiln 4: 107.1 tons/year
- Kiln 5: 336.1 tons/year

The total for all five kilns is 639 tons NO_x/year. The lime kilns currently operate low-NO_x burners.

Graymont evaluated the cost of adding selective non-catalytic reduction (SNCR) to its five lime kilns to reduce NO_x emissions. Graymont commissioned a Class 4 engineering cost estimate to ascertain capital and operating costs associated with installing and operating SNCR. The analysis assumed a 3.25% interest rate, 20-year lifetime, and 20% NO_x emissions reduction, and concluded that cost-effectiveness for the five kilns ranged from $11,000 to $25,000/ton of NO_x removed. Our analysis, using the company's worksheet but with an assumption of 35% NO_x reduction (as suggested by UDAQ), results in cost-effectiveness estimates of $9,000 to $16,000/ton.

The Utah draft SIP says states that the technical feasibility of SNCR on preheater lime kilns in a novel technology not proven in broad application, and that "implementation at two facilities does not indicate feasibility for all lime kilns." However, we are aware of SNCR application at four lime facilities that employ preheater kilns, including Lhoist Nelson in Arizona, Mississippi Lime at Prairie du Rocher, Illinois, Lhoist North America at O'Neal, Alabama, and Unimin Corporation at Calera, Alabama.

The permitted annual emissions limits for this facility (760 tons/year of SO_2 and 3,883 tons of NO_x) are substantially higher than the kiln baseline emissions used for the four-factor analysis (40 tons of SO_2 and 640 tons of NO_x). These limits are 19 times higher than the baseline SO_2 emissions used in the four-factor analysis and 6 times higher than the NO_x baseline emissions. Under the current facility emissions limits, the kilns' emissions could increase considerably, which would improve the cost-effectiveness of potential emissions control options. We recommend that UDAQ consider lowering permitted emissions limits for NO_x and SO_2 to reasonably reflect future potential emissions and prevent backsliding.

4.7 Rowley Plant (US Magnesium LLC)

4.7.1 Summary of NPS Recommendations and Requests for the Rowley Plant

EMISSION LIMITS:

Incorporation of numerical NO_x and SO_2 emission limits into US Magnesium's current permit for the Turbines/duct burners, chlorine reduction burner, melt/reactor, riley boiler, and the diesel engines would ensure that reasonable progress assumptions and determinations for the facility are adhered to.

TURBINES & DUCT BURNERS:

Additional cost information and analysis of the technical feasibility determinations is necessary to fully evaluate the SCR analysis for the turbines and duct burners (see detailed comments below). We recommend that UDAQ re-evaluate the feasibility and costs of installing SCR on the turbines considering this information.

RILEY BOILER:

Control cost estimates for SCR on the riley boiler based on the US Magnesium analysis are within the range of cost-effectiveness thresholds being considered by other states in this round of regional haze planning. UDAQ's analysis shows that the controls are likely even more cost-effective. We recommend that UDAQ reconsider requiring implementation of SCR on this emission unit as part of this planning period. Additionally, actual emission assumptions relied on to eliminate SCR from consideration be reflected in permit limitations for this unit.

SOLAR POND DIESEL ENGINES:

- Diesel engines are the second largest stationary NO_x source at the facility.
- Additional information supporting the cost analysis assumptions is necessary to fully evaluate the four-factor analysis for the diesel engines.
- The calculated NO_x emissions associated with the engines are lower than anticipated. We recommend that the analysis would benefit from verification of these emissions through testing requirements. The cost analysis may need to be updated if the emissions differ from those reported. Unless these are very new engines, or the annual hours of operation are sufficiently low, greater annual NO_x emissions would be expected from each engine.
- Engine replacement and potential electrification are additional emission control options that warrant evaluation for aging engines. We recommend that the four-factor analysis for US Magnesium would be more comprehensive if these options are reviewed.

4.7.2 Rowley Plant Characteristics

US Magnesium LLC (USM) operates a primary magnesium production facility at its Rowley Plant, located in Tooele County, Utah. USM produces magnesium metal from the waters of the Great Salt Lake. Some of the water is evaporated in a system of solar evaporation ponds and the resulting brine solution is purified and dried to a powder in spray dryers. The facility is primarily a NO_x source; facility-wide NO_x and SO_2 baseline and potential to emit (PTE) emissions are as follows:

Table 12. USM facility-wide NO_x and SO_2 baseline and PTE emissions

Pollutant	Potential to Emit (TPY)	2018 Baseline Emissions (TPY)
SO_2	24.1	10.08
NO_x	1,260.99	1,061

The primary NO_x-emitting stationary units at the facility include three gas-fired turbines/duct burners, a 60 MMBtu/hr natural gas-fired riley boiler, and 30 diesel-fired pumping engines. Four-factor analyses evaluating potential NO_x emission control options were completed for these three units (highlighted in gray below), along with the HCl plant, the casting house, and the lithium plant. Our review focuses on the turbines/duct burners, the diesel engines, and the riley boiler as the most significant stationary NO_x sources. We note that while no single unit at the US Magnesium facility is independently a large source of NO_x, collectively, the facility-wide NO_x emissions are significant. As such, multiple, smaller units will need to be addressed at this facility.

Table 13. USM NO_x emissions by equipment type

Equipment	NO_x Baseline 2018 Emissions (TPY)	NO_x Rank
Turbines | Duct Burners	813.58	1
Mobile Sources	73.01	2
Diesel Engines	71.65	3
Riley Boiler	45.25	4
Lithium Plant	26.61	5
Casting House	14.7	6
Chlorine Reduction Burner	11.66	7
HCl Plant	4.32	8
Other Sources	0.02	9

Current Operating Permit for US Magnesium:

The current Title five permit for the US Magnesium facility does not contain numerical NO_x or SO_2 emission limits for the Turbines/duct burners, chlorine reduction burner, riley boiler, or the diesel engines. The current facility-wide annual NO_x emissions are not significantly lower than the estimated potential-to-emit (i.e., this is not a case where actual emissions are significantly lower than the PTE).

We recommend that UDAQ update the permit to include NO_x and SO_2 emission limitations for the facility. Ideally, the permit would include facility-wide annual limitations, as well as short-term and annual limits for individual units and/or stacks. Incorporating NO_x and SO_2 limits into the permit would ensure that reasonable progress assumptions for the facility and determinations are adhered to throughout the planning period. Ensuring emission assumptions are met would also result in co-benefits for the $PM_{2.5}$ and ozone nonattainment area by requiring verifiable emissions calculations/quantification and ensuring the facility is operating within the assumed emissions parameters.

UT SIP Control Determinations Summary:

UDAQ is requiring the installation of flue gas recirculation (FGR) on the UMG riley boiler. UDAQ estimates that FGR can reduce NO_x emissions from the riley boiler by 22.6 tons per year (TPY) at a cost of $2,708/ton of NO_x removed. This is the only control determination that UT found to be technically feasible and cost-effective for the US Magnesium facility.

4.7.3 Turbines and Duct Burners

US Magnesium identified combustion controls, water or steam injection and SCR as potential controls for the turbines and duct burners. Ultimately, UDAQ concluded that "although this is a significant source of NO_x emissions, no technically feasible retrofit technologies were found during the BART analysis. USM will continue to operate the turbines and duct burners as they are currently configured."

Specifically, for SCR, US Magnesium concluded that given the facility configuration and the fact that the turbine "exhaust coupled with a duct burner is used in a spray dryer to dry the magnesium chloride slurry into a magnesium chloride powder" which requires an exhaust temperature of 1,000°F, SCR is not feasible for these units. From the draft SIP: "SCR system is not technically feasible at these operating temperatures and will not be considered further in this analysis."

However, it appears that US Magnesium only considered placing the SCR between the turbine and the duct burners (prior to the spray dryer) and made their technical feasibility decision based on temperature considerations—including both the required minimum temperature for proper spray dryer operation and the optimum temperature range for efficient SCR operation. We have several recommendations regarding these conclusions:

First, the technical feasibility of locating the SCR between the turbine exhaust and duct burner using a high temperature catalyst should be considered. Applications of SCR on high temperature simple cycle turbines is well documented.[6] We recommend that a revised the analysis evaluating options for SCR placement directly after the combustion turbine would improve the four-factor analysis. It is appropriate to factor the cost of any additional flue gas reheat and fuel use into the cost calculations. It is possible that the additional fuel required to reheat the gas stream to 1,000° F will make this placement of the SCR system too expensive, however, this determination can only properly be made through a cost analysis. The recognized application of high temperature catalysts indicates that SCR likely meets technical feasibility concerns and merits consideration.

Second, the technical feasibility of locating the SCR system downstream of the spray dryer (tail end SCR) should be considered. We understand that the turbines/duct burners, melt/reactor, and chlorine reduction burner (CRB) all exit through a single combined stack. We recommend updating the analysis to address flue gas temperatures at various points downstream of the spray dryer and consider the feasibility of placing an SCR system downstream (or near the stack exit). The updated analysis should also discuss whether downstream placement may potentially address NO_x emission from all three processes (turbines/duct burners, melt/reactor and CRB) and consider whether flue gas reheat would be necessary to install a downstream SCR.[7]

4.7.4 Solar Pond Diesel Engines

There are 30 solar pond diesel pumping engines located at the US Magnesium facility. These engines are the second largest point source category for NO_x emissions at the facility and thus are an important category to consider in the four-factor analysis. US Magnesium considered the costs of retrofitting the diesel engines with SCR but concluded that the retrofits were not cost-

[6] From Control Cost Manual Chapter on SCR: "Simple-cycle applications of SCR place the reactor chamber directly at the turbine exhaust, where the flue gas temperature is in the range of 850 to 1000°F (450 to 540°C). This requires the use of a high-temperature catalyst such as zeolite."

Also, see information in Table 2.1b: Summary of SCR Cost Data for Miscellaneous Industrial Sources of the Control Cost Manual Chapter on SCR.

[7] See CCM SCR Chapter discussion of "tail-end SCR."

effective. However, US Magnesium did not provide the specific data relied on in the four-factor analysis. We recommend that this information is necessary for proper review, including:

- The NO_x emission factors used to calculate emissions (i.e., g/hp-hr). Please include the engine age in this information. We are assuming that like the other equipment located at the facility, the diesel pumping engines are older units (i.e., tier 0 engines). As such, the calculated NO_x emissions used in the four-factor analysis (2.39 TPY/engine) seem extremely low, even when you consider the permitted annual use limitations into the calculation.[9] Because the permit does not contain numerical NO_x limits for the engines, there is little incentive for the company to accurately calculate NO_x emissions associated with the engines. Please specify if the emission factor used for each engine type is different (i.e., Cat 3406 and Cat 3208).
- Assumed annual engine operating hours used to calculate annual engine emissions for each engine type. Please specify annual periods used to develop these estimates.
- Please clarify why the same average annual emission rate was assumed for both engine types as opposed to calculating separate emission estimates per engine type. Because emission factors for engines typically include engine output (HP or kw) and operation (hours) in the calculation, separate emission estimates for the two primary engines used at the solar evaporation pond site, the Caterpillar 3406 (420 HP) and the Caterpillar 3208 (225 HP) would be more appropriate.
- The specific SCR cost information provided by caterpillar which is referenced/used in the four-factor analysis.

We also noted several aspects of the analysis for engines that are inconsistent with the recommended methods from EPA's Control Cost Manual (CCM), (i.e., 7% interest rate, the inclusion of sales tax, higher than average reagent costs). Our analysis relied on CCM recommendations for these specific cost components. We re-estimated emissions & potential emission reductions using EPA emission factors for tier 0 engines and an assumed two operating scenarios: 4,000 annual operating hours (based on US Magnesium's four-factor analysis) as well as a reduced operating scenario that would keep them within their limit on annual HP-hours for engines (no more than 26.59 MH-hr/year). Based on this updated analysis, we find that SCR may be cost-effective assuming these are tier 0 engines. (See attached spreadsheet USMag_diesel_engines.xlsx).

Finally, some states have required sources to consider the costs of engine replacement at facilities with a significant number of older engines. This includes replacement with newer cleaner diesel engines or replacement with electric motors. We recommend that UDAQ and US Magnesium evaluate the costs of replacing aging diesel engines with newer, Tier 4 complaint diesel engines or electric motors to power the pumps.

4.7.5 Riley Boiler

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[9] Condition II.B.2.b: Total number of horsepower-hours (Hp-hr) shall be no greater than 26.59 MMHp-hr per rolling 12-month period.

USM utilizes a 60 MMBtu/hr boiler, referred to as the riley boiler, for process steam. The riley boiler was first installed prior to the plant beginning operation in 1972 and currently has no add-on equipment. It is the third largest stationary NO_x emission source at the facility. As noted previously, UDAQ is requiring the installation of flue gas recirculation (FGR) on the riley boiler. UTDAQ estimates that FGR can reduce NO_x emissions from the riley boiler by 22.6 TPY at a cost of $2,708/ton of NO_x removed.

The company also evaluated the cost of SCR but concluded that SCR application was not cost-effective at an estimated $9,726/ton NO_x removed. UDAQ re-evaluated the costs of SCR by correcting several errors in US Magnesium's analysis. (*Please provide a copy of the company and UDAQ analysis inputs, including assumed emission rates, etc.*) From the SIP:

> *"DAQ reanalyzed the use of SCR on the Riley Boiler under two different scenarios. Under PTE, assuming full load, the application of SCR might be expected to remove as much as 188 tons of NO_x at a control cost of $4,073/ton of NO_x removed – assuming the same 90% removal efficiency as did the source. However, the Riley Boiler did not operate at that high an output level – reporting just 45.25 tons of actual emissions in 2018. Adjusting the emission reduction for 90% of the actual emissions gives a removal of 40.7 tons of NO_x (as opposed to the 38 tons suggested by the source), at a control cost of $18,800/ton of NO_x removed. Similar errors were made with respect to the FGR calculations on the Riley Boiler."*

We support UDAQ's re-analysis of the cost information and note that each of the SCR cost estimates (including US Magnesium's) are within the range of cost-effectiveness thresholds selected by other states (i.e., Colorado and Oregon have selected a $10,000/ton cost threshold). (Cost thresholds selected by other states in this round of regional haze planning are discussed in Section 2.2).

NO_x emission control efficiency achievable through SCR (90%) is significantly greater than the control efficiency achievable with FGR (50%) resulting in 40.7 tons of NO_x reduced with SCR versus 22.6 tons of NO_x reduced with FGR. We recommend that UDAQ reconsider SCR for the riley boiler.

In addition, it appears that UDAQ is relying on estimated actual emissions to determine whether a control is cost-effective. Again, we highlight the lack of numerical NO_x emission limitations in the current operating permit for the riley boiler. We recommend that if actual emissions are relied on to eliminate a control technology from further consideration, then at a minimum, the permit should incorporate a requisite emission limitation to ensure operation of the unit continues at or near the assumed emission levels.

5 Oil & Gas Area Source Recommendations

5.1 NPS Conclusions/Response

The Utah draft SIP acknowledges significant air quality issues related to extensive oil and gas development occurring in the Uinta Basin. From the draft SIP:

> *"The unique wintertime ozone issue in the Uinta Basin is caused by oil and gas extraction. UDAQ is working on rule amendments and potentially new rules for the oil and gas industry to stay in compliance with the ozone NAAQS."*

We support statewide rules to address oil and gas emission sources throughout Utah—as noted below, we are concerned about oil and gas sources in both the Paradox and Uinta Basins. In June of 2020, we recommended that Utah consider statewide NO_x requirements for engines that are modeled on other state programs. These recommendations are reiterated below.

Follow up communication from UDAQ regarding the nonattainment status in the Uinta Basin notes that "emission inventories indicate about 80% of the emissions are under tribal and EPA control.[9]" We recognize the jurisdictional complexity that exists in this region—in addition to tribal land, there are other federal partners, including the Bureau of Land Management, that administer oil and gas development on federal lands, which also comprises a decent percentage of the non-tribal development.

None-the-less, we recommend that air quality improvement will require cooperative and commensurate efforts from all agencies involved in air quality management in the basin. We have consistently made similar recommendations to various agencies with jurisdictional responsibility for oil and gas development decisions in this region, including EPA Region 8 and the BLM. For the Uinta Basin in particular, we have recommended that both NO_x and VOC emission reductions will ultimately be necessary to alleviate the significant air quality issues in this region. While each of these pollutants are ozone precursors, they also contribute to haze and visibility impairment.

While not a Class I Park, a recent study demonstrated that Dinosaur National Monument[10] is significantly impacted by oil and gas emissions in the Uinta Basin. In addition to elevated ground level ozone, several wintertime haze episodes were observed that were dominated by ammonium nitrate, with 24-h averaged particle light extinction exceeding 100 Mm^{-1} each winter. Despite elevated ammonium nitrate concentrations, additional gas-phase ammonia was available, such that any increases in NO_x emissions in the region are likely to lead to even greater haze levels. We recognize the state is not required to address Class II parks in the regional haze SIP. However, under the NPS Organic Act, Congress mandated that the NPS protect and manage *all* NPS units to leave them "unimpaired" for the benefit of present and future generations. As such, the NPS supports any measures to improve air quality in all NPS units and statewide engine requirements would achieve this.

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[9] Email communication (01/20/2022) from Chelsea Cancina with UTDAQ to NPS ARD staff.
[10] Even though the park was created prior to 1977, by virtue of being designated as a National Monument rather than a National Park it was not included in the original list of 258 Class I areas.

In addition, there has been interest in further development of federal mineral resources in the Paradox Basin, which surrounds Canyonlands and Arches National Parks. Visibility impairment is an issue the NPS has consistently addressed with the BLM in making federal mineral leasing and development determinations. Statewide engine requirements would assist both the BLM and the NPS in protecting and maintaining visibility in these iconic parks under federal mineral development authorizations. We encourage Utah to seriously consider implementing statewide engine NO_x requirements like the examples from other states provided below.

5.2 Statewide Engine Rules—NO_x Reduction Opportunity

The significant cumulative emissions from the upstream oil and gas source sector combined with the limited emissions footprint from any single wellsite points to the need for source category rules such as statewide engine rules. These recommendations were initially sent to UDAQ in a 06/09/2020 email to Jay Baker. Several states now implement state or region-wide requirements to limit NO_x emissions from area source engines. We encourage Utah to consider similar rules and provide several examples here.

Below is a summary of the best examples of statewide NO_x limits for NG-fired lean-burn engines:

- 0.5 g/hp-hr
    - Texas requires this limit for all engines > 50 HP in their ozone nonattainment areas and a 33-county region.
    - PA requires this limit for all new and existing (permitted between 2013-2018) lean-burn engines > 500 HP
- 0.3 g/hp-hr
    - Pennsylvania requires this limit for all new lean-burn engines > 2,370 HP
    - NM has permitted large (5,000 HP) engines at this limit
- 0.15 g/hp-hr (approximate conversion – limit is expressed as 11 ppmvd where 1 g/bhp-hr = approximately 73 ppmv for lean burn engines)
    - California's South Coast Air Quality Management District and San Joaquin Valley Air Pollution Control District require this for all engines > 50 HP. These were phased-in requirements. It is assumed that post combustion control is necessary to achieve these limits. Furthermore, the SCAQMD prioritizes engine replacement with electric motors.
    - This limit is higher for engines used for gas compression in the SJVAPCD (65 ppmv or 0.89 g/hp-hr).

The options for retrofit or add-on controls that have the most significant emission reduction potential for engines include SCR and Low Emissions Combustion (LEC). The CSAPR TSD Assessment on Non-EGU NO_x Emission Controls provides a good discussion of these control technologies and associated costs for lean-burn RICE. For example, with regard to SCR installation on lean-burn engines, the EPA developed linear regression equations for capital and annual costs based on engine HP (2001–2003$). The EPA relied on information in a 2012 OTC document (Technical Information Oil and Gas Sector Significant Stationary Sources of NO_x

Emissions) and a 2003 cost analysis completed by the California South Coast Air Quality Management District in support of Rule 4702 when developing these linear regressions. NO_x reductions of approximately 90% or greater are achievable. EPA developed similar regression equations to estimate the costs of LEC retrofits.

Below is a summary of the best examples of statewide NO_x limits for NG-fired rich-burn engines:

- 0.20 g/hp-hr with the application of NSCR (a.k.a. 3-way catalyst)
    - Pennsylvania requires this limit for all rich-burn engines > 500 HP. Pennsylvania also has a 0.25 g/hp-hr limit for all existing and new rich burn engines > 100 HP and < 500 HP
- 0.16 g/hp-hr
    - This limit is applicable in California's South Coast Air Quality Management District and San Joaquin Valley Air Pollution Control District (see note below)

Please note, the California and Texas limits described above apply to rich and lean-burn engines alike (for rich burn engines, the 11 ppmvd limit in California is approximately 0.16 g/hp-hr). It is anticipated that these limits will be achieved with NSCR. Colorado currently requires installation of NSCR on all rich-burn engines and recently approved a proposal that established NO_x limits for rich-burn engines of 0.8 g/hp-hr on existing engines (in service on or before November 14, 2020) and 0.5 g/hp-hr for new engines (in service, modified, or relocated after November 14, 2020).

We recommend that Utah consider the engine requirements implemented in Pennsylvania, Texas, or California to reduce NO_x emissions from engines associated with upstream oil and gas operations.

APPENDIX D.2 – NPS Additional Information Requests

APPENDIX D.2.A - Sunnyside

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March 14, 2022

Ms. Chelsea Cancino
Environmental Scientist
Utah Division of Air Quality
195 N 1950 W
Salt Lake City, UT 84116
ccancino@utah.gov

RE: Response to UDAQ questions on Sunnyside Cogeneration Associates Four Factor Analysis

Dear Ms. Cancino:

Sunnyside Cogeneration Associates (Sunnyside) and Trinity Consultants (Trinity) have prepared this letter in response to comments made by Federal Land Managers (FLMs) to Utah Division of Air Quality's (UDAQ's) Four-Factor Analysis Evaluation. Questions centered around the use of a 7% interest rate and further discussion of this interest rate is provided in this memorandum.

If you have further questions about these responses, please reach out to Brian Mensinger at Trinity (801-272-3040/bmensinger@trinityconsultants.com) or Rusty Netz at Sunnyside (rusnetz@hotmail.com) for further information or clarification.

DISCUSSION OF INTEREST RATE

The selection of a firm-specific interest rate is critical to preparing an accurate control cost estimate for use in a four factor analysis. FLMs provided additional comments to UDAQ stating preference for the use of the current bank prime rate of 3.25%. The Sunnyside dry sorbent cost analysis assumed a 7% interest rate and a 20-year life in amortizing the capital cost of this control system. Additionally, a similar interest rate was used for for SCR and SNCR cost analyses.

EPA Guidance

EPA's Air Pollution Control Cost Manual (Cost Manual) states: "When performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, the correct interest rate to use is the nominal interest rate, which is the rate firms actually face."[1] EPA further states: "For input to analysis of rulemakings, assessments of private cost should be prepared using firm-specific nominal interest rates if possible, or the bank prime rate if firm-specific interest rates cannot be estimated or verified."

The bank prime rate is a well-established lending rate, in this case established on a national basis. This rate is generally considered the lowest possible lending rate and is updated annually. For this analysis, which evaluates equipment costs that may take place more than 5 years into the future, it is important to ensure that the selected interest rate represents a longer-term view of corporate borrowing rates. The cost manual cites the bank prime rate as one indicator of the cost of borrowing as an option for use when the specific nominal interest rate is not available.

[1] EPA Air Pollution Control Cost Manual (EPA/452/B-02-001), Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology, s. 2.5.2; November 2017

From 2000 to 2020, the annual average prime rate has varied from 3.25% to 9.23%, with an overall average of 4.79% over that period.[2] Interest rates have been increasing recently with concerns that this trend will continue. The Cost Manual also cautions that the "base rates used by banks do not reflect entity and project specific characteristics and risks including the length of the project, and credit risks of the borrowers."[3] For this reason, the prime rate should be considered the low end of the range for estimating capital cost recovery.

Site Specific Information

Sunnyside solicited an appraisal report in January of 2021 which documented the company's Weighted Average Cost of Capital (WACC). WACC is defined as the "the opportunity cost of all capital invested in an enterprise" on a weighted average basis.[4] WACC generally accounts for a variety of company specific or project specific financial assumptions including:

- Fraction of the cost of capital financed by debt;
- Cost of debt;
- Tax rate;
- Fraction of the cost of capital financed by equity; and
- Cost of equity.[5]

In general a higher WACC is representative of a higher financial risk for the company or financing institution. The appraisal solicited by Sunnyside reported a WACC of 12.46% after adjustment for property taxes.[6] Table 1 compares this WACC to standard industry values.

Table 1. Comparison of WACC Values[7]

Industrial Sector	WACC
Total Market	5.14%
Coal and Related Energy	4.57%
Utility (General)	3.87%
Sunnyside	12.46%

Table 1 demonstrates that the WACC for Sunnyside is significantly higher than the market on average and similar industry sectors. The Sunnyside Plant was originally commissioned in the early 1990s. The age of the plant and anticipated additional operating years both contribute to a higher investment risk and subsequently to the increased WACC.

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[2] Board of Governors of the Federal Reserve System Data Download Program, "H.15 Selected Interest Rates," accessed April 16, 2020.
https://www.federalreserve.gov/datadownload/Download.aspx?rel=H15&series=8193c94824192497563a23e3787878ec&filetype=spreadsheetml&label=include&layout=seriescolumn&from=01/01/2000&to=12/31/2020

[3] EPA Air Pollution Control Cost Manual (EPA/452/B-02-001), Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology, s. 2.5.2; November 2017

[4] New York University, Stern School of Business "The Weighted Average Cost of Capital"
https://pages.stern.nyu.edu/~igiddy/articles/wacc_tutorial.pdf

[5] Pennsylvania State University "Weighted Average Cost of Capital" https://www.e-education.psu.edu/eme801/node/585

[6] Reviewing experts included the following firms: Bodington & Co, Sterling Energy, and Energy Ventures Analysis.

[7] New York University, Stern School of Business published values, dated January 2022;
people.stern.nyu.edu/adamodar/New_Home_Page/datafile/wacc.htm

WACC cannot be substituted for nominal interest rate, because these two values are used for two fundamentally different purposes. WACC allows a company to quantify depreciation, or discount rate, on a whole cost basis while nominal interest rate represents the additional cost required by a financial institution for the acquisition of a loan. However, both values require businesses and/or financial institutions to consider the financing structure of the company and the risk inherent in the investment being made. Thus, the increased WACC supports the use of a nominal interest rate higher than the current bank prime rate.

Since the actual nominal interest rate for a project of this type is not readily available to Sunnyside, additional resources were reviewed to determine appropriate nominal interest rates for this industry sector and project type. One such resource was the Office of Management and Budget (OMB). For economic evaluations of the impact of federal regulations, the OMB uses an interest rate of 7%.

> *"As a default position, OMB Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector."*[8]

Furthermore, the Texas Commission on Environmental Quality (TCEQ) stated in their 2021 Regional Haze State Implementation Plan revision that they had assumed a 10% interest rate for estimating annualized capital costs for EGUs and for non-EGUs, where appropriate.[9] The TCEQ assumed an interest rate of 10% for all sources and units evaluated because it was assumed that regulated entities would be able to secure, on average, this rate when attempting to finance capital investments associated with air pollution control devices and abatement equipment. It is expected that some sources, depending on their financial institution and method of financing, would have interest rates higher or lower than 10%, but the TCEQ assumed that a constant 10% interest rate would be a reasonable 'mid-point' to use across all source categories.

Additionally, EPA used a capital recovery factor (CRF) of 0.0806, which corresponds to 30 years at 7% interest, in its April 2015 Federal Implementation Plan (FIP) for Arkansas.[10] Finally, a nominal interest rate of 7% has been referenced in EPA's Cost Manual and has been commonly relied upon for control technology analyses for several decades, including periods when the bank prime rate was exactly the same as it is now (3.25%).[11]

Based on the information documented in this memorandum, a nominal interest rate of 7% was chosen to perform the cost analysis for Sunnyside's four factor analysis. This rate was supported by a variety of institutions and most closely matched the financial indicators known by Sunnyside.

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[8] OMB Circular A-4, https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4/

[9] TCEQ 2021 Regional Haze SIP Revision, Appendix B, Analysis of Control Strategies to Establish Reasonable Progress Goals, published October 2020 (Project Number 2019-112-SIP-NR)

[10] 80 FR 18944 *Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan, Proposed rule* (April 8, 2015) Docket No. EPA–R06–OAR–2015–0189, Appendix A. *Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plan (SO2 Cost TSD).*

[11] https://www.bankrate.com/rates/interest-rates/prime-rate.aspx

APPENDIX D.2.B – US Magnesium

Chelsea Cancino <ccancino@utah.gov>

US Magnesium 4-Factor Analysis Questions

Rob Hartman <rhartman@usmagnesium.com> Tue, Feb 8, 2022 at 7:25 AM
To: Chelsea Cancino <ccancino@utah.gov>
Cc: Glade Sowards <gladesowards@utah.gov>, Becky Close <bclose@utah.gov>

As you may or may not be aware, US Magnesium (USM) contracted GeoStrata and specifically Todd Wetzel to perform the 4-factor analysis. During USM's permitting of its lithium carbonate plant, Todd Wetzel was the Division of Air Quality's lead engineer for major source/NSR/PTE for the USM facility, thus, his pre-existing knowledge of USM's operation, processes and emission sources made him a logical choice to perform the 4-factor analysis. Todd Wetzel was knowledgeable on the spray dryer operation prior to and as confirmed during his preparation of the 4-factor analysis. In August 2021, Todd Wetzel left GeoStrata and accepted a position with a manufacturing business in the upper mid-west, and USM has no current contact information. Thus, this response to limited to factual information on operation of the spray dryers.

Hot combustion gas from the turbines is boosted as needed with duct burners to achieve a spray dryer inlet gas temperature in the operating range of 900 to 1,100 $^{\circ}$F. The hot gas is ducted directly into the spray dryer co-current to contact and dry aspirated pre-heated brine product (principally concentrated magnesium chloride brine). Spray dryer exhaust gas carrying dried power magnesium chloride ("spray dried powder" or "SDP") exits the bottom of the spray driers at a temperature in the range of 550 to 800 $^{\circ}$F and proceeds to the cyclones that separate and collect the product SDP. The post-cyclones exhaust gas then enters the brine pre-heater / concentrator tanks to preheat brine (prior to feed into the spray dryers) and capture carry-over SDP from the cyclones for recovery back in the spray dryers. Upon exiting the pre-heater / concentrator tanks, the gas temperature is in the range of 250 to 400 $^{\circ}$F. The gas then enters the spray dryer scrubbers (wet, vertical packed bed scrubbers) to remove particulate and hydrochloric acid vapors. The scrubber exhaust temperature is in the range of 130 to 150 $^{\circ}$F. The spray dryer systems are fully integrated in the process from the turbines through the scrubbers that exhaust to the ducting to the main stack.

Rob Hartman, P.G.

Environmental Manager

US Magnesium LLC

2380 N 2200 W

Salt Lake City, UT 84116

801.532.1522 x1355

rhartman@usmagnesium.com

From: Chelsea Cancino <ccancino@utah.gov>
Sent: Tuesday, January 25, 2022 12:23 PM
To: Rob Hartman <rhartman@usmagnesium.com>
Cc: Glade Sowards <gladesowards@utah.gov>; Becky Close <bclose@utah.gov>
Subject: US Magnesium 4-Factor Analysis Questions

Hello Mr. Hartman,

UDAQ has submitted the draft regional haze SIP for the second implementation period to the Federal Land Managers for their mandatory 60-day reviewing period. Below are their questions about US Magnesium's 4-factor analysis, if you could please provide the answers.

Turbines/duct burners: In addition to electrical generation for onsite use, the exhaust gas from the three turbines is further heated with 15.3 MMBtu/hr duct burners and routed to three spray dryers for use in processing/drying operations.

- US Magnesium did not fully evaluate the feasibility of locating the SCR between the turbine exhaust and duct burner using a high-temperature catalyst. Applications of SCR on high temp simple cycle turbines are well documented. Why didn't US magnesium evaluate/consider options for SCR placement directly after the CT and factor the cost of additional reheat (fuel use) into the analysis?
- US Magnesium did not discuss or evaluate the feasibility of locating the SCR downstream of the spray dryer. What is the exhaust temperature of the flue gas exiting the spray dryers? Is the spray drier direct contact or indirect contact heat exchange?

Diesel Pump Engines: US Magnesium performed a cost analysis to evaluate the cost-effectiveness of retrofitting the diesel engines with SCR. The analysis notes that the "costs provided in Table 5-10 below are estimates by Caterpillar based on systems they have in place for other engines of a similar size."

- Can you provide the Caterpillar estimates referenced?

In addition, if you would like a copy of our draft RH SIP, you may request one from me via email. Please note, however, that the draft is subject to change and UDAQ is not accepting any comments until the formal public commenting period.

Thank you,

Chelsea Cancino

Environmental Scientist, Regional Haze Coordinator

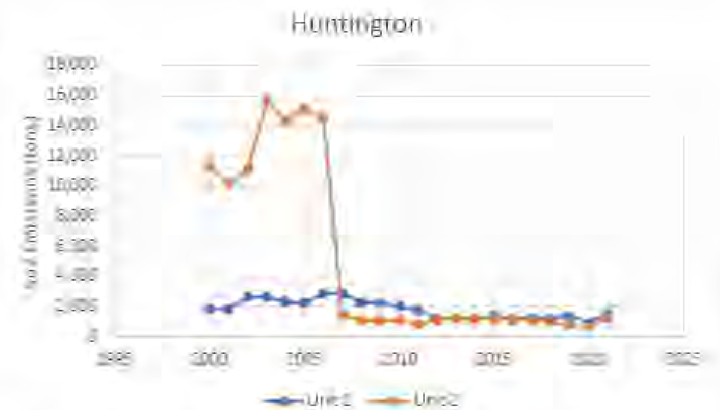
(614) 515-8235

195 North 1950 West, SLC UT 84116

APPENDIX D.2.C – PacifiCorp

Regional Haze second planning period issues regarding SO_2 Controls
for PacifiCorp's power plants

1. In section 4.1.2 of its Feb. 14, 2022 feedback on Utah's regional haze state implementation plan for the second planning period ("RH SIP 2"), the National Park Service ("NPS") incorrectly suggested that PacifiCorp and UDAQ should conduct a "four-factor analysis to explore potential SO_2 emission reduction opportunities for the Hunter and Huntington facilities." NPS also mistakenly asserted that PacifiCorp had provided information that the scrubbers could be upgraded to remove "over 3,000 tons/year of additional SO_2 for less than $1,000 per ton."
2. UDAQ recently informed PacifiCorp that it was going to include significant SO_2 reductions as part of its proposed RH SIP 2. UDAQ stated it derived these reductions from the 2028 "On the Book" control scenario from the WRAP modeling, but PacifiCorp has not been provided any four-factor reasonable progress (including visibility) analysis supporting the proposed limits.
3. *UDAQ should not require additional SO_2 reductions beyond those offered in PacifiCorp's April 21, 2020 submittal for the following reasons: (1) the SO_2 controls at the Hunter and Huntington power plants are efficient and effective; (2) those SO_2 controls cannot be upgraded to become more efficient in a cost-efficient manner; and (3) EPA guidance recognizes that a State may forego further analysis of SO_2 controls at a plant if it has modern, efficient controls.*
4. **Effective SO_2 controls.** The SO_2 controls at the Hunter and Huntington power plants all have control efficiencies in excess of 90%. Each of the units at these plants is subject to a stringent SO_2 emissions limit of 0.12 lb/mmBtu through their respective Title V permits. Section II.B.3.b of each Title V permit contains the relevant limit. The charts below demonstrate the SO_2 emissions reduction improvements PacifiCorp has made at its Utah power plants.



5. **No Cost-Efficient Upgrades.** The NPS mistakenly claims that over 3,000 tons/year of SO_2 could be reduced at less than $1,000 per ton. The SO_2 controls at PacifiCorp's plants are running as efficiently as possible and there are no cost-efficient upgrades available. NPS appears to be misconstruing information provided by PacifiCorp as part of the RPELs offered in PacifiCorp's April 21, 2020 submittal, which combined operational adjustments (such as reduced until utilization) with incremental capital and O&M costs.
6. **Guidance recognizes additional SO2 controls are not required.** EPA's 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" ("2019 Guidance") recognizes that 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." *Id.* at 22.
    a. 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 when an EGU has add-on flue gas desulfurization ("FGD") and meets the applicable alternative SO_2 emission limit (0.2 lb/mmBtu) of the 2012 Mercury Air Toxics Standards ("MATS") rule for power plants. *See* 2019 Guidance, at 23. This example is consistent with the situation here. Moreover, EPA explained in the 2019 Guidance that the 0.2 SO_2 limit in the MATS rule is "low enough that it is *unlikely* that an analysis of control measures for a source already equipped with a scrubber and meeting [this] limit[] would conclude that even more stringent control of SO_2 is necessary to make reasonable progress." *Id.* at 23. (emphasis added).
    b. Such is the case here. All of PacifiCorp's Utah power plants have FGD installed, and each unit has a permitted limit of 0.12 lb/mmBtu for SO_2 emissions, which is significantly lower than the 0.2 SO_2 limit addressed in the 2019 Guidance. Therefore, under the applicable EPA guidance, no further SO_2 controls are needed for PacifiCorp's Utah power plants.
7. **Coal Quality.** UDAQ should also consider that sulfur content varies by mine and coal seam. SO_2 emissions limits imposed on PacifiCorp must consider the potential variability of sulfur content in future coal deliveries.

8. **Visibility.** Finally, UDAQ has not provided PacifiCorp with any information that additional SO_2 emissions limits, as contemplated by UDAQ, will improve visibility in a cost-effective manner, or will even appreciably improve visibility in Class I areas.

APPENDIX D.3 - USFS Feedback

USDA United States Department of Agriculture | Forest Service | Intermountain Region | 324 25th Street
Ogden, UT 84401

File Code: 2580
Date:

Bryce Bird
Utah Department of Environmental Quality
Division of Air Quality
P.O. Box 144820
Salt Lake City, Utah 84114-4820

Dear Mr. Bird:

On December 15, 2021, the State of Utah submitted a draft Regional Haze State Implementation Plan describing your proposal to continue improving air quality by reducing regional haze impacts at mandatory Class I areas across the Region. We appreciate the opportunity to work closely with your State through the initial evaluation, development, and subsequent review of this plan. Cooperative efforts such as these ensure that, together, we will continue to make progress toward the Clean Air Act's goal of natural visibility conditions at our Class I areas.

This letter acknowledges the U.S. Department of Agriculture, U.S. Forest Service has received and conducted a substantive review of your proposed Regional Haze State Implementation Plan. This review satisfies your requirements under federal regulations 40 C.F.R. § 51.308(i)(2). Please note, however, that onlythe U.S. Environmental Protection Agency (EPA) can make a final determination about the document's completeness. Therefore, only the EPA has the authority to approve the document.

We have enclosed comments to this letter based on our review. We look forward to your response required by 40 C.F.R. § 51.308(i)(3). For further information, please contact Pleasant McNeel, at (404) 638-4813 or via email at pleasant.mcneel@usda.gov or Bret Anderson at bret.a.anderson@usda.gov or (970) 295-5981.

Again, we appreciate the opportunity to work closely with the State of Utah. The Forest Service compliments you on your hard work and dedication to significant improvement in our nation's air quality values and visibility.

Sincerely,

DEBORAH OAKESON
Digitally signed by DEBORAH OAKESON
Date: 2022.02.17 09:58:41 -07'00'
MARY FARNSWORTH
Regional Forester

Enclosures (2)

cc: Elise Boeke, Bret Anderson, Pleasant McNeel

Caring for the Land and Serving People

Printed on Recycled Paper

Enclosure

USDA Forest Service (USFS) Technical Comments on State of Utah Department of Environmental Quality (Utah DEQ) Draft Regional Haze State Implementation Plan (SIP)

Attachment A

USDA Forest Service (USFS) Technical Comments on Utah Department of Environmental Quality (Utah DEQ) Draft Regional Haze State Implementation Plan (SIP)

We appreciate the opportunity to work with your agency through the initial evaluation, development, and now, subsequent review of this DRAFT plan. The USFS recognizes the emission reductions made in Utah over the past decade that have resulted in improvements in visibility at the Forest Service Class I Wilderness Areas. Further, we appreciate the strong working relationship among our respective staff.

Overall, the USDA Forest Service finds that the draft RH SIP is well organized and comprehensive. The Long-Term Strategies for this planning period appear to indicate that Forest Service Class I Wilderness Areas will continue to show visibility improvements better than the Uniform Rate of Progress (URP) through 2028, and we appreciate the commitment by Utah DEQ to evaluate progress in meeting the visibility goals during the 5-year progress reports.

We specifically appreciate the willingness of Utah to engage the USDA Forest Service early in the drafting of the RH SIP which is commendable and a model for other states.

The USFS requests Utah DEQ consider the following issues before final adoption of the SIP.

<u>Prescribed Fire Emissions:</u>

The USFS and Utah DEQ are committed partners to managing the air quality impacts of prescribed fires. The Utah Smoke Management Plan, originally created in 1999, has been revised repeatedly with the agreement and leadership of both parties. USFS hosts and provides the bulk of the funding for the Utah Interagency Smoke Coordinator position, and Utah DEQ provides significant staff time as well, primarily in planning, but also providing support through technical analysis, inventory, and monitoring. While prescribed fire is currently a minor contributor to visibility impairment on the 20% most impaired days, the USFS appreciates that Utah DEQ will continue to recognize the ecological role of prescribed fire and is considering the inclusion of a prescribed fire end point adjustment to the glide slope.

Fire plays an important role in shaping the vegetation and landscape in Utah and surrounding states. Recurring fire has been a part of the landscape for thousands of years. Aggressive fire suppression, coupled with an array of other disturbances has changed the historic composition and structure of the forests. Periodic prescribed burning and other vegetation management can recreate the ecological role of fire in a controlled manner. Fire and fuels management supports a variety of desired conditions and objectives across the forests and grasslands (e.g., community protection, hazardous fuels reduction, native ecosystems restoration, historic fire regimes restoration, wildlife openings, and open woodland creation, etc.). The USFS plans to significantly increase the use of prescribed fire to accomplish these goals. The Utah Governor's Catastrophic Wildfire Reduction Strategy states: "the need to use naturally-occurring and controlled fire on a much greater scale is very important, and is a major education and discussion matter for policymakers, communities, and residents across the west. The careful and controlled reintroduction of fire is an essential tool in the suite of activities needed to reduce catastrophic wildland fires."

As you are aware, 40 CFR 51.308(f)(1)(vi)(B) allows states to adjust the glidepath to account for prescribed fire. The draft SIP states that no glidepath adjustment was made to account for prescribed fire emissions. The USFS encourages Utah DEQ to use the adjustment of glidepaths for the increased prescribed fire projections reflected in the "Future Fire Scenario 2" available in Product 18 of Modeling Express Tools of the WRAP TSS. Attachment B provides the methodology and data needed to assess the projected increase in prescribed fire for glidepath adjustment.

When considering the Rx fire end-point adjustment, the USFS is concerned that industry or other groups could improperly argue that additional controls are not necessary to make further progress if modeling demonstrates that the Class I Area in Utah is below adjusted glidepaths, essentially arguing that the glidepath provides safe harbor from additional control requirements. The USFS believes this "safe harbor" argument is erroneous and is not supported by the Regional Haze Rule.

Attachment B

Prescribed Fire Emissions Glidepath Adjustment

Federal land manager policy and funding is shifting to an increase in prescribed fire acres. To consider long-term trends in fire emissions for regional haze planning, the Western Region Air Partnership (WRAP) commissioned a report to evaluate a likely development: that emissions will increase in the future from the 2014 representative baseline. Known as "future fire sensitivities" (FFS), this analysis considered an increase in wildfire emissions (FFS1) or an increase in prescribed fire emissions (FFS2) as two potential future variations in fire activity that are not specific to any single future year.

The fire sensitivities are added to the 2028OTBa2 reference case scenario to replace historic wildfire/prescribed fire emissions originally used in the 2028 on-the-books future year modeling scenario (2028OTBa2), while keeping constant all other U.S. anthropogenic, international, natural, and non-US fire emissions. The only differences between the 2028OTBa2 and the fire sensitivities are due to the FFS1 and FFS2 assumptions. Emissions development of the future fire sensitivities is described in the Air Sciences, Inc. report Fire Emissions Inventories for Regional Haze Planning: Methods and Results (April 2020). Modeling methods are defined in WRAP Future Fire Sensitivity Simulations (August 2021).

Since the only differences between 2028OTBa2 and the FFS2 are the assumptions due to the increased acres treated in FFS2, one should be able to isolate the change in extinction on the most impaired days (MID) by calculating the incremental difference between FFS2 and 2028OTBa2, in other words, subtracting the 2028OTBa2 results from the FFS2 results.

Procedures

1. Get "Default" Rx fire adjustment from Product #5, WRAP TSS, Model Express Tools ("Adjustment Options for End of URP Glidepath")

Figure 1- Example (Bryce Canyon) WRAP TSS Product #5, Model Express Tools

2. Subtract "End Point A – International" from "End Point B – International + Wildland Rx Fire"
    a. Example- Bryce Canyon (BRCA1): B = 6.2 DV, A = 5.9 DV. Rx fire component of adjustment = B – A or 6.2 – 5.9, which yields 0.3 DV different or "default endpoint adjustment for Wildland Rx fire.
3. Convert Wildland Rx Fire DV to extinction units (Mm^{-1})
    a. Obtain 2064 unadjusted end point in DV from Product #5, WRAP TSS (see figure 1 above, URP Glidepath)
        i. Example- BRCA1: end of the URP in 2064 = 4.1 DV
    b. Add Wildland Rx Fire DV from Step 2 to Unadjusted 2064 end point from Step 1 and Subtract 2064 URP end point (unadjusted) to calculate Wildland Rx Fire contribution in extinction units by following formula: $10*EXP((2064_{DV}+RxFire_{DV})/10)-10*EXP(2064_{DV}/10)$.
        i. Example- BRCA1: 10*EXP((4.1 + 0.3)/10) – 10*EXP(4.1/10) = 0.458894 Mm^{-1}
4. To calculate incremental contribution from WRAP Future Fire Scenario 2 (Increased Wildland Rx Fire ("FFS2")), obtain extinction results for 2028 OTBa2 scenario AND 2028 FFS2 scenario from WRAP TSS, Model Express tools, Product #18 ("Future Fire Sensitivities Visibility Projections – Most Impaired Days")
    a.
        i. 2028 OTBa2 results: stacked bar chart, column 2 = 9.62 Mm^{-1} (Figure 2, "A")
        ii. 2028 FFS2 results: stacked bar chart, column 4 = 11.06 Mm^{-1} (Figure 2, "B")
    b. Add Rayleigh scatter back to each value from steps 4.a.i and 4.a.ii
        i. Example- BRCA1: Rayleigh = 9, so add Rayleigh back to 2028 OTBa2 and 2028 FFS2
            1. 2028 OTBa2 = 9.62; Rayleigh = 9; Total Bext = 18.62 Mm^{-1}
            2. 2028 FFS2 = 11.06; Rayleigh = 9; Total Bext = 20.06 Mm^{-1}
    c. Subtract total extinction, 2028 OTBa2 from total extinction, 2028 FFS2
        i. Example- BRCA1: 20.06 Mm^{-1} (2028_{FFS2} Bext) – 18.62 Mm^{-1} (Bext 2028_{OTBa2}) = 1.44 Mm^{-1} ($Bext_{\Delta 2028FFS2}$)
    d. The difference from step 4.c.i yields the incremental increase of 2028_{FFS2} above 2028_{OTBa2} in extinction units (1.44 Mm^{-1} in this example).
    e. Convert the 2064 URP unadjusted endpoint into extinction units (Mm^{-1})
        i. Example- BRCA1: $Bext_{2064URP}$ = 10*EXP($DV_{2064URP}$/10), or 10*EXP(4.1/10)
    f. To calculate the "alternative glideslope adjustment" (which reflects the land management policy change of increasing acres treated with prescribed fire = Total ΔWildland Rx Fire which is the sum of 2028OTBa2 and FFS2 prescribed fire impacts in Mm^{-1}), add the incremental change in extinction units from 2028_{FFS2} (step 4.c.i) to the original projection from 2028_{OTBa2} in extinction units (step 3.b) and convert to deciview units by the following equation: $10*LN(((Bext_{\Delta 2028FFS2}\,(Mm\text{-}1) + Bext_{2028OTBa2}) + Bext_{2064URP})/10) - DV_{2064URP}$
    Ex-BRCA1: 10*LN(((1.89 + 0.45) + 15.08)/10) – 4.1 = 1.18 DV
5. Figure 3 shows the final results, with the green line including the 1.18 DV adjustment. Prescribed fire is expected to ramp up over the next decade. Without this adjustment to the 2064 endpoint deciview value, then impacts from increased prescribed fire activity may prevent states from remaining beneath the URP even if other haze causing pollutants are reduced.

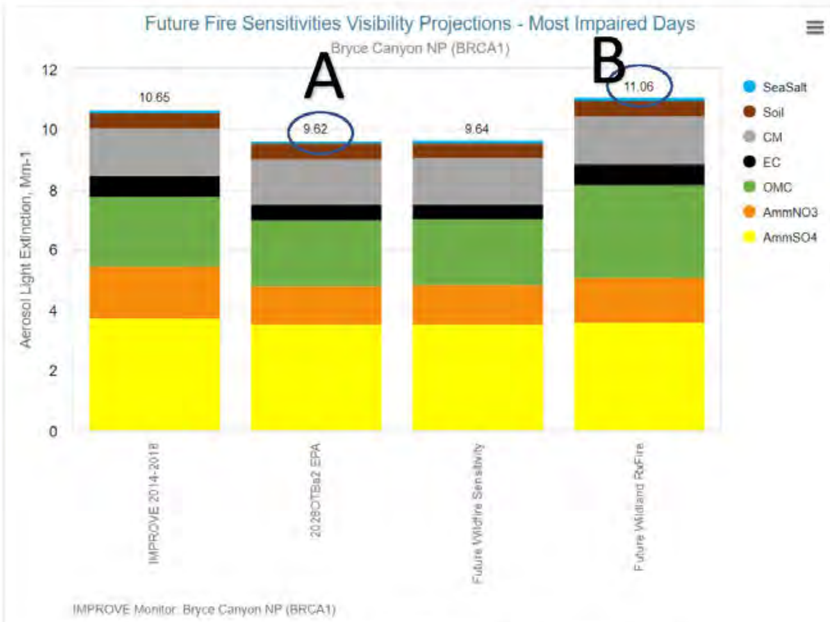


Figure 2- Future Fire Sensitivities Total Extinction - Most Impaired Days

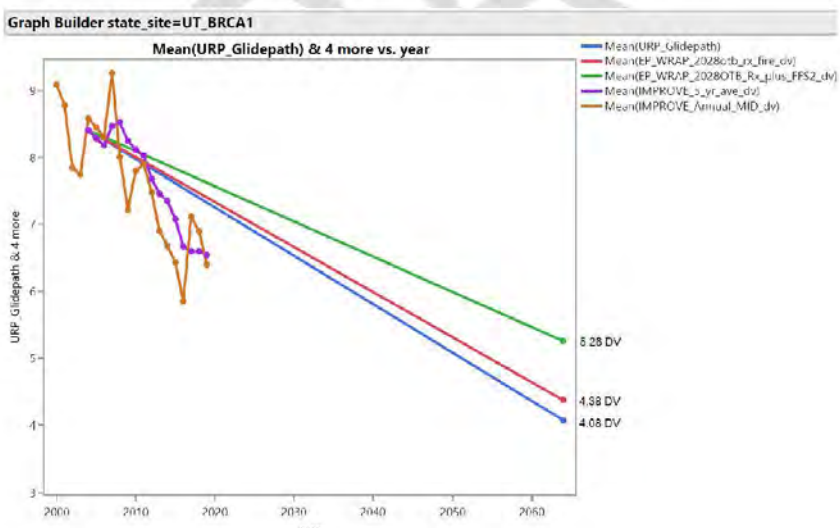


Figure 3- Final result of this accounting for FFS2: Green Line