APPENDIX A

SOUTH DAKOTA REGIONAL HAZE STATE IMPLEMENTATION PLAN: FEDERAL LAND MANAGER COMMENTS

APPENDIX A-1

SOUTH DAKOTA REGIONAL HAZE STATE IMPLEMENTATION PLAN: SUMMARIES OF AND RESPONSES TO FEDERAL LAND MANAGER COMMENTS

Table Of Contents

1.0 Introduction

In accordance with Title 40 of the Code of Federal Regulations (CFR), § 51.308(i)(2), the state must provide the Federal Land Manager with an opportunity for consultation, in person and at least 60 days prior to holding any public hearing on an implementation plan (or plan revisions) for regional haze. In mid-September of 2021, DANR fulfilled this obligation and submitted South Dakota's draft Regional Haze State Implementation Plan to the following Federal Land Managers:

1. Tim Allen, U.S. Fish & Wildlife Service, Lakewood, Colorado;
2. Jeff Sorkin, USDA Forest Service, Great Lakes National Forests – Eastern Region;
3. Melanie Peters, National Park Service, Air Resources Division, Lakewood, Colorado;
4. Don Shepherd, National Park Service, Air Resources Division, Lakewood, Colorado;
5. Andrea Stacy, National Park Service, Air Resources Division, Lakewood, Colorado;
6. Debra Miller, National Park Service, Air Resources Division, Lakewood, Colorado;
7. Lisa Devore, National Park Service, Air Resources Division, Lakewood, Colorado;
8. David Pohlman, National Park Service, Air Resources Division, Lakewood, Colorado;
9. Kirsten King, National Park Service, Air Resources Division, Lakewood, Colorado;
10. Milton Haar, National Park Service, Badlands National Park;
11. Marc Ohms, National Park Service, Wind Cave National Park, and
12. Leigh Welling, National Park Service, Wind Cave National Park.

DANR requested comments by December 13th, 2021. DANR received comments from the United States Department of Agriculture – Forest Service, and United States Department of Interior – National Park Service. This document contains DANR's responses to the comments received during the opportunity for consultation from the federal land managers. A summary of the comments and DANR's responses follows.

2.0 South Dakota Visibility Conditions Calculations

1. The Forest Service encouraged DANR to use the WRAP FFS2 modeling results to construct the prescribed fire 2064 endpoint adjustment. This endpoint adjustment reflects the increased use of prescribed fire since the 2014-2018 baseline emissions inventory (the 2028OTBa2 model run inventory), and more accurately reflect the planning and investment by the Forest Service and wildland management community in the use of prescribed fire to address wildfire risk.

Response: South Dakota analyzed the proposed alternative 2064 endpoint adjustment opportunity provided by the Forest Service. South Dakota understands that the emissions development of the future fire sensitivity (FFS2) scenario included assumptions that increased wildland prescribed fire activity from the 2028OTBa2 projections, and that these increases according to the US Forest Service better represent the growing use of prescribed fire compared to what is represented by the baseline emissions inventory. South Dakota understands that by using the FFS2 scenario, the 2064 endpoints would be adjusted upwards, and performed the calculations to determine exactly how much of an adjustment would hypothetically occur. For Badlands National Park, the 2064 end point would be adjusted upwards by 1.3 deciviews, bringing the new 2064 end point goal value from 10.1dv to 11.4dv. This value is only 0.2dv from the 2028 projected value of 11.6dv, meaning South Dakota would be 95% of the way to its goal by the year 2028. For Wind Cave National Park, the 2064 end point would be adjusted upwards by 5.9dv, bringing the new 2064 endpoint goal value from 10.1dv to 16dv. This value is above the first implementation period's 2000-2004 baseline value, meaning the 2064 goal had already been met before the Regional Haze program even started. South Dakota appreciates the adjustment opportunity provided by the US Forest Service, and looks forward to the opportunity to analyze similar alternatives in the future.

2. The National Park Service notes that, according to the last ten years of IMPROVE data, neither Class I Area has seen dramatic improvements in light extinction on the most impaired days, and data shows visibility impairment to actually be increasing during the last 4-5 years, mainly due to increases in ammonium nitrate and ammonium sulfate. This highlights the need for continued reductions in emissions in order to ensure visibility improvement, and also shows significant additional progress is still necessary before the 2064 visibility goal of no anthropogenic visibility impairment is realized.

Response: South Dakota acknowledges that the visibility impairment appears to be increasing over the last four to five years. However, due to several different variables such as weather patterns, climate, etc., DANR expects the visibility will vary each year. The visibility in some years may be higher and in some years the visibility will be lower. However, if you look at the full data set (Figures 2-5 and 2-6 for Badlands and Wind Cave National Parks, respectively), the visibility overall has continued to decrease from calendar year 2000, which is the baseline for the Regional Haze program. As such, South Dakota's two Class I areas are showing visibility improvement and are making reasonable progress to natural background levels.

3. The National Park Service notes that although it is acceptable that South Dakota used the 2064 adjusted endpoint, this endpoint may be reevaluated in the future, and may be revised as conditions change and as modeling improves.

Response: South Dakota acknowledges that the definition of the 2064 endpoint may be reevaluated and revised in the future as improvements in scientific knowledge and methodologies occur. South Dakota will continue working and collaborating with WRAP, and will continue staying appraised to any changes in definitions of the 2064 endpoint, in order to take appropriate measures as necessary.

3.0 Long-Term Strategy For Regional Haze

1. The Forest Service believes that DANR's four factor analysis is incomplete, because DANR didn't base its final control measure determination on any of the same four statutory factors. The justification for not requiring controls should be confined to the four factor analysis in order to properly conform to the regulatory requirements of the Regional Haze Rule.

Response: DANR did conduct a four factor analysis.
1. DANR considered the cost of compliance. DANR identified the potential cost of the controls for both GCC Dacotah and Pete Liens on a $ per ton basis.
2. DANR considered the time necessary for compliance. DANR identified that the Wind Cave National Park is projected to meet the adjusted national background goal in 2064 by 2028 and Badlands National Park will be about 70% of the goal by 2028 and the potential timelines for installation of the control systems.
3. DANR considered the energy and non-air quality environmental impacts of compliance. DANR considered the additional increase in electricity demand, the safety concerns associated with transport and storage of ammonia, and the impact of ammonia slip from the control system.
4. DANR considered the remaining useful life of both GCC Dacotah and Pete Lien and Sons. Both facilities are expected to operate for the foreseeable future and the potential controls systems had a useful life of 20 years.

The regional haze rules do not specify a specific threshold or bright line for each of the four factors to make a determination if controls should or should not be required. The rules do imply that the four factors are tied to a state's reasonable progress to the rule's goal of natural visibility by 2064. The rules allow the specific circumstances in each state dictate how those four factors will inform that state's decision. Under the specific circumstances in South Dakota DANR does not consider the cost on a dollar per ton basis is reasonable to require the additional emission controls (factor 1). Since Wind Cave National Park is projected to meet the adjusted background goal by 2028 and Badlands National Park will be about 70% of the goal by 2028, additional controls are not required to meet the requirements of the Regional Haze Program (factor 2). In addition, DANR does not consider the risk to Rapid City's attainment of the particulate matter National Ambient Air Quality standard is justified under the current circumstances (factor 3). As such, DANR does not recommend requiring additional controls at GCC Dacotah and Pete Lien and Sons at this time.

2. The National Park Service states that the Uniform Rate of Progress (URP) is a useful planning tool for assessing progress, however, it is not a "safe harbor" that can be used to avoid otherwise reasonable controls, and it is not a standard that indicates whether progress is reasonable. Instead, the Regional Haze Rule expects states to make continuous progress based upon the four-factor analysis. The National Park Service then quoted the EPA July 2021 memo, which also quotes the 2017 Regional Haze Rule preamble and the EPA August 2019 guidance in stating the same.

The US Forest Service commented that DANR determined not to require controls on the basis that South Dakota is already below the glidepath this planning cycle, and that it is erroneous to consider and use the Uniform Rate of Progress as a "safe harbor."

Response: DANR acknowledges that EPA guidance documents, memos, and preambles can be useful and helpful, but ultimately these documents are not the enforceable requirements. The words expressed in the actual Regional Haze Rule itself are the enforceable requirements.

EPA even acknowledges this concept in its August 2019 guidance when it stated on page 1 “this guidance is intended to provide information about EPA’s understanding of the discretion and flexibilities states have within the statutory and regulatory requirements to develop regional haze SIPs, even where states’ approaches differ from those provided in this document. States retain the discretion to develop regional haze SIP revisions that differ from the recommendations in this guidance; however, states must ensure the regional haze SIPs are consistent with applicable requirements of the CAA and EPA regulations, and are the product of reasoned decision-making.” EPA also acknowledges in its August 2019 guidance on page A-3 that “Attaining natural visibility conditions by the end of 2064 is not an enforceable requirement of the regional haze program.”

DANR is required by 40 CFR § 51.308(f)(2)(iv)(E), when developing its long-term strategy, to 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.” After analyzing the 2028 projections, DANR found that visibility impairment at one of its Class I Areas will have surpassed the 2064 natural visibility goal. DANR considers this as reasonable progress, especially given that the projection is for the year 2028, which is over 30 years ahead of the scheduled goal.

Also noteworthy is 40 CFR § 51.308(f)(3)(ii)(A), which provides a series of additional requirements for if the state’s Reasonable Progress Goals are projected to be located above the URP glideslope: “If a State in which a mandatory Class I Federal area is located establishes a reasonable progress goal for the most impaired days that provides for a slower rate of improvement in visibility than the uniform rate of progress calculated under paragraph (f)(1)(vi) of this section, the State must demonstrate […].” This proves the Uniform Rate of Progress Glideslope is not merely an informal and insignificant planning tool, but instead clearly a metric necessarily required for the determination of adequacy or inadequacy.

South Dakota also emphasizes the existence of a less stringent “safe harbor” at 40 CFR § 51.308(f)(3)(i), which states in part: “The long-term strategy and the reasonable progress goals must provide for an improvement in visibility for the most impaired days since the baseline period and ensure no degradation in visibility for the clearest days since the baseline period.”

South Dakota agrees that the Regional Haze Rule expects states to make reasonable progress. As noted in Figures 2-5 and 2-6 of South Dakota’s SIP and in the National Park Service’s comments, South Dakota’s two Class I areas have shown improvement in visibility. In addition, Figures 4-10 and 4-13 in South Dakota’s SIP also project visibility will continue to improve in 2028 at South Dakota’s Class I areas.

South Dakota did not bypass the four statutory factors. South Dakota conducted a four factor analysis on two facilities and determined that additional controls were not considered cost effective and would have potential adverse environmental impacts and as such would not require those controls during this planning period. South Dakota did not automatically reject the implementation of additional controls because South Dakota was less than the URP. South Dakota conducted an analysis of facilities that should be considered for additional controls. As noted in South Dakota's SIP, the regional haze rules do not specify a specific threshold or bright line for each of the four factors to make a determination on what is reasonable. The rules allow the specific circumstances in each state dictate how those four factors will inform that state's decision. South Dakota disagrees with the National Park Service that the use of the URP, visibility impacts, and several other factors may not be used to inform what threshold should be used as a decision point for reasonableness on the four factors.

3. The National Park Service stated it is not appropriate to reject cost-effective control measures simply because the impact on visibility is considered insignificant. The National Park Service then cited EPA who stated, "whether a particular visibility impact or change is "meaningful" should be assessed in the context of the individual state's contribution to visibility impairment, rather than total impairment at a Class I Area."

Response: South Dakota did not automatically reject the control measures because of South Dakota's contribution to visibility impairment is less than 1 percent. South Dakota does acknowledge that the South Dakota's contribution to visibility was a factor among several other factors used to determine what threshold should be considered cost-effective.

South Dakota does not agree with EPA's philosophy that a "meaningful" change in visibility should be assessed in the context of the individual state's contribution to visibility impairment, rather than total impairment at a Class I Area. If all South Dakota pollution sources are eliminated and a 1% improvement in visibility at its Class I Areas and a 0% improvement in visibility at every other Class I Area in the country is achieved as a result, this is not a meaningful improvement in visibility, and it comes at the cost of all South Dakota's industries and eventually the general public. South Dakota does not believe it's currently appropriate to expect facilities emitting insignificant amounts of pollution according to EPA-approved models to incur control measures, given BART sources are still uncontrolled, and that other substantial sources of pollution are still uncontrolled.

4. The National Park Service believes that visibility improvement in Class I areas depends on the continuous incremental cumulative effects of reductions from many small regional sources, and it is therefore not appropriate to reject cost-effective control measures solely because the impact on visibility is considered to be insignificant. Furthermore, that many small incremental improvements will be needed in this and subsequent planning periods in order to meet the goal of no anthropogenic visibility impairment by 2064. The National Park Service therefore requests that

DANR require all technically feasible and cost-effective controls identified through four-factor analysis, in order to make reasonable progress during this second implementation period.

Response: South Dakota understands that "regional haze" is defined as the visibility impairment caused by many sources in a broad geographic region. However, after consulting EPA-approved modeling and other scientific analysis (see Tables 3-1 through 3-19, and figures 3-2 through 3-7,and figures 4-10 and 4-13 in the draft SIP). South Dakota does not agree that the identified technically feasible controls noted in the four factor analysis are considered cost effective. The remaining large uncontrolled or ineffectively controlled pollution sources need to be controlled first, and the effects seen, before it becomes clear whether or not insignificant sources of pollution indeed need to be controlled. In addition, after analyzing the 2028 projections, DANR found that visibility impairment at one of its Class I Areas will have surpassed the 2064 natural background visibility goal. If the Class I Areas are meeting or projected to meet the natural background visibility goal, South Dakota has met the requirements of the Regional Haze Rule.

South Dakota also notes that the term "reasonable progress" is not defined anywhere in the Regional Haze Rule, therefore, DANR does not agree that it must require control measures during this implementation period in order to make reasonable progress.

5. The National Park Service doesn't believe the Transport Rule cited as an example is analogous to the Regional Haze Rule, as the Regional Haze Rule doesn't have an associated standard, only a goal, and no CIA in South Dakota or downstream has yet reached that goal. The glideslope is a planning tool, not a standard, therefore being below the glideslope doesn't indicate a facility is overcontrolled.

Response: South Dakota agrees the Transport Rule did not involve visibility or the Regional Haze Program. However, the court decision may be used as a guideline on how to interpret similar concepts. The National Park Service is misapplying South Dakota's discussion on its state Statute and the court decision involving the Transport Rule. South Dakota is referring to the requirement of reasonable progress and the natural background visibility threshold and not the Uniform Rate of Progress (URP). DANR is required by 40 CFR § 51.308(f)(2)(iv)(E), when developing its long-term strategy, to 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." After analyzing the 2028 projections, DANR found that visibility impairment at one of its Class I Areas will have surpassed the 2064 natural background visibility goal. If the Class I Areas are meeting or projected to meet the natural background visibility goal, South Dakota does not have the authority to require controls that go beyond reasonable progress and/or exceed the natural background visibility goal based upon both its state statutes and its review of the concepts behind the court decision on the Transport Rule.

6. The Forest Service recommends that DANR should use the EPA control cost manual to select appropriate costs and rates, and that the four-factor analysis be completed using the current bank-prime interest rate of 3.25%.

   Response: DANR provided a table showing the costs of selected control measures given a hypothetical range of percentages, including the 3.25% value, and didn't consider any of these values to be cost effective. To DANR's knowledge, the two facilities which provided DANR with four factor analyses hired contractors to conduct the four factor analyses for them, and that these contractors consulted the EPA control cost manual.

7. The Forest Service recommends DANR use an appropriate useful life for the control equipment unless a source-specific justification is provided, such as lender documentation or federally enforceable shut down dates.

   Response: DANR believes an appropriate useful life for the control equipment has been used. However, regardless of what the remaining useful life used is, DANR would still consider the presented cost of control measures to not be cost effective.

8. The National Park Service believes that, given the EPA Control Cost Manual recommended interest rate of the current bank prime rate of 3.25%, the cost estimates of both semi-wet or dry scrubbing and for wet scrubbing are within the range of cost-effectiveness thresholds selected by other states (Texas $5,000/ton, New Mexico $7,000/ton, Colorado and Oregon $10,000/ton). The National Park Service implies therefore that South Dakota should also consider this range of cost estimates to be cost-effective.

   Response: South Dakota does not agree with the National Park Service's definition of cost effectiveness, as the term is not defined in the Regional Haze Rule. South Dakota considered several factors to determine what would be considered cost effective. Furthermore, in the draft SIP DANR provided tables 3-26, 3-27, and 3-28 which show the costs of selected control measures given a hypothetical range of percentages, including 3% and 3.5%, and didn't consider any of these values to be cost effective.

   Cost-effectiveness thresholds established by other states can be useful to make broad comparisons, but every facility and emission source, and each state's specific situation is different. Please refer to the response to comment number 9 of this chapter for a discussion of the differences between South Dakota and Oregon and Colorado. New Mexico and Texas differ from South Dakota in the following ways.

   1. The first factor that differentiates New Mexico and Texas from South Dakota are the 2028 visibility projections, viewable by referencing Figures 4-10 and 4-13 of South Dakota's draft SIP, the WRAP modeling result #5 charts found at https://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx, and Texas' SIP on pages 8-57 and 8-58, found at https://www.tceq.texas.gov/airquality/sip/bart/haze_sip.html. When compared to the adjusted glideslope for international anthropogenic and prescribed fires, South

Dakota's Badlands National Park's 2028 visibility projection will not cross over from below to above the adjusted glideslope until about the year 2045. Wind Cave is projected to already meet the 2064 end goal by 2028. In New Mexico, the Salt Creek Wilderness Area's 2028 visibility is projected to be above the adjusted glideslope for both international anthropogenic and wildland prescribed fires. Furthermore, the Bosque del Apache Wilderness Area, White Mountain Wilderness Area, and the Guadalupe Mountains National Park Class I Areas' 2028 visibility projections are within 5 years from crossing from below to above their adjusted glideslopes, providing little lead time for the continuance of staying on track to reaching the 2064 natural conditions goal. In Texas, Big Bend National Park's 2028 visibility projection is situated on the adjusted URP glideslope, and Gudadalupe Mountains National Park's 2028 visibility projection is situated slightly below the URP glideslope, and will cross from below the glideslope to above it at about the year 2037.

2. The second factor that differentiates New Mexico and Texas from South Dakota can be seen when viewing the WRAP modeling product #9, Figures 3-2 through 3-5 in South Dakota's draft SIP, and Figures 8-21 and 8-22 in Texas' SIP, found at https://www.tceq.texas.gov/airquality/sip/bart/haze_sip.html. The WRAP modeling and South Dakota's draft SIP figures show anthropogenic contributions to visibility impairment at any given Class I Area by state, and by the emission source groups of Oil and Gas, Non-EGU, Mobile, EGU, and Remaining Anthropogenic sources, for both ammonium nitrate and ammonium sulfate. When comparing between the states' Class I Areas, it is important to pay attention to the y-axis, as the axis values aren't standardized. When viewing South Dakota's two Class I Area charts, the largest contributor to either ammonium sulfate or ammonium nitrate anthropogenic visibility impairment from within South Dakota's borders is attributed to mobile sources, which South Dakota does not have the authority to require additional control(s). This source sector is at most only shown to impair visibility by 0.1 Mm^-1. All other in-state anthropogenic sources of ammonium nitrate and ammonium sulfate combined account for no more than roughly 0.025 Mm^-1 of visibility impairment. Furthermore, for both of South Dakota's Class I Areas and for both anthropogenic ammonium nitrate and ammonium sulfate sources of visibility impairment, other states contribute much more significantly to visibility impairment, including values of 0.8 Mm^-1 from North Dakota, Wyoming, and non-WRAP states. To put these numbers in perspective, and in contrast, South Dakota viewed New Mexico's Class I Areas. New Mexico is a dominant contributor to its own visibility impairment at its Class I Areas. For Ammonium Sulfate, at Bandelier National Monument, New Mexico contributes 0.4 Mm^-1 of visibility impairment, at Bosque del Apache National Wilderness area 0.3 Mm^-1 of visibility impairment, at Salt Creek National Wilderness area over 1 Mm^-1 of visibility impairment, and at White Mountain Wilderness area about 0.5 Mm^-1 of visibility impairment. In each of these cases New Mexico is the leading contributor to visibility impairment with the exception of the category of "USnonWRAP," which are all states not in the WRAP area combined. For ammonium nitrate, New Mexico is accountable for the following levels of visibility impairment: 0.4 Mm^-1 at Bandelier National Monument, 2.6

Mm^-1 at Salt Creek National Wilderness area, and 0.3 Mm^-1 at Wheeler Peak Wilderness area. At all Class I Areas it is also very commonly the main contributor to visibility impairment. Texas' Figures 8-21 and 8-22 show similar information, comparing the magnitudes of sources of light extinction which influence their two Class I Areas, according to their PSAT modeling. Big Bend National Park and Guadalupe Mountains National Park are similar in that regarding anthropogenic emissions, Texas contributes the most to their own Class I Areas' visibility impairment, with the exception of international (Canada/ Mexico) anthropogenic emissions sources which are uncontrollable.

3. A third factor that differentiates New Mexico and Texas from South Dakota is the existence of NAAQS non-attainment areas within the counties of and nearby the Class I Areas. The closest non-attainment counties to South Dakota's two Class I Areas are Rosebud County in Montana, Sweetwater County in Wyoming, and Weld County in Colorado, all of which are over 200 miles away. In contrast, Texas' El Paso County is currently in non-attainment, and is 90 miles from Guadalupe Mountains National Park, and Carlsbad Caverns National Park. New Mexico's Dona Ana County is currently in non-attainment, and is about 100 miles away from Chiricahua National Park and Wilderness Area, White Mountain Wilderness Area, Carlsbad Caverns National Park, and Guadalupe Mountains National Park.

9. The National Park Service believes the four-factor analysis cost estimate for the GCC Dacotah NOx-reducing SNCR is reasonable at $2,093/ton assuming a 30% removal efficiency (which is also a low estimate), and therefore this control measure should be implemented. Furthermore, using the updated (March 2021) EPA Excel worksheet, and using the current prime rate (3.25%) as recommended by the EPA Control Cost Manual, the National Park Service came up with a cost of $1,600/ton NOx removed. Finally, as further justification for their opinion, the National Park Service sites that other states are using cost effectiveness thresholds from $4,000/ton in Arizona to $10,000/ton in Oregon and Colorado. Therefore, the National Park Service recommends that DANR establish a cost-effectiveness threshold for reasonable progress that is in line with other states.

Response: South Dakota disagrees with the National Park Service's interpretation of the definition of a reasonable cost per ton. The Regional Haze Rule does not define cost effectiveness, South Dakota considered several factors to determine if the identified cost was or was not cost effective.

GCC Dacotah submitted comments on the draft Regional Haze SIP. In those comments, GCC Dacotah indicated the materials and supply chain issues have increased the cost of installation of an SNCR system. GCC Dacotah's revised cost effectiveness (cost/ton removed) is $4,941, given an annual control cost of $1,636,683, a baseline emission level (tons/year) of 1,394, an expected NOx reduction efficiency of 30%, and an expected emissions reduction of 331 tons/year. A more thorough review of the revisions can be made by viewing the associated formal document supplied by GCC Dacotah, which is provided in this appendix. GCC

Dacoath's updated cost analysis does not change South Dakota's position that an SNCR is not considered cost effective at this time.

Referencing other states' cost effective thresholds as indicators of cost effectiveness can be useful, but only to an extent, as every individual situation should be assessed carefully on a case-by-case basis. South Dakota faces different circumstances than the other states which have determined cost effectiveness thresholds.

1. The first factor that differentiates Oregon and Arizona from South Dakota in this regard is the 2028 visibility projections; the Regional Haze Rule states in 40 CFR § 51.308(f)(2)(iv)(E) that South Dakota must consider this additional visibility factor in developing its long-term strategy. This information can be viewed by referencing Figures 4-10 and 4-13 of South Dakota's draft SIP, and the WRAP modeling result #5 charts, found at https://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx. When compared to the adjusted glideslope for international anthropogenic and prescribed fires, South Dakota's Badlands National Park's 2028 visibility projection will not cross over from below to above the adjusted glideslope until about the year 2045. Wind Cave is projected to already meet the 2064 end goal by 2028. Comparing these facts to Arizona, Saguaro National Park's 2028 projection will cross over from below to above the adjusted glideslope by roughly the year 2032. The Superstition Mountains area's 2028 projections will cross over from below to above the adjusted glideslope by approximately the year 2034. And the Sycamore Canyon area's 2028 projections are already above the adjusted glideslope. In Oregon, the Kalmiopsis Wilderness area's 2028 projections are to cross over from below to above the adjusted glideslope by about the year 2040, and that the projection is currently above the unadjusted glideslope.
2. The second factor that differentiates Colorado, Oregon, and Arizona from South Dakota in this regard is the existence of NAAQS non-attainment areas within the counties of and nearby the Class I Areas. The closest non-attainment counties to South Dakota's two Class I Areas are Rosebud County in Montana, Sweetwater County in Wyoming, and Weld County in Colorado, all of which are over 200 miles away. In contrast, Colorado has 9 counties currently in non-attainment, two of which contain Class I Areas. Specifically, Boulder County partially contains Rocky Mountain National Park, and Larimer County at least partially contains Rocky Mountain National Park and the Rawah Wilderness Area. Oregon has two counties currently in non-attainment, both of which contain Class I Areas. Specifically, Klamath County at least partially contains Diamond Peak, Mountain Lakes Wilderness Area, Gearhart Mountain, and Crater Lake National Park. Lane County Oregon at least partially contains the Three Sisters peaks and Diamond Peak. Finally, Arizona currently has seven counties in non-attainment, four of which contain Class I Areas. Specifically, Cochise County at least partially contains Chiricahua National Park and the Chiricahua Wilderness Area. Gila County at least partially includes the Superstition Mountains, the Sierra Ancha Wilderness area, and the Mazatzal Mountains. Maricopa County at least partially contains the Superstition Mountains. Pima County at least partially contains Saguaro National Park.

3. The third factor that differentiates Colorado, Oregon, and Arizona from South Dakota in this regard can be seen when viewing the WRAP modeling product #9, and Figures 3-2 through 3-5 in South Dakota's draft SIP. These figures show anthropogenic contributions to visibility impairment at any given Class I Area by state, and by the emission source groups of Oil and Gas, Non-EGU, Mobile, EGU, and Remaining Anthropogenic sources, for both ammonium nitrate and ammonium sulfate. When comparing between the states' Class I Areas, it is important to pay attention to the y-axis, as the axis values aren't standardized. When viewing South Dakota's two Class I Area charts, the largest contributor to either ammonium sulfate or ammonium nitrate anthropogenic visibility impairment from within South Dakota's borders is attributed to mobile sources, which South Dakota does not have the authority to require additional control(s). This source sector is at most only shown to impair visibility by 0.1 Mm^-1. All other in-state anthropogenic sources of ammonium nitrate and ammonium sulfate combined account for no more than roughly 0.025 Mm^-1 of visibility impairment. Furthermore, for both of South Dakota's Class I Areas and for both anthropogenic ammonium nitrate and ammonium sulfate sources of visibility impairment, other states contribute much more significantly to visibility impairment, including values of 0.8 Mm^-1 from North Dakota, Wyoming, and non-WRAP states. To put these numbers in perspective, and in contrast, South Dakota viewed Arizona's Class I Areas, and found that Arizona in-state sources affect their own Class I Area's visibility impairment to a much larger extent. This is especially true for the Superstition Mountains and Saguaro Class I Areas regarding anthropogenic sources of ammonium nitrate visibility extinction, where Arizona in-state sources contribute to 0.4 Mm^-1 and 0.6 Mm^-1 of visibility impairment, respectively. This is also especially true of Mount Baldy, Petrified Forest, Saguaro, and the Superstition Mountains Class I Areas regarding anthropogenic sources of ammonium sulfate visibility extinction, where Arizona in-state sources contribute to 0.175 Mm^-1, 0.2 Mm^-1, 0.3 Mm^-1, and 0.175 Mm^-1 of visibility impairment, respectively. Furthermore, at almost every Class I Area, Arizona is their own largest contributor to anthropogenic visibility impairment, larger than any other US state. Regarding Oregon, the overall situation here is similar to that of Arizona. It can be analyzed in more detail through the WRAP website at https://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx. Colorado's ammonium nitrate and ammonium sulfate charts also show significant in-state contributions to visibility impairment at some of their Class I Areas. These are significant differences between South Dakota and the other states identified as having set cost effectiveness thresholds. South Dakota is clearly not in a comparable situation as the three states which have set higher cost effectiveness thresholds, when viewed holistically.

10. The Forest Service states that the SNCR control measure is cost effective and should be applied to the GCC Dacotah Cement Kilns.

Response: Please refer to the responses to comment numbers 8 and 9 of this chapter.

11. The National Park Service recommends that the draft SIP include a four-factor analysis of the existing DSI system at GCC Dacotah to determine whether there is the potential to improve the SO2 removal efficiency, as this could be a more cost-effective option. The kiln currently uses a dry sorbent injection (DSI) system "as needed" for HCl and SO2 control to meet its current BACT limits.

Response: Sulfur dioxide emissions are effectively reduced when the flue gas is in contact with limestone. Cement kilns have large quantities of crushed limestone and fresh highly reactive lime present in the raw material to reduce the sulfur dioxide emissions. The existing in-line raw mill system has an inherent removal of the sulfur dioxide emissions for the kiln system. In 2003, South Dakota issued GCC Dacotah a Prevention of Significant Deterioration preconstruction permit establishing the Best Available Control Technology (BACT) emission limitations considering BACT was the inherent removal process.

The dry sorbent injection involves spraying a powdered sorbent, typically consisting of lime or sodium bicarbonate. The dry sorbent injection system at GCC Dacotah is predominantly used for hydrogen chloride control and not for sulfur dioxide. Adding more lime will not significantly improve the sulfur dioxide control efficiency of the system. A quick review of EPA's RBLC database indicates GCC Dacotah's current BACT sulfur dioxide emission limits are similar to those sulfur dioxide limits being established for more recent cement kiln installations around the United States. Therefore, DANR will not require an additional four factor analysis on the existing dry absorbent injection system during this review period but may consider it in future review periods.

12. The National Park Service does not believe that ammonia slip is likely to result in NAAQS compliance issues in the Rapid City area regarding particulate matter, and claims the SNCR system can be adjusted to maximize NOx reduction while minimizing ammonia slip. The National Park Service is aware of other plants successfully operating SNCR systems.

Response: DANR acknowledges the Selective Noncatalytic Reduction (SNCR) system may be able to be adjusted to maximize NOx reduction while minimizing ammonia slip. Based on South Dakota's 2028 adjusted visibility projection, Wind Cave National Park will meet the 2064 natural background goal by 2028. In addition, Badlands National Park's 2028 adjusted visibility projection is already meeting approximately 70% of the 2064 natural background goal by 2028.

DANR is prioritizing maintaining and meeting the National Ambient Air Quality Standard over visibility goal of natural background by 2064 that South Dakota is projected to all ready meet by 2028. As such, the risk ever so slight to a potential violation of the National Ambient Air Quality Standard outweighs the additional improvement to visibility.

13. The National Park Service notes that the Pete Lien and Sons four-factor analysis says selective non-catalytic reduction (SNCR) control technology has not been demonstrated on lime kilns, however the National Park Service is aware of several instances where this has been demonstrated for the reduction of NOx emissions: the Nelson Arizona lime plant, Mississippi Lime in Prairie du Rocher Illinois, Lhoist North America (Lhoist) in O'Neal Alabama, and Unimin Corporation in Calera Alabama.

Response: DANR appreciates the National Park Service for providing facilities that have demonstrated SNCRs on lime kilns across the country. In the four factor analysis Pete Lien submitted to DANR, Pete Lien provided a cost analysis for an SNCR system on its kiln. DANR did not reject the SNCR system due to technical feasibility. DANR rejected the control due to the cost of the system.

14. The National Park Service believes that the Pete Lien and Sons four-factor analysis costs are overestimated for three reasons, and provided a technical review document and supporting calculation worksheet for a detailed review: 1) The interest rate used is above 3.25% which is what the Control Cost Manual recommends. 2) The analysis used a cost for urea reagent of $4.42/gallon, which is substantially higher than the default urea cost of $1.66/gallon. The analysis states that the cost used is twice the current cost to account for historically high-cost variability; this should be explained and justified. 3) The analysis also included a substantial annual cost due to the loss of kiln dust sales, amounting to $1.2 to $1.5 million per year or roughly 40-50% of the total annualized cost. The National Park Service would like this cost to be fully explained and justified.

Response: DANR agrees that EPA's SNCR Cost Development Methodology does indicate a default cost of $1.66 per gallon and a bank prime interest rate of 3.25%. The Cost Methodology also notes that the operational and maintenance costs are variable. For example, in the 1940's the bank prime rate (i.e. interest rate) was approximately 5%, then in the early 1980's bank prime rate increased to over 20% and then fell back below 5% in 2010. The cost of the urea on a bulk basis has gone from approximately $100 per ton in the late 1990s to $800 per ton in 2008 to $350 per ton in 2014 to almost $900 per ton in 2021. The cost(s) of urea and the interest rate(s) suggested by the National Park Service and used by Pete Lien are within the historical range of these parameters. Therefore, DANR does not agree that Pete Lien and Sons is required to use the default numbers used by EPA. The variable factors should be revised accordingly based on the most recent and available information. However, for discussion purposes, DANR reran Pete Lien's cost analysis using $1.66 per gallon for the Urea cost, a 3.25% interest rate, and removed the cost for the lost kiln dust sales. If we revise the urea cost ($4.42 to $1.66 per gallon), the dollar per ton cost would decrease from $34,860 to approximately $27,100 for kiln #1 and $58,830 to approximately $47,000 for kiln #2. If we revise both the urea cost and the interest rate (5% to 3.25%), the dollar per ton cost would decrease from $34,860 to approximately $26,800 for kiln #1 and from $58,830 to approximately $46,500 for kiln #2. If we revise the urea cost, the interest rate, and remove the lost sales ($1.1 million and $1.5 million to $0), the dollar per ton cost would decrease from $34,860 to approximately $11,400 for kiln #1 and from $58,830 to $17,400 for kiln #2. Even with these revisions, DANR would still consider the SNCR not cost effective and would not require Pete Lien and Sons to install the control system at this time.

4.0 Coordination And Consultation

1. The National Park Service voiced their concerns regarding the timing of South Dakota's public notice process. South Dakota initiated its 30 day public comment period concurrently with the 60 day Federal Land Manager comment period, therefore the public notice materials did not contain any reference to FLM comments or the DANR's response to those comments. The National Park Service sites the Clean Air Act, the Regional Haze Rule, and EPA guidance which they believe requires states to include a summary of the conclusions and recommendations of the Federal land managers in the notice to the public. The National Park Service therefore requests that DANR opens a new public comment period for the regional haze SIP that includes FLM SIP review comments in the public review materials.

Response: South Dakota agrees with the National Park Service, and as a result provided the public with another 30 day comment period which included access to these Federal Land Manager comments and responses. South Dakota thanks the National Park Service for making this recommendation.

2. The National Park Service agrees that other states have large impacts on South Dakota's Class I Areas, and encourages South Dakota to discuss this matter with those other states.

Response: South Dakota appreciates the acknowledgement. DANR has discussed this matter with states that contribute to visibility impairment at South Dakota's Class I Areas, and will continue the dialog.

APPENDIX A-2

SOUTH DAKOTA REGIONAL HAZE STATE IMPLEMENTATION PLAN: FEDERAL LAND MANAGER FORMAL COMMENT LETTERS

National Park Service (NPS) Regional Haze SIP feedback for the South Dakota, Department of Agriculture and Natural Resources

December 9, 2021

Contents

1 Long-Term Strategy and Reasonable Progress Goals

1.1 Uniform Rate of Progress

According to Section 4.1 of the draft SIP, which discusses the projected reasonable progress goals, South Dakota Department of Agriculture and Natural Resources (DANR) has determined that additional controls are not needed in this planning period. One reason cited by the state for this decision is that visibility conditions in the state's two Class I areas are below the adjusted uniform rate of progress (URP) and are projected to remain below the URP in 2028. The Regional Haze Rule requires that the state determine the URP needed to meet the goal of unimpaired visibility by 2064. However, EPA has clarified that the URP is not a "safe harbor." States should not dismiss otherwise technically feasible, cost-effective controls solely because visibility progress in their Class I areas is better than the URP. The URP is a planning tool that allows states to evaluate their overall progress toward the goal, but it is not a standard that indicates whether progress is reasonable. It may be that a state's Class I areas are not meeting the URP, but the state is still making reasonable progress if it finds by applying four-factor analysis to its sources that there are no technically feasible, cost-effective controls to implement. Conversely, it may be that a state's Class I areas are meeting the URP but are still not making reasonable progress if the state rejects technically feasible cost-effective controls because the Class I areas are below the glideslope. As EPA noted in its July 2021 memo "Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period":

> *The 2017 RHR preamble and the August 2019 Guidance clearly state that it is not appropriate to use the URP in this way, i.e., as a "safe harbor." The URP is a planning metric used to gauge the amount of progress made thus far and the amount left to make. It is not based on consideration of the four statutory factors and, therefore, cannot answer the question of whether the amount of progress made in any particular implementation period is "reasonable progress." This concept was explained in the RHR preamble. Therefore, states must select a reasonable number sources and evaluate and determine emission reduction measures that are necessary to make reasonable progress by considering the four statutory factors.*

This memo is consistent with earlier guidance from EPA. As EPA noted in the preamble to the 2017 Regional Haze Rule (82 FR 3099):

> *The CAA requires that each SIP revision contain long-term strategies for making reasonable progress, and that in determining reasonable progress states must consider the four statutory factors. Treating the URP as a safe harbor would be inconsistent with the statutory requirement that states assess the potential to make further reasonable progress towards natural visibility goal in every implementation period.* ***Even if a state is currently on or below the URP, there may be sources contributing to visibility impairment for which it would be reasonable to apply additional control measures in light of the four factors****. Although it may conversely be the case that no such sources or control measures exist in a particular state with respect to a particular*

Class I area and implementation period, this should be determined based on a four-factor analysis for a reasonable set of in-state sources that are contributing the most to the visibility impairment that is still occurring at the Class I area. ***It would bypass the four statutory factors and undermine the fundamental structure and purpose of the reasonable progress analysis to treat the URP as a safe harbor, or as a rigid requirement*** *(emphasis added).*

1.2 Potential for Over-Control

In section 3.3.2.3, Four Factor Analysis Summary, the draft SIP says that state law prohibits the state from requiring controls if it is meeting its reasonable progress goals. The draft SIP cites a state statute (codified law 1-41.3.4) that says "DANR may not promulgate a regulation that is more stringent than the corresponding federal law." The state also cites a Supreme Court case (572 U. S. 489 (2014)) in which the Court reversed a lower court's decision to vacate the Cross-State Air Pollution Rule. The draft SIP highlights the following statement by the court: "We agree with the Court of Appeals to this extent: EPA cannot require a State to reduce its output of pollution by more than is necessary to achieve attainment in every downwind State or at odds with the one-percent threshold the Agency has set. If EPA requires an upwind State to reduce emissions by more than the amount necessary to achieve attainment in *every* downwind State to which it is linked, the Agency will have overstepped its authority, under the Good Neighbor Provision, to eliminate those 'amounts [that] contribute . . . to nonattainment.'" Based upon these references, the draft SIP concludes that: "Both South Dakota's statute and the decision of the United States Supreme Court implies that DANR may not require emission controls that go above and beyond the reasonable progress to natural conditions and cannot go beyond what is deemed natural conditions through the Regional Haze regulations."

We disagree with the state's conclusion that the uniform rate of progress constitutes a limit on the amount of visibility progress that can be made during the planning period and that the state is legally prohibited from requiring additional controls when visibility in an affected Class I area is below that line. The Regional Haze Rule is not analogous to the Transport Rule and it does not require states to meet an associated standard. The Regional Haze Rule sets a goal, not a requirement, of unimpaired visibility conditions at Class I areas by 2064, and no Class I area in the South Dakota or downstream has yet reached that goal. Furthermore, as noted in the preceding section, the URP is a planning tool intended to assess the amount of progress being made toward the goal, not a standard that must be met or a "safe harbor" indicating controls are not required. Therefore, requiring controls found to be technically feasible and cost effective based upon the four-factor analyses in this planning period would not be a violation of the state statute.

1.3 Significance of State Contributions to Visibility Impairment

In Section 3.3.2.3, the SIP says: "The projected emissions from South Dakota will have less than 1% impact on visibility impairment in Badlands National Park and Wind Cave National Park. In short, more than 99% of the impacts come from outside South Dakota." This suggests that South Dakota emissions do not significantly impact visibility in these parks. In its 2021 memo, EPA addressed the consideration of impacts to visibility at Class I areas when evaluating potential emissions controls. Similar to its conclusion regarding the use of the URP, EPA stated that it is not appropriate to reject cost-effective control measures simply because the impact on visibility is considered to be insignificant:

> *We have observed that some draft SIPs are using modeled visibility benefits to justify rejecting otherwise cost-effective control measures. It is important that, where applicable, each state considers the magnitude of modeled visibility impacts or benefits in the context of its own contribution to visibility impairment. That is, whether a particular visibility impact or change is "meaningful" should be assessed in the context of the individual state's contribution to visibility impairment, rather than total impairment at a Class I area. As stated in the RHR preamble:*
>
> > *Regional haze is visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. At any given Class I area, hundreds or even thousands of individual sources may contribute to regional haze. Thus, it would not be appropriate for a state to reject a control measure (or measures) because its effect on the RPG is subjectively assessed as not "meaningful."*

The draft SIP is correct in noting that Class I areas in South Dakota receive substantial impacts from out-of-state emissions. We encourage the state to discuss these impacts in their state-to-state consultations.

1.4 Class I Area Trends in Impairment

Section 2.6 of the draft SIP displays trends in visibility on the most impaired days at Badlands and Wind Cave National Parks. The draft SIP notes that the long-term trends over the period from 2000-2018 show improvement in visibility conditions. However, it is worth noting that haze has increased on the most impaired days since 2015 at Badlands NP (Figure 1) and 2016 at Wind Cave NP (Figure 2). This highlights the need for continued reductions in emissions in order to ensure visibility improvement during the current planning period.

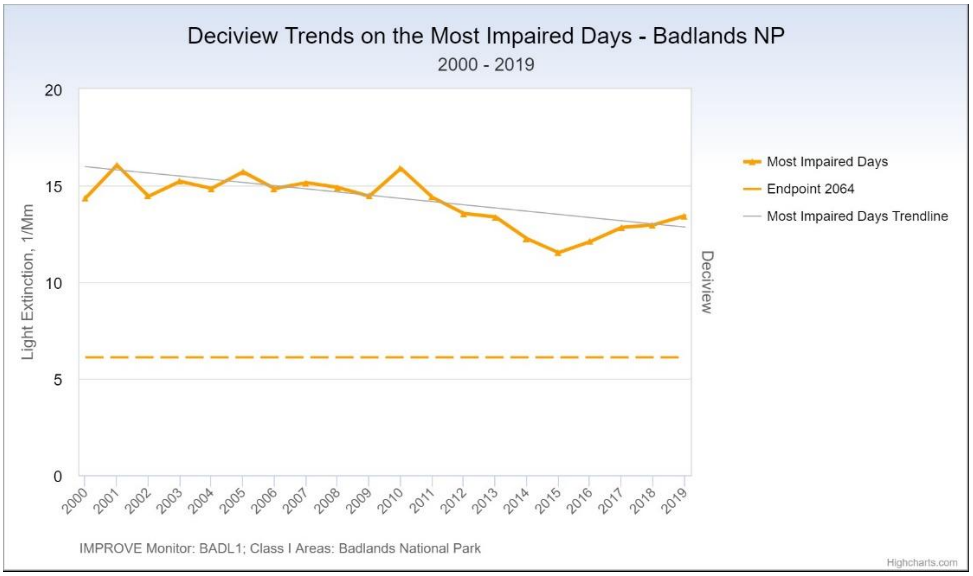


Figure 1. Trends in Haze on Most Impaired Days at Badlands NP

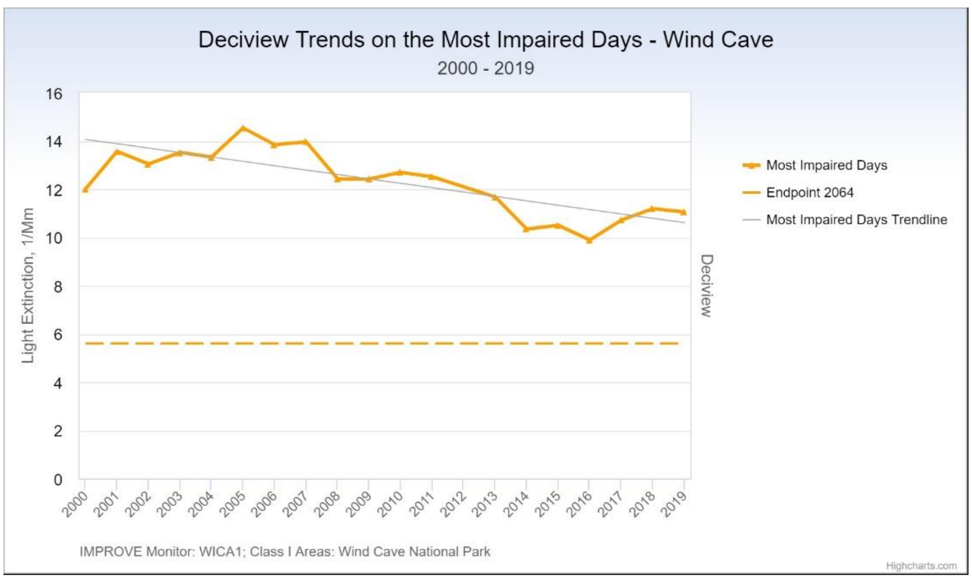


Figure 2. Trends in Haze on Most Impaired Days at Wind Cave NP

In addition, the draft SIP 2064 projection of natural conditions has been adjusted upward to account for impairment from international anthropogenic sources and U.S. prescribed fires. This endpoint adjustment will need to be reevaluated in future planning periods and could be revised downward as conditions change and the modeling of international emissions improves.

2 Four-factor Analyses

The state selected two facilities for four-factor analysis in this planning period—the GCC Dacotah Cement Plant and the Pete Lien & Sons lime plant in Rapid City. We agree with the state's choice of sources for analysis. We have reviewed the analyses and have the following comments.

2.1 GCC Dacotah Cement

The GCC Dacotah facility operates a single dry kiln at its Portland cement plant. The kiln system features a low-NO_X burner, a preheater and a precalciner, as well as an in-line raw mill and in-line coal mill. The four-factor analysis evaluated potential additional SO_2 and NO_x controls. According to the analysis, baseline projected kiln system emissions are 734 tons/year of SO_2 at a rate of 0.93 lb SO_2/ton clinker and 1,975 tons/year of NO_x at a rate of 2.3 lb NOx/ton clinker.

The review of potential SO_2 emissions controls indicates that the kiln uses a dry sorbent injection (DSI) system "as needed" for HCl and SO_2 control to meet its current BACT limits. The analysis did not clearly explain exactly what is mean by "as needed," but this language suggests that the DSI does not operate continuously. The company concluded that additional SO_2 controls (such as wet or dry scrubbing) would not be cost effective; costs were estimated at $6,694/ton of SO_2 removed for semi-wet or dry scrubbing and $7,874/ton for wet scrubbing. These costs are somewhat overestimated, as the company assumed a 7% interest rate instead of the current bank prime rate (3.25%) as recommended by the EPA's Control Cost Manual. In the draft SIP, DANR estimated costs using a 3.5% interest rate resulted in estimates of $5,496/ton of SO_2 removed for semi-dry scrubbing and $6,394/ton for wet scrubbing. Nonetheless, these costs are within the range of cost-effectiveness thresholds selected by other states. States that have selected thresholds include Texas at $5,000/ton, New Mexico at $7,000/ton, and Colorado and Oregon at $10,000/ton. We recommend that the draft SIP include a four-factor analysis of the existing DSI system to determine whether there is the potential to improve the SO_2 removal efficiency, as this could be a more cost-effective option.

The four-factor analysis determined that selective non-catalytic reduction (SNCR) was the only technically feasible method for NOx emissions reduction. The company estimated the cost effectiveness of adding SNCR at $2,093/ton of NOx removed assuming only a 30% reduction in NOx emissions. While the removal efficiency of SNCR systems varies widely, it is possible to obtain higher NOx reduction efficiencies with SNCR at cement facilities. We estimated costs using the updated (March 2021) EPA Excel worksheet, using the current prime rate (3.25%) as recommended by the EPA Control Cost Manual, which resulted in a cost of $1,600/ton NOx removed. Assuming a slightly higher NOx removal efficiency of 40% results in a cost of $1,300/ton NOx removed. In the draft SIP, DANR provided a range of estimated costs by varying the assumed interest rate from 3.0% to 6.5%. All of these estimates, included the company's cost estimate, are still well within the range of cost effectiveness thresholds we have seen.

According to the draft SIP, the state is concerned that requiring SNCR on GCC Dacotah would result in ammonia slip that could cause the Rapid City area to exceed air quality standards for particulate matter. We do not agree that this is a likely outcome; the SNCR system can be adjusted to maximize NO_x reduction while minimizing ammonia slip. We are aware of other plants successfully operating SNCR systems (e.g., GCC Rio Grande in Pueblo and CEMEX in Lyons, Colorado).

2.2 Pete Lien & Sons

The Pete Lien & Sons lime manufacturing plant in Rapid City, South Dakota includes two direct-fired preheater-type rotary kilns. The kilns are fired by coal and petroleum coke. The four-factor analysis provided by the company only considered options for reducing NO_x emissions; baseline emissions were determined to be 310 tons/year for Kiln #1 and 204 tons/year for Kiln #2. The analysis includes estimated costs for an SNCR system but the authors consider SNCR to be infeasible as they are not aware of an installation of SNCR on a lime kiln. The draft SIP also states that SNCR is likely infeasible. However, we are aware of four lime facilities that are using SNCR: Nelson Arizona lime plant; Mississippi Lime in Prairie du Rocher, Illinois; Lhoist North America (Lhoist), O'Neal, Alabama; and Unimin Corporation, Calera, Alabama.

The four-factor analysis cost estimates for SNCR ranged from $34,860 to $68,430/ton of NOx removed for Kiln #1 and $58,830 to $118,620/ton of NOx removed for Kiln #2, depending upon the assumed efficiency of NOx removal. However, our review suggests these costs are overestimated. The analysis assumed an interest rate of 5%; unless the facility can justify a firm-specific rate, the current bank prime rate of 3.25% should be used in accordance with the guidance in the Control Cost Manual. The analysis used a cost for urea reagent of $4.42/gallon, which is substantially higher than the default urea cost of $1.66/gallon. The analysis states that the cost used is twice the current cost to account for historically high-cost variability; this should be explained and justified. The analysis also included a substantial annual cost due to the loss of kiln dust sales, amounting to $1.2 to $1.5 million per year or roughly 40-50% of the total annualized cost. The four-factor analysis says that "ammonia absorption into the lime kiln dust collected in the baghouse would seriously impact, if not eliminate the ability to sell this byproduct." This cost should be fully explained and justified. Finally, we recommend that SNCR costs be evaluated using the most current version of EPA's Control Cost Manual, which was updated in 2019.

3 FLM Consultation and Public Notice Process

We have concerns regarding the timing of South Dakota's public notice process. The DANR provided us with the draft SIP for review on September 20th, 2021 and initiated the start of the 60-day Federal Land Manger (FLM) consultation period. In an October 15 email to NPS, DANR extended the consultation period through December 13th. When we met virtually with DANR personnel to discuss our comments on November 8th, DANR restated the December 13th due date for NPS consultation comments. We recently learned that the state issued the public notice for the draft SIP and began the 30-day public comment period on November 12th.

The Clean Air Act requires that the state consult in person[1] with the FLMs on their regional haze SIP and "shall include a summary of the conclusions and recommendations of the Federal land managers in the notice to the public" (42 U.S.C. §7491). In addition, the Regional Haze Rule (40 CFR § 51.308) states:

[1] NPS staff agreed that a virtual meeting was acceptable in lieu of an in-person meeting for consultation on this draft SIP.

> *"The State must provide the Federal Land Manager with an opportunity for consultation, in person at a point early enough in the State's policy analyses of its long-term strategy emission reduction obligation so that information and recommendations provided by the Federal Land Manager can meaningfully inform the State's decisions on the long-term strategy…The opportunity for consultation on an implementation plan (or plan revision) or on a progress report must be provided no less than 60 days prior to said public hearing or public comment opportunity."*

In this case, the public comment period began prior to the conclusion of FLM consultation, providing no opportunity for DANR to consider our input or provide our conclusions and recommendations regarding the draft SIP in the public review version. This schedule did not allow information and recommendations provided by the FLMs to meaningfully inform the state's decisions. In addition, the state did not include a summary of our conclusions and recommendations regarding the draft SIP in the public notice as specified in the Clean Air Act. In order to ensure that the requirements for substantive FLM involvement and public transparency are met, we request that South Dakota open a new public comment period for the regional haze SIP and include a summary of our conclusions and recommendations in the public review materials.

Illinois Environmental Protection Agency Bureau of Air
September 2015 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

Comments from Lhoist North America

There are three preheater rotary lime kilns, very similar to those proposed by Mississippi Lime, in the United States using Selective Non-Catalytic Reduction (SNCR) technology to control NO_x emissions. In addition, SNCR technology is proposed to be installed on two existing kilns to comply with limits for NO_x that reflect a reduction of 50% from baseline levels. A summary of these applications of SNCR technology on rotary lime kilns is provided below.

Lhoist North America (Lhoist), O'Neal, Alabama (O'Neal plant)

The O'Neal plant has successfully used SNCR on both of its preheater rotary kilns to significantly reduce NO_x emissions. Kiln 1 was constructed in 1997 and Kiln 2 was constructed in 2007.

Actual emissions of NO_x, based on CEMS data, from O'Neal Kilns 1 and 2 for 2012 and 2013 are summarized below. (Detailed data was included with the comments.)

Year	Emission Rates (lbs NO_x/ton lime)			
	Kiln 1		Kiln 2	
	Maximum Monthly	Annual Average	Maximum Monthly	Annual Average
2012	2.9	1.8	2.4	1.2
2013	2.8	1.1	1.3	1.1

The NO_x emission of O'Neal Kilns 1 and 2, combined, are limited to a total of 791.5 tons/year and 83 tons, on a 30-day rolling average. As each kiln has a permitted capacity of 1500 tons of lime per day, the effective annual emission limit, for the kilns if operating at permitted capacity, would be 1.45 lbs NO_x/ton of lime. The effective 30-day rolling average emission limit, when operating at rated capacity, would be 1.84 lbs NO_x/ton of lime. Kiln 1 also retains its original BACT limit of 3.5 lbs NO_x/ton of lime, 3-hour average.

These emission limits were established by the permit amendments by the Alabama Department of Environmental Management (ADEM)in 2005. (Permits 411-0039-X028 and –X029 for Lhoist O'Neal were attached to these comments.)

Unimin Corporation, Calera, Alabama (Unimin).

Unimin installed an SNCR system in October 2010 on its preheater rotary lime kiln in Calera, Alabama, to achieve compliance with a NO_X limit of 3.2 lbs NO_X/ton of lime. The plant reported in a meeting on November 3, 2011 of the Environmental Committee of the National Lime Association that compliance was being achieved for an operating cost of less than 0.5 percent per ton of lime produced.

In addition, a rulemaking by USEPA requires retro-fitting of SNCR technology to two existing preheater lime kilns at Lhoist's lime facility in Nelson, Arizona. This rulemaking requires implementation of Best Available Retrofit Technology (BART) on these kilns for the NO_X emissions to reduce their contribution to visibility impairment in mandatory Class I Areas under the PSD Program, pursuant to Section 169A of the Clean Air Act. Kilns 1 and 2 at the Lhoist's Nelson lime facility were constructed in 1973 and 1976 respectively. Both kilns are subject to requirements to use BART controls for NO_X. On June 27, 2014, the USEPA Administrator signed the Arizona; Regional Haze and Interstate Visibility Transport Federal Implementation Plan (FIP). This proposed rule would limit NO_X emissions of Nelson Kiln 1 to 3.80 lbs/ton of lime and Nelson Kiln 2 to 2.61 lbs/ton of lime on a 30-day rolling basis, with compliance demonstrated by CEMS. The preamble for this rulemaking indicates that these limits are equivalent to using SNCR control technology. Further, the proposed rule would limit the combined NO_X emissions from Kilns 1 and 2 to 3.27 tons/day. These limits are based on SNCR providing a 50 percent reduction from historical actual emission levels. As USEPA has clearly documented that SNCR is technologically and economically feasible, even in retrofit situations, Mississippi Lime's BACT analysis must be updated to account for the use of SNCR technology on the proposed lime kilns.

Our National Parks

South Dakota Regional Haze Consultation *– 11/08/2021*
NPS, Air Resources Division & Interior Regions 3, 4, & 5
South Dakota Department of Agriculture and Natural Resources

11/08/2021 - NPS Formal Consultation Call with the South Dakota Department of Agriculture and Natural Resources (DANR) on Regional Haze SIP Development. Invitees:

- National Park Service
    - Eddie Childers, Badlands NP, SD
    - Marc Ohms, Wind Cave NP, SD
    - David Pohlman, Interior Region 3, 4, & 5 – St. Paul, MN
    - Kirsten King, Air Resources Division (ARD) – Denver, CO
    - Debbie Miller, ARD – Denver, CO
    - Melanie Peters, ARD – Denver, CO
    - Don Shepherd, ARD – Denver, CO
- South Dakota DANR
    - Rick Boddicker
    - Anthony Lueck
- Fish & Wildlife Service
    - Tim Allen
- U. S. Forest Service
    - Jeff Sorkin
- Environmental Protection Agency (EPA) Region 8
    - Clayton Bean
    - Jaslyn Dobrahner
    - Aaron Worstell

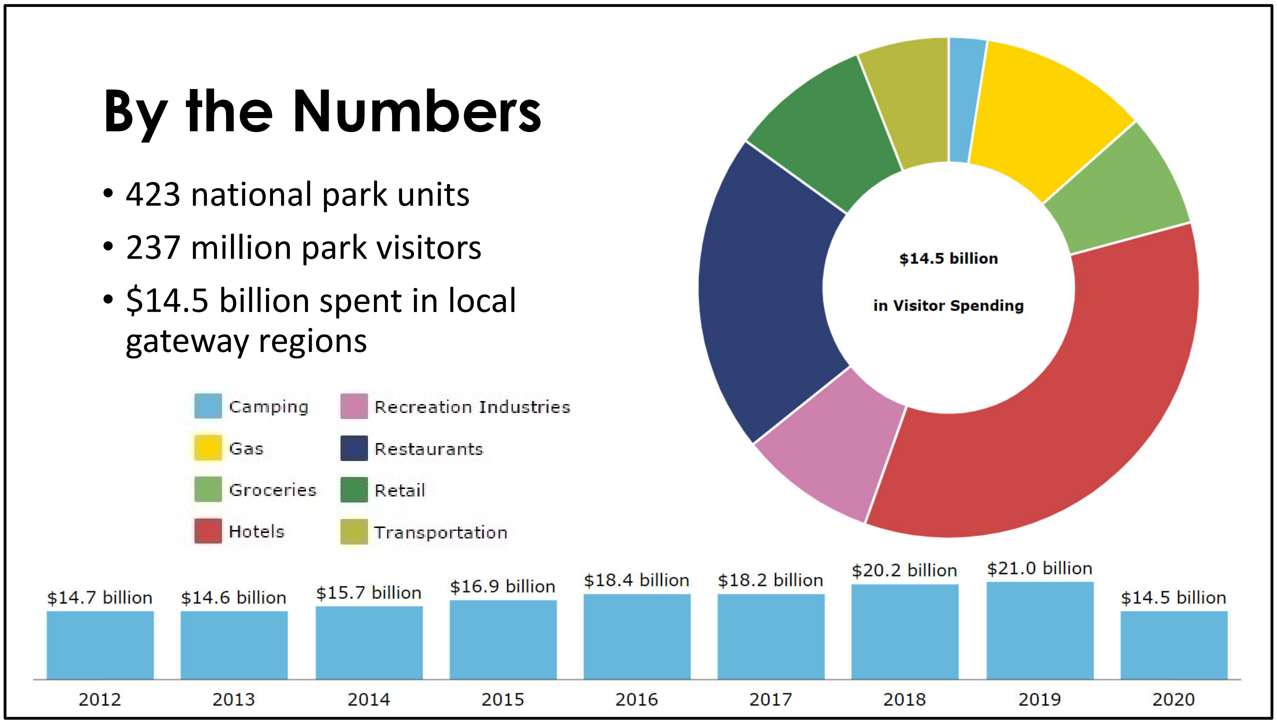
NPS photos from left to right: Acadia NP, Denali NP, Yellowstone NP, Grand Canyon NP

Agenda

- Welcome & Introductions
- NPS Regional Haze Background
- NPS Class I Areas in South Dakota
  - Badlands and Wind Cave NPs
- NPS SIP Feedback for South Dakota
  - Source Selection
  - Four-Factor Analysis Feedback
  - Long Term Strategy
- Next-Steps

We welcome discussion at any time during this presentation. Please feel free to ask questions or add information along the way.

NPS Photo of a bison, Badlands NP.



Nationally, in 2020 NPS visitation and spending numbers were down due to the pandemic. It is pretty amazing that even in 2020 there were 237 million park visitors who generated $14.5 billion for the economy – perhaps emphasizing more than ever the economic value of National Parks to our country.

For comparison in 2019:

328 million park visitors spent an estimated $21 billion in local gateway regions while visiting National Park Service lands across the country.

These expenditures supported a total of

- 341 thousand jobs,
- $14.1 billion in labor income,
- $24.3 billion in value added, and
- $41.7 billion in economic output in the national economy.

https://www.nps.gov/subjects/socialscience/vse.htm

By the Numbers

- **48** Class I areas
- In **24** states
- **90%** of visitors surveyed say that scenic views are ***extremely*** to ***very*** important
- **100%** of visitors surveyed rate clean air in the **top 5** attributes to protect in national parks

List of Class I areas: https://www.nps.gov/subjects/air/npsclass1.htm

States with at least one Class I area:
AK, AZ, CA, CO, FL, HI, ID, KY, ME, MI, MN, MT, NC, ND, NM, OR, SD, TN, TX, UT, VA, VI, WA, WY

Statistics citation:
Kulesza C and Others. 2013. National Park Service visitor values & perceptions of clean air, scenic views, & dark night skies; 1988–2011. Natural Resource Report. NPS/NRSS/ARD/NRR—2013/622. National Park Service. Fort Collins, Colorado

NPS photo of Great Smoky Mountains NP, NC & TN

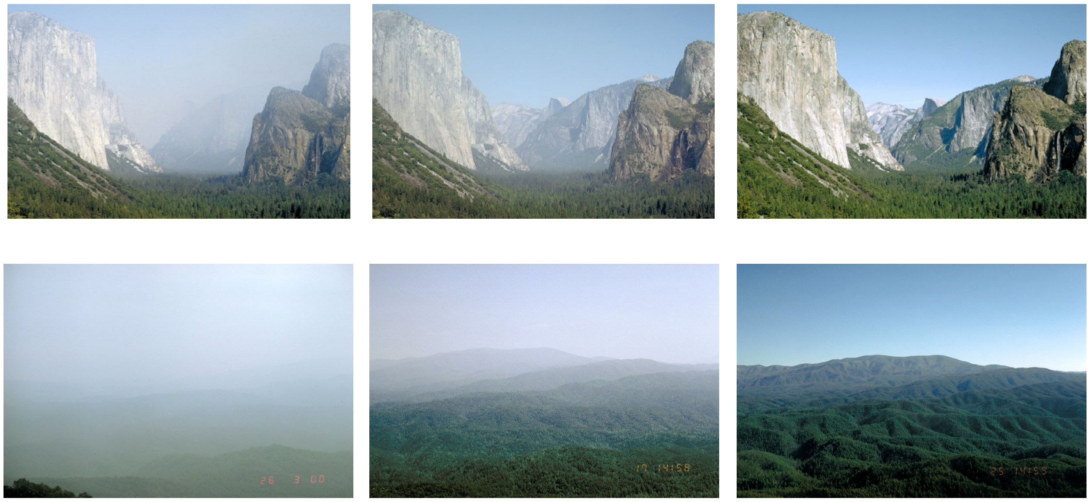
The NPS has an affirmative legal responsibility to protect clean air in national parks.

- 1916 NPS Organic Act: created the agency with the mandate to conserve the scenery, natural and cultural resources, and other values of parks in a way that will leave them unimpaired for the enjoyment of future generations. This statutory responsibility to leave National Park Service units "unimpaired" requires us to protect all National Park Service units from the harmful effects of air pollution.
- 1970 Clean Air Act: authorized the development of comprehensive federal and state regulations to limit emissions from both stationary (industrial) sources and mobile sources. The Act also requires the Environmental Protection Agency to set air quality standards.
- 1977 Clean Air Act Amendments: these amendments to the Clean Air Act provide a framework for federal land managers such as the National Park Service to have a special role in decisions related to new sources of air pollution, and other pollution control programs to protect visibility, or how well you can see distant views. The Act established a national goal to prevent future and remedy existing visibility impairment in national parks larger than 6,000 acres and national wilderness areas larger than 5,000 acres that were in existence when the amendments were enacted (Class I areas).
- 1990 Clean Air Act Amendments: created regulatory programs to address acid rain and expanded the visibility protection and toxic air pollution programs. The acid rain regulations began a series of regional emissions reductions from electric generating facilities and industrial sources that have substantially reduced air pollutant emissions.

NPS photo of Washington DC: https://npgallery.nps.gov/AirWebCams/wash

Visibility goal:

Restore natural conditions by 2064

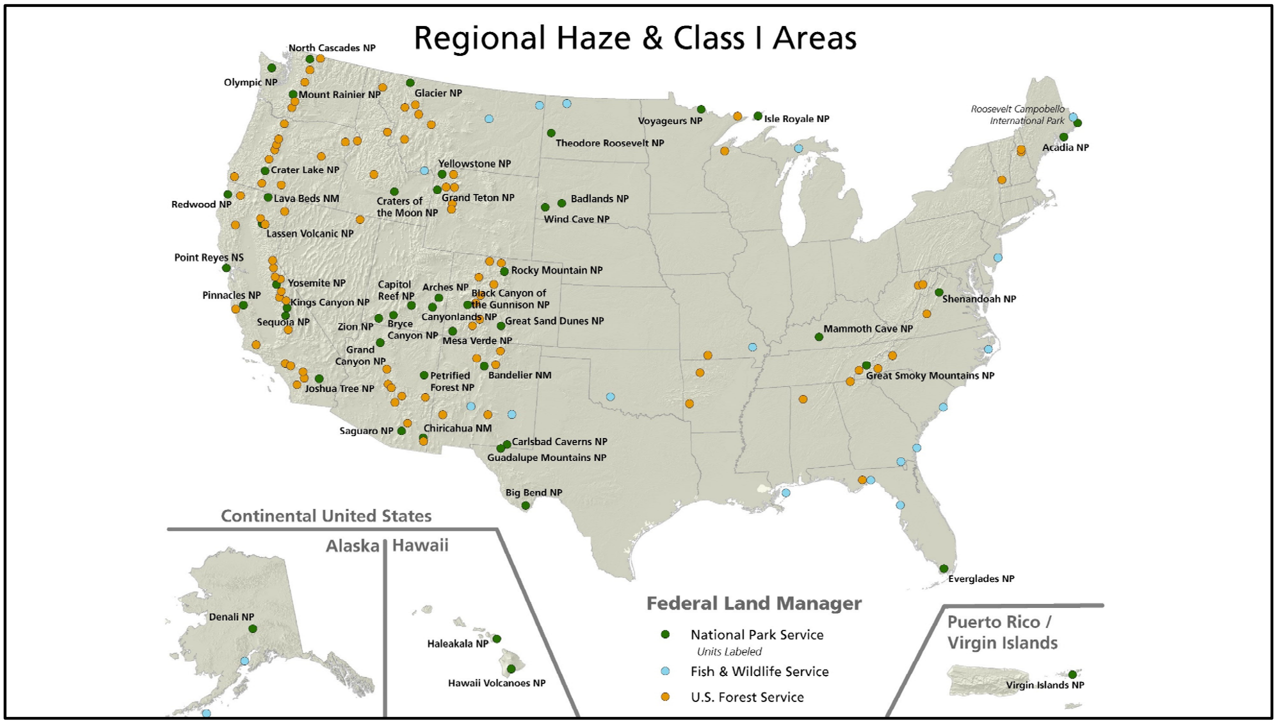


Yosemite NP, California and Great Smoky Mountains NP, Tennessee and North Carolina

Left to right images illustrate hazy to clear conditions.

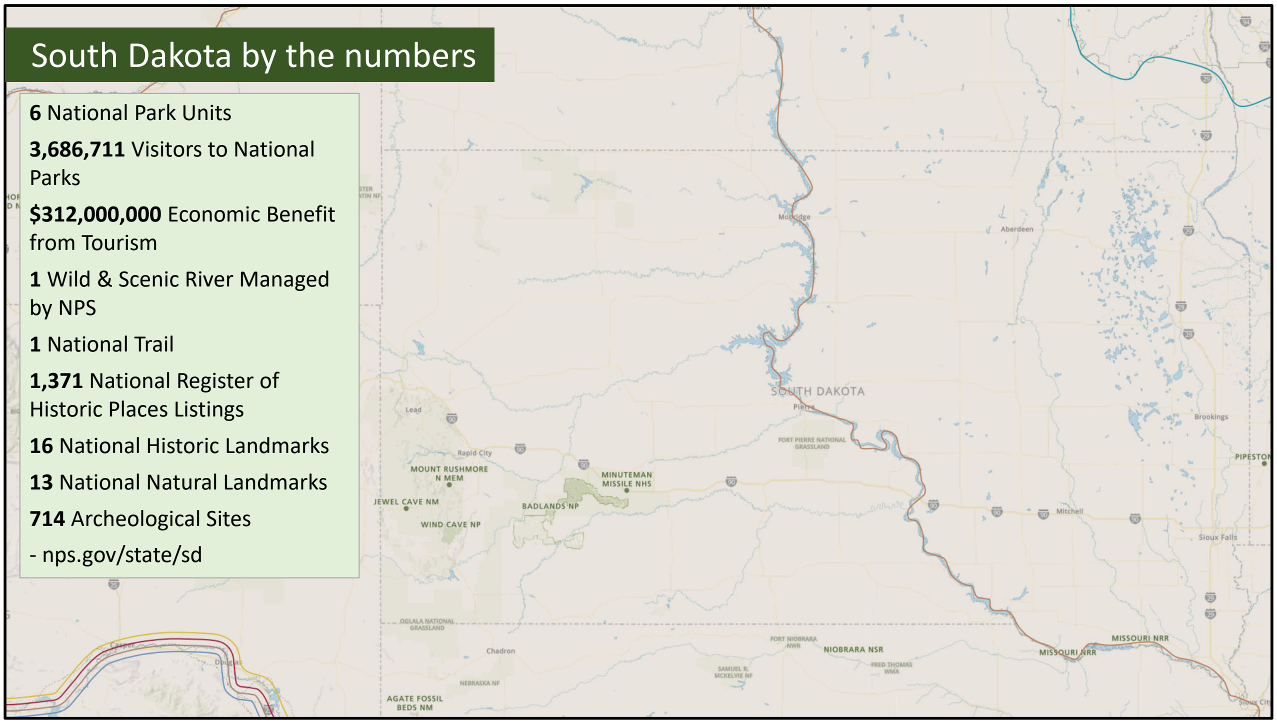
Haze obscures the color and detail in distant features.

NPS photos



As you know, the NPS is one of three Federal Land Managers (FLMs) with responsibility for the 156 Class I areas nationwide. The NPS manages 48 Class I areas. South Dakota is home to two Class I areas: Wind Cave and Badlands National Parks.

NPS map of Class I areas, 2020



Parks managed by the National Park Service in South Dakota:

1. Badlands National Park; Southwestern, SD
2. Jewel Cave National Monument; Custer, SD
3. Minuteman Missile National Historic Site; Southwestern , SD
4. Missouri National Recreational River; Yankton, SD,NE
5. Mount Rushmore National Memorial; Keystone, SD
6. Wind Cave National Park; Hot Springs, SD

Lewis & Clark National Historic Trail; Sixteen States: IA,ID,IL,IN,KS,KY,MO,MT,NE,ND,OH,OR,PA,SD,WA,WV

NPS information and map, 2021; https://www.nps.gov/state/sd/index.htm

NPS Class I Areas

in South Dakota

BADLANDS NATIONAL PARK

WIND CAVE NATIONAL PARK

Badlands National Park

The rugged beauty of the Badlands draws visitors from around the world. These striking geologic deposits contain one of the world's richest fossil beds. Ancient horses and rhinos once roamed here. The park's 244,000 acres protect the largest expanse of mixed-grass prairie in the Region, where bison, bighorn sheep, prairie dogs, and black-footed ferrets live.

Badlands National Park is home to many resilient creatures, including some of the most endangered species in North America. To survive the bitter winters and searing summers of the Great Plains, you need a good plan -- and the wildlife of the park have arrived at many ingenious solutions to the problems of exposure, heat, cold, and drought.

A mixed-grass prairie is a grassland where grasses of many different heights grow. Mixed-grass prairies are the transition between the wetter tall-grass prairies of the East and the drier short-grass prairies of the West. Grasses can range in height from ankle-high to waist-high. Because they are in this transition zone, mixed-grass prairies have a greater number of plant species than any other type of prairie. There are over 400 plant species in Badlands National Park. Although trees, shrubs, and forbs grow in the Badlands, grasses dominate the landscape. The most common grass in the park is Western Wheatgrass, which grows one to three feet tall and is the state grass of South Dakota!

Badlands National Park contains the Badlands Wilderness Area, which covers 64,000 acres, and is the reason the Park is a class one area.

The Park is also in the process of being designated as an International dark sky site. Badlands NP is truly a world class park!

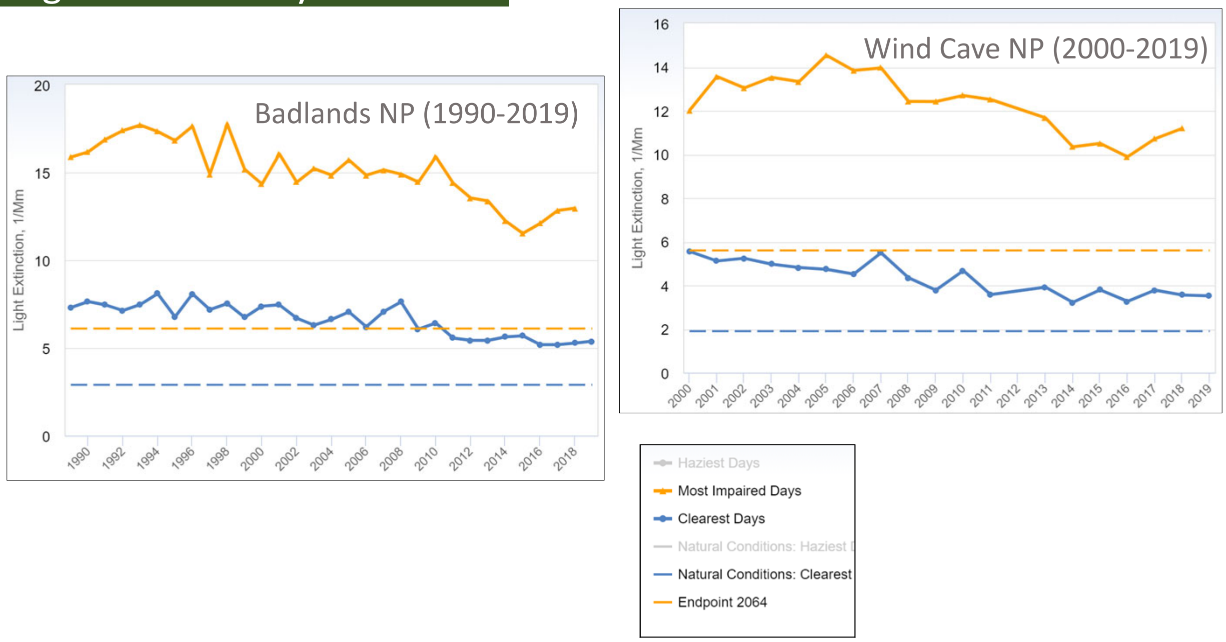
NPS photos of the rugged Badlands Landscape, Rocky Mountain Bighorn lambs, and a Sego Lily.

Wind Cave NP is one of only 48 Clean Air Act designated Class I areas managed by the NPS.

- The park was established in 1903 and is the 7th oldest national park in the NPS.
- The mapped portions of Wind Cave itself include over 157 miles of passages, making it one of the longest caves on the world. Exploration is still ongoing.
- The park is sacred to the Lakota people, who trace their origin and that of the buffalo as emerging from Wind Cave. Many other Native American Tribes also have cultural affiliations with the park.
- The surface area of the park is 34,000 acres in size and consists of a mixed grass prairie and ponderosa pine forest. Wildlife includes a genetically distinct bison herd, elk, prairie dogs, and the endangered black-footed ferret.
- There are over 30 miles of hiking trails at Wind Cave, allowing visitors to experience and view the prairie grasslands and its wildlife. The eastern views are very scenic, including the iconic Buffalo Gap and, on a clear day from the top of Rankin Ridge, you can see the Badlands.
- The park receives around 650,000 recreational visitors per year. 89% of visitors indicate they view wildlife and surface features during their visit and scenic vistas are the most highly rated value for a park visitor. Air quality is vital to maintaining this opportunity.
- Wind Cave has over 30 years of air quality monitoring, dating back to 1979. Currently we operate a NADP, CASTnet, IMPROVE, Purple Air, ozone, and particulate matters stations.
- Air quality is considered a vital resource in all management and planning documents. The park completed its Resource Stewardship Strategy in 2021, which states both long term and short-term goals regarding air quality.
- Short term goals include improving our understanding of resource sensitivity, outreach and education about the importance of air quality, and collaboration with partners and other management agencies to protect our airshed.
- The Park is in the process of receiving the designation of an International Dark Sky Park.
- Long-Term stewardship goals are to maintain the data record through continued in-park monitoring, to work with others to reduce pollutant deposition to below ecosystem critical loads, and to eliminate human-caused visibility impairment by the year 2064.

Moon Rise Over Boland Ridge, Wind Cave National Park. NPS Photo/Callie Tominsky

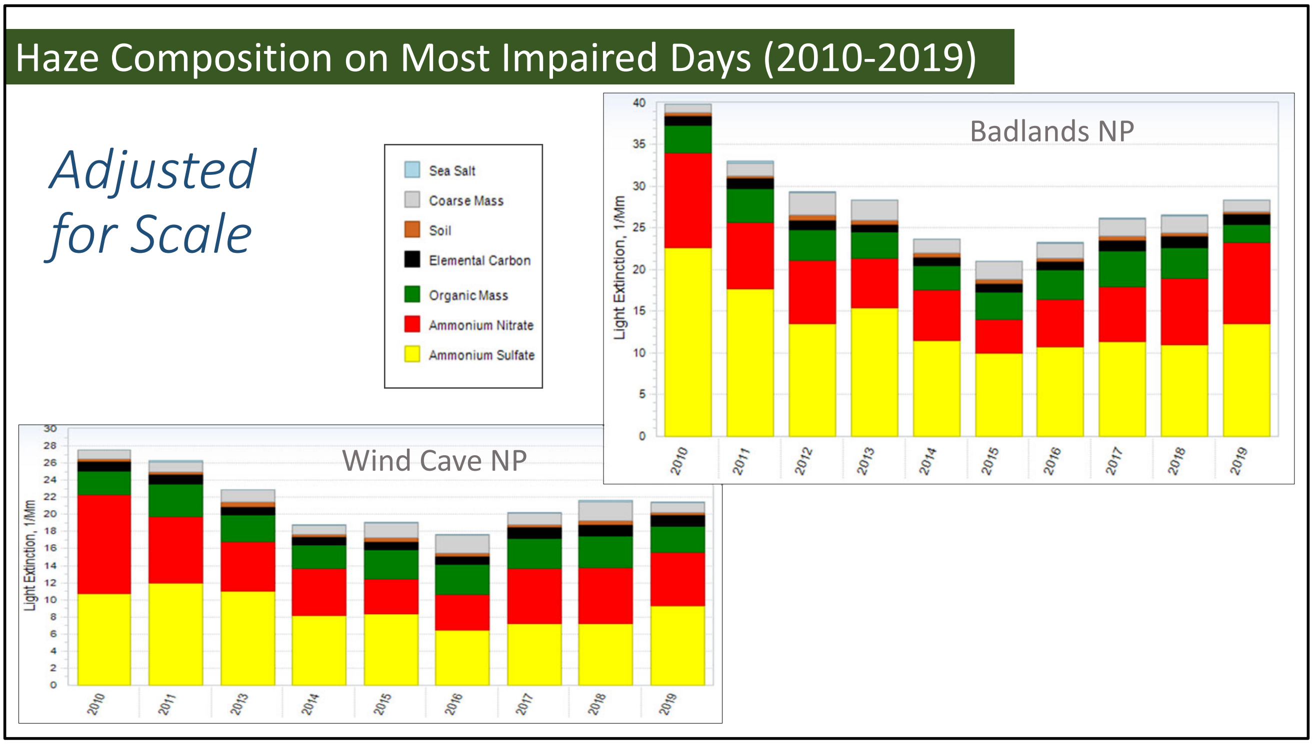
Long-term Visibility Trends



There is a long history of visibility monitoring in our regional Class I areas.

- The monitor for Badlands National Park began operation in 1989 while the monitor at Wind Cave NP dates back to 2000. NPS staff support the operation of the IMPROVE monitoring network nationally and for many individual monitoring sites. This is how we keep track of the visibility conditions in our Class I areas and monitor progress.
- Graphs shown here highlight the annual average light extinction on most impaired days and on clearest days compared to the target condition (endpoint) for most impaired days and estimated natural conditions on clearest days. These charts show long term improvement and recent increases in haze on most impaired days.

Long term visibility trend graphs generated from:
http://views.cira.colostate.edu/fed/Express/AqrvTools.aspx



These annual extinction bar graphs show total haze composition over the past 10 years at Badlands NP and Wind Cave NP. These areas have not seen dramatic improvements in light extinction on most impaired days over the past 10 years. In fact, the past few years at Badlands and Wind Cave NPs have seen increasing levels of haze. This may not be a statistically significant trend yet, but it is certainly something that we are keeping an eye on. It is interesting to note that ammonium sulfate and ammonium nitrate are mostly responsible for recent increases in haze.

Most-impaired days annual light extinction composition stacked bar graphs from:
http://vista.cira.colostate.edu/Improve/aqrv-summaries/

South Dakota Draft SIP Feedback

Four-Factor Sources

- Selected by South Dakota

South Dakota selected both NPS-recommended sources for four-factor analysis

1. GCC Dacotah
2. Pete Lien & Sons

NPS Photo of Blanket Flower, Wind Cave NP.

South Dakota Draft SIP Feedback

GCC Dacotah (1 of 2)

- Cement Production Facility

- Single cement kiln with low-NOx burner, preheater, and precalciner
- Baseline projected kiln system emissions are:
  - 734 tons/year SO_2 (0.93 lb SO_2/ton clinker)
  - 1,975 tons/year NOx (2.3 lb NOx/ton clinker)
- Kiln uses DSI system "as needed" for HCl and SO_2 control
  - Four-factor analysis should include potential for improving SO_2 removal efficiency

NPS Photo of Burrowing Owls, Wind Cave NP

South Dakota Draft SIP Feedback

GCC Dacotah (2 of 2)

- Cement Production Facility

- SNCR cost calculations did not include input data, so we could not fully evaluate cost estimates
- Nonetheless, four-factor analysis cost estimate for SNCR is reasonable at $2,093/ton assuming 30% removal efficiency
    - Other states using cost effectiveness thresholds from $4,000/ton (Arizona) to $10,000/ton (Oregon, Colorado)
- All technically feasible and cost-effective controls should be included in the long-term strategy
- Ammonia slip is not likely to result in NAAQS compliance issues

South Dakota Draft SIP Feedback

Pete Lien and Sons

- Lime Production Facility

- Includes two preheater kilns
- The facility four-factor analysis states that SNCR has not been demonstrated on lime kiln. We are aware of several:
  - Nelson Arizona lime plant; Mississippi Lime in Prairie du Rocher, Illinois; Lhoist North America (Lhoist), O'Neal, Alabama; and Unimin Corporation, Calera, Alabama.
- Costs are overestimated
  - Interest rate >3.25%
  - Inclusion of lime kiln dust sales loss requires additional justification

We recommend updating cost estimates using current EPA Control Cost Manual

South Dakota Draft SIP Feedback

Long Term Strategy (1 of 3)

- Visibility benefit and URP

SIP concludes that additional measures not needed because:

1. **Trends in haze on most impaired days are going down**
    - Overall trends beginning in 2000 are down, but trends in haze are up since 2015; continuous improvement will be needed to meet the 2064 goals
    - Also, SIP 2064 projection uses adjusted endpoint; this endpoint may change in the future

NPS Photo, Wind Cave NP

South Dakota Draft SIP Feedback

Long Term Strategy (2 of 3)

- Visibility benefit and URP

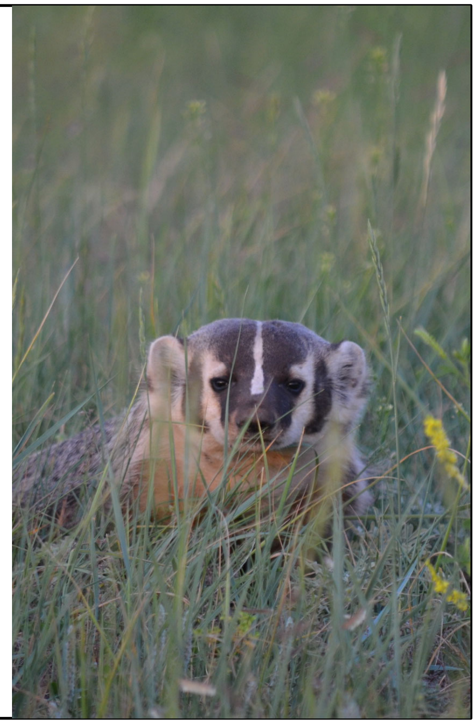
2. **State law prevents DANR from making regulations that are more stringent than the corresponding federal law**
   - The Transport Rule cited as an example is not analogous to the Regional Haze Rule, as RHR does not have an associated standard.
   - The glideslope is a planning tool, not a standard. If a Class I area is under the glideslope it is not overcontrolled.
   - RHR expects states to make continuous progress based upon the four-factor analysis. EPA has made it clear that being under the glideslope is not a reason to dismiss otherwise reasonable controls.
   - The goal of the RHR is natural conditions, and no Class I area in the state or downstream has reached that goal yet.

South Dakota Draft SIP Feedback

Long Term Strategy (3 of 3)

- Visibility benefit and URP

3. **SD contributions to visibility impairment are not significant**
   - RHR requires continuous progress on a cumulative basis by controlling many sources over a large area.
   - We agree that other states have large impacts on South Dakota's Class I areas and encourage the state to discuss with others including WY, MT, and ND.



NPS Photo of a Badger, Badlands NP

Next Steps

- Thank you for meeting with us!
- Please share:
  - Anticipated SIP schedule
  - How you will respond to NPS comments
- Please let us know:
  - When public comment period opens
  - If/when a public hearing will be held
- The NPS will:
  - Email call summary & detailed comments
    - By **December 13, 2021**
  - Share our comments with EPA Region 8

The NPS will submit an email summary of our November 8, 2021 consultation call along with final review comments by December 13, 2021.

We ask that the state notify us when the draft SIP will be open for public review and comment, and alert us to any public hearing dates.

Please reach out to us with any questions.

For any formal notifications of public documents, please include the above list of NPS staff.

The NPS values clean air and clear views and recognizes these as essential to our visitor experience and the very purpose of our Class I areas. We recognize opportunities for significant progress to be made in this planning period as we strive toward the goal of unimpaired visibility. We welcome future opportunities to engage with South Dakota and work together on efforts to reduce haze causing pollution and address regional haze in our national parks.

NPS photo of Badlands National Park by Mackenzie Reed

PERMIT #63592 (AS REVISED BY MINOR PERMIT REVISION #82742)
PLACE ID # 5992

PERMITTEE:	**Lhoist North America**
FACILITY:	**Nelson Lime Plant**
PERMIT TYPE	**Class I Air Quality Permit**
DATE ISSUED:	**July 29, 2016 (As Revised on August 24, 2020)**
EXPIRY DATE:	**July 29, 2021**

SUMMARY

This Class I renewal permit is issued to Lhoist North America of Arizona, Inc., the Permittee, for continued operation of its limestone processing and lime manufacturing plant located approximately six (6) miles east of Peach Springs in Yavapai County, Arizona. This permit renews and supersedes Permit #42782.

The potential to emit particulate matter with an aerodynamic diameter less than 10 microns (PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon monoxide (CO) is greater than the major source thresholds. In addition, the potential to emit hydrogen chloride (HCl) exceeds the major hazardous air pollutants (HAPs) threshold for a single HAP. Therefore, the facility is classified as a major source as defined in A.A.C. R18-2-101.75, and requires a Class I permit pursuant to A.A.C. R18-302.B.1.a.

This permit is issued in accordance with Arizona Revised Statutes (A.R.S.) 49-426. It contains requirements from Title 18, Chapter 2 of the Arizona Administrative Code (A.A.C.) and Title 40 of the Code of Federal Regulations (CFR). All definitions, terms, and conditions used in this permit conform to those in the A.A.C. R18-2-101 et. seq. and Title 40 of the CFR, except as otherwise defined in this permit.

MINOR PERMIT REVISION #82742

The facility will add a series of air cannons at the bottom of Product Silo 3A to prevent product buildup. Hence, the Permittee would like to install a dust collector on Product Silo 3A with a maximum capacity of 200 acfm. This equipment change will not increase emissions and thus, it will not trigger Minor New Source Review. Under this Minor Permit Revision #82742, the Permittee is authorized to make this equipment change.

Table of Contents

ATTACHMENT "A": GENERAL PROVISIONS

I. PERMIT EXPIRATION AND RENEWAL

[ARS § 49-426.F, A.A.C. R18-2-304.C.2, and -306.A.1]

A. This permit is valid for a period of five years from the date of issuance.

B. The Permittee shall submit an application for renewal of this permit at least 6 months, but not more than 18 months, prior to the date of permit expiration.

II. COMPLIANCE WITH PERMIT CONDITIONS

[A.A.C. R18-2-306.A.8.a and b]

A. The Permittee shall comply with all conditions of this permit including all applicable requirements of the A.R.S. Title 49, Chapter 3, and the air quality rules under Title 18, Chapter 2 of the A.A.C. Any noncompliance is grounds for enforcement action; for permit termination, revocation and reissuance, or revision; or for denial of a permit renewal application. In addition, noncompliance with any federally enforceable requirement constitutes a violation of the Clean Air Act.

B. It shall not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

III. PERMIT REVISION, REOPENING, REVOCATION AND REISSUANCE, OR TERMINATION FOR CAUSE

[A.A.C. R18-2-306.A.8.c, -321.A.1, and -321.A.2]

A. The permit may be revised, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a permit revision, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

B. The permit shall be reopened and revised under any of the following circumstances

1. Additional applicable requirements under the Clean Air Act become applicable to the Class I source. Such a reopening shall only occur if there are three or more years remaining in the permit term. The reopening shall be completed no later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless an application for renewal has been submitted pursuant to A.A.C. R18-2-322.B. Any permit revision required pursuant to this subparagraph shall comply with the provisions in A.A.C. R18-2-322 for permit renewal and shall reset the five-year permit term.

2. Additional requirements, including excess emissions requirements, become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the Class I permit.

3. The Director or the Administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions

standards or other terms or conditions of the permit.

4. The Director or the Administrator determines that the permit needs to be revised or revoked to assure compliance with the applicable requirements.

C. Proceedings to reopen and reissue a permit, including appeal of any final action relating to a permit reopening, shall follow the same procedures as apply to initial permit issuance and shall, except for reopenings under Condition III.B.1 above, affect only those parts of the permit for which cause to reopen exists. Such reopenings shall be made as expeditiously as practicable. Permit reopenings for reasons other than those stated in Condition III.B.1 above shall not result in a resetting of the five-year permit term.

IV. POSTING OF PERMIT

[A.A.C. R18-2-315]

A. The Permittee shall post this permit or a certificate of permit issuance where the facility is located in such a manner as to be clearly visible and accessible. All equipment covered by this permit shall be clearly marked with one of the following:

1. Current permit number; or

2. Serial number or other equipment ID number that is also listed in the permit to identify that piece of equipment.

B. A copy of the complete permit shall be kept on site.

V. FEE PAYMENT

[A.A.C. R18-2-306.A.9 and -326]

The Permittee shall pay fees to the Director pursuant to A.R.S. § 49-426(E) and A.A.C. R18-2-326.

VI. ANNUAL EMISSION INVENTORY QUESTIONNAIRE

[A.A.C. R18-2-327.A and B]

A. The Permittee shall complete and submit to the Director an annual emissions inventory questionnaire. The questionnaire is due by March 31st or ninety days after the Director makes the inventory form available each year, whichever occurs later, and shall include emission information for the previous calendar year.

B. The questionnaire shall be on a form provided by the Director and shall include the information required by A.A.C. R18-2-327.

VII. COMPLIANCE CERTIFICATION

[A.A.C. R18-2-309.2.a, -309.2.c-d, and -309.5.d]

A. The Permittee shall submit a compliance certification to the Director semiannually, which describes the compliance status of the source with respect to each permit condition. The first certification shall be submitted no later than August 15th, and shall report the compliance status of the source during the period between January 1st and June 30th of the current year. The second certification shall be submitted no later than February 15th, and shall report the compliance status of the source during the period between July 1st and December 31st of the previous year.

The compliance certifications shall include the following:

1. Identification of each term or condition of the permit that is the basis of the certification;

2. Identification of the methods or other means used by the Permittee for determining the compliance status with each term and condition during the certification period.

3. The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification shall be based on the methods or means designated in Condition VII.A.2 above. The certifications shall identify each deviation and take it into account for consideration in the compliance certification;

4. For emission units subject to 40 CFR Part 64, the certification shall also identify as possible exceptions to compliance any period during which compliance is required and in which an excursion or exceedance defined under 40 CFR Part 64 occurred;

5. All instances of deviations from permit requirements reported pursuant to Condition XII.B of this Attachment; and

6. Other facts the Director may require to determine the compliance status of the source.

B. A copy of all compliance certifications shall also be submitted to the EPA Administrator.

C. If any outstanding compliance schedule exists, a progress report shall be submitted with the semi-annual compliance certifications required in Condition VII.A above.

VIII. CERTIFICATION OF TRUTH, ACCURACY AND COMPLETENESS

[A.A.C. R18-2-304.H]

Any document required to be submitted by this permit, including reports, shall contain a certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

IX. INSPECTION AND ENTRY

[A.A.C. R18-2-309.4]

Upon presentation of proper credentials, the Permittee shall allow the Director or the authorized representative of the Director to:

A. Enter upon the Permittee's premises where a source is located, emissions-related activity is conducted, or where records are required to be kept under the conditions of the permit;

B. Have access to and copy, at reasonable times, any records that are required to be kept under the conditions of the permit;

C. Inspect, at reasonable times, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit;

D. Sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with the permit or other applicable requirements; and

E. Record any inspection by use of written, electronic, magnetic and photographic media.

X. PERMIT REVISION PURSUANT TO FEDERAL HAZARDOUS AIR POLLUTANT STANDARD

[A.A.C. R18-2-304.C]

If this source becomes subject to a standard promulgated by the Administrator pursuant to Section 112(d) of the Act, then the Permittee shall, within twelve months of the date on which the standard is promulgated, submit an application for a permit revision demonstrating how the source will comply with the standard.

XI. ACCIDENTAL RELEASE PROGRAM

[40 CFR Part 68]

If this source becomes subject to the provisions of 40 CFR Part 68, then the Permittee shall comply with these provisions according to the time line specified in 40 CFR Part 68.

XII. EXCESS EMISSIONS, PERMIT DEVIATIONS, AND EMERGENCY REPORTING

A. Excess Emissions Reporting

[A.A.C. R18-2-310.01.A and -310.01.B]

1. Excess emissions shall be reported as follows:

   a. The Permittee shall report to the Director any emissions in excess of the limits established by this permit. Such report shall be in two parts as specified below:

      (1) Notification by telephone or facsimile within 24 hours of the time when the Permittee first learned of the occurrence of excess emissions including all available information from Condition XII.A.1.b below.

      (2) Detailed written notification by submission of an excess emissions report within 72 hours of the notification pursuant to Condition XII.A.1.a.(1) above.

   b. The report shall contain the following information:

      (1) Identity of each stack or other emission point where the excess emissions occurred;

      (2) Magnitude of the excess emissions expressed in the units of the applicable emission limitation and the operating data and calculations used in determining the magnitude of the excess emissions;

      (3) Date, time and duration, or expected duration, of the excess emissions;

      (4) Identity of the equipment from which the excess emissions

emanated;

(5) Nature and cause of such emissions;

(6) If the excess emissions were the result of a malfunction, steps taken to remedy the malfunction and the steps taken or planned to prevent the recurrence of such malfunctions; and

(7) Steps taken to limit the excess emissions. If the excess emissions resulted from start-up or malfunction, the report shall contain a list of the steps taken to comply with the permit procedures.

2. In the case of continuous or recurring excess emissions, the notification requirements of this section shall be satisfied if the source provides the required notification after excess emissions are first detected and includes in such notification an estimate of the time the excess emissions will continue. Excess emissions occurring after the estimated time period, or changes in the nature of the emissions as originally reported, shall require additional notification pursuant to Condition XII.A.1 above.

[A.A.C. R18-2-310.01.C]

B. Permit Deviations Reporting

[A.A.C. R18-2-306.A.5.b]

The Permittee shall promptly report deviations from permit requirements, including those attributable to upset conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. Prompt reporting shall mean that the report was submitted to the Director by certified mail, facsimile, or hand delivery within two working days of the time when emission limitations were exceeded due to an emergency or within two working days of the time when the owner or operator first learned of the occurrence of a deviation from a permit requirement.

C. Emergency Provision

[A.A.C. R18-2-306.E]

1. An "emergency" means any situation arising from sudden and reasonable unforeseeable events beyond the control of the source, including acts of God, that require immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

2. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if Condition XII.C.3 is met.

3. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. An emergency occurred and that the Permittee can identify the cause(s) of the emergency;

b. The permitted facility was being properly operated at the time;

c. During the period of the emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards or other requirements in the permit; and

d. The Permittee submitted notice of the emergency to the Director by certified mail, facsimile, or hand delivery within two working days of the time when emission limitations were exceeded due to the emergency. This notice shall contain a description of the emergency, any steps taken to mitigate emissions, and corrective action taken.

4. In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.

5. This provision is in addition to any emergency or upset provision contained in any applicable requirement.

D. Compliance Schedule

[ARS § 49-426.I.5]

For any excess emission or permit deviation that cannot be corrected within 72 hours, the Permittee is required to submit a compliance schedule to the Director within 21 days of such occurrence. The compliance schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with the permit terms or conditions that have been violated.

E. Affirmative Defenses for Excess Emissions Due to Malfunctions, Startup, and Shutdown

[A.A.C. R18-2-310]

1. Applicability

This rule establishes affirmative defenses for certain emissions in excess of an emission standard or limitation and applies to all emission standards or limitations except for standards or limitations:

a. Promulgated pursuant to Sections 111 or 112 of the Act;

b. Promulgated pursuant to Titles IV or VI of the Clean Air Act;

c. Contained in any Prevention of Significant Deterioration (PSD) or New Source Review (NSR) permit issued by the U.S. EPA;

d. Contained in A.A.C. R18-2-715.F; or

e. Included in a permit to meet the requirements of A.A.C. R18-2-406.A.5.

2. Affirmative Defense for Malfunctions

Emissions in excess of an applicable emission limitation due to malfunction shall constitute a violation. When emissions in excess of an applicable emission limitation are due to a malfunction, the Permittee has an affirmative defense to a civil or administrative enforcement proceeding based on that violation, other than a judicial action seeking injunctive relief, if the Permittee has complied with the reporting requirements of A.A.C. R18-2-310.01 and has demonstrated all of the following:

a. The excess emissions resulted from a sudden and unavoidable breakdown of process equipment or air pollution control equipment beyond the reasonable control of the Permittee;

b. The air pollution control equipment, process equipment, or processes were at all times maintained and operated in a manner consistent with good practice for minimizing emissions;

c. If repairs were required, the repairs were made in an expeditious fashion when the applicable emission limitations were being exceeded. Off-shift labor and overtime were utilized where practicable to ensure that the repairs were made as expeditiously as possible. If off-shift labor and overtime were not utilized, the Permittee satisfactorily demonstrated that the measures were impracticable;

d. The amount and duration of the excess emissions (including any bypass operation) were minimized to the maximum extent practicable during periods of such emissions;

e. All reasonable steps were taken to minimize the impact of the excess emissions on ambient air quality;

f. The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

g. During the period of excess emissions there were no exceedances of the relevant ambient air quality standards established in Title 18, Chapter 2, Article 2 of the A.A.C. that could be attributed to the emitting source;

h. The excess emissions did not stem from any activity or event that could have been foreseen and avoided, or planned, and could not have been avoided by better operations and maintenance practices;

i. All emissions monitoring systems were kept in operation if at all practicable; and

j. The Permittee's actions in response to the excess emissions were documented by contemporaneous records

3. Affirmative Defense for Startup and Shutdown

a. Except as provided in Condition XII.E.3.b below, and unless otherwise provided for in the applicable requirement, emissions in excess of an applicable emission limitation due to startup and shutdown shall constitute a violation. When emissions in excess of an applicable emission limitation are due to startup and shutdown, the Permittee has an affirmative defense to a civil or administrative enforcement proceeding based on that violation, other than a judicial action seeking injunctive relief, if the Permittee has complied with the reporting requirements of A.A.C. R18-2-310.01 and has demonstrated all of the following:

(1) The excess emissions could not have been prevented through careful and prudent planning and design;

(2) If the excess emissions were the result of a bypass of control equipment, the bypass was unavoidable to prevent loss of life, personal injury, or severe damage to air pollution control equipment, production equipment, or other property;

(3) The air pollution control equipment, process equipment, or processes were at all times maintained and operated in a manner consistent with good practice for minimizing emissions;

(4) The amount and duration of the excess emissions (including any bypass operation) were minimized to the maximum extent practicable during periods of such emissions;

(5) All reasonable steps were taken to minimize the impact of the excess emissions on ambient air quality;

(6) During the period of excess emissions there were no exceedances of the relevant ambient air quality standards established in Title 18, Chapter 2, Article 2 of the A.A.C. that could be attributed to the emitting source;

(7) All emissions monitoring systems were kept in operation if at all practicable; and

(8) Contemporaneous records documented the Permittee’s actions in response to the excess emissions.

b. If excess emissions occur due to a malfunction during routine startup and shutdown, then those instances shall be treated as other malfunctions subject to Condition XII.E.2 above.

4. Affirmative Defense for Malfunctions during Scheduled Maintenance

If excess emissions occur due to a malfunction during scheduled maintenance, then those instances will be treated as other malfunctions subject to Condition XII.E.2 above.

5. Demonstration of Reasonable and Practicable Measures

For an affirmative defense under Condition XII.E.2 or XII.E.3 above, the Permittee shall demonstrate, through submission of the data and information required by Condition XII.E and A.A.C. R18-2-310.01, that all reasonable and practicable measures within the Permittee’s control were implemented to prevent the occurrence of the excess emissions.

XIII. RECORDKEEPING REQUIREMENTS

[A.A.C. R18-2-306.A.4]

A. The Permittee shall keep records of all required monitoring information including, but not limited to, the following:

1. The date, place as defined in the permit, and time of sampling or measurements;
2. The date(s) analyses were performed;
3. The name of the company or entity that performed the analyses;
4. A description of the analytical techniques or methods used;
5. The results of such analyses; and
6. The operating conditions as existing at the time of sampling or measurement.

B. The Permittee shall retain records of all required monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings or other data recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.

C. All required records shall be maintained either in an unchangeable electronic format or in a handwritten logbook utilizing indelible ink.

XIV. REPORTING REQUIREMENTS

[A.A.C. R18-2-306.A.5.a]

The Permittee shall submit the following reports:

A. Compliance certifications in accordance with Section VII of Attachment “A”.

B. Excess emission; permit deviation, and emergency reports in accordance with Section XII of Attachment “A”.

C. Other reports required by any condition of Attachment “B”.

XV. DUTY TO PROVIDE INFORMATION

[A.A.C. R18-2-304.G and -306.A.8.e]

A. The Permittee shall furnish to the Director, within a reasonable time, any information that the Director may request in writing to determine whether cause exists for revising, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. Upon request, the Permittee shall also furnish to the Director copies of records required to be kept by the permit. For information claimed to be confidential, the Permittee shall furnish an additional copy of such records directly to the Administrator along with a claim of confidentiality.

B. If the Permittee has failed to submit any relevant facts or has submitted incorrect information in the permit application, the Permittee shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information.

XVI. PERMIT AMENDMENT OR REVISION

[A.A.C. R18-2-318, -319, and -320]

The Permittee shall apply for a permit amendment or revision for changes to the facility which do not qualify for a facility change without revision under Section XVII, as follows:

A. Administrative Permit Amendment (A.A.C. R18-2-318);

B. Minor Permit Revision (A.A.C. R18-2-319); and

C. Significant Permit Revision (A.A.C. R18-2-320)

The applicability and requirements for such action are defined in the above referenced regulations.

XVII. FACILITY CHANGE WITHOUT A PERMIT REVISION

[A.A.C. R18-2-317]

A. The Permittee may make changes at the permitted source without a permit revision if all of the following apply:

1. The changes are not modifications under any provision of Title I of the Act or under A.R.S. § 49-401.01(24);

2. The changes do not exceed the emissions allowable under the permit whether expressed therein as a rate of emissions or in terms of total emissions;

3. The changes do not violate any applicable requirements or trigger any additional applicable requirements;

4. The changes satisfy all requirements for a minor permit revision under A.A.C. R18-2-319.A; and

5. The changes do not contravene federally enforceable permit terms and conditions that are monitoring (including test methods), record keeping, reporting, or compliance certification requirements.

B. The substitution of an item of process or pollution control equipment for an identical or substantially similar item of process or pollution control equipment shall qualify as a change that does not require a permit revision, if it meets all of the requirements of Conditions XVII.A and XVII.C of this Attachment.

C. For each change under Conditions XVII.A and XVII.B above, a written notice by certified mail or hand delivery shall be received by the Director and the Administrator a minimum of 7 working days in advance of the change. Notifications of changes associated with emergency conditions, such as malfunctions necessitating the replacement of equipment, may be provided less than 7 working days in advance of the change, but must be provided as far in advance of the change~~,~~ as possible or, if advance notification is not practicable, as soon after the change as possible.

D. Each notification shall include:

1. When the proposed change will occur;

2. A description of the change;

3. Any change in emissions of regulated air pollutants; and

4. Any permit term or condition that is no longer applicable as a result of the change.

E. The permit shield described in A.A.C. R18-2-325 shall not apply to any change made under this Section.

F. Except as otherwise provided for in the permit, making a change from one alternative operating scenario to another as provided under A.A.C. R18-2-306.A.11 shall not require any prior notice under this Section.

G. Notwithstanding any other part of this Section, the Director may require a permit to be revised for any change that, when considered together with any other changes submitted by the same source under this Section over the term of the permit, do not satisfy Condition XVII.A above.

XVIII. TESTING REQUIREMENTS

[A.A.C. R18-2-312]

A. The Permittee shall conduct performance tests as specified in the permit and at such other times as may be required by the Director.

B. Operational Conditions During Testing

Tests shall be conducted during operation at the maximum possible capacity of each unit under representative operational conditions unless other conditions are required by the applicable test method or in this permit. With prior written approval from the Director, testing may be performed at a lower rate. Operations during periods of start-up, shutdown, and malfunction (as defined in A.A.C. R18-2-101) shall not constitute representative operational conditions unless otherwise specified in the applicable standard.

C. Tests shall be conducted and data reduced in accordance with the test methods and procedures contained in the Arizona Testing Manual unless modified by the Director pursuant to A.A.C. R18-2-312.B.

D. Test Plan

At least 14 calendar days prior to performing a test, the Permittee shall submit a test plan to the Director in accordance with A.A.C. R18-2-312.B and the Arizona Testing Manual. This test plan must include the following:

1. Test duration;

2. Test location(s);

3. Test method(s); and

4. Source operation and other parameters that may affect test results.

E. Stack Sampling Facilities

The Permittee shall provide, or cause to be provided, performance testing facilities as follows:

1. Sampling ports adequate for test methods applicable to the facility;

2. Safe sampling platform(s);

3. Safe access to sampling platform(s); and

4. Utilities for sampling and testing equipment.

F. Interpretation of Final Results

Each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic mean of the results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs is required to be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances beyond the Permittee's control, compliance may, upon the Director's approval, be determined using the arithmetic mean of the results of the other two runs. If the Director or the Director's designee is present, tests may only be stopped with the Director's or such designee's approval. If the Director or the Director's designee is not present, tests may only be stopped for good cause. Good cause includes: forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances beyond the Permittee's control. Termination of any test without good cause after the first run is commenced shall constitute a failure of the test. Supporting documentation, which demonstrates good cause, must be submitted.

G. Report of Final Test Results

A written report of the results of all performance tests shall be submitted to the Director within 30 days after the test is performed. The report shall be submitted in accordance with the Arizona Testing Manual and A.A.C. R18-2-312.A.

XIX. PROPERTY RIGHTS

[A.A.C. R18-2-306.A.8.d]

This permit does not convey any property rights of any sort, or any exclusive privilege.

XX. SEVERABILITY CLAUSE

[A.A.C. R18-2-306.A.7]

The provisions of this permit are severable. In the event of a challenge to any portion of this permit, or if any portion of this permit is held invalid, the remaining permit conditions remain valid and in force.

XXI. PERMIT SHIELD

[A.A.C. R18-2-325]

Compliance with the conditions of this permit shall be deemed compliance with all applicable requirements identified in the portions of this permit subtitled "Permit Shield". The permit shield shall not apply to minor revisions pursuant to Condition XVI.B of this Attachment and any facility changes without a permit revision pursuant to Section XVII of this Attachment.

XXII. PROTECTION OF STRATOSPHERIC OZONE

[40 CFR Part 82]

If this source becomes subject to the provisions of 40 CFR Part 82, then the Permittee shall comply with these provisions accordingly.

XXIII. APPLICABILITY OF NSPS/NESHAP GENERAL PROVISIONS

[40 CFR Part 60, Part 63]

For all equipment subject to a New Source Performance Standard or a National Emission Standard for Hazardous Air Pollutants, the Permittee shall comply with all applicable requirements contained in Subpart A of Title 40, Chapter 60 and Chapter 63 of the Code of Federal Regulations.

ATTACHMENT "B": SPECIFIC CONDITIONS

I. GENERAL REQUIREMENTS

A. The Permittee shall have on site or on call a person certified in EPA Reference Method 9 unless all Method 9 observations or instantaneous visual observations required by this permit are conducted as Alternative Method-082 (Digital Camera Operating Technique). The Permittee shall certify the camera and the associated software in accordance with ALT-082 procedures. Any Method 9 test or instantaneous visual survey required by this permit can be conducted as ALT-082. The results of a Method 9 observation or any individual instantaneous visual observation conducted as ALT-082 shall be obtained within 30 minutes of completing the Method 9 observation or individual instantaneous visual observation.

[A.A.C. R18-2-306.A.2 and A.3.c]

B. All equipment, facilities, and systems used to achieve compliance with the terms and conditions of this permit shall be maintained in good working order and be operated as efficiently as practicable so as to minimize air pollutant emissions.

[Installation Permit No. 1046 and No. 1111]

C. The Permittee shall comply with the requirements of the current approved Dust Control Plan. Changes to the approved Dust Control Plan shall not be implemented unless approved by the Director.

[A.A.C. R18-2-306.A.3.c]

D. Nothing in this Attachment shall be so construed as to prevent the utilization of measurements from emissions monitoring devices or techniques not designated as performance tests as evidence of compliance with applicable good maintenance and operating requirements.

[A.A.C. R18-2-312.I]

E. At the time the compliance certifications required by Section VII of Attachment "A" are submitted, the Permittee shall submit reports of all monitoring and reporting activities required by this Attachment performed in the same six month period as applies to the compliance certification period.

[A.A.C. R18-2-306.A.5.a]

F. Control Device Monitoring and Maintenance Procedure:

[A.A.C. R18-2-306.A.3.c]

1. The Permittee shall implement a baghouse monitoring procedure as follows for all baghouses identified in Attachment "C" in accordance to the schedule that is specified by each condition that refers to this procedure:

   a. The Permittee shall record the differential pressure across the baghouse using a differential pressure measurement device.

   b. The Permittee shall verify proper pulse timing sequence for the baghouses and record of the verification.

   c. The Permittee shall maintain the baghouses as follows:

      (1) The Permittee shall conduct an inspection of the baghouse cleaning system and fan.

(2) The Permittee shall inspect the internal components of the baghouse including hoppers, and shell. The Permittee shall record the various components of the system that have been inspected.

2. If maintenance is required, the Permittee shall record details of the type of maintenance and the date the maintenance was performed. If maintenance is not required, the Permittee shall record the fact that maintenance is not required.

3. If the baghouse has not operated during the timeframe in which the inspection is required, the Permittee shall record the fact that the baghouse has not operated.

G. Visible Emissions Observation Procedure:

1. The Permittee shall implement the Visual Observation Plan, Fifth Edition, dated May 4, 2012, approved by the Director June 4, 2012. Any changes to the approved Visual Observation Plan shall not be implemented unless approved by the Director.

2. The Permittee shall conduct visible emissions observations in accordance with the Visual Observation Plan. When multiple observation points are used, all the sources associated with each observation point shall be specifically identified within the observation plan.

3. A certified Method 9 observer shall conduct a visual survey of visible emissions from the sources in accordance with the observation plan under representative operating conditions. The survey shall be conducted at the frequency specified in the permit condition that refers to this procedure. The Permittee shall keep a record of the name of the observer, the date and time on which the survey was made, the location(s) of the survey, and the results of the survey.

4. If the observer sees a plume from a source that on an instantaneous basis appears to exceed the applicable opacity standard, then the observer shall, if practicable, take a six-minute Method 9 observation of the plume.

5. If the six-minute opacity of the plume is less than the applicable opacity standard, the observer shall make a record of the following:

   a. Location, date, and time of the observation; and

   b. The results of the Method 9 observation.

6. If the six-minute opacity of the plume exceeds the applicable opacity standard, then the Permittee shall do the following:

   a. Adjust or repair the controls or equipment to reduce opacity to below the applicable opacity standard;

   b. Report as an excess emission in accordance with Section XII of Attachment "A" of this permit; and

   c. Conduct a six-minute Method 9 observation reading within 48 hours after taking corrective action. The results of this observation, including the date, time, and location, shall be recorded.

II. CRUSHING AND SCREENING PLANT AND KILN FEED EQUIPMENT SUBJECT TO A.A.C. R-18-2-720

A. Applicability

This Section applies to equipment that is identified in Attachment "C" as subject to this Section.

B. Particulate Matter and Opacity

1. Emission Limitations

a. The opacity of any plume or effluent emanating from the emissions units subject to this Section shall not exceed 20 percent, as determined by EPA Reference Method 9 in 40 CFR 60 Appendix A.

[A.A.C. R18-2-702.B]

b. The Permittee shall not cause, allow, or permit the discharge into the atmosphere in any one hour, from any emission unit subject to this Section, particulate matter in excess of the amounts calculated by the following equations:

[A.A.C. R18-2-720.B]

(1) For process sources having a process weight rate of 60,000 pounds per hour (30 tons per hour) or less, the maximum allowable emissions shall be determined by the following equation:

$$E = 4.10P^{0.67}$$

Where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.

P = the process weight rate in tons-mass per hour.

(2) For process sources having a process weight rate greater than 60,000 pounds per hour (30 tons per hour), the maximum allowable emissions shall be determined by the following equation:

$$E = 55.0P^{0.11} - 40$$

Where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.

P = the process weight rate in tons-mass per hour.

c. For the purposes of this permit, the total process weight from all similar units employing a similar type process shall be used in determining the maximum allowable emission of particulate matter.

[A.A.C. R18-2-720.D]

2. Air Pollution Control Requirements

*At all times when any emission unit subject to this Section is in operation including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable*, maintain _*and operate the associated control measure/device in a manner consistent with good air pollution control practice for minimizing particulate matter emissions.*_

[A.A.C. R18-2-306.A.2 and -331.A.3.e]
[Material permit conditions are indicated by underline and italics]

3. Monitoring, Reporting, Recordkeeping Requirements

   a. The Permittee shall conduct a Visible Emission Observation Procedure, as defined in Condition I.G of this Attachment, once every two weeks to monitor emissions from material transfer points at the process sources affected under this Section and emissions from baghouses DC 234, DC 213, DC 219-D, and DC 206-D.

   [A.A.C. R18-2-306.A.3.c]

   b. The Permittee shall conduct a Control Device Monitoring and Maintenance Procedure, as defined in Condition I.F of this Attachment, once every month on baghouses DC 234, DC 213, DC 219-D, and DC 206-D.

   [A.A.C. R18-2-306.A.3.c]

C. Permit Shield

Compliance with the terms of this Section shall be deemed compliance with A.A.C. R18-2-702.B, A.A.C. R18-2-720.B and A.A.C. R18-2-720.D.

[A.A.C. R18-2-325]

III. CRUSHING AND SCREENING PLANT AND KILN FEED EQUIPMENT SUBJECT TO NSPS SUBPART OOO

A. Applicability

This Section applies to equipment that is identified in Attachment "C" as subject to this Section.

B. Particulate Matter and Opacity

1. Emission Limitations and Standards

*At all times except during periods of startup, shutdown, or malfunction, the Permittee shall not allow to be discharged into the atmosphere from any affected facility except crushers any fugitive emissions which exhibit visible emissions greater than 10 percent opacity.*

[40 CFR 60.672.b, 60.11(c) and A.A.C. R18-2-331.A.3.f]
[Material permit conditions are indicated by underline and italics]

2. Air Pollution Control Requirements

*At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable*, maintain and _*operate any affected facility*_ *including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Director which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.*

[A.A.C. R18-2-331.A.3.e, -306.A.2, 40 CFR § 60.11(d)]
[Material permit conditions are indicated by underline and italics]

3. Monitoring, Reporting, Recordkeeping Requirements

The Permittee shall conduct a Visible Emission Observation Procedure, as defined in Condition I.G of this Attachment, once every two weeks to monitor emissions from the affected process sources under this Section.

[A.A.C. R18-2-306.A.3.c]

C. Permit Shield

Compliance with the terms of this Section shall be deemed compliance with 40 CFR 60.672(b) and 60.675(c)(1).

[A.A.C. R18-2-325]

IV. SOLID FUEL HANDLING EQUIPMENT SUBJECT TO A.A.C. R18-2-716

A. Applicability

This Section applies to equipment that is identified in Attachment “C” as subject to this Section.

B. Particulate Matter and Opacity

1. Emission Limitations and Standards

a. The opacity of any plume or effluent emanating from any emission unit subject to this Section shall not exceed 20 percent, as determined by EPA Reference Method 9 in 40 CFR 60 Appendix A.

[A.A.C. R18-2-702.B]

b. The Permittee shall not cause, allow, or permit the discharge into the atmosphere in any one hour, from any emission unit subject to this Section, particulate matter in excess of the amounts calculated by one of the following equations:

(1) For process sources having a process weight rate of 60,000 pounds per hour (30 tons per hour) or less, the maximum allowable emissions shall be determined by the following equation:

$$E = 4.10P^{0.67}$$

Where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.

P = the process weight rate in tons-mass per hour.

(2) For process sources having a process weight rate greater than 60,000 pounds per hour (30 tons per hour), the maximum allowable emissions shall be determined by the following equation:

$E = 55.0P^{0.11} - 40$

Where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.

P = the process weight rate in tons-mass per hour.

[A.A.C. R18-2-716.B]

(3) For the purposes of this permit, the total process weight from all similar units employing a similar type process shall be used in determining the maximum allowable emission of particulate matter.

[A.A.C. R18-2-716.D]

2. Air Pollution Control Requirements

At all times when any emission unit subject to this Section is in operation, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and *operate the associated control measure/devices, in a manner consistent with good air pollution control practice for minimizing particulate matter emissions*.

[A.A.C. R18-2-306.A.2 and -331.A.3.e]
[Material permit conditions are indicated by underline and italics]

3. Monitoring, Reporting, Recordkeeping Requirements

a. The Permittee shall conduct a Visible Emissions Observation Procedure, as defined in Condition I.G of this Attachment, once every two weeks to monitor emissions from all material transfer points subject to this Section.

[A.A.C. R18-2-306.A.3.c]

b. The Permittee shall, once every month, conduct a Control Device Monitoring and Maintenance Procedure, as defined in Condition I.F for baghouse DC 527.

[A.A.C. R18-2-306.A.3.c]

C. Permit Shield

Compliance with the terms of this Section shall be deemed compliance with A.A.C. R18-2-702.B, -716.B and -716.D.

[A.A.C. R18-2-325]

V. SOLID FUEL HANDLING EQUIPMENT SUBJECT TO NSPS SUBPART Y

A. Applicability

This Section applies to equipment that is identified in Attachment "C" as subject to this Section.

B. Emission Limitations and Standards

1. Particulate Matter and Opacity

a. *At all times except during periods of startup, shutdown, or malfunction, the Permittee shall not cause to be discharged into the atmosphere from any emissions unit subject to this Section that commenced construction, reconstruction or modification after October 27, 1974 and on or before April 28, 2008, gases which exhibit 20 percent opacity or greater.* Compliance with the opacity standard shall be determined by conducting observations in accordance with EPA Reference Method 9 in 40 CFR 60, Appendix A.

[40 CFR § 60.254(a), 60.11(c) and A.A.C. R18-2-331.A.3.f]
[Material permit conditions are indicated by underline and italics]

b. *At all times except during periods of startup, shutdown, or malfunction, the Permittee shall not cause to be discharged into the atmosphere from any emissions unit subject to this Section that commenced construction, reconstruction or modification after April 28, 2008, gases which exhibit 10 percent opacity or greater.* Compliance with the opacity standard shall be determined by conducting observations in accordance with EPA Reference Method 9 in 40 CFR 60, Appendix A.

[40 CFR § 60.254(b)(1), 60.11(c) and A.A.C. R18-2-331.A.3.f]
[Material permit conditions are indicated by underline and italics]

2. Air Pollution Control Requirements

At all times, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and *operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.* Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Director which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

[40 CFR § 60.11(d) and A.A.C. R18-2-331.A.3.e]
[Material permit conditions are indicated by underline and italics]

3. Performance Test Requirements

a. For each affected facility subject to an opacity standard in Condition V.B.1.b, within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup, an initial performance test shall be performed in accordance with Condition V.B.3.b. Thereafter, a new performance test shall be conducted according to the following requirements:

[40 CFR § 60.255(b)(2)]

(1) If any 6-minute average opacity reading in the most recent performance test exceeds half the applicable opacity limit, a new performance test shall be conducted within 90 operating days of

the date of the previous performance test.

(2) If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date of the previous performance test.

b. The Permittee shall use Method 9 of appendix A–4 of 40 CFR 60 and the procedures in 40 CFR 60.11 to determine opacity, with the following exceptions:

[40 CFR § 60.257(a)(1)]

(1) The duration of the Method 9 performance test shall be 1 hour (ten 6-minute averages).

(2) If, during the initial 30 minutes of the observation of a Method 9 performance test, all of the 6-minute average opacity readings are less than or equal to half the applicable opacity limit, then the observation period may be reduced from 1 hour to 30 minutes.

4. Monitoring, Reporting, Recordkeeping Requirements

a. The Permittee shall conduct a Visible Emissions Observation Procedure, as defined in Condition I.G of this Attachment, once every two weeks to monitor emissions from the affected emission units subject to this Section.

[A.A.C. R18-2-306.A.3.c]

b. The Permittee shall report semiannually periods of excess emissions for all 6-minute average opacities that exceed the applicable standard.

[40 CFR § 60.258(b)(3)]

c. The Permittee shall submit the results of initial performance tests to the Director, consistent with 40 CFR 60.8.

[40 CFR § 60.258(c)]

d. Within 60 days after the date of completing Method 9 opacity performance tests, the Permittee shall mail a summary copy to United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; mail code: D243–01; RTP, NC 27711.

[40 CFR § 60.258(d)]

C. Permit Shield

Compliance with the terms of this Section shall be deemed compliance with 40 CFR 60.254(a), 254(b)(1), 255(b)(2), 60.257(a) and 60.258.

[A.A.C. R18-2-325]

VI. KILN 1 AND KILN 2 SYSTEMS AND ASSOCIATED STONE HANDLING FACILITIES

A. Applicability

This Section applies to all equipment in Kilns 1 and 2 systems and associated stone handling facilities identified in Attachment "C" as subject to this Section.

B. General Requirements

1. Operating Requirements

a. Operations, Maintenance and Monitoring (OM&M) Plan

[40 CFR 63.7100(d)]

(1) The Permittee shall implement the written OM&M Plan. Any subsequent changes to the plan must be submitted to the Director for approval. Pending approval of the initial or amended plan, the Permittee shall comply with the provisions of the submitted plan.

(2) The OM&M Plan shall contain all the information required in 40 CFR 63.7100(d)(1) through 40 CFR 63.7100(d)(7).

b. Startup, Shutdown, and Malfunction Plan (SSMP)

[40 CFR 63.7100(e)]

The Permittee shall implement a SSMP according to the requirements in 40 CFR 63.6(e)(3).

c. Fuel Limitation

The Permittee shall only use the following material as fuel for the rotary kilns identified in this Section:

(1) Fuel oil;

(2) Coal;

(3) Petroleum coke;

(4) Any combination of (1) though (3) above.

[A.A.C R18-2-306.A.2]

d. Kiln 1 Stack Limitation

The Kiln 1 Stack must be at least 140 feet above ground level.

[A.A.C R18-2-306.A.2]

C. Particulate Matter and Opacity

1. Emission Limitations and Standards

a. The Permittee shall not cause, allow or permit the discharge of particulate matter in excess of 0.12 pounds per ton of stone feed (lb/tsf) from Kiln 1, Kiln 2 and their associated lime coolers, or the weighted average of the two kilns and associated lime coolers.

[40 CFR 63.7090(a) Table 1, Item 1 & Item 4]

b. The Permittee shall not cause or allow to be emitted into the atmosphere from each kiln and associated lime cooler any gases which exhibit opacity greater than 15 percent, based on a 6-minute block average.

[40 CFR 63.7090(b), Table 2, Item 1]

c. Fugitive emissions from processed stone handling (PSH) operations-Stone Bin 2-304, Stone Bin 1-304, Belt Conveyor 329, and Weigh Belt 303A shall not exceed 10 percent opacity.

[40 CFR 63.7090(a), Table 1, Item 7]

d. The Permittee shall not cause, allow or permit the discharge of particulate matter into the atmosphere in any one hour from the PSH Operations in total quantities in excess of the amounts calculated by one of the following equations:

[A.A.C. R18-2-730.B]

(1) For process sources having a process weight rate of 60,000 pounds per hour (30 tons per hour) or less, the maximum allowable emissions shall be determined by the following equation:

$E = 4.10P^{0.67}$

Where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.

P = the process weight rate in tons-mass per hour.

(2) For process sources having a process weight rate greater than 60,000 pounds per hour (30 tons per hour), the maximum allowable emissions shall be determined by the following equation:

$E = 55.0P^{0.11} - 40$

Where "E" and "P" are defined as indicated in Condition VI.C.1.d(1) above.

e. The Permittee shall be in compliance with the opacity limits in Conditions VI.C.1.b and c above at all times except during periods of startup, shutdown, and malfunction. If a startup, shutdown, or malfunction of one portion of an affected source does not affect the ability of particular emission points within other portions of the affected source to comply with the opacity and visible emission standards, then that emission point shall still be required to comply with the opacity and visible emission standards and other applicable requirements

[40 CFR 63.6(h)(1)]

2. Operating Limitations and Standards

a. The Permittee shall vent captured emissions from each emission unit equipped with an add-on air pollution control device though a closed system. Dilution air may be added to emission streams for the purpose of controlling temperature at the inlet to a fabric filter.

[40 CFR 63.7090(b), Table 2 Item 6]

b. The Permittee shall operate each capture and control system according to the procedures and requirements in the Operation, Maintenance and

Monitoring (OM&M) Plan required in Condition VI.B.1.a.

[40 CFR 63.7090(b), Table 2 Item 6]

3. Air Pollution Control Requirements

a. *At all times that Kiln 1 is in operation, the Permittee shall operate both the Kiln 1 negative pressure baghouse BGH1and the Multicyclone 1-319 in a manner consistent with good air pollution control practice for minimizing particulate emissions*.

[A.A.C. R18-2-331.A.3.e, and 306.A.2]
[Material permit conditions are indicated by underline and italics]

b. *At all times that Kiln 2 is in operation, the Permittee shall operate both the Kiln 2 negative pressure baghouse BGH2 and the Multicyclone 2-319 in a manner consistent with good air pollution control practice for minimizing particulate emissions*.

[A.A.C. R18-2-331.A.3.e, and 306.A.2]
[Material permit conditions are indicated by underline and italics]

c. *At all times, including periods of startup, shutdown, and malfunction, the Permittee shall operate* and maintain *any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.* During a period of startup, shutdown, or malfunction, this general duty to minimize emissions requires that the Permittee reduce emissions from the affected source to the greatest extent which is consistent with safety and good air pollution control practices. The general duty to minimize emissions during a period of startup, shutdown, or malfunction does not require the Permittee to achieve emission levels that would be required by the applicable standard at other times if this is not consistent with safety and good air pollution control practices, nor does it require the Permittee to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Director which may include, but is not limited to, monitoring results, review of operation and maintenance procedures (including the startup, shutdown, and malfunction plan, review of operation and maintenance records, and inspection of the source.

[40 CFR 63.6(e)(1)(i), A.A.C. R18-2-331.A.3.e]
[Material permit conditions are indicated by underline and italics]

4. Monitoring Requirements

a. The Permittee shall inspect each capture/collection and closed vent system for each emission unit equipped with an add on air pollution device at least once each calendar year to ensure that each system is operating in accordance with Conditions VI.C.2.a and b above, and record the results of the inspection.

[40 CFR 63.7113(f)]

b. Continuous Opacity Monitoring System (COMS) Requirements

(1) *The Permittee shall calibrate*, maintain, and operate *the two*

continuous opacity monitoring systems (COMS) installed at the Kiln 1 stack and the Kiln 2 stack to monitor and record the opacity of the gases discharged from each kiln at all times when the associated kiln is in operation. The span of the systems shall be set at 70% opacity.

[A.A.C. R18-2-720.F, 40 CFR 63.7113(g) and A.A.C. R18-2-331.A.3.c]
[Material permit conditions are indicated by underline and italics]

(2) The COMS shall be maintained, calibrated and operated in accordance with 40 CFR part 63, subpart A, General Provisions and according to 40 CFR 60, Appendix B, "Performance Specification 1 - Specification and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources". Facilities that operate COMS installed on or before February 6, 2001, may continue to meet the requirements in effect at the time of COMS installation unless specifically required to re-certify the COMS by the Director.

[A.A.C. R18-2-A9.3.1.1, 40 CFR 63.7113(g)(2)]

(3) For each lime kiln, the Permittee shall demonstrate continuous compliance by collecting the COMS data at a frequency of at least once every 15 seconds, determining block averages for each 6-minute period and demonstrating for each 6-minute block period the average opacity does not exceed 15 percent.

[40 CFR 63.7121(e), Table 5, Item 4]

(4) The COMS shall meet the following quality assurance requirements:

(a) Calibration checks

[A.A.C. R18-2-A9.4, 40 CFR 63.8(c)(6)]

The Permittee shall check the zero (or low-level value between 0 and 20% of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure prescribed by the manufacturer.

(b) Zero and span drift adjustments

[A.A.C. R18-2-A9.4, 40 CFR 63.8(c)(6)]

(i) The zero and span shall, as a minimum, be adjusted whenever the 24-hr zero drift exceeds two times the limits of the performance specifications in the relevant standard.

(ii) For systems using automatic zero adjustments, the optical and instrumental surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4% opacity.

(iii) The optical and instrumental surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments, except for systems using automatic zero adjustments.

(c) System checks
[A.A.C. R18-2-A9.4.3, 40 CFR 63.8(c)(5), 40 CFR §63.7113(g)(2)]

The Permittee shall, as minimum procedures, apply a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. All procedures applied shall provide a system check of all analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly normally used in the measurement of opacity.

(d) Minimum frequency of operation
[A.A.C. R18-2-A9.5.1, 40 CFR 63.8(c)(4)(i)]

Except for system breakdowns, repairs, calibration checks, and zero and span adjustments, the COMS shall be in continuous operation and shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 10-second period, and one cycle of data recording for each successive 6-minute period.

(e) Data reduction procedures
[A.A.C. R18-2-A9.8, 40 CFR 63.8(g)]

(i) The Permittee shall reduce all data from the COMS to 6-minute averages calculated from 24 or more data points equally spaced over each 6-minute period.

(ii) Data recorded during periods of system breakdowns, out-of-control periods, repairs, maintenance periods, calibration checks, and zero and span adjustments shall not be included in the data averages computed under Condition VI.C.4.b(4)(e)(i). An arithmetic or integrated average of all data may be used.

c. The Permittee shall conduct visual observations as follows for the equipment subject to the opacity limit in Condition VI.C.1.c.
[40 CFR 63.7121(e), Table 6, Item 1]

(1) The Permittee shall conduct a monthly 1-minute visible emissions (VE) observations of each emission unit; observation shall be conducted while the affected source is in operation.

(2) If no VE are observed in 6 consecutive month checks, decrease the frequency of VE checking from monthly to semi-annually; if

VE are observed during any semiannual observation, resume VE observations on a monthly basis, and maintain that schedule until no VE observations are observed in 6 consecutive monthly observations.

(3) If no VE are observed during the semi-annual observation, decrease observations from semi-annually to annually; if VE are observed during any annual check, resume VE observations on a monthly basis, and maintain that schedule until no VE observations are observed in 6 consecutive monthly observations.

(4) If VE are observed during any VE observation, the Permittee shall conduct a 6-minute EPA Reference Method 9 opacity test within 1 hour of any observation of VE, and the 6-minute opacity reading shall not exceed the opacity limit in Condition VI.C.1.c.

(5) The Permittee shall select a position at least 15 feet but not more than 1,320 feet from the affected emission point with the sun at your back.

d. The Permittee shall monitor and collect data according to the following:
[40 CFR 63.7120]

(1) Except for monitor malfunctions, associated repairs, required quality assurance or control activities (including, as applicable, calibration checks and required zero adjustments), and except for PSH operations subject to monthly VE testing, the Permittee shall monitor continuously (or collect data at all required intervals) at all times that the emission unit is operating.

(2) Data recorded during the Conditions VI.C.4.d(2)(a) through (c) below may not be used either in data averages or calculations of emission or operating limits; or in fulfilling a minimum data availability requirement. The Permittee shall use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(a) Monitoring system breakdowns, repairs, preventive maintenance, calibration checks, and zero (low-level) and high-level adjustments;

(b) Periods of non-operation of the process unit (or portion thereof), resulting in cessation of the emissions to which the monitoring applies; and

(c) Start-ups, shutdowns, and malfunctions.

5. Performance Testing Requirements

a. The Permittee shall conduct all required performance tests within 5 years following the initial performance test and within 5 years following each performance test thereafter.
[40 CFR 63.7111]

b. The Permittee shall conduct each performance test for particulate matter and opacity according to the requirements in 40 CFR 63.7(e)(1) and in accordance with Conditions VI.C.5.g and h below.

[40 CFR 63.7112(b)]

c. The Permittee shall not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in 40 CFR 63.7(e)(1).

[40 CFR 63.7112(c)]

d. The Permittee shall, except for opacity and VE checks, conduct three separate test runs for each performance test required in this section, as specified in 40 CFR 63.7(e)(3). Each test run shall last at least 1 hour.

[40 CFR 63.7112(d)]

e. The Permittee shall calculate the PM emissions from each lime kiln using the following equation:

[40 CFR 63.7112(e)]

$$\mathrm{E} = {(C_k Q_k)}/{PK}$$

Where

E = Emission Rate of PM, pounds per ton (lb/ton) of stone feed

Ck = Concentration of PM in the kiln effluent, grain/dry standard cubic feet (gr/dscf)

Qk = Volumetric flow rate of kiln effluent gas, dry standard cubic feet per hour.

P = Stone feed rate, tons per hour (tons/hr)

K = Conversion factor, 7000 grains per pound (grains/lb)

f. The Permittee may comply with a weighted average PM emission limit by calculating a combined particulate emission rate from all kilns using the following equation:

[40 CFR 63.7112(f)(1)]

$$\mathrm{E_T} = \sum_{i-1}^{n} E_i P_i \Big/ \sum_{i-1}^{n} P_i$$

Where

E_T = Weighted Emission Rate of PM from all kilns and coolers, lb/ton of stone feed.

E_i = Emission rate of PM from kiln i, or from kiln/cooler combination I, lb/ton of stone feed.

P_i = Stone feed rate to kiln i, tons/hr.

n = number of kilns used in averaging

g. Performance Testing Requirements for Kiln 1 and Kiln 2

(1) For each lime kiln, the Permittee shall conduct the performance tests when the source is operating at representative operating conditions in accordance with 40 CFR 63.7(e) and in accordance with requirements in Table 4 of 40 CFR 63 Subpart AAAAA.
[40 CFR 63.7112(a), Table 4 to 40 CFR 63 Subpart AAAAA]

(2) The Permittee shall determine the mass rate of stone feed to the kiln during the kiln PM emissions test using any suitable device. The Permittee shall calibrate and maintain the device according to manufacturer's instructions; the measuring device to be used must be accurate to within +/- 5 percent of the mass rate of stone feed over its operating range.
[40 CFR 63.7112(a) Table 4, Item 7]

(3) The Permittee shall have installed and operating a COMS device prior to conducting the PM emissions test on the kilns; the COMS shall be operated in accordance with the requirements set forth in Condition VI.C.4.b.
[40 CFR 63.7112(a) Table 4, Item 11]

h. Performance Testing Requirement for Stone Bin 2-304, Stone Bin 1-304, Belt Conveyor 329, and Weigh Belt 303A.
[40 CFR 63.7112(a) Table 4, Item 17]

(1) The Permittee shall conduct opacity observations of the above emissions points using EPA Reference Method 9.

(2) The Permittee shall use a test duration of at least 3 hours, but the 3-hour test may be reduced to 1 hour if, during the first 1-hour period, there are no individual readings greater than 10 percent opacity and there are no more than three readings of 10 percent during the first 1-hour period.

i. The Permittee shall document in complete test report the following information:
[40 CFR 63.7112(h)]

(1) A description of the process and the air pollution control system

(2) Sampling location descriptions;

(3) A description of sampling and analytical procedures and any modification to standard procedures;

(4) Test results, including opacity;

(5) Quality assurance procedures and results;

(6) Records of operating conditions during the test, preparation of standards, and calibration procedures;

(7) Raw data sheets for field sampling and field and laboratory analysis;

(8) Documentation of calculations

(9) All data recorded and used to establish operating limits; and

(10) Any other information required by the test method

6. Notification Requirements

a. The Permittee shall submit all of the notifications in 40 CFR 63.6(h)(4), and (5); 63.7(b) and (c); 63.8(e), f(4) and (6); and 63.9(a) through (j)that apply by the applicable deadline below.

[40 CFR 63.7130(a)]

b. The Permittee shall submit a notification of intent to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin, as required in 40 CFR 63.7(b)(1).

[40 CFR 63.7130(d)]

7. Reporting Requirements

a. The Permittee shall submit semi-annual compliance certification reports to the Administrator and to the Director detailing the compliance status with the 40 CFR §63 Subpart AAAAA requirements by January 31 for the reporting period July 1 through December 31, and by July 31 for the reporting period January 1 through June 30 of each year.

[40 CFR §63.7131]

b. The semi-annual compliance certification shall include the following information:

[40 CFR 63.7131(c)]

(1) Company name and address.

(2) Statement by the responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If the facility had a startup, shutdown or malfunction during the reporting period and the Permittee took actions consistent with the SSMP, the compliance report shall include the information in §63.10(d)(5)(i).

(5) If there were no deviations from any emission limitations (emission limit, operating limit, opacity limit, and VE limit) that apply to the facility, the compliance report shall include a

statement that there were no deviations from the emission limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring systems (CMS) were out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CMS were out-of-control during the reporting period.

c. The Permittee shall report as a deviation each instance in which the operating limit, opacity limit, or VE limit in Table 2 and Table 6 of 40 CFR §63 Subpart AAAAA as applicable are exceeded. This includes periods of startup, shutdown, and malfunction.

[40 CFR §63.7121(b)]

d. Consistent with 40 CFR 63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if the Permittee demonstrates to the Director that the facility and equipment were operating in accordance with 40 CFR 63.6(e)(1). The Director will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e).

[40 CFR §63.7121(d)]

e. If there was a deviation from an emission limitation set forth in Conditions VI.C.1.a through c at an affected source where the Permittee is not using a CMS to comply with the emission limitations, the compliance report shall contain the following information:

[40 CFR 63.7131(d)]

(1) The total operating time of each emission unit during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

f. If there was a deviation from an emission limitation set forth in Conditions VI.C.1.a through c at an affected source where the Permittee is using a CMS to comply with the emission limitations, the compliance report shall contain the following information:

[40 CFR 63.7131(e)]

(1) The date and time that each malfunction started and stopped.

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time and duration that each CMS was out-of-control, including the information in40 CFR 63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(5) A summary of the total duration of the deviations during the reporting period and the total duration as a percent of the total affected source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period and the total duration of CMS downtime as a percent of the total emission unit operating time during that reporting period.

(8) A brief description of the process units.

(9) A brief description of the CMS.

(10) The date of the latest CMS certification or audit.

(11) A description of any changes in CMS, processes, or controls since the last reporting period.

g. If the Permittee submits a compliance report specified in Table 7 to 40 CFR 63 Subpart AAAAA along with, or as part of, the semiannual monitoring, and the compliance report includes all required information concerning deviations from any emission limitation (including any operating limit), submission of the compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report shall not otherwise affect any obligation to report deviations from permit requirements to the Department.

[40 CFR 63.7131(e)]

8. Recordkeeping Requirements

a. The Permittee shall keep a copy of each notification and report including all documentation supporting any Initial Notification or Notification of Compliance Status that was submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv).

[40 CFR §63.7132(a)(1)]

b. The Permittee shall keep records specified in 40 CFR 63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

[40 CFR §63.7132(a)(2)]

c. The Permittee shall keep records of performance tests, performance evaluations, and opacity and VE observations as required in 40 CFR 63.10(b)(2)(viii).

[40 CFR §63.7132(a)(3)]

d. The Permittee shall keep records specified in 40 CFR 63.6(h)(6) for VE observations.

[40 CFR §63.7132(b)]

e. The Permittee shall keep records of all COM data, including records of installation, maintenance, and calibration.
[40 CFR 63.7132(c) Table 5, Item 4]

f. The Permittee shall keep records of all VE checks.
[40 CFR 63.7132(c) Table 6, Item 1]

g. The Permittee shall keep the records which document the basis for initial applicability determination as required under 40 CFR 63.7081.
[40 CFR 63.7132(d)]

h. The Permittee shall keep all records in a form suitable and readily available for expeditious review, according to 40 CFR 63.10 (b)(1).
[40 CFR 63.7133(a)]

i. The Permittee shall keep all records for a period of 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.
[40 CFR 63.7133(b)]

j. The Permittee shall keep each record onsite for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1).
[40 CFR 63.7133(c)]

9. Permit Shield

Compliance with the terms of this Section shall be deemed compliance with A.A.C. R18-82-720.B and 40 CFR 63.7090(a), 63.7090(b), 63.7100(d) and (e), 63.7111, 63.7112(a), 63.7112(b), 63.7112(c), 63.7112(d), 63.7112(e), 63.7112(f), 63.7112(h), 63.7113(f), 63.7113(g), 63.7120, 63.7121(b) , 63.7121(d), 63.7121(e), 63.7130(a), 63.7130(d), 63.7131, 63.7131(c) , 63.7131(d), 63.7131(e), 63.7131(f), 63.7132(a), 63.7132(b), 63.7132(c), 63.7132(d), 63.7133(a), 63.7133(b), and 63.7133(c).
[A.A.C. R18-2-325]

VII. FRONT LIME HANDLING SYSTEM, BACK LIME HANDLING SYSTEM, AND KILN DUST HANDLING SYSTEM

A. Applicability

This Section applies to all equipment in the Front Lime Handling System (FLHS), the Back Lime Handling System (BLHS), and the Kiln 1 and Kiln 2 Dust Handling System identified in Attachment “C” as subject this Section.

B. Particulate Matter and Opacity

1. Emission Limitations and Standards

a. The opacity of any plume or effluent emanating from the emissions units subject to this Section shall not exceed 20 percent.
[A.A.C. R18-2-702.B]

b. The Permittee shall not cause, allow, or permit the discharge of particulate matter into the atmosphere in any one hour from stacks at FLHS/DC 430, DC 437A-G, DC 419-5, DC 452, DC 762-1, BLHS/DC 414, DC-DS1 and Kiln 1 and Kiln 2 Dust Handling/DC 1-321, DC 2-321 in total quantities in excess of the amounts calculated by one of the following equations:

[A.A.C. R18-2-730.A.1]

(1) For process sources having a process weight rate of 30 tons per hour or less, the maximum allowable emissions shall be determined by the following equation:

$E = 4.10\ P^{0.67}$

Where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.

P = the process weight rate in tons-mass per hour.

(2) For process weight rate greater than 30 tons per hour, the maximum allowable emissions shall be determined by the following equation:

$E = 55.0\ P^{0.11} - 40$

Where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.

P = the process weight rate in tons-mass per hour.

c. For the purpose of Condition VII.B.1.b, the total process weight rate from all similar units employing a similar type process shall be used in determining the maximum allowable emission of particulate matter.

[A.A.C. R18-2-730.B]

2. Air Pollution Control Requirements

At all times when any emission unit subject to this Section is in operation, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, install, maintain and operate *the associated control measure/device identified in Attachment "C" in a manner consistent with good air pollution control practice for minimizing particulate matter emissions*.

[A.A.C. R18-2-306.A.3.c and -331.A.3.e]

[Material permit conditions are indicated by underline and italics]

3. Monitoring, Reporting and Recordkeeping Requirements

a. The Permittee shall conduct a Visible Emission Observation Procedure, as defined in Condition I.G of this Attachment, once every two weeks to monitor emissions from FLHS/DC 430, DC 437A-G, DC 419-5, DC 452, DC 762-1, DC-DS1, BLHS/DC 414, and Kiln 1 and Kiln 2 Dust

Handling/DC 1-321 and DC 2-321 stacks and all identifiable emission points at the process sources under this Section.

[A.A.C. R18-2-306.A.3.c]

b. The Permittee shall, once every month, conduct a Control Device Monitoring and Maintenance Procedure, as defined in Condition I.F of this Attachment, for the control devices FLHS/DC 430, DC 437A-G, DC 419-5, DC 452, DC 762-1, DC-DS1, BLHS/DC 414, and Kiln 1 and Kiln 2 Dust Handling/DC 1-321 and DC 2-321.

[A.A.C. R18-2-306.A.3.c]

C. Permit Shield

Compliance with the terms of this Section shall be deemed compliance with A.A.C. R18-2-702.B, 730.A.1 and 730.B.

[A.A.C. R18-2-325]

VIII. HYDRATOR

A. Applicability

This Section applies to all the equipment that is part of the Hydrator System identified in Attachment "C" that is subject to this Section.

B. Particulate Matter and Opacity

1. Emission Limitations and Standards

a. The opacity of any plume or effluent emanating from the equipment subject to this Section shall not exceed 20 percent.

[A.A.C. R18-2-702.B]

b. The Permittee shall not cause, allow or permit the discharge of particulate matter into the atmosphere in any one hour from DF 711, DC 721, and DC 750A stacks in total quantities in excess of the maximum allowable emissions calculated by the following equation:

[A.A.C. R18-2-720.B]

(1) For process sources having a process weight rate of 30 tons per hour or less, the maximum allowable emissions shall be determined by the following equation:

$E = 4.10\ P^{0.67}$

Where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.

P = the process weight rate in tons-mass per hour.

(2) For process weight rate greater than 30 tons per hour, the maximum allowable emissions shall be determined by the following equation:

$E = 55.0 P^{0.11} - 40$

Where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.

P = the process weight rate in tons-mass per hour.

c. For the purposes of this Condition VIII.B.1.b, the total process weight rate from all similar units employing a similar type process shall be used in determining the maximum allowable emission of particulate matter.

[A.A.C. R18-2-720.D]

d. *The Permittee shall not cause, allow or permit the discharge of particulate matter into the atmosphere in any one hour from the DF 711 stack in total quantities in excess of 5.71 pounds-mass per hour.*

[I.P. No. 65011 Condition B, A.A.C. R18-2-306.01.A, A.A.C. R18-2-331.A.3.e]
[Material permit conditions are indicated by underline and italics]

2. Air Pollution Control Requirements

At all times when any emission unit subject to this Section is in operation, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, install, maintain *and operate the associated control measure/device identified in Attachment "C" in a manner consistent with good air pollution control practice for minimizing particulate matter emissions.*

[A.A.C. R18-2-331.A.3.d and e, A.A.C. R18-2-306.A.2]
[Material permit conditions are indicated by underline and italics]

3. Monitoring, Reporting and Recordkeeping Requirements

a. The Permittee shall conduct a Visible Emissions Observation Procedure, as defined in Condition I.G, once every two weeks to monitor emissions from all identifiable emission units listed under VIII.A including the DF 711, DC 721, and DC 750A stacks.

[A.A.C. R18-2-306.A.3.c]

b. The Permittee shall, once every month, conduct a Control Device Monitoring and Maintenance Procedure, as defined in Condition I.F, for the control devices DF 711, DC 721 and DC 750A.

[A.A.C. R18-2-306.A.3.c]

C. Permit Shield

Compliance with the terms of this Section shall be deemed compliance with A.A.C. R18-2-702.B, 720.B, and 720.D, and with conditions of the Installation Permits No. 65011, and 1000988 for the stack emission sources under this Section.

[A.A.C. R18-2-325]

IX. REQUIREMENTS FOR DIESEL ENGINES NOT SUBJECT TO NSPS

A. Applicability

The Conditions of this Section apply to

1. Detroit Diesel Emergency Fire Pump Engine; and

2. Kiln 1 and Kiln 2 Pony Motors.

B. Fuel Limitations

1. The Permittee shall use diesel fuel that meets the requirements in 40 CFR 80.510(b) for sulfur content of non-road diesel fuel.

[A.A.C. R18-2-719.H]

2. Permit Shield

Compliance with the terms of this Part shall be deemed compliance with A.A.C. R18-2-719.H.

[A.A.C. R18-2-325]

C. Particulate Matter and Opacity

1. Emission Limitations and Standards

a. The Permittee shall not cause, allow or permit to be emitted into the atmosphere from any generator sets affected under this Section, smoke for any period greater than 10 consecutive seconds which exceeds 40% opacity, measured in accordance with EPA Reference Method 9. Visible emissions when starting cold equipment shall be exempt from this requirement for the first ten minutes.

[A.A.C. R18-2-719.E]

b. The Permittee shall not cause or allow to be discharged into the atmosphere from the generator stacks affected under this Section, particulate matter in excess of the amount calculated by the following equation and rounded off to two decimal points:

[A.A.C. R18-2-719.C.1]

$E = 1.02Q^{0.769}$

Where:

E = The maximum allowable particulate emissions rate in pounds-mass per hour.

Q = The heat input in million Btu per hour.

c. For the purposes of this condition, the heat input shall be the aggregate heat content of all fuels whose products of combustion pass through a stack or other outlet. The total heat input of all operating fuel-burning units at a plant or premises shall be used for determining the maximum allowable amount of particulate matter which may be emitted.

[A.A.C. R18-2-719.B]

2. Monitoring and Recordkeeping Requirements

   a. The Permittee shall conduct a Visible Emissions Observation Procedure, as defined in Condition I.G, once every two weeks when the generators are operating to monitor emissions from stacks of the Generator sets affected under this Section.

   [A.A.C. R18-2-306.A.3.c]

   b. The Permittee shall keep records of a current, valid purchase contract, tariff sheet or transportation contract. The records shall contain information regarding the lower heating value of the fuel. These records shall be made available to ADEQ upon request.

   [A.A.C. R18-2-306.A.3.c and 306.A.4.a].

3. Permit Shield

   Compliance with the terms of this Part shall be deemed compliance with A.A.C. R18-2-719.B, 719.C.1 and 719.E.

   [A.A.C. R18-2-325]

D. Sulfur Dioxide

1. Emission Limitations and Standards

   The Permittee shall not cause, allow, or permit emissions of more than 1.0 pound of sulfur dioxide per million Btu heat input from each generator set affected under this Section.

   [A.A.C. R18-2-719.F]

2. Monitoring, Recordkeeping and Reporting Requirements

   a. The Permittee shall keep records of fuel supplier certifications or other documentation listing the sulfur content to demonstrate compliance with the sulfur content limit specified in Condition IX.B.1 of this Attachment. These records shall be made available to ADEQ upon request.

   [A.A.C. R18-2-306.A.3.c and -719.I]

   b. The Permittee shall report to the Director any daily period during which the sulfur content of the fuel being fired in the machine exceeds 0.8%.

   [A.A.C. R18-2-719.J]

3. Permit Shield

   Compliance with the terms of this Part shall be deemed compliance with A.A.C. R18-2-719.F, 719.I and 719.J.

   [A.A.C. R18-2-325]

E. National Emission Standards for Hazardous Air Pollutant (NESHAP) Requirements

1. General Requirements

a. The Permittee shall operate and maintain at all times the engine including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.

[40 CFR 63.6605(b)]

b. The Permittee shall minimize the engine time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in shall apply.

[40 CFR 63.6625(h)]

c. The Permittee shall operate and maintain the engine and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop a maintenance plan which shall provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

[40 CFR 63.6625(e)]

2. Requirements for Emergency Engines

a. Operation Requirements

(1) The Permittee shall comply with the following operation and maintenance requirements:

[40 CFR 63.6602, 63.6625(i) and 40 CFR 63, Subpart ZZZZ, Table 2c]

(a) The Permittee shall change the oil and filter every 500 hours operation or annually, whichever comes first. If the Permittee prefers to extend the oil change requirement, an oil analysis program shall be completed. The oil analysis must be performed at the same frequency specified for changing the oil. The Permittee shall at a minimum analyze the following three parameters: Total Base Number, viscosity and water content. The condemning limits for these parameters are as follows:

(i) Total Base Number is less than 30 percent of the Total Base Number of the oil when new;

(ii) Viscosity: changed more than 20 percent from the viscosity of oil when new; and

(iii) Water Content: greater than 0.5 percent by volume.

If all of the above limits are not exceeded, the Permittee is not required to change the oil. If any of the above limits are exceeded, the Permittee shall change the oil within 2 business days of receiving the results of the analysis or before commencing operation, whichever is later. Records shall be kept of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program shall be part of the maintenance plan for the operation of the engine.

(b) The Permittee shall inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(c) The Permittee shall inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

(2) If the emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Conditions IX.E.2.a(1)(a) through (c), or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice shall be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated.

[40 CFR 63 Subpart ZZZZ, Table 2c]

(3) The Permittee shall operate the emergency engines according to the requirements in Conditions IX.E.2.a(3)(a) through (c) below. In order for the engines to be considered emergency stationary ICE under 40 CFR 63 Subpart ZZZZ, any operation other than emergency operation, maintenance response, and operation in non-emergency situations for 50 hours per year, as described in these Conditions, is prohibited. If the emergency engine is not operated in accordance with the requirements in Conditions IX.E.2.a(3)(a) through (c) below, the engine will not be considered an emergency engine and must meet all requirements for non-emergency engines.

[40 CFR 60.6640 (f)]

(a) There is no time limit on the use of emergency engine in emergency situations.

[40 CFR 60.6640 (f)(1)]

(b) The Permittee may operate the emergency engine for any combination of the purposes specified in Condition in Conditions IX.E.2.a(3)(b)(i) for a maximum of 100 hours per calendar year. Any non-emergency situations as allowed by Condition IX.E.2.a(3)(c) below counts as part of the 100 hours per calendar year allowed by this condition.

[40 CFR 63.6640(f)(2)]

(i) The Permittee may operate the emergency engine for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. The Permittee may petition the Administrator and the Director for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the Permittee maintains records indicating that the Federal, State, or local standards require maintenance and testing beyond 100 hours per year. Copies of records shall be made available to ADEQ upon request.

[40 CFR 63.6640 (f)(2)(i)]

(c) The Permittee may operate an emergency engine for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

[40 CFR 63.6640(f)(3)]

(4) *<u>The Permittee shall install a non-resettable hour meter if one is not already installed.</u>*

[40 CFR 63.6625(f), R18-2-331.A.3.c]
[Material Permit Conditions are indicated by underline and italics]

b. Recordkeeping Requirements

(1) The Permittee shall keep records of the hours of operation of the RICE that is recorded through the non-resettable hour meter. Records shall include the date, start and stop times, hours spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.

[40 CFR 63.6655(f)]

(2) The Permittee shall keep records of the parameters that are analyzed and the results of the oil analysis, if any, and the oil changes for the engine.

[40 CFR 63.6625(i)]

(3) The Permittee shall keep the records of actions taken during periods of malfunction to minimize emissions in accordance with Condition IX.E.1.b, including corrective actions to restore

malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.
[40 CFR 63.6655(a)(5)]

(4) The Permittee shall keep records of the maintenance conducted on the engine in order to demonstrate that the engine and after-treatment control device (if any) were operated and maintained in accordance with the Permittee's maintenance plan.
[40 CFR 63.6655(e)]

(5) The Permittee shall keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The Permittee shall document how many hours are spent for emergency operation; including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, the Permittee shall keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response.
[40 CFR 63.6655(f)]

(6) The records shall be in a form suitable and readily available for expeditious review according to 40 CFR 63.10(b)(1).
[40 CFR 63.6660(a)]

(7) The Permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.
[40 CFR 63.6660(b)]

(8) The record shall be readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record.
[40 CFR 63.6660(c)]

3. Requirements for Non-Emergency Compression Ignition Engines

a. Operation Requirements

The Permittee shall comply with the following operation and maintenance requirements:
[40 CFR 63.6602, and 40 CFR 63, Subpart ZZZZ, Table 2c]

(1) The Permittee shall change the oil and filter every 1,000 hours operation or annually, whichever comes first. If the Permittee prefers to extend the oil change requirement, an oil analysis program described in Condition IX.E.2.a(1)(a). The oil analysis shall be performed at the same frequency specified for changing the oil.

(2) Every 1,000 hours of operation or annually, whichever comes first, the Permittee shall inspect and replace air cleaner as necessary.

(3) Every 500 hours of operation or annually, whichever comes first, the Permittee shall inspect all hoses and belts and replace as necessary.

b. Continuous Compliance Requirements

The Permittee shall demonstrate continuous compliance by operating and maintaining the engine according to the manufacturer's emission-related operation and maintenance instructions; or by developing and following its own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions

[40 CFR 63.6640(a), Table 6 to 40 CFR 63 Subpart ZZZZ]

c. Recordkeeping Requirements

(1) The Permittee shall keep records of the maintenance conducted on the stationary RICE in order to demonstrate that , the Permittee operated and maintained the stationary RICE and after-treatment control device (if any) according to the Permittee's own maintenance plan.

[40 CFR 63.6655(e)]

(2) The Permittee shall keep the records of actions taken during periods of malfunction to minimize emissions in accordance with Condition IX.E.1.b, including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

[40 CFR 63.6655(a)(5)]

(3) The Permittee shall keep records of the parameters that are analyzed and the results of the oil analysis, if any, and the oil changes for the engine.

[40 CFR 63.6625(i)]

(4) The records shall be in a form suitable and readily available for expeditious review according to 40 CFR 63.10(b)(1).

[40 CFR 63.6660(a)]

(5) The Permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

[40 CFR 63.6660(b)]

(6) The record shall be readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record.

[40 CFR 63.6660(c)]

4. Permit Shield

Compliance with the terms of this Part shall be deemed compliance with 40.CFR 63.6602, 63.6605(b), 63.6625(e), 63.6625(f), 63.6625(i), 63.6625(h), 63.6640(a), 63.6650(d), 63.6650(h), 63.6640(f), 63.6655(a)(5), 63.6655(e), 63.6655(f), 63.6660(a) through (c).

[A.A.C. R18-2-325]

X. REQUIREMENTS FOR ENGINES SUBJECT TO NSPS SUBPART IIII

A. Applicability

This Section applies to the <125 kW Canyon Well Generator engine.

B. Operating Requirements

1. The Permittee shall not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 kW (25 HP) and less than 56 kW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

   [40 CFR 60.4208(c)]

2. The Permittee shall not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 kW (75 HP) and less than 130 kW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

   [40 CFR 60.4208(d)]

3. The Permittee shall operate and maintain the CI-ICE to comply with the emission standards as required in Condition X.D over the entire life of the engine.

   [40 CFR 60.4206]

4. The Permittee shall operate and maintain the CI-ICE and any control device according to the manufacturer's emission-related written instructions.

   [40 CFR 60.4211(a)(1)]

5. The Permittee shall change only those emission-related settings that are permitted by the manufacturer, or demonstrate compliance in accordance with Condition X.F.3.

   [40 CFR 60.4211(a)(2)]

6. The Permittee shall meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply.

   [40 CFR 60.4211(a)(3)]

C. Fuel Requirements

The Permittee shall only burn diesel fuel that meets the following requirements of 40 CFR 80.510(b):

1. Sulfur content: 15 ppm maximum; and

2. A minimum cetane index of 40 or a maximum aromatic content of 35 volume percent.

[40 CFR 60.4207(b)]

D. Emission Limitations and Standards

1. Nitrogen Oxides (NO_X)

[40 CFR 60.4204(a) and 40 CFR 60.4204(b), 40 CFR 60.4201(a)) and 40 CFR 1039.101]

For model year 2015 or later engines less than 130 kW but at least 56 kW, the Permittee shall not allow NOx emissions to exceed 0.40 g/kW-hr.

2. Nitrogen Oxides and Non-Methane Hydrocarbons (NMHC)

[40 CFR 60.4204(b), 40 CFR 60.4201(a), 40 CFR 1039.101 and 102]

a. 2014 and prior year engines with a power rating of 37≤kW<75, the Permittee shall not cause or allow to be discharged into the atmosphere any gases that contain NO_X and non-methane hydrocarbons in excess of 4.7 g/kW-hr.

b. 2014 and prior year engines with a power rating of 75≤kW<130, the Permittee shall not cause or allow to be discharged into the atmosphere any gases that contain NO_X and non-methane hydrocarbons in excess of 4.0 g/kW-hr.

c. For model year 2015 or later engines with a power rating of 37≤kW<56, the Permittee shall not cause or allow to be discharged into the atmosphere any gases that contain NO_X and non-methane hydrocarbons in excess of 4.7 g/kW-hr..

3. Carbon Monoxide

[40 CFR 60.4204(a), 40 CFR 60.4204(b), 40 CFR 60.4201(a), 40 CFR 1039.101 and 102]

The Permittee shall not cause or allow to be discharged into the atmosphere any gases which contain carbon monoxide in excess of 5.0 g/kW-hr.

4. Particulate Matter

[40 CFR 60.4204(b), 40 CFR 60.4201(a), 40 CFR 1039.101 and 102]

a. For engines with a power rating of 37≤kW<56, the Permittee shall not cause or allow to be discharged into the atmosphere any gases that contain particulate matter in excess of 0.03 g/kW-hr.

b. For engines with a power rating of 56≤kW<130, the Permittee shall not cause or allow to be discharged into the atmosphere any gases that contain particulate matter in excess of 0.03 g/kW-hr.

E. Air Pollution Control Requirements

If the engine is equipped with a diesel particulate filter, the Permittee shall install, operate and maintain *the particulate filter in accordance with good air pollution control practices for minimizing emissions*.

[A.A.C. R18-2-306.01 and -331.a.3.d and e]
[Material permit conditions are indicated by underline and italics]

F. Compliance Requirements

1. The Permittee shall only use a certified engine. The Permittee shall install and configure the engine to the manufacturer's specifications.

[40 CFR 60.4211(c)]

2. The Permittee shall maintain a copy of engine certifications or other documentation demonstrating that each engine complies with the applicable standards in this Permit, and shall make the documentation available to ADEQ upon request.

[A.A.C. R18-2-306.A.4]

3. If the Permittee does not install, configure, operate, and maintain the engine and control device according to the manufacturer's emission-related written instructions, or changes emission-related settings in a way that is not permitted by the manufacturer, the Permittee shall keep a maintenance plan and records of conducted maintenance to demonstrate compliance and shall, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if the Permittee does not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or changes the emission-related settings in a way that is not permitted by the manufacturer, the Permittee shall conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

[40 CFR 60.4211(g)(1)]

G. Monitoring and Recordkeeping Requirements

1. *If the engine is equipped with a diesel particulate filter to comply with the particulate emission standards, the Permittee shall install a backpressure monitor that notifies the Permittee when the high backpressure limit of the engine is approached*.

[40 CFR 60.4209(b) and A.A.C. R18-2-331.a.3.c]
[Material permit conditions are indicated by underline and italics]

2. If the engine is equipped with a diesel particulate filter, the Permittee shall keep records of any corrective action taken after the backpressure monitor has notified the Permittee that the high backpressure limit of the engine is approached.

[40 CFR 60.4214(c)]

H. Permit Shield

Compliance with the terms of this Section shall be deemed compliance with 40 CFR 60.4201(a), 60.4204(a) and (b), 60.4206, 60.4207(b), 60.4209(b), 60.4211(a) and (c), 60.4211(g)(1) and 60.4214(c).

[A.A.C. R18-2-325]

XI. GASOLINE STORAGE TANK

A. Applicability

This Section applies to the 8,000 gallon gasoline storage tank.

B. Operating Limitations

1. Gasoline storage tank shall be equipped with a submerged filling device or acceptable equivalent, for control of hydrocarbon emissions.

   [A.A.C. R18-2-710.B]

2. All pumps and compressors that handle gasoline shall be equipped with mechanical seals or other equipment of equal efficiency to prevent release of organic contaminants into the atmosphere.

   [A.A.C. R18-2-710.D]

C. Monitoring and Recordkeeping Requirements

[A.A.C. R18-2-710.E]

The Permittee shall maintain a storage tank log showing the following:

1. The Permittee shall maintain a file of each type of petroleum liquid stored, the typical Reid vapor pressure of the petroleum liquid stored and the dates of storage. Dates on which the storage vessel is empty shall be shown.

2. The Permittee shall determine and record the average monthly storage temperature and true vapor pressure of the petroleum liquid stored at such temperature if either:

   a. The petroleum liquid has a true vapor pressure, as stored, greater than 26 mm Hg (0.5 psia) but less than 78 mm Hg (1.5 psia) and is stored in a storage vessel other than one equipped with a floating roof, a vapor recovery system or their equivalents; or

   b. The petroleum liquid has a true vapor pressure, as stored, greater than 470 mm Hg (9.1 psia) and is stored in a storage vessel other than one equipped with a vapor recovery system or its equivalent.

3. The average monthly storage temperature shall be an arithmetic average calculated for each calendar month, or portion thereof, if storage is for less than a month, from bulk liquid storage temperatures determined at least once every seven days.

4. The true vapor pressure shall be determined by the procedures in American Petroleum Institute Bulletin 2517, amended as of February 1980 (and no future editions), which is incorporated herein by reference and on file with the Office of the Secretary of State. This procedure is dependent upon determination of the

storage temperature and the Reid vapor pressure, which requires sampling of the petroleum liquids in the storage vessels. Unless the Director requires in specific cases that the stored petroleum liquid be sampled, the true vapor pressure may be determined by using the average monthly storage temperature and the typical Reid vapor pressure. For those liquids for which certified specifications limiting the Reid vapor pressure exist, the Reid vapor pressure may be used. For other liquids, supporting analytical data must be made available upon request to the Director when typical Reid vapor pressure is used.

D. Permit Shield

Compliance with the terms of this Section shall be deemed compliance with the A.A.C. R18-2-710.D, 710.D and 710.E.

[A.A.C. R18-2-325]

XII. DIESEL STORAGE TANKS

A. Applicability

The Section is applicable to 10,000 gallon and 20,000 gallon diesel storage tanks 10 and 12.

B. Volatile Organic Compounds (VOCs)

1. The storage tank shall be equipped with a submerged filling device or acceptable equivalent, for control of hydrocarbon emissions.

[A.A.C. R18-2-306.A.2]

2. All pumps and compressors that handle volatile organic compounds shall be equipped with mechanical seals or other equipment of equal efficiency to prevent release of organic contaminants into the atmosphere.

[A.A.C. R18-2-306.A.2]

3. Materials including solvents or other volatile compounds, and other chemicals utilized in the processes under this Section shall be processed, stored, used, and transported in such a manner and by means that they will not evaporate, leak, escape or be otherwise discharged into the ambient air so as to cause or contribute to air pollution. Where means are available to reduce effectively the contribution to air pollution from evaporation, leakage or discharge, the installation and use of such control methods, devices, or equipment shall be mandatory.

[A.A.C. R18-2-730.F]

4. Where a stack, vent or other outlet is at such a level that fumes, gas mist, odor, smoke, vapor or any combination thereof constituting air pollution is discharged to adjoining property, the Director may require the installation of abatement equipment or the alteration of such stack, vent, or other outlet by the Permittee to a degree that will adequately dilute, reduce or eliminate the discharge of air pollution to adjoining property.

[A.A.C. R18-2-730.G]

C. Permit Shield

Compliance with the terms in this Section shall be deemed compliance with A.A.C. R18-2-730.F and G.

[A.A.C. R18-2-325]

XIII. HOT WATER PRESSURE WASHER

A. Applicability

This Section applies to the hot water pressure washer identified in Attachment "C" as subject to this Section.

B. Particulate Matter and Opacity

1. Emission Limitations and Standards

   a. The opacity of any plume or effluent emanating from the emissions units subject to this Section shall not exceed 15 percent.

   [A.A.C. R18-2-724.J]

   b. The Permittee shall not cause, allow, or permit the emission of particulate matter, caused by combustion of fuel, from any fuel-burning operation in excess of the amounts calculated by the following equation:

   $E = 1.02Q^{0.769}$

   Where:

   E = the maximum allowable particulate emissions rate in pounds-mass per hour.

   Q = the heat input in million Btu per hour.

   [A.A.C. R18-2-724.C.1]

   c. For purposes of this Section, the heat input shall be the aggregate heat content of all fuels whose products of combustion pass through a stack or other outlet. The total heat input of all fuel-burning units on a plant or premises shall be used for determining the maximum allowable amount of particulate matter which may be emitted.

   [A.A.C. R18-2-724.B]

2. Monitoring, Recordkeeping, and Reporting Requirements

   The Permittee shall conduct a Visible Emissions Observation Procedure as defined in Condition I.G of this Attachment once every two weeks.

   [A.A.C R18-306.A.3.c]

C. Sulfur Dioxide (SO_2) Standards

1. Fuel Limitations

The Permittee shall not fire high sulfur diesel fuel in the hot-water pressure washer.
[A.A.C. R18-2-724.G]

2. Emission Limitations and Standards

The Permittee shall not emit more than 1.0 pounds of SO_2 per million BTU heat input.
[A.A.C. R18-2-724.E]

3. Monitoring, Recordkeeping, and Reporting Requirements

The Permittee shall keep records of fuel supplier certifications or other documentation listing the sulfur content. These records shall be made available to ADEQ upon request.
[A.A.C. R18-2-306.A.3.c]

D. Permit Shield

Compliance with the terms of this Section shall be deemed compliance with A.A.C.R18-2-724.B, 724.C.1, -724.E, -724.G, and 724.J.
[A.A.C. R18-2-325]

XIV. FUGITIVE DUST REQUIREMENTS

A. Applicability

This Section applies to any source of fugitive dust in the facility.

B. Particulate Matter and Opacity

Open Areas, Roadways & Streets, Storage Piles, and Material Handling

1. Emission Limitations/Standards

a. Opacity of emissions from any fugitive dust non-point source shall not be greater than 40% measured in accordance with the Arizona Testing Manual, Reference Method 9.
[A.A.C. R18-2-614]

b. The Permittee shall not cause, allow or permit visible emissions from any fugitive dust point source, in excess of 20% opacity.
[A.A.C. R18-2-702.B]

c. The Permittee shall employ the following reasonable precautions to prevent excessive amounts of particulate matter from becoming airborne:

(1) Keep dust and other types of air contaminants to a minimum in an open area where construction operations, repair operations, demolition activities, clearing operations, leveling operations, or

any earth moving or excavating activities are taking place, by good modern practices such as using an approved dust suppressant or adhesive soil stabilizer, paving, covering, landscaping, continuous wetting, detouring, barring access, or other acceptable means;

[A.A.C. R18-2-604.A]

(2) Keep dust to a minimum from driveways, parking areas, and vacant lots where motor vehicular activity occurs by using an approved dust suppressant, or adhesive soil stabilizer, or by paving, or by barring access to the property, or by other acceptable means;

[A.A.C. R18-2-604.B]

(3) Keep dust and other particulates to a minimum by employing dust suppressants, temporary paving, detouring, wetting down or by other reasonable means when a roadway is repaired, constructed, or reconstructed;

[A.A.C. R18-2-605.A]

(4) Take reasonable precautions, such as wetting, applying dust suppressants, or covering the load when transporting material likely to give rise to airborne dust;

[A.A.C. R18-2-605.B]

(5) Take reasonable precautions, such as the use of spray bars, wetting agents, dust suppressants, covering the load, and hoods when crushing, handling, or conveying material likely to give rise to airborne dust;

[A.A.C. R18-2-606]

(6) Take reasonable precautions such as chemical stabilization, wetting, or covering when organic or inorganic dust producing material is being stacked, piled, or otherwise stored;

[A.A.C. R18-2-607.A]

(7) Operate stacking and reclaiming machinery utilized at storage piles at all times with a minimum fall of material, or with the use of spray bars and wetting agents;

[A.A.C. R18-2-607.B]

(8) Any other method as proposed by the Permittee and approved by the Director.

[A.A.C. R18-2-306.A.3.c]

d. In conjunction with the requirements in Condition XIV.B.1.c of this Attachment, the Permittee shall also implement an approved Dust Control Plan referenced in Condition I.C of this Attachment which identifies the areas to be controlled, the methods to be utilized, and cleanup frequency.

[A.A.C. R18-2-306.A.3.c]

2. Air Pollution Control Requirements

Haul Roads and Storage Piles

Water, or an equivalent control, shall be used to control visible emissions from haul roads and storage piles.

[A.A.C. R18-2-306.A.2 and -331.A.3.d]
[Material Permit Condition is indicated by underline and italics]

3. Monitoring and Recordkeeping Requirements

a. The Permittee shall maintain records of the dates on which any of the activities listed in Conditions XIV.B.1.c(1) through XIV.B.1.c(8) above were performed and the control measures that were adopted.

[A.A.C. R18-2-306.A.3.c]

b. The Permittee shall conduct a Visible Emissions Observation Procedure, as defined in Condition I.G, once every two weeks to monitor emissions from all activities covered by this Section.

[A.A.C. R18-2-306.A.3.c]

C. Permit Shield

Compliance with the conditions of this Section shall be deemed compliance with A.A.C. R18-2-604.A, A.A.C. R18-2-604.B, A.A.C. R18-2-605, A.A.C. R18-2-606, A.A.C. R18-2-607, A.A.C. R18-2-608 and A.A.C. R18-2-612.

[A.A.C. R18-2-325]

XV. MOBILE SOURCE REQUIREMENTS

A. Applicability

The requirements of this Section are applicable to mobile sources which either move while emitting air contaminants or are frequently moved during the course of their utilization but are not classified as motor vehicles, agricultural vehicles, or agricultural equipment used in normal farm operations. Mobile sources shall not include portable sources as defined in A.A.C. R18-2-101.90.

[A.A.C. R18-2-801.A]

B. Particulate Matter and Opacity

1. Emission Limitations/Standards

a. Off-Road Machinery

The Permittee shall not cause, allow, or permit to be emitted into the atmosphere from any off-road machinery, smoke for any period greater than ten consecutive seconds, the opacity of which exceeds 40%. Visible emissions when starting cold equipment shall be exempt from this requirement for the first ten minutes. Off-road machinery shall include trucks, graders, scrapers, rollers, and other construction and mining machinery not normally driven on a completed public roadway.

[A.A.C. R18-2-802.A and -802.B]

b. Roadway and Site Cleaning Machinery

(1) The Permittee shall not cause, allow or permit to be emitted into

the atmosphere from any roadway and site cleaning machinery smoke or dust for any period greater than ten consecutive seconds, the opacity of which exceeds 40%. Visible emissions when starting cold equipment shall be exempt from this requirement for the first ten minutes.

[A.A.C. R18-2-804.A]

(2) The Permittee shall take reasonable precautions, such as the use of dust suppressants, before the cleaning of a site, roadway, or alley. Earth or other material shall be removed from paved streets onto which earth or other material has been transported by trucking or earth moving equipment, erosion by water or by other means.

[A.A.C. R18-2-804.B]

c. Unless otherwise specified, no mobile source shall emit smoke or dust the opacity of which exceeds 40%.

[A.A.C. R18-2-801.B]

2. Recordkeeping Requirement

The Permittee shall keep a record of all emissions related maintenance activities performed on the Permittee's mobile sources stationed at the facility as per manufacturer's specifications.

[A.A.C. R18-2-306.A.5.a]

3. Permit Shield

Compliance with the terms of this Section shall be deemed compliance with A.A.C. R18-2-801, A.A.C. R18-2-802.A, A.A.C. R18-2-804.A and A.A.C. R18-2-804.B.

[A.A.C. R18-2-325]

XVI. OTHER PERIODIC ACTIVITIES

A. Abrasive Blasting

1. Particulate Matter and Opacity

a. Emission Limitations/Standards

The Permittee shall not cause or allow sandblasting or other abrasive blasting without minimizing dust emissions to the atmosphere through the use of good modern practices. Good modern practices include:

(1) Wet blasting;

(2) Effective enclosures with necessary dust collecting equipment; or

(3) Any other method approved by the Director.

[A.A.C. R18-2-726]

b. Opacity

The Permittee shall not cause, allow or permit visible emissions from sandblasting or other abrasive blasting operations in excess of 20% opacity, as measured by EPA Reference Method 9.

[A.A.C. R18-2-702.B]

2. Monitoring and Recordkeeping Requirement

Each time an abrasive blasting project is conducted, the Permittee shall make a record of the following:

a. The date the project was conducted;

b. The duration of the project; and

c. Type of control measures employed.

[A.A.C. R18-2-306.A.3.c]

3. Permit Shield

Compliance with the terms on this Part shall be deemed compliance with A.A.C. R18-2-726 and A.A.C. R18-2-702.B.

[A.A.C.R18-2-325]

B. Use of Paints

1. Volatile Organic Compounds

a. Emission Limitations/Standards

While performing spray painting operations, the Permittee shall comply with the following requirements:

(1) The Permittee shall not conduct or cause to be conducted any spray painting operation without minimizing organic solvent emissions. Such operations, other than architectural coating and spot painting, shall be conducted in an enclosed area equipped with controls containing no less than 96 percent of the overspray.

[A.A.C.R18-2-727.A]

(2) The Permittee or their designated contractor shall not either:

(a) Employ, apply, evaporate, or dry any architectural coating containing photochemically reactive solvents for industrial or commercial purposes; or

(b) Thin or dilute any architectural coating with a photochemically reactive solvent.

[A.A.C.R18-2-727.B]

(3) For the purposes of Condition XVI.B.1.a(2), a photochemically reactive solvent shall be any solvent with an aggregate of more than 20 percent of its total volume composed of the chemical compounds classified in Conditions XVI.B.1.a(3)(a) through XVI.B.1.a(3)(c) below, or which exceeds any of the following

percentage composition limitations, referred to the total volume of solvent:

(a) A combination of the following types of compounds having an olefinic or cyclo-olefinic type of unsaturation-hydrocarbons, alcohols, aldehydes, esters, ethers, or ketones: 5 percent.

(b) A combination of aromatic compounds with eight or more carbon atoms to the molecule except ethylbenzene: 8 percent.

(c) A combination of ethylbenzene, ketones having branched hydrocarbon structures, trichloroethylene or toluene: 20 percent.

[A.A.C.R18-2-727.C]

(4) Whenever any organic solvent or any constituent of an organic solvent may be classified from its chemical structure into more than one of the groups of organic compounds described in Conditions XVI.B.1.a(3)(a) through XVI.B.1.a(3)(c) above, it shall be considered to be a member of the group having the least allowable percent of the total volume of solvents.

[A.A.C.R18-2-727.D]

b. Monitoring and Recordkeeping Requirements

(1) Each time a spray painting project is conducted, the Permittee shall make a record of the following:

(a) The date the project was conducted;

(b) The duration of the project;

(c) Type of control measures employed;

(d) Material Safety Data Sheets for all paints and solvents used in the project; and

(e) The amount of paint consumed during the project.

(2) Architectural coating and spot painting projects shall be exempt from the recordkeeping requirements of Condition XVI.B.1.b(1) above.

[A.A.C. R18-2-306.A.3.c]

c. Permit Shield

Compliance with the terms on this Part shall be deemed compliance with A.A.C.R18-2-727.

[A.A.C.R18-2-325]

2. Opacity

a. Emission Limitation/Standard

The Permittee shall not cause, allow or permit visible emissions from painting operations in excess of 20% opacity, as measured by EPA Reference Method 9.

[A.A.C. R18-2-702.B]

b. Permit Shield

Compliance with the conditions of this Part shall be deemed compliance with A.A.C.R18-2-702.B.

[A.A.C. R18-2-325]

C. Demolition/Renovation - Hazardous Air Pollutants

1. Emission Limitation/Standard

The Permittee shall comply with all of the requirements of 40 CFR 61 Subpart M (National Emissions Standards for Hazardous Air Pollutants - Asbestos).

[A.A.C. R18-2-1101.A.8]

2. Monitoring and Recordkeeping Requirement

The Permittee shall keep all required records in a file. The required records shall include the "NESHAP Notification for Renovation and Demolition Activities" form and all supporting documents.

[A.A.C. R18-2-306.A.3.c]

3. Permit Shield

Compliance with the terms on this Part shall be deemed compliance with A.A.C. R18-2-1101.A.12.

[A.A.C. R18-2-325]

ATTACHMENT "C": ARIZONA STATE REGIONAL HAZE IMPLEMENTATION PLAN FOR LHOIST NELSON LIME PLANT

I. STATE IMPLEMENTATION PLAN REQUIREMENTS

A. Applicability

This section applies to NOx and SO_2 emission limits for Kiln 1 and Kiln 2.

[A.A.C. R18-2-306 A.2]

B. General Requirements

1. For the purpose of this Section, Kiln operating day means a 24-hour period between 12 midnight and the following midnight during which there is operation of Kiln 1, Kiln 2, or both kilns at any time. Kiln operation means any period when any raw materials are fed into the Kiln or any period when any combustion is occurring or fuel is being fired in the Kiln.

2. *<u>The Permittee shall at all times, to the extent practicable, including periods of startup, shutdown, and malfunction,</u>* maintain and *<u>operate the kilns, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. Pollution control equipment shall be designed and capable of operating properly to minimize emissions during all expected operating conditions</u>*. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA Administrator and Arizona Department of Environmental Quality (ADEQ) Director, which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the kilns.

[A.A.C. R18-2-331.A.3.e, and 306.A.2]
[Material permit conditions are indicated by underline and italics]

3. *<u>After completion of installation of ammonia injection on Kiln 1 and Kiln 2, the Permittee shall inject sufficient ammonia to achieve compliance with the NOx emission limits in Condition I.C.1 of this section for Kiln 1 and Kiln 2 while preventing excessive ammonia emissions</u>*.

[A.A.C. R18-2-331.A.3.d and e, and 306.A.2]
[Material permit conditions are indicated by underline and italics]

C. Nitrogen Oxides (NOx)

1. Emission Limitations

   a. The Permittee shall not emit or cause to be emitted NOx emissions in excess of 3.80 pounds per ton of lime product (lb/ton) from Kiln 1 and 2.61 lb/ton of lime product from Kiln 2. Each emission limit shall be based on a 12-month rolling basis.

   b. The Permittee shall not emit or cause to be emitted NOx emissions in excess of 3.27 tons per day, combined from both kilns, based on a rolling 30-kiln-operating-day basis.

2. Monitoring Requirements

a. *At all times, the Permittee shall install, calibrate*, maintain, and operate *CEMS on Kilns 1 and 2 in full compliance with the requirements found at 40 CFR 60.13 and 40 CFR Part 60, appendices B and F, to accurately measure diluent, stack gas volumetric flow rate, and concentration by volume of NO_X emissions into the atmosphere from kilns 1 and 2*.

[A.A.C. R18-2-331.A.3.c]

[Material permit conditions are indicated by underline and italics]

b. The CEMS shall be used by the Permittee to determine compliance with the emission limitations in Condition I.C.1 of this Section, in combination with data on actual lime production.

c. The Permittee shall operate the monitoring system and collect data at all required intervals at all times that an affected kiln is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments).

3. Compliance Requirements

a. The Permittee shall demonstrate compliance with the NO_X emission limits in Condition I.C.1.a of this section by calculating the 12-month rolling NOx emission rate for each kiln within 30 days following the end of each calendar month in accordance with the procedure below:

(1) Step One. Sum the hourly pounds of NOx emitted for the month just completed and the 11 months preceding the month just completed to calculate the total pounds of NOx emitted over the most recent 12-month period for that kiln.

(2) Step Two. Sum the total lime product, in tons, produced during the month just completed and the 11 months preceding the month just completed to calculate the total lime product produced over the most recent 12-month period for that kiln.

(3) Step Three. Divide the total pounds of NOx calculated from Step One by the total tons of lime product calculated from Step Two to calculate the 12-month rolling NOx emission rate in lb/ton lime for that kiln.

For each 12-month rolling NOx emission rate, the Permittee shall include all emissions and all lime product that occurred during all periods within the 12-month period, including emissions from startups, shutdowns, and malfunctions.

b. The Permittee shall demonstrate compliance with the NO_X emission limit described in Condition I.C.1.b of this section of this section shall be determined based on a rolling 30-kiln-operating-day basis as per the following procedure:

(1) Step One. Sum the hourly pounds of NOx emitted from both kilns for the current kiln-operating-day and the preceding 29 kiln-

operating-day period for both kilns.

(2) Step Two. Divide the total pounds of NOx calculated from Step One by 2000 to calculate the total tons of NOx emitted over the most recent 30-kiln-operating-day period.

(3) Step three. Divide the total tons of NOx calculated from Step Two by 30 to calculate the rolling 30-kilnoperating-day NOx emission rate for both kilns.

For each rolling 30-kiln-operating-day NOx emission rate, the Permittee shall include all emissions from both kilns during all periods within any kiln-operating-day, including emissions from startups, shutdowns, and malfunctions.

D. Sulfur Dioxide (SO_2)

1. Emission Limitations

a. The Permittee shall not emit or cause to be emitted SO_2 emissions in excess of 9.32 pounds per ton of lime product (lb/ton) from Kiln 1 and 9.73 lb/ton from Kiln 2. Each emission limit shall be based on a 12-month rolling basis.

b. The Permittee shall not emit or cause to be emitted SO_2 emissions in excess of 10.10 tons per day, combined from both kilns, based on a rolling 30-kiln-operating-day basis.

2. Air Pollution Control Requirements

<u>*The Permittee shall inject dry lime to kilns 1 and 2 as needed to comply with the SO_2 emission limitations in Condition I.D.1*</u>.

[A.A.C. R18-2-331.A.3.e]
[Material permit conditions are indicated by underline and italics]

3. Monitoring Requirements

a. <u>*At all times*</u>, <u>*the Permittee shall install, calibrate*</u>, maintain, and operate <u>*CEMS on Kilns 1 and 2 in full compliance with the requirements found at 40 CFR 60.13 and 40 CFR part 60, appendices B and F, to accurately measure diluent, stack gas volumetric flow rate, and concentration by volume of SO_2 emissions into the atmosphere from kilns 1 and 2*</u>.

[A.A.C. R18-2-331.A.3.c]
[Material permit conditions are indicated by underline and italics]

b. The CEMS shall be used by the Permittee to determine compliance with the emission limitations in Condition I.D.1 of this section, in combination with data on actual lime production.

c. The Permittee shall operate the monitoring system and collect data at all required intervals at all times that an affected kiln is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments).

4. Compliance Requirements

a. Compliance with the SO_2 emission limits described in Condition I.D.1.a of this section shall be determined based on a rolling 12-month basis. The Permittee shall calculate the 12-month rolling SO_2 emission rate for each kiln within 30 days following the end of each calendar month in accordance with the procedure below:

(1) Step One. Sum the hourly pounds of SO_2 emitted for the month just completed and the 11 months preceding the month just completed to calculate the total pounds of SO_2 emitted over the most recent 12-month period for that kiln.

(2) Step Two. Sum the total lime product, in tons, produced during the month just completed and the 11 months preceding the month just completed to calculate the total lime product produced over the most recent 12-month period for that kiln.

(3) Step Three. Divide the total pounds of SO_2 calculated from Step One by the total tons of lime product calculated from Step Two to calculate the 12-month rolling SO_2 emission rate in lb/ton lime for that kiln.

For each 12-month rolling SO_2 emission rate, the Permittee shall include all emissions and all lime product that occurred during all periods within the 12-month period, including emissions from startups, shutdowns, and malfunctions.

b. Compliance with the SO_2 emission limit described in Condition I.D.1.b of this section shall be determined based on a rolling 30-kiln-operating-day basis. The Permittee shall calculate the rolling 30-kiln-operating-day SO_2 emission rate for the kilns each kiln operating day in accordance with the following procedure:

(1) Step One. Sum the hourly pounds of SO_2 emitted from both kilns for the current kiln-operating-day and the preceding 29 kiln-operating-day period for both kilns.

(2) Step Two. Divide the total pounds of SO_2 calculated from Step One by 2000 to calculate the total tons of SO_2 emitted over the most recent 30-kiln-operating-day period.

(3) Step three. Divide the total tons of SO_2 calculated from Step Two by 30 to calculate the rolling 30-kilnoperating-day SO_2 emission rate for both kilns.

For each 30-kiln-operating-day SO_2 emission rate, the Permittee shall include all emissions from both kilns during all periods within any kiln-operating-day, including emissions from startups, shutdowns, and malfunctions.

E. Ammonia Consumption Monitoring Requirement

Upon and after the completion of installation of ammonia injection on kilns, the Permittee shall install, and thereafter maintain and operate, instrumentation to continuously monitor and record levels of ammonia consumption for each kiln.

F. Recordkeeping Requirements

1. The Permittee shall maintain the following records for at least five years:

   a. All CEMS data, including the date, place, and time of sampling or measurement; parameters sampled or measured; and results.

   b. All records of lime production.

   c. Monthly rolling 12-month emission rates of NO_X and SO_2 calculated in accordance with Conditions I.C.3.a and I.D.4.a of this section

   d. Daily rolling 30-kiln-operating-day emission rates of NO_X and SO_2 accordance with Conditions I.C.3.b and I.D.4.b of this section

   e. Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records specified by 40 CFR part 60, Appendix F, Procedure 1, as well as the following:

      (1) The occurrence and duration of any startup, shutdown, or malfunction, performance testing, evaluations, calibrations, checks, adjustments maintenance, duration of any periods during which a CEMS or COMS is inoperative, and corresponding emission measurements.

      (2) Date, place, and time of measurement or monitoring equipment maintenance activity;

      (3) Operating conditions at the time of measurement or monitoring equipment maintenance activity;

      (4) Date, place, name of company or entity that performed the measurement or monitoring equipment maintenance activity and the methods used; and

      (5) Results of the measurement or monitoring equipment maintenance.

   f. Records of ammonia consumption as recorded by the instrumentation required in Condition I.E of this section

   g. Records of all major maintenance activities conducted on emission units, air pollution control equipment, CEMS, and lime production measurement devices.

h. All other records specified by 40 CFR part 60, Appendix F, Procedure 1.

G. Reporting Requirements

1. The Permittee shall submit any data that are required under this section in Excel format. The reports required under Conditions I.G.1.a through f of this section shall be submitted at least semiannually thereafter, within 30 days after the end of a semiannual period. The Permittee may submit reports more frequently than semiannually for the purposes of synchronizing reports required under this section with other reporting requirements, such as the Title V monitoring report required by 40 CFR 70.6(a)(3)(iii)(A), but at no point shall the duration of a semiannual period exceed six months.

   a. The Permittee shall submit a report that lists the daily rolling 30-kiln-operating-day emission rates for NOx and SO_2, calculated in accordance with Conditions I.C.3.a and I.D.4.a respectively of this section.

   b. The Permittee shall submit a report that lists the monthly rolling 12-month emission rates for NOx and SO_2, calculated in accordance with Conditions I.C.3.b and I.D.4.b respectively of this section.

   c. The Permittee shall submit excess emissions reports for NOx and SO_2 limits. Excess emissions means emissions that exceed any of the emissions limits specified in Conditions I.C.1 and I.D.1 respectively of this section. The reports shall include:

      (1) The magnitude, date(s), and duration of each period of excess emissions;

      (2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the kiln;

      (3) The nature and cause of any malfunction (if known); and

      (4) The corrective action taken or preventative measures adopted.

   d. The Permittee shall submit a summary of CEMS operation, to include:

      (1) Dates and duration of each period during which the CEMS was inoperative (except for zero and span adjustments and calibration checks),

      (2) Reason(s) why the CEMS was inoperative and steps taken to prevent recurrence, and

      (3) Any CEMS repairs or adjustments.

   e. The Permittee shall submit results of all CEMS performance tests required by 40 CFR Part 60, Appendix F, Procedure 1 (Relative Accuracy Test Audits, Relative Accuracy Audits, and Cylinder Gas Audits).

   f. When no excess emissions have occurred or the CEMS has not been inoperative, repaired, or adjusted during the reporting period, the owner/operator shall state such information in the semiannual report.

2. The Permittee shall submit all reports to the Director, Enforcement Division, U.S. Environmental Protection Agency, Region 9, electronically via email to aeo_r9@epa.gov.

ATTACHMENT "D": EQUIPMENT LIST

Equipment	Rated Capacity (tons/hour or indicated units)	Make	Model/Serial No.	Date of Manufacture	Applicable Section
Crushing and Screening Equipment					
Dump Hopper	1,400	NA	NA	NA	Section II
Apron Feeder 102	1,400	NA	NA	NA	Section II
Cleanup Belt Conveyor 102B	1,400	NA	NA	Pre-1983	Section II
Belt Conveyor 104	1,400	Hi-Line	42"	1973	Section II
Grizzley 102A	1,260	NA	NA	Pre-1983	Section II
Jaw Crusher 103	1260	KVS	48"x60"/554-P-73	1973	Section II
Belt Conveyor 202	1,400	Hi-Line	42"	Pre-1983	Section II
Primary Screen 108	1,400	Symons	GP-2820 / GP-8153	1999 (Like Kind Repl.)	Section II
Belt Conveyor 235	0.04	Hi-Line	24"	1976	Section II
Belt Conveyor 223	630	Hi-Line	24"	1976	Section II
Surge Bin 107	60 ton	KVS	NA	1973	Section II
Vibrating Feeder 201	1,050	Syntron	RF-120	1973	Section II
Belt Conveyor 202	1,050	Hi-Line	42"	Pre-1983	Section II
Vibrating Screen 203	1,260	Tyler	F-900, 6"x16"	1973	Section II
Chat Silo 210	500 ton	KVS	NA	1973	Section II
Belt Conveyor 208	1,120	Hi-Line	24"	1973	Section II
Belt Conveyor 222	300	Hi-Line	24"	1976	Section II
Cone Crusher 206	465	Symons	5 ½" 5947	1981	Section II
Belt Conveyor 204	1,400	Hi-Line	30"	1973	Section II
Belt Conveyor 207	1,050	Hi-Line	30"	1973	Section II
Vibrating Screen 205	1,050	Tyler	F-900, 6"x16"	1973	Section II
Belt Conveyor 215	1,400	Hi-Line	42"	1976	Section II
Vibrating Feeders 216-1,2,3	1,400	Syntron	MF-200-B	Pre-1983	Section II

Equipment	Rated Capacity (tons/hour or indicated units)	Make	Model/Serial No.	Date of Manufacture	Applicable Section
Belt Conveyor 217	1,400	Hi-Line	42”	1976	Section II
Vibrating Screen 218	1,050	Tyler	F-1406-X, 6”x16”	1976	Section II
Belt Conveyor 222	300	Hi-Line	24”	1976	Section II
Belt Conveyor 209	630	Hi-Line	24”	1973	Section II
Belt Conveyor 220	910	Hi-Line	24”	1976	Section II
Cone Crusher 219	302	Symons	5803	1977	Section II
Belt Conveyor 224	910	Hi-Line	30”	1976	Section II
Belt Conveyor 202	910	Hi-Line	42”	1973	Section II
Belt Conveyor 226	630	NA	NA	1999	Section III
Portable Grizzly	25	NA	NA	Pre-1983	Section II
Dust Collector DC 234	4,853 dscfm	Pneumafil	PCFH 284	NA	Section II
Dust Collector DC 213	895 dscfm	Mikro-Pulsaire	64-S-8-20B	1973	Section II
Dust Collector DC 206-D	5108 dscfm	Industrial Accessories	120TB-BVT-225:S6	NA	Section II
Dust Collector DC 219-D	1532 dscfm	Industrial Accessories	120TB-BVT-100:S6	NA	Section II
Kiln Feed System Equipment					
Vibrating Feeders 301-1 to 301-6 (6 Feeders)	393	Syntron	RF-40 and RF-80	1976	Section II
Belt Conveyor 302	393	Hi-Line	30”	1973 (extended in 1976)	Section II
Vibrating Screen 328	393	Tyler	R-1005-CS-G	1997	Section III
Belt Conveyor 329	393	Hi-Line	24”	1973 (extended in 1976)	Section VI
Belt Conveyor 303-A	236	Hi-Line	24”	1976	Section VI
Stone Bin 1-304	800 ton	KVS	NA	1973	Section VI
Stone Bin 2-304	700 ton	KVS	NA	1976	Section VI
Solid Fuel Handling Equipment					

Equipment	Rated Capacity (tons/hour or indicated units)	Make	Model/Serial No.	Date of Manufacture	Applicable Section
Solid Fuel Hopper	220	KVS	NA	1973	Section IV
Track Hopper	220	KVS	NA	1973	Section IV
Feeder 504A	220	Syntron	FH-24-D-HP	2017	Section V
Feeders 504B	220	Syntron	FH-24-D-HP	2017	Section V
Crusher 505	220	McLanahan	36” x 18”/1400-73	1973	Section IV
Weigh Belt 504C	220	NA	NA	2001	Section V
Bucket Elevator 521	220	Rex	1618-05M	1973	Section IV
Belt Conveyor 514	220	Hi-Line	24”	1973 (extended 1976)	Section IV
Roll Crusher 522	220	KVS	36”x36” / 891-P-76	1973	Section IV
Belt Conveyor 516	220	KVS	24”	1976	Section V
Fuel Bin 2-517	650 ton	KVS	NA	1976	Section V
Fuel Bin 1-508	500 ton	KVS	NA	1973	Section IV
Weigh Feeder 1-601	14	Ramsey	10-301	1973	Section IV
Screw Conveyor 1-613	14	Thomas Conveyor	12” x 32.4’	2009	Section V
Ball Mill 1-602	28	KVS	9’x12’6”	1973	Section IV
Classifier 1-604	28	Vari-Mesh	No. 6	1973	Section IV
Weigh Feeder 2-601	21	Ramsey	10-301	1976	Section V
Weigh Feeder 2-601A	21	TBD*	TBD*	2017	Section V
Weigh Feeder 1-601A	14	TBD*	TBD*	2017	Section V
Belt Conveyor 2-601B	21	TBD*	TBD*	2018	Section V
Ball Mill 2-602	42	KVS	10’x10’6”	1976	Section V
Classifier 2-604	42	Vari-Mesh	NA	1976	Section V
Dust Collector 527	4,795 dscfm	Mikro-Pulsaire	100-S-10-20	1973	Section IV
Kiln 1 and Kiln 2 System Equipment					
Kiln 1	39.38	KVS	15’dia x 155’	1973	Sections VI and XIV

Equipment	Rated Capacity (tons/hour or indicated units)	Make	Model/Serial No.	Date of Manufacture	Applicable Section
Kiln 1 Multicyclone 1-319	200,000 acfm	Research Cottrell	CY-119	1973	Section VI
Kiln 1 Baghouse BGH1	82,612 dscfm	BoldEco	FBCL-14-2-18-16-10	2006	Section VI
Kiln 2	58.96	KVS	17'diax178.5'	1976	Sections VI and XIV
Kiln 2 Multicyclone 2-319	200,000 acfm	Cyclo-Trell	Type C-24 / 41-311738	1976	Section VI
Kiln 2 Baghouse BGH2	109431 dscfm	Amerex RexPulse	10RP-14-324D6	1998	Section VI
Contact Cooler 1-310	39.38	Ferenco	Knimes	1995	Section VI
Contact Cooler 2-310	58.96	KVS	20' dia.	1976	Section VI
Pneumatic Dry Lime Injection System	2000 pounds/hour	Lhoist	Injection Trailer	TBD	Section XIV
Kiln 1 and Kiln 2 Dust Handling					
Screw Conveyor 1-316E	12	Bold-Eco	10"	2006	Section VII
Screw Conveyor 1-316D	12	Bold-Eco	10"	2006	Section VII
Screw Conveyor 1-316C	24	Bold-Eco	12"	2006	Section VII
Screw Conveyor 1-316B	24	Bold-Eco	12"	2006	Section VII
Screw Conveyor 1-316A	24	Ft Worth Steel	12"	1973	Section VII
Screw Conveyor 1-318/1-316	24	Ft Worth Steel	12"	1973	Section VII
Bin Elevator 1-317	24	Rexnord	1110-01	1973	Section VII
Dust Bin 1-318	50 ton	KVS	NA	1973	Section VII
Screw Conveyor 2-316	24	Ft Worth Steel	9"	1976	Section VII
Dust Collector DC 1-321	1,324 dscfm	Mikro-Pulsaire	36S-8-30	1973	Section VII
Screw Conveyor 2-316G	36	NA	NA	1998	Section VII
Screw Conveyor 2-316F	36	NA	NA	1998	Section VII
Screw Conveyor 2-316E	36	NA	NA	1998	Section VII
Screw Conveyor 2-316D	36	NA	NA	1998	Section VII
Screw Conveyor 2-316C	36	Ft. Worth Steel	16"	1976	Section VII

Equipment	Rated Capacity (tons/hour or indicated units)	Make	Model/Serial No.	Date of Manufacture	Applicable Section
Screw Conveyor 2-316A	36	Ft. Worth Steel	9”	1976	Section VII
Screw Conveyor 2-316B	36	Ft. Worth Steel	12”	1976	Section VII
Screw Conveyor 2-316C	36	Ft. Worth Steel	16”	1976	Section VII
Bin Elevator 2-317	36	Rexnord	1112-01	1976	Section VII
Dust Bin 2-318	150 ton	KVS	NA	1976	Section VII
Dust Collector DC 2-321	2,331 dscfm	Mikro-Pulsaire	64S-8-20B	1976	Section VII
Screw Conveyor 461	36	Mesco Conveying Corp	UT 40-40-08	1994	Section VII
Front Lime Handling System					
Vibrating Feeders 340A, B, C, D	39.38	NA	NA	1995	Section VII
Apron Conveyor 420	39.38	Rexnord	24”	1976	Section VII
Vibrating Feeder 2-311	58.96	KVS	60”	1976	Section VII
Apron Conveyor 420	58.96	Rexnord	24”	1976	Section VII
Dust Collector DC 762-1	3,464 dscfm	Pneumafil	PKE-24	NA	Section VII
Apron Conveyor 421	98	Rexnord	42”	1976	Section VII
Apron Conveyor 421	0.0004	Rexnord	42”	1976	Section VII
Dust Collector DC 419-5	925 dscfm	Mikro-Pulsaire	16S-8-30	NA	Section VII
Bucket Elevator 423	98	Rexnord	1100 Series	1976	Section VII
Bucket Elevator 424-1	98	Rexnord	1100 Series	1976	Section VII
Bucket Elevator 424-2	98	Rexnord	1100 Series	1976	Section VII
Screen 432	197	Tyler	5”x14” 3S R-1406X/50-2685	1976	Section VII
Undersize Lime Hopper	10	NA	NA	1999	Section VII
Screw Conveyor 430-A	0.006	NA	NA	NA	Section VII
Screw Conveyor 428	36	Purvis Bearing	20”	1999	Section VII
Dust Collector DC 430	6,568 dscfm	Mikro-Pulsaire	196S-10-TRH	1976	Section VII
Screw Conveyor 428	10	Purvis Bearing	20”	1999	Section VII

Equipment	Rated Capacity (tons/hour or indicated units)	Make	Model/Serial No.	Date of Manufacture	Applicable Section
Bucket Elevator 424-C	10	Rexnord	1100 Series	1999	Section VII
Screw Conveyor 427	10	Ft. Worth Steel	24”	1976	Section VII
Product Silo 3A (428-3)	3,300 ton capacity	KVS	45’ dia.	1976	Section VII
Dust Collector DC 437G	200 acfm	Baghouse	9S-BV-05P	TBD*	Section VII
Hammer mill 422	98	NA	NA	1999	Section VII
Screw Conveyor 413	98	Ft. Worth Steel	16”	1973	Section VII
Bucket Elevator 423	98	Rexnord	1100 Series	NA	Section VII
Screw Conveyor 425	98	Ft. Worth Steel	24”	1976	Section VII
Screw Conveyors 426	98	Ft. Worth Steel	24”	1976	Section VII
Product Silo 1A (428-1)	3,300 ton capacity	KVS	45’ dia	1976	Section VII
Product Silo 2A(428-2)	3,300 ton capacity	KVS	45’ dia	1976	Section VII
Dust Collector DC 437B	925 dscfm	Mikro-Pulsaire	25S-8-30	1976	Section VII
Vibrating Feeder 443-1	167	FMC	Syntron RF-80 30” x 54”	1976	Section VII
Vibrating Feeder 443-2	167	FMC	Syntron MF-200-B 48” x 84”	1976	Section VII
Vibrating Feeder 443-3	167	FMC	Syntron MF-200-B 48” x 84”	1976	Section VII
Belt Conveyor 435	167	Hi-Line	42”	1976	Section VII
Vibrating Feeder 433-1	83	FMC	Syntron RF-80 30” x 54”	1976	Section VII
Vibrating Feeder 433-2	83	FMC	Syntron RF-80 30” x 54”	1976	Section VII
Vibrating Feeder 433-3	83	FMC	Syntron RF-80 30” x 54”	1976	Section VII
Belt Conveyor 434	83	Hi-Line	30”	1976	Section VII
Screw Conveyor 441	10	NA	NA	NA	Section VII
Screw Conveyor 470	10	Purvis Bearing	9”	1999	Section VII
Screw Conveyor 471	10	Purvis Bearing	9”	1999	Section VII
Bucket Elevator 423	10	Rexnord	1100 Series	NA	Section VII

Equipment	Rated Capacity (tons/hour or indicated units)	Make	Model/Serial No.	Date of Manufacture	Applicable Section
Screw Conveyor 444	25	NA	NA	NA	Section VII
Belt Conveyor 434	25	Hi-Line	30”	1976	Section VII
Dust Recovery Bin BN 464	16 ton	Silotek	NA	1994	Section VII
Screw Conveyor 465	36	NA	9”	1994	Section VII
Screw Conveyor 466	36	NA	9”	1994	Section VII
Belt Conveyor 434	36	Hi-Line	30”	1976	Section VII
Belt Conveyor 435	36	Hi-Line	42”	1976	Section VII
Dust Collector DC 452	1,122 dscfm	Pneumafil	PCFH 8BV	1994	Section VII
Dust Collector DC 437A	809 dscfm	Mikro-Pulsaire	25S-8-30	1976	Section VII
Dust Collector DC 437C	809 dscfm	Mikro-Pulsaire	36S-10-30	1976	Section VII
Dust Collector DC 437D	1,858 dscfm	Mikro-Pulsaire	49S-8-20	NA	Section VII
Dust Collector DC 437E	1,858 dscfm	Mikro-Pulsaire	49S-8-20	NA	Section VII
Dust Collector DC 437F	1,858 dscfm	Mikro-Pulsaire	49S-8-20	NA	Section VII
Dolo QL Silo	60 tons	DSS	WAM 400 PJ	2012	Section VII
Dust Collector DC DS1	2400 cfm	DSS	550 BBL Port	2012	Section VII
Back Lime Handling System					
Belt Conveyor 401	58.96	Hi-Line	24”	1973 (extended 1976)	Section VII
Bucket Elevator 403	98	Rexnord	1612-02	1973	Section VII
Off-Load Hopper	100	NA	NA	NA	Section VII
Screw Conveyor 412	100	Ft. Worth Steel	16”	1973	Section VII
Bucket Elevator 403	100	Rexnord	1612-02	1973	Section VII
Hammer Mill 402-2	98	Williams	C-32 Slugger/14399	1992	Section VII
Bucket Elevators 406E, W	98	Rexnord	1612-01	1973	Section VII
Screw Conveyor 443	250	Conveyor Inc.	24”	1991	Section VII
Roll Crusher 444	250	McLanahan	24” x36”/903060	1991	Section VII

Equipment	Rated Capacity (tons/hour or indicated units)	Make	Model/Serial No.	Date of Manufacture	Applicable Section
Screw Conveyor 445	250	Conveyors Inc.	24”	1991	Section VII
Bucket Elevator 446	250	NA	NA	1991	Section VII
Screen 404	250	Tyler	F-600, 4’ x 12’/20423	1973	Section VII
Hammermill 405	98	Williams	340R/15562	1998	Section VII
Screw Conveyor 447	98	Conveyors, Inc.	16”	1991	Section VII
Bucket Elevator 446	98	NA	NA	1991	Section VII
Screw Conveyor 408	98	NA	NA	1994	Section VII
Screw Conveyors 408A, B, C	98	Thomas Conveyors	20”	1994	Section VII
Silos 1, 3, 4, 5	950 ton	KVS	NA	1973	Section VII
Silo 2	950 ton	KVS	NA	1973	Section VII
Belt Conveyor 402	98	NA	NA	NA	Section VII
Dust Collector DC 414	4,940 dscfm	Mikro-Pulsaire	1F-2-48	1973	Section VII
Screw Conveyor 414-2	0.23	NA	NA	NA	Section VII
Filling Supersacks	2	NA	NA	NA	Section VII
Hydrator System					
Screw Conveyor 701	15	NA	NA	1988	Section VIII
Screw Conveyor 702	15	NA	NA	1988	Section VIII
Quicklime Feed Surge Bin 703	15	3 Tons	NA	1988	Section VIII
Belt Conveyor 704	15	Ramsey	Belt Scale System/ Scale 10-101R1/Integrator 2001	1988	Section VIII
Screw Conveyor 707	15	NA	NA	1988	Section VIII
Pug Mill 708	15	Ehrsam	Twin Paddle	1988	Section VIII
Seasoning Chamber 710	15	18’ x 8’ Diameters	NA	1988	Section VIII
Ducon Slaker Scrubber DF 711	3,909 dscfm	Ducon Wet Scrubber	UW-4(48)	1988	Section VIII
Screw Conveyor 712	16	NA	NA	1999	Section VIII

Equipment	**Rated Capacity (tons/hour or indicated units)**	**Make**	**Model/Serial No.**	**Date of Manufacture**	**Applicable Section**
Bucket Elevator 719	31	NA	NA	1999	Section VIII
Air Separator 715	31	Sturtevant	Whirlwind 12"/3086	1999	Section VIII
Screw Conveyor 718	16	NA	NA	1999	Section VIII
Dust Collector DC 721	6,192 dscfm	American Air Filter	Millenium	1999	Section VIII
Bucket Elevator 713	31	NA	NA	1988	Section VIII
Hammermill 717	16	Williams	Meteor Mill, Size 18	1999	Section VIII
Hydrated Lime Silo 6	31	KVS	950 Ton Bin/#409-6	1973	Section VIII
Dust Collector 750A	2,000 dscfm	Industrial Accessories	108TB-BHI-36-S6	NA	Section VIII
Pneumatic Dust Collector DC-SC1	NA	TBD*	TBD*	TBD*	Section VIII
Screw Conveyor 750	31	NA	NA	NA	Section VIII
Diesel Generators/Engines					
Canyon Well Generator	<125 kW	Generac	361PSL1647/ 4045HFG92D	2013	Section X
Detroit Diesel Emergency Fire Pump Engine	140 hp	Detroit Diesel	5043-7001/4D-104282	1975	Section IX
Kiln 1 Pony Motor	80 hp	Cummins	4B3.9C/44641085	1991	Section IX
Kiln 2 Pony Motor	80 hp	Cummins	4B3.9C/46178244	2002	Section IX
Hot Water Pressure Washer	768,000 btu	Hotsey	5730SS/PW16	2012	Section XIII
Gasoline Storage Tank #11	8,000 gallons	NA	NA	NA	Section XI
Diesel Storage Tank #12	20,000 gallons	NA	NA	NA	Section XII
Diesel Storage Tank #10	10,000 gallons	NA	NA	NA	Section XII

*TBD – To Be Determined

USDA United States Department of Agriculture
Forest Service
Rocky Mountain Region
1617 Cole Boulevard
Building 17
Lakewood, CO 80401-3305
303-275-5350
Fax: 303-275-5366

File Code: 2580
Date: November 18, 2021

Mr. Hunter Roberts
Department Secretary
South Dakota Department of Agriculture and Natural Resources
523 E Capitol Avenue
Pierre, SD 57501-3182

Dear Mr. Roberts:

On September 15, 2021, the State of South Dakota 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 that the USDA'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 only the 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.

Overall, the Forest Service finds the draft SIP is well organized and comprehensive. We wish to thank the South Dakota DANR for their recognition of the importance of the role of prescribed fire to help reduce catastrophic wildfire and the utilization of the prescribed fire adjustment represented in the 2028OTBa2 modeling results. Additionally, we encourage the DANR to use the WRAP FFS2 modeling results to construct the prescribed fire 2064 endpoint adjustment. The data and visibility effects are included in our attachments and provide the basis for an endpoint adjustment which reflects the increasing use of prescribed fire since the baseline emissions inventory of 2014 to the present (2028OTBa2 inventory). The data and visibility impacts more accurately reflect the planning and investment by the Forest Service and the federal and state wildland management community in the use of prescribed fire to address wildfire risk.

We have provided detailed technical comments in enclosures A and B.

We look forward to your response as required by 40 C.F.R. § 51.308(i)(3). For further information, please contact Jeff Sorkin jeffrey.sorkin@usda.gov or Bret Anderson bret.a.anderson@usda.gov.

Again, we appreciate the opportunity to work closely with the State of South Dakota. The Forest Service compliments you on your hard work and dedication to significant improvement in our nation's air quality values and visibility.

Sincerely,

FRANK R. BEUM
Regional Forester

Enclosures

cc: Jeff Sorkin, Bret Anderson, Rick Truex, Brian Keating

Attachment A

USDA Forest Service (USFS) Technical Comments on South Dakota Department of Agriculture and Natural Resources (DANR) Draft Regional Haze State Implementation Plan (SIP)

The USFS recognizes the emission reductions made in South Dakota over the past decade that have resulted in improvements in visibility at Forest Service Class I Areas within the state. Further, we appreciate the strong working relationship among our respective staff.

Overall, the USFS finds that the draft SIP is well organized and comprehensive, and we look forward to evaluating continued progress in meeting the visibility goals during the 5-year progress reports.

The USFS requests South Dakota DANR consider the following issues before final adoption of the SIP.

<u>Incomplete Four Factor Analysis:</u>

The USFS believes that DANR's "four factor" analysis (40 CFR 51.308(f)(2)(i)) is incomplete and does not meet the requirements of the RHR. While DANR did evaluate several of the four statutory factors, *it did not base its final control determination on any of the same statutory factors.* Rather, the DANR based its decision not to require controls on the basis that they are already below the glidepath for this planning cycle. A State's current visibility conditions compared to the Uniform Rate of Progress cannot be considered a "safe harbor" which allows a State to forego a proper four factor analysis. The justification for not requiring controls should be confined to the aforementioned elements in (f)(2)(i) in order to properly conform to the regulatory requirements of the RHR. DANR has already addressed several of these elements in the draft SIP, and we encourage DANR to fully address the four factors and justify its control decision based on those elements.

<u>SNCR is Cost Effective and should be applied to the GCC Dacotah Cement Kilns:</u>

In comparing the status of pollution controls at GCC to those at other cement plants in
The Midwestern US, cement kilns generally have SNCR for NOx control and some type of post-combustion SO2 controls. GCC has 3 kilns. None of which have NOx or SO2 controls. By the DANR's analysis, these control technologies are cost-effective.

DANR should use the EPA control cost manual to select appropriate costs and rates. USFS recommends that site-specific four-factor analyses be completed using the current bank-prime interest rate (3.25%) and appropriate useful life for the control equipment unless a source-specific justification is provided, such as lender documentation or federally enforceable shut down date.

From Table 3.26 -- Cost of Compliance Based on Nitrogen Oxides Emissions Reduction

Control Option	Baseline Emission Level (tons)	NOx Reduction (%)	Emission Reduction (tons)	Interest Rate	Control Cost ($/year)	Cost Effectiveness ($/ton removed)
SNCR	1,394	30	331	3.50%	$564,340	$1,705
				3.00%	$547,479	$1,654

From Table 3.27 -- Cost of Compliance Based on Sulfur Dioxide Emissions Reduction

Control Option	Baseline Emission Level (tons)	SO2 Reduction (%)	Emission Reduction (tons)	Interest Rate	Control Cost ($/year)	Cost Effectiveness ($/ton removed)
Semi-Dry Scrubber	560	90%	453.6	3.50%	$2,538,572	$5,596
				3.00%	$2,473,435	$5,453
Wet Scrubber	560	90%	453.6	3.50%	$2,978,085	$6,565
				3.00%	$2,900,421	$6,394

Prescribed Fire Emissions

The USFS strongly supports DANR's adoption of the prescribed fire glideslope adjustment. While prescribed fire is currently a minor contributor to visibility impairment on the 20% most impaired days, the USFS appreciates that South Dakota DANR will continue to recognize the important ecological role of prescribed fire as stated on page 112 of the draft SIP, "*prescribed burns were designed to simulate natural conditions, and therefore will not be taken into consideration in the natural 2064 visibility goal*."

Fire plays an important role in shaping the vegetation and landscape in South Dakota 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, along with our land-management partners in the South Dakota DANR (formerly DENR), plan to significantly increase in the use of prescribed fire to accomplish these goals.

The 2017 Regional Haze Rule includes a provision to allow states to adjust the glidepath to account for prescribed fire. The draft SIP states that prescribed fire emissions were taken from the 2011 National Emissions Inventory (NEI) and were carried forward into the 2028 future year emissions without any changes. Recent data on prescribed fire activity, especially within the USFS, show that the number of acres burned in prescribed fires during 2011 were lower than all other recent years. Therefore, keeping prescribed fire emissions steady to 2028 undercounts emissions. The USFS is requesting South Dakota DANR adjust the glidepaths for prescribed fire projections as a clear acknowledgement of the shared state and federal goals of restoring fire adapted ecosystems. 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 each Class I Areas in South Dakota is below adjusted glidepaths, essentially arguing that the glidepath provides safe harbor from additional control requirements. The USFS firmly believes this "safe harbor" argument is erroneous and is not supported by the Regional Haze Rule.

Attachment B
Methodology and Data for Glidepath Adjustment

Future fire sensitivities added wildfire emissions (FFS1) or wildland 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 fire emissions originally used in the 2028OTBa2 scenario 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).

Theoretically, 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 FFS2 and 2028OTBa2 by subtracting the 2028OTBa2 results from the FFS2 results.

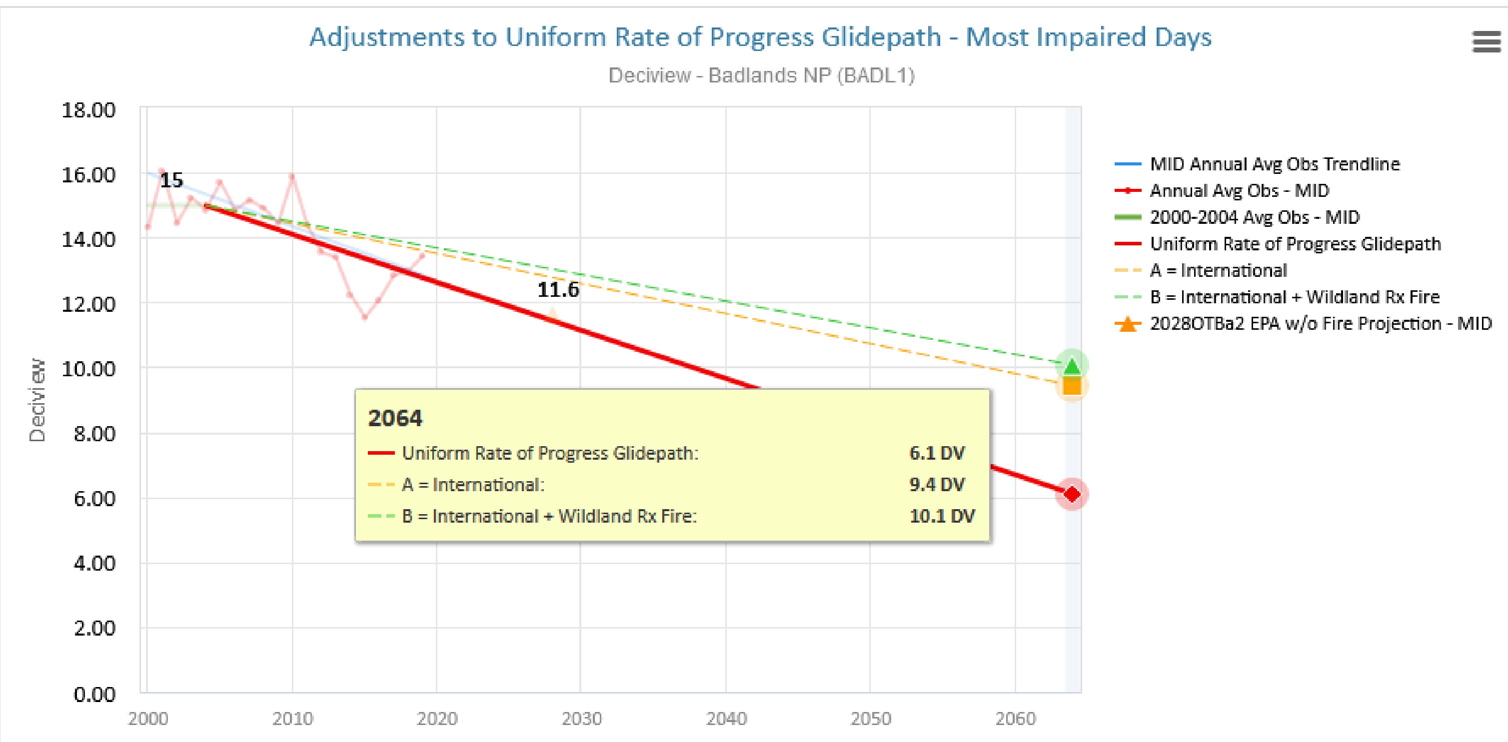


Figure 1- Example WRAP TSS Product #5, Model Express Tools

Procedures

1. Get "Default" Rx fire adjustment from Product #5, WRAP TSS, Model Express Tools ("Adjustment Options for End of URP Glidepath")

2. Subtract "End Point A – International" from "End Point B – International + Wildland Rx Fire"
    a. Example: BADL1: B = 10.1 DV, A = 9.4 DV. Rx fire component of adjustment = B – A or 10.1 – 9.4, which yields 0.7 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: BADL1: end of the URP in 2064 = 6.1 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: BADL1: 10*EXP((6.1 + 0.7)/10) – 10*EXP(6.1/10) = 1.33 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 = 21.88 Mm^{-1} (Figure 2, "A")
        ii. 2028 FFS2 results: stacked bar chart, column 4 = 23.16 Mm^{-1} (Figure 2, "B")
    b. Add Rayleigh scatter back to each value from steps 4.a.i and 4.a.ii
        i. Example: BADL1: Rayleigh = 11, so add Rayleigh back to 2028 OTBa2 and 2028 FFS2
            1. 2028 OTBa2 = 8.67; Rayleigh = 8; Total Bext = 32.88 Mm^{-1}
            2. 2028 FFS2 = 8.9; Rayleigh = 8; Total Bext = 34.16 Mm^{-1}
    c. Subtract total extinction, 2028 OTBa2 from total extinction, 2028 FFS2
        i. Example: BADL1: 34.16 Mm^{-1} (2028_{FFS2} Bext) – 32.88 Mm^{-1} (Bext 2028_{OTBa2}) = 1.3288 Mm^{-1} ($Bext_{\Delta 2028FFS2}$)
    d. Difference from 4.c.i will yield the incremental increase of 2028_{FFS2} above 2028_{OTBa2} in extinction units (Mm^{-1}).
    e. Convert the 2064 URP unadjusted endpoint into extinction units (Mm^{-1})
        i. Example: BADL1: $Bext_{2064URP} = 10*EXP(DV_{2064URP}/10)$, or 10*EXP(6.1/10)
    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: $10*LN(((Bext_{\Delta 2028FFS2}\ (Mm-1) + Bext_{2028OTBa2}) + Bext_{2064URP})/10) – DV_{2064URP}$

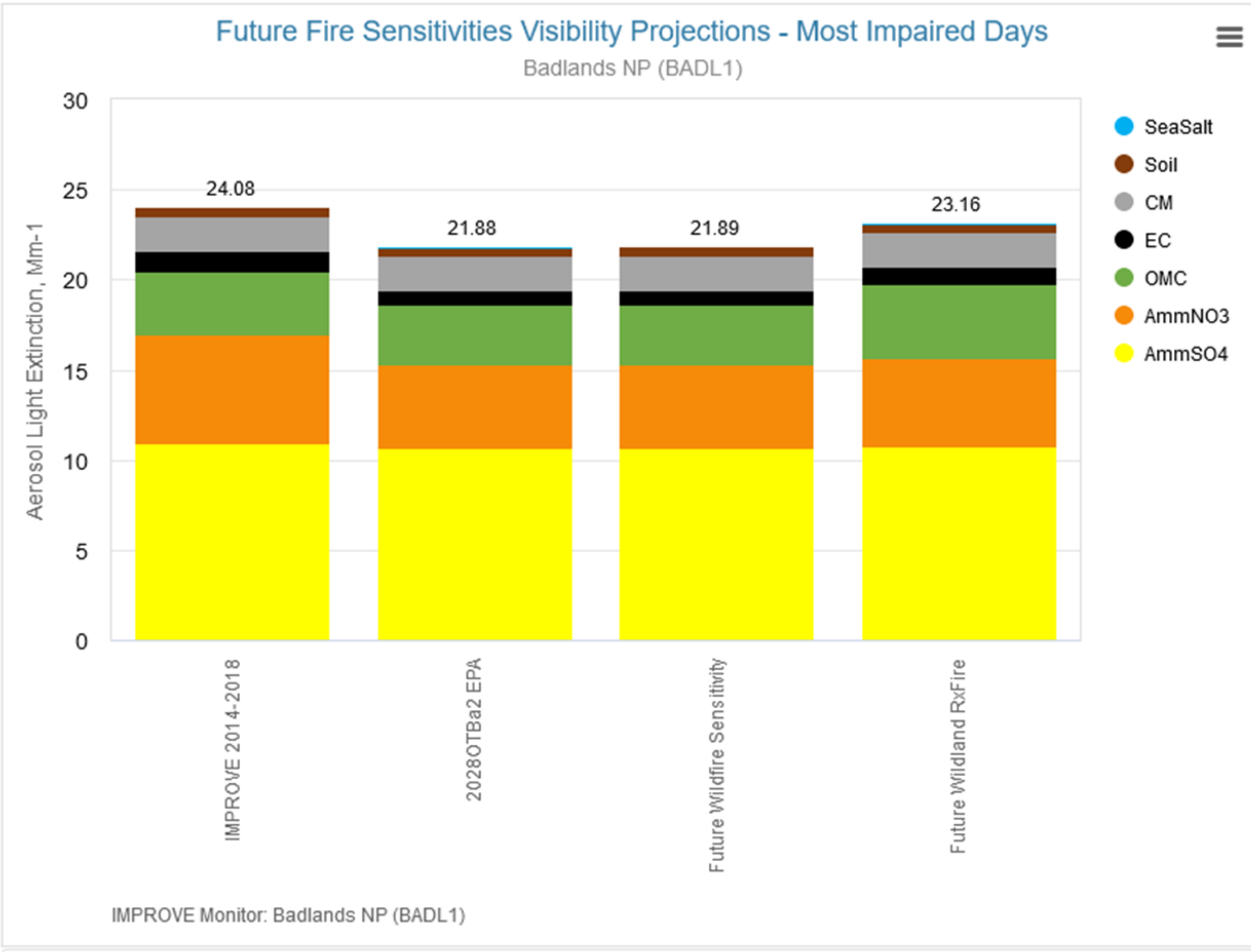
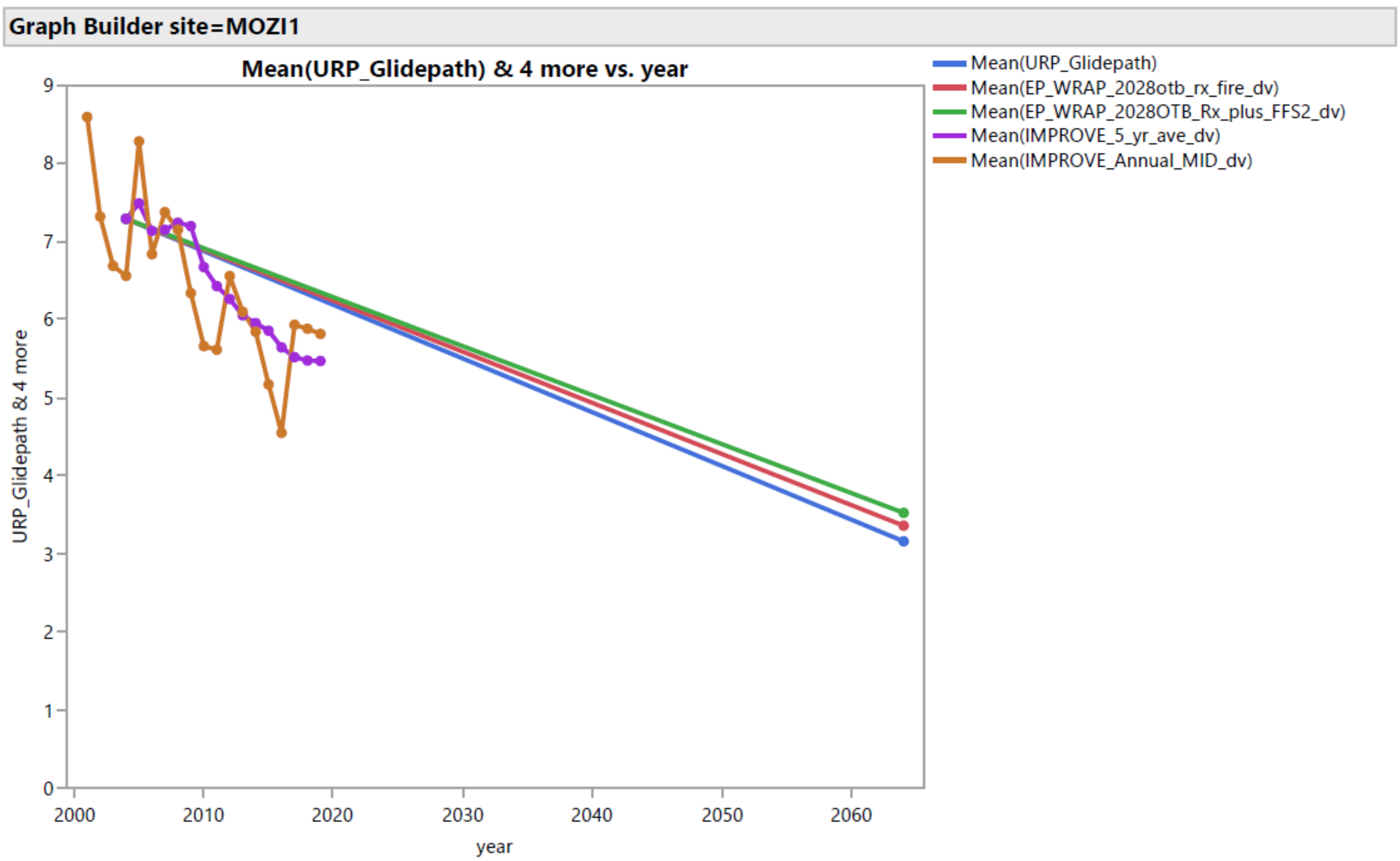


Figure 2- Future Fire Sensitivities Total Extinction - Most Impaired Days

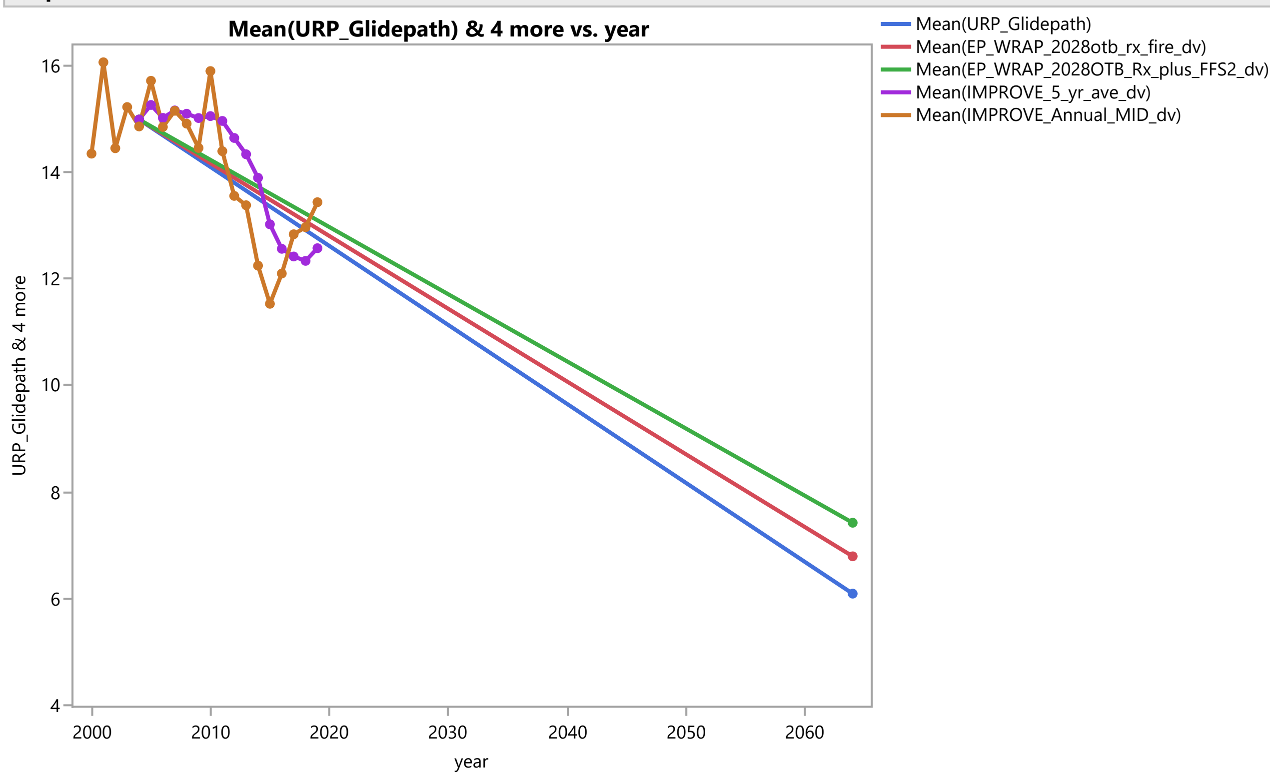
How to read the prescribed fire adjusted regional haze glide slope plots

There are five lines plotted in each figure. The blue line is the default EPA guidance[1] Uniform Rate of Progress (URP) glideslope beginning in 2004 with the baseline five-year-average Most Impaired Days (MID) in decivew and ending in 2064 with the default natural conditions or endpoint deciview. None of the plotted lines include an adjustment for international contributions to endpoint. The red line is the same as the blue line with the 2064 endpoint adjusted for the amount of prescribed fire modeled in WRAP 2028OTBa2 read from product #5 on the WRAP TSS. Similarly, the green line includes both WRAP 2028OTBa2 prescribed fire adjustment as well as the FFS2 adjustment and corresponds to the "alternative glideslope adjustment" case. The orange and purple lines are the annual and five-year-average IMPROVE MID in deciview, respectively.

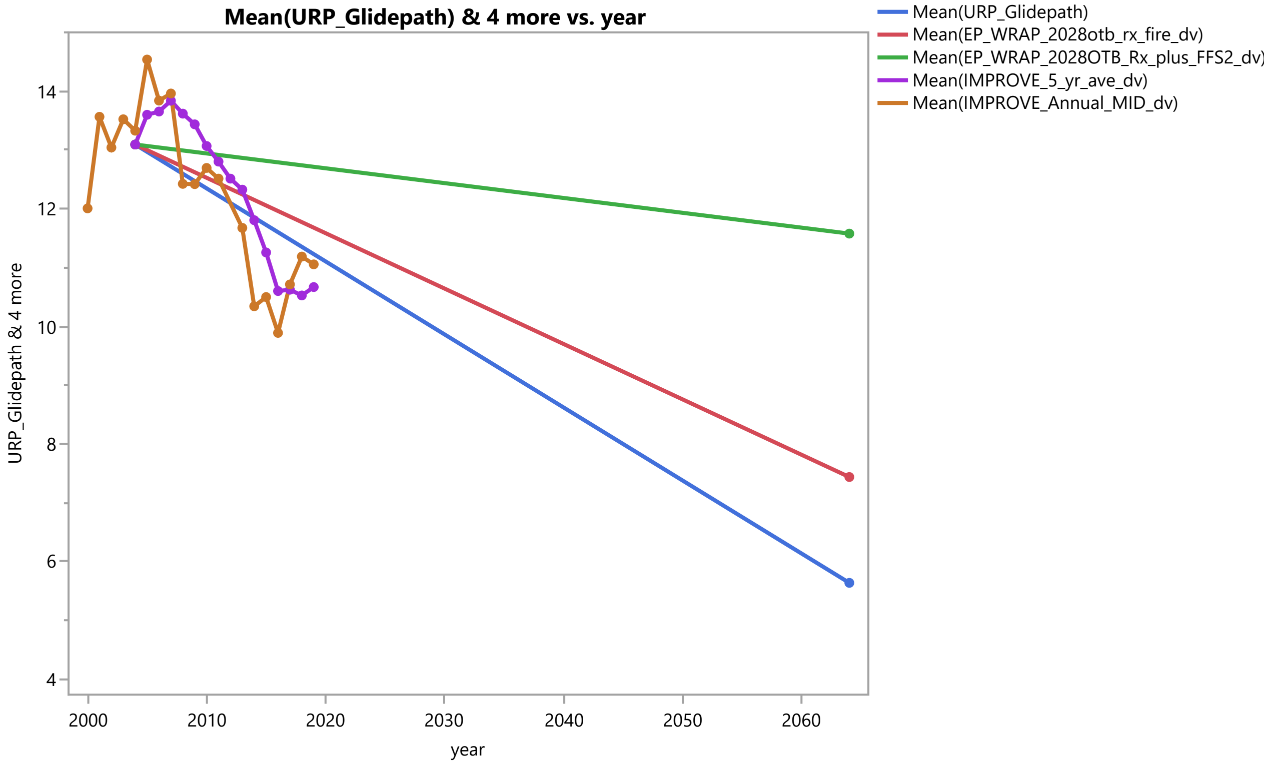


[1] *Technical Support Document (TSD) Revised Recommendations for Visibility Progress Tracking Metrics for the Regional Haze Program*, U.S. Environmental Protection Agency, May 2016

Graph Builder state_site=SD_BADL1



Graph Builder state_site=SD_WICA1



Class I Area	2064 Unadjusted dv	Rx Fire (2028 OTBa2 (dv))	2028 OTBa2 Rx Fire Mm-1
BADL1	6.09	0.7	1.33
WICA1	5.64	1.8	3.47

Class I Area	2064 Unadjusted (DV)	2064 unadjusted Mm-1	Rayleigh	2028 OTBa2 (Mm-1)	2028OTBa2 (Mm-1)	2028 FFS2 (Mm-1)	Total FFS2 (Mm-1)	FFS2 - OTBa2 (Mm-1)	Alternative Adjustment (Mm-1)	Alternative DV
BADL1	6.1	18.39	11	21.88	32.88	23.16	34.16	1.28	2.61	1.32884961
WICA1	5.4	17.57	10	17.82	27.82	28.61	38.61	10.79	14.26	5.93997764

		Rx Fire (read from product #5)	Rx Fire (Mm-1)	2064 Unadjusted (DV)	2064 unadjusted Mm-1	Rayleigh	2028 OTB Total Extintion	FFS2 Total Extinction	FFS2-2028 OTB (Mm-1)	Alternative Adjustment (Mm-1)	Alternative DV
site	State	WRAP_2028_Rx_Fire_dv	ep_wrap_rx_fire_bext	end_point_episodic_routine_dv	ep_bext	ss_Rayleigh	WRAP2028_Tbext	tbext_g90_f	ffs_bext		
BADL1	SD	0.7	1.333	6.091	18.388	11	32.892	34.174	1.281	2.614	1.329
WICA1	SD	1.8	3.466	5.638	17.573	10	27.821	38.609	10.788	14.254	5.939

site	year	glidepath dv	WRAP_FFS dv	WRAP_FFS_RX dv	Five_yr_ave_dv	haze_dv
BADL1	2064	6.09115976				
BADL1	2004	14.98036061				
BADL1	2064		6.764670836			
BADL1	2004		14.98036061			
BADL1	2064			7.12418535		
BADL1	2004			14.98036061		
BADL1	2004				14.98036061	
BADL1	2005				15.25355631	
BADL1	2006				15.01101943	
BADL1	2007				15.15144495	
BADL1	2008				15.0891438	
BADL1	2009				15.00844526	
BADL1	2010				15.04495653	
BADL1	2011				14.95415375	
BADL1	2012				14.63505556	
BADL1	2013				14.32916846	
BADL1	2014				13.88794272	
BADL1	2015				13.0152888	
BADL1	2016				12.5565221	
BADL1	2017				12.41263374	
BADL1	2018				12.33036223	
BADL1	2019				12.56819185	
BADL1	2000					14.34045485
BADL1	2001					16.05383224
BADL1	2002					14.44224367
BADL1	2003					15.21438912
BADL1	2004					14.85088319
BADL1	2005					15.70643335
BADL1	2006					14.84114783
BADL1	2007					15.14437127
BADL1	2008					14.90288337
BADL1	2009					14.44739048
BADL1	2010					15.88898973
BADL1	2011					14.38713392
BADL1	2012					13.54888033
BADL1	2013					13.37344786
BADL1	2014					12.24126175
BADL1	2015					11.52572012
BADL1	2016					12.09330046
BADL1	2017					12.82943853
BADL1	2018					12.96209028
BADL1	2019					13.43040984
BALD1	2064	4.181456391				
BALD1	2004	8.801600129				
BALD1	2064		4.257778267			
BALD1	2004		8.801600129			

site	year	glidepath dv	WRAP_FFS dv	WRAP_FFS_RX dv	Five_yr_ave_dv	haze_dv
BALD1	2064			4.361757637		
BALD1	2004			8.801600129		
BALD1	2004				8.801600129	
BALD1	2005				8.907272373	
BALD1	2006				8.685618399	
BALD1	2007				8.683099292	
BALD1	2008				8.636979335	
BALD1	2009				8.553891499	
BALD1	2010				8.358831891	
BALD1	2011				8.482825785	
BALD1	2012				8.458897857	
BALD1	2013				8.260805748	
BALD1	2014				8.130195974	
BALD1	2015				7.935955992	
BALD1	2016				7.559171525	
BALD1	2017				7.367566433	
BALD1	2018				7.292924587	
BALD1	2019				7.348832418	
BALD1	2001					9.110556119
BALD1	2002					9.01972966
BALD1	2003					9.129964038
BALD1	2004					7.9461507
BALD1	2005					9.329961349
BALD1	2006					8.002286248
BALD1	2007					9.007134123
BALD1	2008					8.899364254
BALD1	2009					7.53071152
BALD1	2010					8.354663312
BALD1	2011					8.622255718
BALD1	2012					8.887494483
BALD1	2013					7.908903709
BALD1	2014					6.877662649
BALD1	2015					7.3834634
BALD1	2016					6.738333382
BALD1	2017					7.929469026
BALD1	2018					7.535694479
BALD1	2019					7.157201804
WICA1	2064	5.637992604				
WICA1	2004	13.09231746				
WICA1	2064		10.42452875			
WICA1	2004		13.09231746			
WICA1	2064			10.96331439		
WICA1	2004			13.09231746		
WICA1	2004				13.09231746	
WICA1	2005				13.59847218	
WICA1	2006				13.65353752	

site	year	glidepath dv	WRAP_FFS dv	WRAP_FFS_RX dv	Five_yr_ave_dv	haze_dv
WICA1	2007				13.83736109	
WICA1	2008				13.61762756	
WICA1	2009				13.43583454	
WICA1	2010				13.06722275	
WICA1	2011				12.80188666	
WICA1	2012				12.51231188	
WICA1	2013				12.32514801	
WICA1	2014				11.80577482	
WICA1	2015				11.25683769	
WICA1	2016				10.60096629	
WICA1	2017				10.62339323	
WICA1	2018				10.5258443	
WICA1	2019				10.66852169	
WICA1	2000					12.00669738
WICA1	2001					13.56397024
WICA1	2002					13.04106796
WICA1	2003					13.52208375
WICA1	2004					13.32776797
WICA1	2005					14.53747098
WICA1	2006					13.83929694
WICA1	2007					13.96018581
WICA1	2008					12.42341609
WICA1	2009					12.4188029
WICA1	2010					12.69441202
WICA1	2011					12.5126165
WICA1	2013					11.67476063
WICA1	2014					10.34131015
WICA1	2015					10.49866347
WICA1	2016					9.889130918
WICA1	2017					10.71310098
WICA1	2018					11.18701601
WICA1	2019					11.05469708

Regional Haze Rule: Prescribed Fire Supporting Documentation
United States Forest Service, Rocky Mountain Region
For: the State of South Dakota

August, 2021

Benefits of Prescribed Fire on Reducing Wildfire Risk to High Resources of Value (HVRA)

To address increased wildfire risk, land managers of all agencies rely on many tools to both restore and maintain landscapes to help mitigate the risk of severe and large wildfires. Prescribed fire is one of the key tools that the United States Forest Service (USFS) utilizes to both restore ecological function, maintain carbon stock and maintain landscapes to reduce the risk of wildfires across all landscapes of National Forest System (NFS) lands. As both a natural process and one of the most cost-effective tools the USFS has at its disposal, increased utilization of prescribed fire remains a goal of the USFS across the state of Rocky Mountain Region and the state of South Dakota.

Often used in combination with mechanical treatments, prescribed fire is a way to both restore natural processes and maintain those conditions to help mitigate severe impacts from large wildfires. In a 2012 study, benefits of prescribed fire were shown to mitigate impacts from wildfires… "We found considerable evidence that prescribed fires have landscape-level influences within treatment boundaries; most notable was an interaction between distance from the prescribed fire perimeter and distance from treated patch edges, which explained up to 66% of the variation in wildfire severity. Early season prescribed fires may not directly target the locations most at risk of high severity wildfire, but proximity of these areas to treated patches and the discontinuity of fuels following treatment may influence wildfire severity and explain how even low severity treatments can be effective management tools in fire-prone landscapes." (Arkle et al., 2012).

In another recent study involving a large literature review, prescribed fire was recognized to benefit a broad range of ecological and societal factors. "Prescribed fire can result in significant benefits to ecosystems and society. Examples include improved wildlife habitat, enhanced biodiversity, reduced threat of destructive wildfires and enhanced ecosystem function… Both empirical and modeling studies overwhelming show that increasing the use of prescribed fire can result in wildfire regimes of lower extent and intensity. In some studies, a consequence associated with increased use of prescribed fire is an increase in the total, cumulative amount of fire on a landscape over time. Presumably this has implications for emissions and ecosystem carbon, however, effects on ecosystem carbon dynamics are much less clear as results vary considerably across studies." (Hunter et al., 2020).

Current Ecological Status and Need for Prescribed Fire in South Dakota

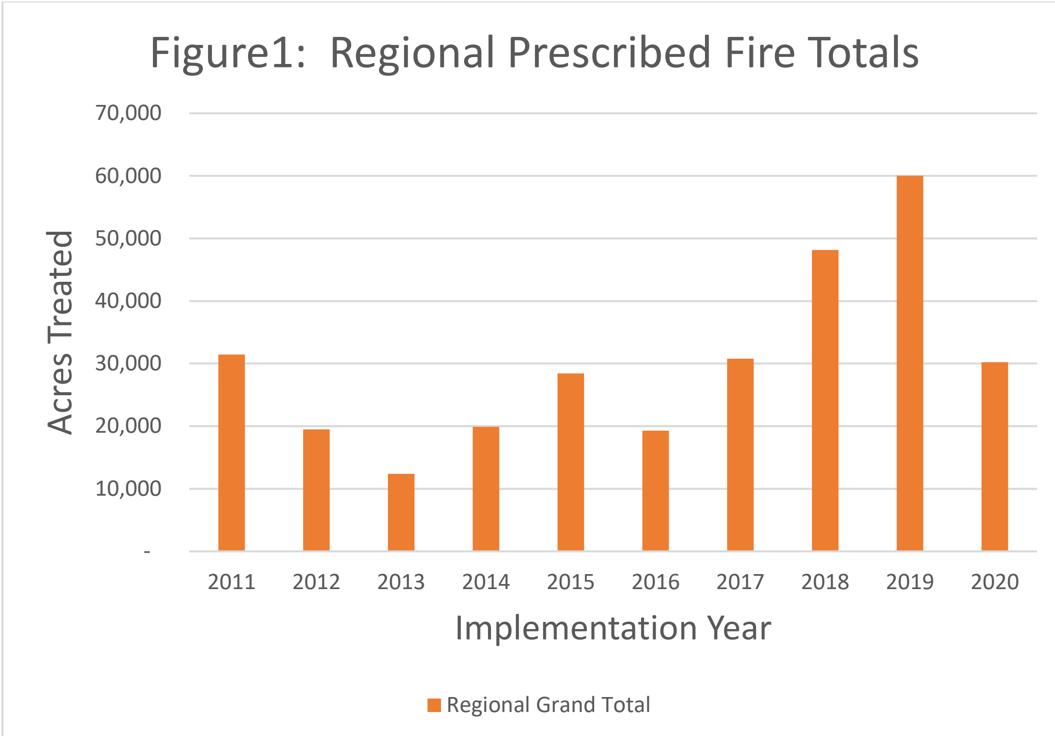
Wildfires in South Dakota have been increasing in size and severity in the past two decades compared to historical averages. Causes for this change are many fold but include a combination of past land management practices (when fire policy was to extinguish wildfires as quickly and as small as possible) which has contributed to a buildup of vegetation; effects from climate change (warmer and drier environmental conditions) which has resulted in longer and more severe fire seasons; and effects from natural disturbances (such as the historic beetle infestations of forested ecosystems) which resulted in millions of dead and dying trees and contributed to increased fire risk. All of these factors are further complicated by growing populations and expansion of the Wildland Urban Interface (WUI) lands where homes are adjacent to or intermixed with wildland vegetation.

A strictly spatial analysis using LANDFIRE data was used to inform a baseline annual goal for prescribed fire across the region that assumes that Broadcast Burning is appropriate where Fire Regime Groups 1, 2 and 3 and Condition Class 2 and 3 intersect outside of designated Wilderness to bring these areas into closer alignment with the natural fire return interval.

On NFS lands in South Dakota, the 10 year average number of acres treated through broadcast burning between 2009-2018 was approximately 1,400. In 2019, 1,374 acres of broadcast burning was implemented. The analysis shows that between 19,500 and 29,000 acres would need to be burned annually to bring these landscapes into alignment with the natural fire return interval and maintain ecosystem function. This demonstrates an annual deficit of between 18,000 and 28,000 acres of prescribed fire application on NFS lands in South Dakota.

At the same time, South Dakota has been experiencing larger and more severe wildfires the past two decades compared to historical averages. Prescribed fire is an effective management tool utilized by the USFS that can help reduce fire risk, decrease the severity of wildfires and mitigate size of wildfires in the future.

USFS & Rocky Mountain Region Prescribed Fire Trends and Long-term Goals
In response to the increasing threat of large and destructive wildfires and in an effort to accelerate risk mitigation efforts, the USFS has increased its level of investment and resources in recent years to advance prescribed fire application across the region (Figure 1). In 2019 for example, the Rocky Mountain Region more than doubled its ten-year average of prescribed fire acres treated. This trend slowed in 2020 due primarily to Regional Leadership direction to take an operational pause in prescribed fire implementation in response to concerns over potential air quality impacts from prescribed fire smoke during the COVID-19 epidemic and associated public health and respiratory concerns. However, thus far in 2021, the Region has again surpassed the 10-year average of acres treated through prescribed fire and expect more acres treated as the year continues.



In addition, there is growing recognition and discussion of accelerated risk reduction investments, including prescribed fire implementation, being discussed in Congress and at the national level of many agencies which will prioritize increased prescribed fire targets of most federal land management agencies.

State and Federal land management agencies have both embraced a Shared Stewardship approach to land management planning and implementation efforts to which a Memorandum of Understanding (MOU) between the state and the USFS us being developed. The goal of the MOU is to promote a common goal to focus on priority, landscape-scale forest and grassland restoration activities that protect at-risk communities and watersheds across all lands. Prescribed fire is one of the tools the USFS has identified to restore and maintain South Dakota landscapes to protect communities, watersheds and forest health.

References and Additional Resources

Arkle, Robert S., Pilliod, David S., Welty, Justin L., 2012. Pattern and process of prescribed fires influence effectiveness at reducing wildfire severity in dry coniferous forests. Forest Ecology and Management, 276, 174-184.

South Dakota Department of Agriculture, Resource Conservation and Forestry Division, 2020. South Dakota State Forest Action Plan

Hunter, Molly E., Robles, Marcos D., 2020. Tamm review: The effects of prescribed fire on wildfire regimes and impacts: A framework for comparison. Forest Ecology and Management, 475, 118435.

USDA Forest Service, Rocky Mountain Research Station, 2005. Rainbow Series Volume 1: Wildland fire in ecosystems: effects of fire on fauna. General Technical Report RMRS-GTR-42- volume 4

APPENDIX B

SOUTH DAKOTA REGIONAL HAZE STATE IMPLEMENTATION PLAN: PUBLIC COMMENTS

APPENDIX B-1

SOUTH DAKOTA REGIONAL HAZE STATE IMPLEMENTATION PLAN: SUMMARIES OF AND RESPONSES TO PUBLIC COMMENTS

Table Of Contents

1.0 Introduction

DANR public noticed South Dakota's Regional Haze Program for public comments on or before November 16th, 2021. South Dakota's Regional Haze Program consists of "South Dakota's Regional Haze State Implementation Plan" which addresses the federal requirements in 40 Code of Federal Regulations (CFR), Part 51, Section 308. On December 16th, 2021, a public hearing in front of the Board of Minerals and Environment is to be held to take testimony on South Dakota's Regional Haze Program.

DANR received comments from the United States Environmental Protection Agency (EPA) – Region 8 and Otter Tail Power Company. Both a summary of comments and DANR's responses to the comments, and the original comment letters received during the public notice period may be viewed here.

2.0 Otter Tail Power Company Comments

1. Otter Tail Power Company believes South Dakota is justified in adding no additional control measures to the Big Stone Plant based on these factors: 1) South Dakota's two Class I Areas are projected, when adjusting for both international anthropogenic and prescribed fire emissions, to have already met or be more than 71% of the way to meeting the 2064 natural visibility goal. 2) The Big Stone Power Plant is already an effectively controlled source, having completed a $365 million BART air quality control system upgrade in 2015 during the Regional Haze first implementation period, which reduced emissions of both sulfur dioxide and nitrogen oxides by more than 90%. 3) Other evidence as provided by the source selection analysis and other modeling indicates Big Stone power plant is not a significant contributor to visibility impairment at any Class I Area in the WRAP or surrounding regions. 4) Screening the Big Stone power plant from consideration for further Regional Haze controls is consistent with years of EPA guidance.

   Response: DANR agrees with Otter Tail Power Company's statements, and thanks Otter Tail Power Company for commenting.

3.0 GCC Dacotah Comments

1. GCC Dacotah provided additional information to supplement the four factor analysis they submitted on October 28, 2019. GCC Dacotah continues to support the original conclusions made by GCC Dacotah and DANR that controls are not appropriate for the GCC Dacotah kiln during this second implementation period. GCC reviewed previously submitted operating cost calculations for selective non-catalytic reduction technology (SNCR) and updated the cost calculations. The preliminary cost calculations were reliant on several default input variables and assumptions which GCC Dacotah reevaluated, which resulted in a substantial initial underestimation of anticipated costs. The new cost effectiveness value is $4,941/ton, up from $2,094/ton. GCC Dacotah also emphasized their ammonia slip concern, indicating from its experience with SNCR technologies, ammonia slip rates of over 50 ppm have been

necessary to achieve required NOx reduction, which would add to Rapid City's historical challenges with high PM air concentrations.

Response: DANR thanks GCC Dacotah for providing updated cost estimates in these tumultuous times. DANR has taken the updated cost estimates into account, and has determined they will not change DANR's initial determination, but instead bolster its decision.

4.0 National Park Service Comments

1. NPS wants to thank the DANR for the opportunity to provide comments on the regional haze plan for the second implementation period and would like to emphasize their request for South Dakota to strengthen the SIP and require cost effective controls to reduce nitrogen oxide emissions from the GCC Dacotah facility

   Response: South Dakota thanks the NPS for providing additional comments during the public comment period. DANR has decided to stand by its original decision of no additional control measures during this second implementation period.

5.0 Sierra Club Comments

1. Sierra club urges South Dakota to not lean improperly on the Uniform Rate of Progress and believes it is inappropriate to use visibility conditions and status of the glideslope to justify not needing additional control measures at GCC Dacotah and Pete Lien and Sons

   Response: DANR did not lean improperly on the Uniform Rate of Progress, but used it as one of the factors in its cost effectiveness determination. South Dakota is required to 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, as stated in 40 CFR § 51.308(f)(3)(iv)(E). Please also see comment number 2 of section 3 of appendix A-1.

2. Sierra Club wants to point out that data shows distinct upticks in hazy conditions in recent years and Badlands National Park and Wind Cave National Park. This demonstrates a need for the state to require emission reductions to avoid the continuation of this trend in the future.

   Response: South Dakota acknowledges this observation. However, due to several different variables such as weather patterns, climate, etc., DANR expects the visibility will vary each year. However, looking at the full data set, the visibility overall has continued to decrease from calendar year 2000 which is the baseline year for the Regional Haze program. Please also see comment number 2 of section 2 of appendix A-1.

3. Sierra Club supports the NPS comment that states South Dakota is wrong in their interpretation that South Dakota is unable to add additional measures due to them

being unwarranted and run contrary to state rule. Sierra clubs believes the Regional Haze Rule and the Transport rule are not analogous, and believes South Dakota is improperly comparing the rules.

Response: South Dakota agrees the Transport Rule did not involve visibility or the Regional Haze Program. However, the court decision may be used as a guideline on how to interpret similar concepts. The National Park Service is misapplying South Dakota's discussion on its state Statute and the court decision involving the Transport Rule. South Dakota is referring to the requirement of reasonable progress and the natural background visibility threshold and not the Uniform Rate of Progress (URP). DANR is required by 40 CFR § 51.308(f)(2)(iv)(E), when developing its long-term strategy, to consider visibility in its decision making. After analyzing the 2028 projections, DANR found that visibility impairment at one of its Class I Areas will have surpassed the 2064 natural background visibility goal. If the Class I Areas are meeting or projected to meet the natural background visibility goal, South Dakota does not have the authority to require controls that go beyond reasonable progress and/or exceed the natural background visibility goal based upon both its state statutes and its review of the concepts behind the court decision on the Transport Rule. Please also see comment number 5 of section 3 of appendix A-1.

4. Sierra Club believes that the state has overestimated the interest rates throughout the proposed SIP. Using the current 3.25% bank prime rate, many controls options for both facilities would be even more cost effective.

   Response: DANR considered multiple interest rates in its cost of compliance four factor analysis, including 3.25%, and no interest rate produced final cost values that were deemed cost effective. Please also see comment numbers 14, 9, 8, and 6 of section 3 of appendix A-1.

6.0 EPA Comments

1. EPA thanks South Dakota for their effort and work on this draft SIP and looks forward to continuing to work with the state.

   Response: DANR thanks EPA for providing additional comments, and also looks forward to continuing to work together.

2. EPA believes South Dakota should not use visibility to dismiss cost-effective potential controls. EPA would like the state to reconsider its four-factor analysis accordingly to help reach the national goal of preventing and remedying anthropogenic impairment of visibility in class I areas.

   Response: As part of the long-term strategy, South Dakota is required to 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, as stated in 40 CFR § 51.308(f)(3)(iv)(E). South Dakota used this information to help inform its four factor cost effectiveness decision. Please also see comment numbers 1 and 2 of section three of appendix A-1.

3. EPA wants to emphasize that glidepath is not a “safe harbor” and class I areas below the glidepath cannot be used to justify the decision to implement controls. The glidepath should be used to gauge the progress that has been made and how much progress is left to make.

   Response: South Dakota did not use the glidepath as a “safe harbor,” but did use it to gauge the progress that has been made and how much progress is left to make. This observation was used to help DANR determine which control measures were considered cost effective. South Dakota also emphasizes the existence of 40 CFR § 51.308(f)(3)(i), which can be interpreted as a less stringent "safe harbor," which states in part: “The long-term strategy and the reasonable progress goals must provide for an improvement in visibility for the most impaired days since the baseline period and ensure no degradation in visibility for the clearest days since the baseline period.” South Dakota has met this requirement, and therefore believes to be making reasonable progress. Please also see comment number 2 of section 3 of appendix A-1.

4. EPA believes the state quotes the “Good neighbor Provision” out of context. The EPA also believes that the state is obligated to reduce causes of regional haze and their claim that “DANR may not require emission controls that go above and beyond the reasonable progress to natural conditions” has no legal relevance in this situation.

   Response: DANR does not believe to have quoted the “Good neighbor provision” out of context, and understands that the Regional Haze Rule and the Good Neighbor provisions are different, but the concept is still similar. Please also see comment number 5 of section 3 of appendix A-1.

5. EPA believes that south Dakota is basing decisions off the NAAQS and does not believe that is relevant to the regional haze rule. EPA believes South Dakota should determine cost effectiveness of its four factor analyses strictly based on information and guidance found in the regional haze rule.

   Response: South Dakota decisions were based on the four factors, including cost effectiveness. As also noted in response to comment numbers 8 and 9 of section three of appendix A-1, what numeric value should be considered cost effective is not defined in the Regional Haze Rule. Therefore, the question becomes how do you determine that value. South Dakota considered several factors in determining at what numeric value South Dakota would consider as being cost effective. South Dakota did consider is compliance with the NAAQS as one of the several factors in making its determination on cost effectiveness. South Dakota did not based its decision solely on its compliance with the NAAQS.

6. EPA wants to emphasize that south Dakota cannot use the glidepath as a safe harbor when determining justification for a particular set of controls. The glide path is not based on the four statutory factors and cannot be used to determine whether the amount of progress in an implementation period is reasonable.

   Response: DANR did not use the glidepath as a safe harbor. Although the glidepath is not based on the four statutory factors, it was used to help inform South Dakota's cost of compliance factor decision, and can be used for that purpose according to the Regional Haze Rule. Please also see comment number two of section three of appendix A-1.

7. EPA wants to commend the state for considering a more stringent threshold of their Q/d screening.

   Response: South Dakota thanks EPA for its comment.

8. EPA believes that south Dakota should review the four-factor analysis regarding the SNCR infeasibility for Pete Lien and Sons. The information provided is incorrect and South Dakota has since been provided with accurate information regarding the subject.

   Response: For discussion purposes, DANR reran Pete Lien's cost analysis by using EPA preferred inputs and by eliminating the cost for the lost kiln dust sales. The dollar per ton cost would decrease from $34,860 to approximately $11,400 for kiln #1 and from $58,830 to $17,400 for kiln #2. Even with these revisions, DANR would still consider the SNCR not cost effective and would not require Pete Lien and Sons to install the control system at this time. Please also see comment number 14 of section three of appendix A-1.

9. EPA would like South Dakota to specify which NEI year was used and how in the four-factor analysis for Pete Lien and Sons. If emissions data prior to 2017 NEI was used, EPA requests that the state analyze and present updated 2017 emissions information.

   Response: In Pete Lien's four factor analysis, Pete Lien considered its actual emissions from calendar years 2013 through calendar years 2018. Pete Lien actual emissions are noted in Table 3-1 on page 7 of their Four-Factor analysis. Pete Lien used the average of rate of calendar year 2017 and 2018 in there analysis. DANR understands that emissions information from 2014 to 2017 does not change significantly— only minor changes to emissions can be expected. One way this can be demonstrated is by viewing the WRAP TSSv2 emissions data analysis express tool product number 4 for both NOx and SO2, which shows insignificant changes in emissions projections from 2014 to 2028 for South Dakota sources.

10. EPA requests that for each selected source the state consider whether a source can achieve a lower emission rate using its existing control measures. EPA also recommends the state consider equipment upgrades or more efficient use of existing measures being a reasonable way to reduce emissions.

    Response: DANR does not believe further analysis on the topic is necessary at this time. Such measures may be considered by South Dakota in subsequent planning periods should the objective analyses conducted during that time indicate such measures would significantly improve visibility impairment at Class I Areas. Please also see comment number 11 of section three of appendix A-1.

11. EPA believes that SNCR should be acceptable to implement at GCC Dacotah due to numerous individual reasons. These reasons include the state currently complying with all particulate matter NAAQS, the fact that the state has previously asserted that exceedances of PM10 in Rapid City were due to uncontrollable natural events, and that the state must comply with both the CAA and RHR.

    Response: DANR does not agree with EPA's conclusion. DANR has followed all requirements of the CAA and RHR and has made reasonable interpretations. Please also see comment number 9 of section three of appendix A-1.

12. EPA recommends that South Dakota to complete a four-factor analysis providing reason as to why Big Stone Power Plant should be excluded from consideration of additional emission controls measures instead of automatically excluding them from this implementation period.

    Response: DANR did not automatically disregard Big Stone Power Plant. South Dakota did not include Big Stone Power Plant for a four factor analysis because it was not screened in during the source selection step, using established and even more stringent thresholds.

13. EPA believes that if no additional or new measures are required to make reasonable progress for a particular source, the state should determine whether the sources existing measures are required to make reasonable progress. If this is the case, South Dakota will need to adopt emissions limits based on those existing controls.

    Response: South Dakota considers it is making reasonable progress to natural background and is projected to continue to make reasonable progress as noted in figures 4-10 and 4-13 on pages 163 through 165 of South Dakota's Regional Haze SIP. Therefore, DANR does not believe it needs to "require" more stringent limitations on existing operations at the two sources selected for its four factor analysis at this time. DANR will reconsider that position during future reviews.

14. EPA recommends that in the draft SIP document existing emission limits are identified and the state explains where the limits are located (e.g., in the SIP, in a state permit etc.).

Response: Both Pete Liens and GCC Dacotah are required to obtain and maintain a Title V air quality operating permit. The applicable requirements, including the emission limits, are identified in their permits.

15. EPA would like more clarification on the dry sorbent injection used for Kiln #6 at GCC Dacotah. EPA would like to know if it is used for continuous reduction of SO2 or in order to meet a emission limit on a short-term basis.

    Response: It was used to meet the federal max standard for HCl if they ever have a spike—it was not put there to meet the SO2 requirements. Please also see comment number 11 of section three of appendix A-1.

16. EPA would like further information on the initial basis to implement control technologies on Kiln #6 at GCC Dacotah and the reasoning behind the decision to remove the requirement at a later date.

    Response: The reasoning behind the decision to remove this requirement is that the SCR system was originally required at GCC Dacotah. The requirement was removed because they didn't need it to make sure they were meeting the emission limit that was established under that system.

17. EPA recommends that South Dakota focus the analysis of sources on direct energy consumption rather than indirect energy inputs. EPA would like to also point out that just because a control measure would create liquid and solid waste that would need to be disposed of, does not mean that it is not necessary to make reasonable progress, especially if it has been implemented at other facilities. EPA would like the state to provide more information on how ammonia slip would negatively impact the state if they are to use it as a reason to not implement control measures at a site. In rare instances, new controls or increasing the efficiency of existing control measures might result in adverse energy or non-air quality environmental impacts. If this is the case, such impacts should generally be addressed in the context of a four-factor analysis, rather than be used as a reason to not analyze increased efficiency of the measure in the first instance.

    Response: South Dakota considers it is making reasonable progress to natural background and is projected to continue to make reasonable progress as noted in figures 4-10 and 4-13 on pages 163 through 165 of Regional Haze SIP. In addition, South Dakota's decisions were based on the four factors, with one of those being cost effectiveness. Please refer to the response to comment numbers 8 and 9 of section three of appendix A-1 for further discussion.

18. EPA states that the Pete Lien and Sons four-factor analysis indicates potential lime kiln dust product sales loss of greater than \$1.1 million to greater than \$1.4 million for kilns 1 and 2 from ammonia impacts to lime dust quality, and that no justification has been provided for these sales loss figures.

    Response: For discussion purposes, DANR reran Pete Lien's cost analysis by using EPA preferred inputs and by eliminating the cost for the lost kiln dust sales. The dollar per ton cost would decrease from $34,860 to approximately $11,400 for kiln #1 and from $58,830 to $17,400 for kiln #2. Even with these revisions, DANR would still consider the SNCR not cost effective and would not require Pete Lien and Sons to install the control system at this time.

19. EPA indicates that continuous progress over planning periods may be necessary to meet the intent of Congress in section 169A of the CAA, and that EPA has concerns with states that choose to forego any additional cost effective controls during this second implementation period because the sources are insignificant contributors to visibility impairment. Instead, South Dakota should consider a source's visibility impact relative to its own total contribution to impairment, not other states.

    Response: South Dakota agrees that continuous progress over planning periods may be necessary to meet the intent of Congress, but it is not possible to know definitively until more IMPROVE data comes in. South Dakota disagrees that insignificant sources to visibility impairment need to be controlled during the second implementation period, especially if those controls amount to a fraction of a percent of visibility impairment change at any Class I Area.

20. EPA encourages South Dakota to consider environmental justice impacts inside and outside the state, and to describe any outreach to environmental justice communities or opportunities provided or plans to provide for communities to give feedback on its proposed strategy.

    Response: DANR does not agree that South Dakota needs to consider environmental justice impacts, as the topic is not mentioned in the Regional Haze Rule. However, we did public notice our information twice in 11 daily newspapers, and also put information on our webpage for multiple months, and therefore the general public had every opportunity to become informed.

APPENDIX B-2

SOUTH DAKOTA REGIONAL HAZE STATE IMPLEMENTATION PLAN: FORMAL PUBLIC COMMENT LETTERS

215 South Cascade Street
PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200
www.otpco.com

OTTER TAIL POWER COMPANY

November 30, 2021

Mr. Kyrik Rombough
Administrator, Air Quality Program
South Dakota Department of Environment
and Natural Resources
523 East Capitol
Pierre, SD 57501

<Submitted electronically to anthony.lueck@state.sd.us>

Dear Mr. Rombough:

RE: South Dakota's Second Round Draft Regional Haze State Implementation Plan

Otter Tail Power Company (Otter Tail) appreciates the opportunity to provide comments to the South Dakota Department of Agriculture and Natural Resources (DANR) regarding the draft South Dakota Regional Haze State Implementation Plan (SIP) for the second planning period. Otter Tail is submitting these comments on behalf of the Big Stone Plant owners, who also include Montana-Dakota Utilities, Co. and NorthWestern Energy.[1]

As an initial comment, Otter Tail commends DANR for the extensive efforts that went into developing the SIP and for the tremendous visibility progress that has been made at the Badlands and Wind Cave National Parks. It is impressive to see that these Class I areas are projected to nearly meet their visibility glideslope goals in 2028 without even adjusting for international anthropogenic and U.S. prescribed fires, of which South Dakota has no control. Even more impressive, when adjusting for these uncontrollable activities, by 2028 Badlands National Park is projected to be more than 71% of the way to meeting the 2064 goal of natural visibility conditions, and Wind Cave National Park is projected to fully meet the 2064 goal.[2]

Based that fact alone, DANR's position that no additional control measures are necessary for this second implementation period is justified. However, Otter Tail would also like to take this opportunity to further support DANR's decision to not consider additional controls at Big Stone Plant for this round of Regional Haze.

1. **Big Stone Plant is already an effectively controlled source, having completed a $365 million air quality control system upgrade in late 2015 for the first implementation period of Regional Haze that reduced emissions of sulfur dioxide and nitrogen oxides by more than 90%.**

[1] Otter Tail Power Company is 53.9% owner and operator, Montana-Dakota Utilities, Co. is 22.7% owner, and NorthWestern Energy is 23.4% owner of Big Stone Plant
[2] See Figures 4-10 and 4-13, South Dakota Regional Haze State Implementation Plan draft

For the Regional Haze Rule's first implementation period, Big Stone Plant was subject to a Best Available Retrofit Technology (BART) determination. As a result of this process, the Big Stone Plant owners installed a dry scrubber for sulfur dioxide (SO_2) control and a selective catalytic reduction (SCR) system with separated overfire air for nitrogen oxides (NO_x) control. In conjunction with an activated carbon injection system that was installed concurrently for mercury control, the Big Stone Plant owners invested $365 million in this air quality control system project. Big Stone Plant's SO_2 and NO_x emissions dropped markedly following installation of this equipment. Based on the annual emissions data presented in Table 7-1 of the SIP, on average SO_2 emissions decreased 93%, and NO_x emissions decreased 91%, during the years 2016-2020 as compared to years 2010-2014.[3]

These substantial reductions and the $365 million investment in controls for the first implementation period supports DANR's conclusion that Big Stone Plant should not be subject to consideration for additional controls during this second implementation period. This conclusion is reinforced by reviewing Tables 3-8 through 3-11 of the SIP, which identify the facilities with projected year 2028 NO_x and SO_2 Q/d (emissions in "Q" divided by distance "d" to a specific Class I area) thresholds greater than 10. Big Stone Plant is not one of the facilities that fits within this Q/d screening threshold used by the Western Regional Air Partnership's (WRAP) contractor, Ramboll Corporation, and most WESTAR-WRAP states.[4] Had the tables been expanded to also include sources with Q/d results below 10, it would reveal that Big Stone Plant's Q/d rankings for South Dakota's Class I areas would place the facility in 60th place for SO_2 (Q/d of 2.07) and 66th place for NO_x (Q/d of 2.38) at Badlands National Park, and 72nd position for SO_2 (Q/d of 1.64) and 88th position for NO_x (Q/d of 1.88) at Wind Cave National Park.[5]

2. **<u>At greater than 400 km away from South Dakota's Class I areas, Big Stone is an insignificant contributor to visibility impairment.</u>**

South Dakota's Regional Haze SIP for the first implementation period identified the following distances to Class I areas from Big Stone Plant:[6]

State	Class I Area	Min Distance
SD	Badlands	470 km
SD	Wind Cave	572 km
MN	Boundary Waters	431 km
MN	Voyageurs	438 km
MT	Medicine Lake	690 km
MT	UL Bend	902 km
ND	Lostwood	585 km

[3] Page 184, South Dakota Regional Haze State Implementation Plan draft
[4] Ibid, pages 64-65
[5] Rank Point files available at vice.cira.colostate.edu - /files/iwdw/platforms/WRAP_2014/WEP_AOI/WEP_AOI_20200925/RANK_POINT/SD/
[6] See Table 6-3 https://danr.sd.gov/Environment/AirQuality/RegionalHaze/docs/RHSIP20110818.pdf

ND	Theodore Roosevelt	555 km
WY	Bridger	1,041 km
WY	Fitzpatrick	1,050 km
WY	Grand Teton	1,112 km
WY	North Absaroka	1,013 km
WY	Teton	1,052 km
WY	Washakie	1,006 km
WY	Yellowstone	1,049 km

Considering that Big Stone Plant is further than 400 km than the nearest Class I area, in conjunction with the 90+% reductions in SO_2 and NO_x from installing BART in Round 1, this provides a strong indication that Big Stone Plant is an insignificant contributor to visibility impairment at these areas. As noted by South Dakota's draft SIP, WRAP did not include sources greater than 400 km from the nearest Class I area in their initial Q/d analysis.[7]

However, beyond simply relying on distance to Class I areas and low emissions to determine that Big Stone Plant is an insignificant contributor to visibility impairment at Badlands and Wind Cave National Parks, the supporting information presented in South Dakota's SIP solidifies this as a clear fact. For example, Figures 3-2 through 3-6 shows the states and source categories of anthropogenic emissions that are projected to have the most impact on visibility at these Class I areas.[8] The state of South Dakota is a far lesser overall contributor as compared to other states. Looking further into the figures, specific to Big Stone Plant, the source apportionment contributions from South Dakota's Electric Generating Unit (EGU) category is indistinguishable.

Further evidence confirming it was appropriate to exclude Big Stone Plant from a controls analysis is presented in WRAP's Residence Time (RT) charts, Extinction Weighted Residence Time (EWRT) charts, and Weighted Emissions Potential (WEP) maps presented in Figures 3-17 through 3-34.[9] Looking at the RT charts in Figures 3-17 and 3-18, Grant County is outside the area of influence (AOI) for Badlands and Wind Cave. Focusing on the EWRT plots in Figures 3-19 through 3-22, Grant County is outside the AOI with the one minor exception being the EWRT ammonium nitrate plot for Badlands, where Grant County is in the least category of influence. Finally, for the WEP analysis maps, which combines the EWRT and Q/d of a given pollutant, Grant County is again completely outside the isopleths that indicate the highest areas of visibility impairment influence.

This weight of evidence, in combination with the existing effective control measures in place, irrefutably support DANR's determination that Big Stone Plant should not be considered for additional scrutiny during this second implementation period.

---

[7] Page 64, South Dakota Regional Haze State Implementation Plan draft
[8] Ibid, pages 49-53
[9] Ibid, pages 76-96

3. **Screening Big Stone Plant from consideration for further Regional Haze controls is consistent with years of EPA guidance.**

Screening Big Stone Plant out of consideration from the sources selected to perform a four-factor controls analysis is consistent with numerous guidance documents, including:

- EPA's "*Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period*", July 2016.[10]

  Section 6.4 of this guidance document states that "A source subject to a federally enforceable emission limit that effectively requires it to apply the most effective control technology for a given PM species or precursor may be screened out of further analysis for that pollutant."[11] This section goes on to provide an example that highly effective control technologies include year-round operation of flue gas desulfurization (FGD) equipment with an effectiveness of at least 90% or year-round operation of selective catalytic reduction (SCR) with an effectiveness of at least 90%. As discussed earlier in these comments, the data presented in Table 7-1 of DANR's SIP shows that Big Stone Plant has utilized that exact SO_2 and NO_x control equipment year-round to reduce emissions greater than 90%.

  Elsewhere in this guidance document EPA discusses how states can conduct a screening analysis based on visibility impact levels. As discussed earlier, Big Stone Plant is outside the predicted area of influence for Badlands and Wind Cave National Parks and contributes an indistinguishable amount to projected 2028 anthropogenic visibility impairment.

- EPA's "*Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*", August 20, 2019.[12]

  Section B.3 of this EPA 2019 guidance document addresses how a state may select emission sources for analysis of emission control measures. The section begins off by stating "a state is not required to evaluate all sources of emissions in each implementation period",[13] and then lists several factors to consider. Similar to the 2016 EPA guidance, this 2019 guidance describes how it may be reasonable to exclude effectively controlled sources, including BART-eligible units that installed and began operating controls to meet BART emission limits for the first implementation period.[14] Additionally, this guidance document reinforces that states may consider several possible visibility impact metrics to select sources, including Q/d, trajectory analyses, and residence time analysis.

---

[10] Available at: https://www.epa.gov/sites/default/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf
[11] Ibid, page 77
[12] Available at: https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf
[13] Ibid, Page 9
[14] Ibid, Page 25

- WRAP's "*Regional Haze Source Control Assessment Considerations*"[15]

  As part of a collaborative effort within WRAP, a memorandum was developed to provide criteria for existing source controls such that a four-factor analysis would not be necessary. WRAP's contractor, Ramboll Corporation, reviewed several federal emission control programs to determine if the control technology they require is at a level of stringency comparable to the effective control technology described in EPA's 2016 guidance. Again, Big Stone Plant meets the screening criteria described in this WRAP memo due to having already installed year-round BART controls consisting of FGD and SCR.

- EPA's "*Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period*", July 8, 2021[16]

  Just 23 days prior to the SIP submittal deadline for the second implementation period, EPA issued a "clarifications" memo. Notably, the Western States Air Resources Council (WESTAR) reviewed the memo and communicated in a letter to EPA that the timing of this memo was problematic since it included issues that may be impossible for states to address in the limited timeframe available.[17]

  Within the memo, EPA brought up new concepts that had not previously been raised regarding the screening of effectively controlled sources from a four-factor analysis. One new concept was that EPA expressed that states that identify effectively controlled sources should explain why it is reasonable to assume that a four-factor analysis would likely result in the conclusion that no further controls are reasonable.[18] Otter Tail believes that this is concept is unnecessary as applied to Big Stone Plant, considering the plant meets the screening criteria of the previously discussed EPA and WRAP guidance. Another new concept from EPA is that if an effectively controlled source is achieving a significantly lower emission rate, "a state should further evaluate the lower emission rate(s) as a control option."[19] Although Otter Tail believes this concept is nonsensical since it disregards the need for sources to operate with a margin of compliance as well as it would serve as punishment for sources that are over-compliant, we will proactively address this concept only as it pertains to Big Stone Plant NO_x and SO_2 emissions.

  In order to summarize the margin of compliance that Big Stone Plant has historically operated with, Table 2 below provides the maximum 30-day average SO_2 and NO_x emission rates presented to DANR in the quarterly Title V air permit reports since the Big Stone Plant air quality control system began commercial operation in late 2015.

[15] http://views.cira.colostate.edu/data/tss/ramboll/WRAP_Q_Over_D_Analyses/Task6_RH_Source_Control_Assessment_Considerations_Memo_FINAL.pdf
[16] https://www.epa.gov/system/files/documents/2021-07/clarifications-regarding-regional-haze-state-implementation-plans-for-the-second-implementation-period.pdf
[17] http://www.westar.org/Docs/Draft%20RH%20Clarification%20Response_final.pdf
[18] Clarifications memo, Page 5
[19] Ibid

Table 2: Maximum 30-day average SO_2 and NO_x emission rates since AQCS project

Period	Maximum 30-day average emission rate	
	NOx lb/mmbtu	SO_2 lb/mmbtu
Q1 2016	0.09	0.08
Q2 2016	0.08	0.08
Q3 2016	0.08	0.08
Q4 2016	0.08	0.08
Q1 2017	0.09	0.08
Q2 2017	0.09	0.08
Q3 2017	0.08	0.07
Q4 2017	0.08	0.08
Q1 2018	0.08	0.08
Q2 2018	0.09	0.08
Q3 2018	0.08	0.08
Q4 2018	0.10	0.08
Q1 2019	0.07	0.08
Q2 2019	0.08	0.07
Q3 2019	0.08	0.07
Q4 2019	0.08	0.09
Q1 2020	0.08	0.07
Q2 2020	0.08	0.08
Q3 2020	0.08	0.07
Q4 2020	0.09	0.07
Q1 2021	0.08	0.06
Q2 2021	0.08	0.07
Q3 2021	0.08	0.07
Permit Limit	0.10	0.09
Quarters with data at maximum permitted limit	1	1
Quarters with data within 0.01 lb/mmbtu of maximum permitted limit	5	13
Quarters with data within 0.02 lb/mmbtu of maximum permitted limit	16	8
Quarters with data within 0.03 lb/mmbtu of maximum permitted limit	1	1

As shown in the table, Big Stone Plant maximum 30-day average emission rates are typically within a 0.01-0.02 lb/mmbtu margin of compliance with permit limits, but there is one instance for both NO_x and SO_2 where emissions were at the maximum permit limit. Having a permit limit that allows for this slim margin of compliance is essential to allow for control equipment swings and unanticipated circumstances. Moreover, in the context of regional haze, debating a one-hundredth or two-hundredth difference in emission rates for a source that is over 400 km away from the nearest Class I area, that has already installed Best Available Retrofit Technology, and that is within a state whose Class I areas are significantly below the intended visibility glidepath trajectory, would be an ill-suited use of time.

We appreciate the opportunity to provide our comments at this stage in the process and for DANR's well-reasoned approach to this Regional Haze second implementation period.

Please contact me at (218) 739-8526 or at mthoma@otpco.com if you have any questions.

Sincerely,

Mark Thoma
Manager, Environmental Services

December 13, 2021

Mr. Rick Boddicker
Environmental Scientist
Air Quality Program, South Dakota Department of Agriculture and Natural Resources
Joe Foss Building
523 East Capitol
Pierre, SD 57501

RE: GCC Dacotah Cost Calculations for Regional Haze

Dear Mr. Boddicker:

GCC Dacotah (GCC) appreciates the opportunity to provide additional information to supplement the four-factor analysis submitted for GCC's Rapid City, SD Portland cement plant (GCC Dacotah or the facility) on October 28, 2019. In the draft South Dakota Regional Haze State Implementation Plan (draft SIP), the South Dakota Department of Agriculture and Natural Resources (DANR) concludes that additional emissions controls at GCC Dacotah should not be required for the 2nd round of the Regional Haze Program. GCC supports DANR's conclusion and is providing the following comments to further support DANR's conclusions. After the initial submittal of four-factor analysis, GCC reviewed previously submitted operating cost calculations for selective non-catalytic reduction technology (SNCR) and would like to update the cost calculations.

FOUR-FACTOR ANALYSIS COST CALCULATIONS

The previously submitted four-factor analysis for the GCC Dacotah plant included an assessment of SNCR as a potential retrofit technology for the GCC Dacotah kiln. Despite notable technical concerns related to reaction temperature and potential adverse environmental impacts related to ammonia slip and condensable particulate matter formation, GCC concluded in the original four-factor analysis that SNCR was a technically feasible control technology for the GCC Dacotah kiln. GCC provided a preliminary cost estimate based on the EPA's Air Pollution Control Cost Manual (CCM) and associated cost calculation spreadsheet tool. It is worth noting that the cost calculation spreadsheet tool and the underlying cost curves developed for the CCM were not designed for use in the Portland cement industry (the preliminary cost calculations). The tools were specifically developed for use in the utility industry and rely on design variables specific to utility boilers. Nevertheless, the tool allowed for a preliminary study-level estimate of anticipated retrofit costs for installing SNCR at GCC Dacotah.

The preliminary cost calculations, while meeting the need for providing a study-level estimate of anticipated retrofit costs for the purposes of the four-factor analysis, were reliant on several default input variables and assumptions. To provide additional site-specific analysis, GCC reviewed the assumptions used to develop the annual direct operating costs.

REVISED SNCR COST CALCULATIONS

In further review of the direct operating costs provided by GCC in the October 2019 four-factor analysis, GCC used several default input variables, which resulted in a substantial underestimation of anticipated costs incurred by a potential retrofit of the GCC Dacotah kiln system for SNCR. The input variables, preliminary cost calculation values, and revised values are summarized in Table 1 below.

Table 1. Summary of Refinements to SNCR Cost Calculations

Calculation Input Variable	Preliminary Cost Calculation Value	Refined Cost Calculation Value	Units	Source for Refinement
Concentration of Reagent as Stored	29%	19%	%	Site-specific vendor estimate for aqueous ammonia supply
Density of Reagent as Stored	56	57.8	lb/ft^3	
Concentration of Reagent Injected	10%	19%	%	
Reagent Cost [a]	$0.293	$1.67	$/gallon	
Fuel Cost	$2.40	$2.87	$/MMBtu	Site-specific operating costs for November 2021
Electricity Cost	$0.0796	$0.08	$/kWh	

a. Note that in addition to the change in price per gallon of reagent, the revised costs are specifically provided for a 19% by weight aqueous ammonia solution, rather than the 29% default value used in the CCM and GCC's preliminary cost calculations. Adjustments for the required quantity of ammonia for the SNCR reduction reaction are taken into account in the EPA's cost calculation spreadsheet tool.

As seen in the table above, the most noteworthy adjustments to the cost calculations are those made to the reagent use calculations and costs. GCC contacted a vendor to obtain an estimate of aqueous ammonia costs and noted that the costs were substantially higher than those presented as defaults in the EPA CCM. Adjustments to fuel and electricity costs to use site-specific information are also necessary, though the impacts on the cost effectiveness of the control technology are smaller in magnitude than those resulting from the refinement of reagent use and cost assumptions.

The result of these cost calculation refinements overall is an increase in the anticipated annual cost of implementing SNCR as a retrofit control technology. The refined cost calculations are summarized in Table 2 below.

Table 2. Summary of GCC Dacotah Refined SNCR Cost Calculations

Annual Control Cost ($/year)	Baseline Emission Level (tons/year)	Expected NO_X Reduction Efficiency (%)	Expected Emissions Reductions [a] (tons/year)	Cost Effectiveness ($/ton removed)
$1,636,683	1,394	30%	331	$4,941

a. On an annual basis, the calculated emissions reduction assumes 90% control technology uptime.

The refinement of the operating cost assumptions provided in Table 2 results in a substantial increase in anticipated annual operating costs, with a cost effectiveness more than double that of the preliminary four-factor analysis cost calculations. These refinements support GCC and DANR's conclusions that SNCR does not represent an appropriate emissions reduction measure for the GCC Dacotah plant under the Regional Haze Program.

SNCR POTENTIAL ADVERSE ENVIRONMENTAL IMPACTS

In addition to providing refined cost calculations for SNCR as a potential retrofit technology at GCC Dacotah, GCC feels it is important to emphasize the notable adverse environmental impacts that could result from use of SNCR at the facility. As noted by DANR in the draft SIP, the Rapid City, SD area has historically struggled with high levels of particulate matter and Rapid City was classified as nonattainment for total suspended particulate from 1978 to 1986 before being designated as "unclassifiable" for PM_{10}. DANR developed a

Natural Events Action Plan specifically designed to help maintain compliance with the particulate matter National Ambient Air Quality Standards (NAAQS).

GCC noted in the initial four factor analysis for GCC Dacotah that use of ammonia injection with SNCR could result in the formation of ammonia slip and additional condensable particulate matter. Given GCC's experience with the installation of SNCR on other kilns at several GCC plants, the potential for substantial ammonia slip is a paramount concern when attempting to achieve substantial levels of NO_X control using SNCR. In GCC's experience, ammonia slip rates over 50 ppm have been necessary to achieve required NO_X reduction. Given Rapid City's historical challenges with PM air concentrations in the area, the potential for increased PM from ammonia means the installation of SNCR on the GCC Dacotah kiln in particular could negatively impact local efforts to maintain compliance with air quality standards. As such, GCC continues to support the conclusions made in both GCC Dacotah's four-factor analysis and DANR's draft SIP that SNCR is not an appropriate control technology retrofit for the GCC Dacotah kiln under the Regional Haze Program.

If you have any questions or comments about the information presented in this letter, please do not hesitate to call me at (605) 721-7033.

Sincerely,

GCC Dacotah

Jim Anderson
Environmental Engineer

Attachments: Refined SNCR Cost Calculations

cc: Ms. Sarah Vance, GCC

ATTACHMENT 1

Revised SNCR Cost Calculations

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? Industrial

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 687.92 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 10,368 Btu/lb

What is the estimated actual annual fuel consumption? 511,508,000 lbs/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 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: Bituminous

Enter the sulfur content (%S) = 0.36 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 9.23 percent by weight

*The ash content of 9.23% is a default value. See below for data source. Enter actual value, if known.

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	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted 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})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.46	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.32	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.05	
Concentration of reagent as stored (C_{stored})	19	Percent
Density of reagent as stored (ρ_{stored})	57.82	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	

Plant Elevation	3360	Feet above sea level

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	2018			
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI
Annual Interest Rate (i)	5.5	Percent*		
Fuel ($Cost_{fuel}$)	2.87	$/MMBtu		
Reagent ($Cost_{reag}$)	1.67	$/gallon for a 19 percent solution of ammonia		
Water ($Cost_{water}$)	0.0042	$/gallon*		
Electricity ($Cost_{elect}$)	0.08	$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)

* 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

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)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Site-specific vendor estimate.
Water Cost ($/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.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	Site-specific purchasing data for November 2021.
Fuel Cost ($/MMBtu)	2.40	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 purchasing data for November 2021.
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)	1.84	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/.	Sulfur content of coal is from the EIA Coal Data Browser, Sulfur Content by Plant State for South Dakota https://www.eia.gov/coal/data/browser/#/topic/53?agg=1,0&rank=g&mntp=g&geo=vvvvvvvvvvvvo&freq=A&rtype=s&pin=&rse=0&maptype=0&ltype=pin&ctype=map&end=2017&start=2008
Percent ash content for Coal (% weight)	9.23	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/.	
Higher Heating Value (HHV) (Btu/lb)	11,841	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/.	EIA, Monthly Energy Review July 2019, Table A4. Approximate Heat Content of Coal and Coal Coke (Page 210) - 2018 Heat content of Coal for Industrial Sector, Other, is 20.735 MMBtu/Ton (https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf)
Interest Rate (%)	5.5	Default bank prime 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 =	688	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	581,259,091	lbs/Year
Actual Annual fuel consumption (Mactual) =		511,508,000	lbs/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.88	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	7709	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	30	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	95.48	lb/hour
Total NO_x removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000$ =	368.02	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)	1.00	
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.13	
Atmospheric pressure at 3360 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	13.0	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 =	57.824 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)	124	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	651	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	84.2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	28,300	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	0.0837

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	15.7	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.47	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1×10^6)/HHV =	4.2	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 ($SNCR_{cost}$) =	$1,636,063	in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,487,469	in 2018 dollars
Total Capital Investment (TCI) =	$5,360,592	in 2018 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 ($SNCR_{cost}$) =	$1,636,063	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}) =	$0	in 2018 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}) =	$2,487,469	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,185,590	in 2018 dollars
Indirect Annual Costs (IDAC) =	$451,094	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$1,636,683	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 =	$80,409	in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$1,084,200	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$9,686	in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$10,500	in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$795	in 2018 dollars
Direct Annual Cost =		$1,185,590	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,412	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$448,682	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$451,094	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,636,683	per year in 2018 dollars
NOx Removed =	331	tons/year
Cost Effectiveness =	$4,941	per ton of NOx removed in 2018 dollars

APPENDIX C

SOUTH DAKOTA REGIONAL HAZE STATE IMPLEMENTATION PLAN: GCC DACOTAH FOUR FACTOR ANALYSIS

REGIONAL HAZE 2ND IMPLEMENTATION PERIOD FOUR-FACTOR ANALYSIS

GCC Dacotah > Rapid City, SD

Rapid City Plant Four-Factor Analysis

Prepared For:

Gina Lotito – Vice President of Energy and Environmental, GCC
James Anderson – Environmental Engineer, GCC

GCC DACOTAH
501 North Saint Onge Street
Rapid City, SD

Prepared By:

Anna Henolson – Managing Consultant
Sam Najmolhoda – Associate Consultant

TRINITY CONSULTANTS
20819 72nd Avenue S
Suite 610
Kent, WA
(253) 867-5600

October 2019

Project 190501.0146

TABLE OF CONTENTS

LIST OF TABLES

1. EXECUTIVE SUMMARY

GCC Dacotah (GCC) owns and operates a cement dry kiln at its Portland cement plant located at 501 North Saint Onge Street, Rapid City, SD (GCC Dacotah, or the facility). The kiln system features a low-NO_X burner, a preheater and a precalciner, as well as an in-line raw mill and in-line coal mill. The facility operates under the jurisdiction of the South Dakota Department of Environment and Natural Resources (DENR).

The following report represents GCC's response to a request by DENR on July 18, 2019 that GCC conduct a four-factor analysis of the plant's emission reduction options for visibility impairing pollutants. Per DENR, 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 cement kiln at the GCC Dacotah plant. 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 DENR and the Western Regional Air Partnership (WRAP) regarding potential SO_2 and NO_X emission reduction measures for the GCC Dacotah Portland cement kiln. Based on the Regional Haze Rule, associated U.S. EPA guidance, and DENR's request, GCC understands that DENR will only move forward with requiring emission reductions from the GCC Dacotah kiln if DENR 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. GCC 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	Dry Sorbent Injection	Yes	N/A	N/A	Already installed and operating primarily for HCl control
	Wet Scrubbing	Yes	No	No	Cost ineffective and has negative environmental impacts outweighing any benefit.
	Semi-Wet/Dry Scrubbing	Yes	No	No	Cost ineffective
NO_X	Low-NO_X Burners	Yes	N/A	N/A	Already installed and operating.
	Selective Catalytic Reduction (SCR)	No	N/A	No	Cost ineffective and has accompanying technical challenges as an unproven control on cement kilns.
	Selective Non-Catalytic Reduction (SNCR)	Yes	Possibly	No	Negative environmental and safety impacts.

As discussed in this four-factor analysis, GCC Dacotah concludes that the facility's existing control measures are the most suitable for SO_2 and NO_X emissions from the kiln. The emissions reduction methods analyzed in this report are found to be either technically infeasible or cost-ineffective, with the exception of SNCR. SNCR is deemed inappropriate because the adverse environmental, safety, and visibility impacts from ammonia slip outweigh the limited visibility improvement that may be gained from NO_X reduction. In particular, ammonia slip from SNCR leads to formation of secondary particulate matter (PM), which results in adverse environmental impacts both on regional haze in Class I areas and near the plant in the Rapid City area. Given Rapid City's historical challenges with demonstrating compliance with the National Ambient Air Quality Standards (NAAQS) for PM in the Rapid City area, the potential for increased PM from ammonia means the installation of SNCR on the GCC Dacotah kiln could negatively impact local efforts to maintain air quality. SNCR is also not necessary because the kiln has existing NO_X emission limits in place based on Prevention of Significant Deterioration (PSD) permitting Best Available Control Technology (BACT) levels, and its performance is already similar to new kilns with new PSD BACT limits. As such, add-on NO_X control may provide minimal benefit to visibility, but will have detrimental PM impacts to the nearby Rapid City area.

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.

On July 18, 2019, DENR sent a letter to GCC Dacotah requesting "a four-factor analysis of its operations for nitrogen oxide and sulfur dioxide" for GCC Dacotah's Rapid City plant.[1] GCC understands that the information provided in a four-factor review of control options will be used by DENR in their evaluation of reasonable progress goals for South Dakota. Based on the RHR, associated U.S. EPA guidance, and DENR's request, GCC understands that DENR will only move forward with requiring emission reductions from the GCC Dacotah kiln if DENR 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 DENR and WRAP regarding SO_2 and NO_X emission reductions that could or could not be achieved for the GCC Dacotah kiln, if the emission reductions are determined by DENR 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 kiln

[1] Refer to letter from DENR to GCC Dacotah dated July 18, 2019.

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 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.

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 GCC Dacotah kiln's existing/baseline emissions.

3. SOURCE DESCRIPTION

The GCC Dacotah plant is located in Rapid City, South Dakota. The nearest Class I areas to the plant are Badlands National Park and Wind Cave National Park, which are approximately 35.5 miles and 32.5 miles away, respectively.

The facility operates a dry kiln that features dual four-stage pre-heaters and a pre-calciner, as well as an in-line raw mill and in-line coal mill. GCC Dacotah previously operated two older wet kilns, which were retired in 2008 prior to the dry kiln upgrade permitted under SD Construction Permit 28.1121-02-03C. The kiln (in addition to the low-NO_X burner, pre-heater, pre-calciner, and in-line raw mill) is permitted to use lime injection as needed for HCl and SO_2 control. GCC Dacotah made significant capital investments in recent years to transition from two wet kilns to a single modern dry kiln and to upgrade the dry kiln and its precalciner burner. The project resulted in a substantial net decrease in the facility's emissions since the beginning of the regional haze program. This reduction was largely due to the retirement of the two wet kilns, but the kiln upgrade project also substantially improved the emissions performance of the kiln system.

The current dry kiln system produces emissions from three stacks at GCC's Rapid City plant. The kiln, alkali bypass, and coal mill each have their own stack, numbered 9, 11, and 41 respectively in the air permit. For the purposes of a control technology review, only the emissions from the kiln stack itself are considered. Emissions from other two stacks are smaller in magnitude compared to the main kiln stack.

3.1. PROCESS DESCRIPTION

The following subsections describe the processes and equipment used to manufacture Portland cement at the GCC Dacotah plant. A general process overview of the Portland cement manufacturing process is presented in Figure 2-3. The manufacturing process can be divided into three main steps: kiln feed preparation, clinker production, and finished cement grinding.

3.1.1. Kiln Feed Preparation

The basic ingredients of cement include oxides of calcium, silicon, aluminum, and iron. GCC Dacotah uses limestone (CaO) as a calcium source. The limestone, silica source, and aluminum source used for the manufacturing process are typically mined from quarries owned by GCC. The iron source is typically purchased and transported to the facility either by truck or rail car. Operations at the quarry involve topsoil removal, drilling, blasting, and hauling of blasted material. The blasted material, or raw material, is delivered to a crusher, which breaks material down into smaller sizes. After crushing, raw materials are stored and transported to raw mills, which are used to grind the crushed materials into appropriate sizes. The ground raw material is collected and fed to a blending system to provide the kiln with homogenous raw feed.

3.1.2. Clinker Production

The clinker production process involves high temperature processing of raw materials in a rotary kiln. Several different chemical reactions necessary to produce Portland cement take place within the kiln. The kiln is a countercurrent heating device, which is configured so that the material fed into the cooler upper section is gravity fed to the hotter discharge section prior to being discharged to a clinker cooler. Burners at the discharge section of the kiln produce hot gases to heat materials and drive the clinkering reactions.

The cement clinker formation process in the kiln consists of five stages which occur at an increasing temperature of the raw materials. In the preheater, uncombined water evaporates from raw materials as the temperature increases to 100 °C. Calcination occurs between 800 °C and 1,100 °C, liberating carbon dioxide (CO_2) from the carbonate component. Sintering of oxides occurs in the burning zone of the kiln at temperatures up to 1,510 °C. The sintering (or clinkering) reactions chemically combine calcined material with silica, alumina, and iron to form tricalcium silicate (Ca_3SiO_5), dicalcium silicate (Ca_2OSiO_2), tricalcium aluminate ($Ca_3OAl_2O_3$), and tetracalcium alumino-ferrite (Ca_4AlFeO_7). Clinker is quick-cooled following the sintering reactions in the clinker cooler, as the material heat is recovered and re-used in the process.

3.1.3. Finished Cement Grinding

Cooled clinker is conveyed to intermediate storage then fed to the finishing mills, where it is combined with gypsum, limestone, and other additive materials. The clinker, gypsum, limestone, and other additives are ground into a fine, homogenous powder in the finishing mills to form Portland cement. The finished product is transferred to the cement storage silos prior to shipment off site either by truck or railcar.

4. EXISTING EMISSIONS

This section summarizes emission rates that are used as baseline rates in the four factor analyses 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.

Regarding impacts on Class I areas in the region, it is worthwhile to consider the impacts of SO_2 and NO_X on visibility impairment. While the site-specific contributions to visibility impairment are not analyzed in this report, it is worth mentioning that SO_2 contributions to visibility impairment are nearly double those of NO_X emissions.[2] While both pollutants certainly can have a direct impact on visibility impairment, examination of SO_2 reduction methods are more readily applicable to the reduction of visibility impairment in South Dakota than that of NO_X reduction methods.

GCC Dacotah recently obtained a permit for and completed construction to upgrade the existing dry kiln. As part of the Kiln 6 upgrade, the kiln operations at the facility have since been subject to 3-hour rolling average limits for both NO_X and SO_2. These limits were set on a short-term pound per hour basis in order to establish and verify that the upgrade did not increase short-term emission rates (and thus did not meet the definition of modification under New Source Performance Standards [NSPS]). Since its start-up, Kiln No. 6 has experienced multiple operational challenges, which resulted in force-majeure events. GCC Dacotah has not achieved in practice its final, steady state, full-scale production rates as of the date of this report (October 2019). Therefore, for the purposes of the four-factor analysis, emission rates from the kiln stack are based on the projected actual emission rates used in the construction permit application for the kiln upgrade. Since the projected actual emissions in the application applied rates for the kiln, coal mill, and alkali bypass stacks combined, the projected annual emissions from the kiln stack for both NO_X and SO_2 are determined using CEMS data at each stack. The proportion of the total emissions feeding to the kiln stack is then applied to the overall projected actual emissions rate used in the permit. The baseline annual emission rates for the purposes of this analysis are summarized in Table 4-1, with values expressed in pounds per ton of clinker produced summarized in Table 4-2

[2] Federal Land Manager Environmental Database, Visibility Status and Trends Following the Regional Haze Rule Metrics. Light Extinction Summary – Most Impaired Days (DRAFT) for Wind Cave and Badlands National Park. http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx?appkey=SBCF_VisSum

Table 4-1. Baseline Emission Rates (tons/yr)

Pollutant	Baseline Annual Emissions (tons/yr)	
	Total Kiln System[1]	Kiln Stack[2]
SO_2	734	560
NO_X	1975	1,394

[1] Total kiln system baseline emissions are the projected actual emissions for the construction permit for the Kiln 6 upgrade, which accounts for the kiln, alkali bypass, and coal mill stacks.
[2] Kiln baseline emissions are derived from the total kiln system projected actual emissions and the proportion of the total emissions associated with the kiln stack. The proportion of kiln stack versus total kiln system is determined using CEMS data.

Based on the projected actual clinker production rate of 3,300 tons of clinker produced per day based on an annual average (used in the Kiln 6 upgrade permit application), these emissions can be expressed in terms of pounds of pollutant per ton of clinker produced. These values are provided in Table 4-2, below. When compared to Prevention of Significant Deterioration (PSD) permitting Best Available Control Technology (BACT) limits in the RACT/BACT/LAER Clearinghouse (RBLC) database, the kiln's SO_2 and NO_X emission levels on a lb/ton basis are comparable to recent PSD BACT limits.[3]

Table 4-2. Baseline Emission Rates (lb/ton clinker)

Pollutant	Baseline Emission Rate (lb/ton clinker)	RBLC Search Results Range (lb/ton clinker)[1]
SO_2	0.93	0.16-1.99
NO_X	2.31	1.5-4.48

[1] Range represents all PSD BACT and Lowest Achievable Emission Rate (LAER) RBLC database entries with a listed lb/ton clinker limit in the last 20 years. All entries for "Other case-by-case" determinations were excluded as outlier values significantly higher than the rest of the range.

The projected actual NO_X emissions from the kiln upgrade project were forecast to be below the historical baseline levels on a lb/ton clinker basis. Preliminary results indicate that the NO_X levels are in fact even lower than the originally predicted levels. While data are limited at this point in time, GCC expects continued performance at these satisfactory NO_X emissions levels.

[3] RBLC Search results are provided in Appendix C.

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 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 4-1. The basis of the emission rates is provided in Section 4 of this report. The kiln currently has inherent process limestone/lime scrubbing via an in-line raw mill that removes a substantial amount of the SO_2 that would otherwise be emitted from the raw material. This kiln configuration was determined to be BACT at the time of the kiln's PSD permit issuance date. In-line raw mill configuration is also commonly found to be BACT for preheater rotary kilns permitted today.[4]

When compared to the permitted emission rates for SO_2 found in the RBLC database,[5] GCC Dacotah's kiln emits SO_2 at a rate comparable to more recent kiln 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 cement kiln, as the sulfur in the fuel and raw materials 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 Dacotah kiln are summarized in Table 5-1. The retrofit controls include both add-on controls that eliminate SO_2 after it is formed and switching to lower sulfur fuels to reduce formation of SO_2.

[4] See Mississippi Lime permit (IL) from December 2010.

[5] RBLC Search results are located in Appendix C.

Table 5-1. Available SO_2 Control Technologies and Measures for the GCC Dacotah Kiln

SO_2 Control Technologies
Inherent Dry Scrubbing (Base Case)
Dry Sorbent Injection (Base Case)
Alternative Low Sulfur Fuels
Wet Scrubbing
Semi-Wet/Dry Scrubbing

5.1.1. Inherent Removal

In a kiln with an in-line raw mill, combustion gasses pass over the raw material, resulting in a reaction between sulfur dioxide and calcium in the limestone and other raw materials. This in-line raw mill configuration results in a removal efficiency as high as 98.8%.[6]

The kiln at the GCC Dacotah plant is equipped with an in-line raw mill, and the combined reduction in SO_2 emissions that would otherwise be emitted from the raw material, resulting from inherent removal in both the in-line raw mill and the kiln itself, is assumed to be approximately 90%. This in-line raw mill is not new to the kiln for the purposes of determining baseline emission reductions, and the control efficiency is therefore considered part of the baseline operating conditions. All additional control technologies will be evaluated with this control included in the basis, and the control measure will not be evaluated further as an additional available control.

5.1.2. Dry Sorbent Injection

Dry sorbent injection involves spraying a powdered sorbent, typically consisting of lime, sodium bicarbonate, or trona,[7] into the flue gas stream. The sorbent interacts with acid gases (HCl, for example) or SO_2 and forms larger particles that can be removed using an electrostatic precipitator or dry filter downstream.

The kiln as currently operated was determined to be BACT for SO_2 at the time of the kiln's PSD permit issuance date. When compared to the permitted emission rates for SO_2 found in the RBLC database, GCC Dacotah's kiln emits SO_2 at a rate comparable to SO_2 BACT limits on more recent kiln installations around the country. The GCC Dacotah kiln is already equipped with lime injection. Lime injection is currently installed primarily for HCl control, and GCC Dacotah is permitted to inject lime to manage HCl and SO_2 emissions as needed to meet the existing, appropriately-low SO_2 BACT limit. Therefore, dry sorbent injection will not be evaluated further.

[6] "Formation and Techniques for Control of Sulfur Dioxide and Other Sulfur Compounds in Portland Cement Kiln Systems," F. M. Miller, G. L. Young, and M. von Seebach, Portland Cement Association. 2001. Pages 37-39. http://www2.cement.org/pdf_files/sn2460.pdf

[7] Trona is a sodium carbonate compound, which is processed into soda ash or baking soda. https://www.wyomingmining.org/minerals/trona/

5.1.3. Alternative Low Sulfur Fuels

Fuels that can be considered for the cement kiln must have sufficient heat content, be dependable and readily available locally in significant quantities so as to not disrupt continuous production. Also, they must not adversely affect product quality.

Traditional fuels for cement kilns include natural gas, coal, and petroleum coke. GCC Dacotah is currently in the process of applying for a permit for the use of several additional alternative sources of fuel that are not expected to affect overall sulfur levels. While the commercial availability of these fuels has not been fully examined, GCC Dacotah is optimistic about the future operational flexibility that will allow for better emission management. The use of alternative fuels is not considered an available long-term method of SO_2 control for the purposes of regional haze because the availability of individual fuels with known lower sulfur content is not verifiable.

5.1.4. Wet Scrubbing

A wet scrubber is a tailpipe technology that may be installed downstream of the kiln. 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 calcium (typically) in the reagent 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.

5.1.5. Semi-Wet/Dry Scrubbing

Semi-wet/dry scrubbing is a method similar to wet scrubbing in principal; however, less water is used. 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 turns it into 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 are identified as available in Step 1.

5.2.1. Wet Scrubbing

A wet scrubbing system utilizes a ground alkaline agent, such as lime or limestone, in slurry to remove SO_2 from 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.

With the Dacotah plant's previous operation of wet kilns, the water rights are currently sufficient for the necessary water required to operate a wet scrubber. This technology is considered technically feasible and will be evaluated further.

5.2.2. Semi-Wet/Dry Scrubbing

Semi-wet/dry scrubbing is also technically feasible and will 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 control effectiveness. Table 5-2 presents potential SO_2 control technologies for the kiln and their associated control efficiencies.

Table 5-2. Ranking of SO_2 Control Technologies by Effectiveness

Pollutant	Control Technology	Potential Control Efficiency (%)
SO_2	Semi-wet/dry Scrubbing [a]	90
	Wet Scrubbing [a]	90

[a] Wet Scrubber and Semi-wet/dry Scrubber reduction efficiencies are determined using the U.S. EPA Air Pollution Control Technology Fact Sheet, Flue Gas Desulfurization (FGD) – Wet, Spray Dry, and Dry Scrubbers https://www3.epa.gov/ttn/catc/dir1/ffdg.pdf

5.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE SO_2 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

For purposes of this four-factor analysis, the capital costs, operating costs, and cost effectiveness of wet scrubbing and semi-wet/dry scrubbing have been estimated.

5.4.1.1. Control Costs

The capital and operating costs of the semi-wet/dry scrubber and the wet scrubber used in the cost effectiveness calculations are estimated based on recent vendor quotes for similar sources and published calculations methods. The capital cost is annualized over a 20-year period and then added to the annual operating costs to obtain the total annualized cost. The details of the capital and operating cost estimates are provided in Appendix A of this report.

5.4.1.2. Annual Tons Reduced

The annual tons reduced that are used in the cost effectiveness calculations are determined by subtracting the estimated controlled annual emission rates from the baseline annual emission rates. The baseline annual emission rates are summarized in Table 4-1. For a wet or semi-wet/dry scrubber, the controlled annual emission rate is based on the assumed maximum control efficiency noted in Table 5-2. Details are provided in Appendix A.

An estimate of the amount of SO_2 that may be reduced annually for each of the proposed options is summarized in Table 5-3.

5.4.1.3. Cost Effectiveness

The cost effectiveness is determined by dividing the annual control cost by the annual tons reduced. Table 5-3 summarizes the results.

Table 5-3. SO_2 Cost of Compliance Based on Emissions Reduction

Control Option	Control Cost ($/yr)	Baseline Emission Level (tons)	SO_2 Reduction (%)	Emission Reduction[a] (tons)	Cost Effectiveness ($/ton removed)
Semi-wet/dry Scrubbing	$3,036,248	560	90%	453.6	$6,694
Wet Scrubbing	$3,571,468	560	90%	453.6	$7,874

[a] Assumes a 90% Uptime for the Add-on Control Device

5.4.2. Timing for Compliance

GCC believes that reasonable progress compliant controls are already in place. However, if the U.S. EPA determines 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 long-term strategy for regional haze (approximately ten years following the U.S. EPA'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. 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.

The use of emissions reduction options involving the injection of lime (dry sorbent injection, wet scrubbing, and semi-wet/dry 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 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 GCC Dacotah 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

Both of the add-on SO_2 control options that have been considered in this analysis also have additional non-air quality impacts associated with them.

- A semi-wet/dry hydrated lime control system will require water to hydrate lime. There will also be additional material collected in the baghouses that will require disposal.
- A wet scrubber will require a significant quantity of water as well. In the Colorado Air Pollution Control Division (APCD) general analysis in the Regional Haze SIP Technical Analyses (April, 2010), the APCD

concluded, with regards to SO_2 controls, that wet scrubbing or wet flue gas desulfurization (FGD) has significant negative environmental impacts, particularly in the arid West, where water scarcity is a significant concern.[8] This holds especially true when weighing the benefits of a wet vs. a semi-wet or dry control technology, as wet scrubbing requires a substantial quantity of water. In addition, environmental concerns associated with sludge disposal and visible plumes resulted in the APCD's determination that wet scrubbers did not qualify as BART in Colorado. This logic is equally relevant for regional haze in South Dakota.

5.4.5. Remaining Useful Life

The remaining useful life of the kiln does not impact the annualized cost of an add-on control technology (semi-wet/dry scrubbing control) because the useful life is anticipated to be at least as long as the capital cost recovery period, which is 20 years.

5.5. SO_2 Conclusion

The dry cement kiln, equipped with an in-line raw mill, inherently removes the vast majority of SO_2 that is created from the process. In-line raw mill configuration was determined to be BACT for this kiln when its PSD permit was issued in 2003 and is a common BACT for rotary kilns recently permitted under the PSD program.[9]

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 kiln.

[8] Colorado Air Pollution Control Division (APCD) General Analysis: April 2010 (Regional Haze SIP Technical Analyses), "Regarding Energy and Non Air-Quality Impacts: SO_2 Controls."

[9] BACT determinations provided in RBLC Search Results, Appendix C.

As described in Section 2, Factors 1 and 3 of the four-factor analysis are considered 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 impacts 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 4-3. The basis of the emission rates is provided in Section 4 of this report. The kiln currently has a low-NO_X burner, a preheater, and a precalciner. The baseline NO_X emission rates for the GCC Dacotah kiln are within the range of permitted PSD BACT and LAER values on a lb/ton basis. In two instances, there are kilns with SNCR installed that have permitted emissions rates greater than the baseline emission rate for the GCC Dacotah kiln.

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. 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 kiln system, which in turn affects the creation of NO_x.[10]

Most of the NO_X formed within a cement 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 degrees Fahrenheit. 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. The addition of a preheater and precalciner to a kiln system not only allows for more efficient heat transfer, reducing the fuel required to achieve sufficient material temperatures, but also reduces the heat input required in the peak combustion zone in the kiln, limiting thermal NO_X production in the kiln system. A preheater/precalciner kiln system uses staged combustion in reducing conditions, limiting the formation of NO_X.[11] By controlling the combustion air using this low-NO_X burner technique, maintaining a reducing environment, fuel NO_X is controlled. This effect is combined with the benefits of combusting the fuel in stages

[10] Alternative Control Techniques Document Update - NOx Emissions from New Cement Kilns, U.S. Environmental Protection Agency, November 2007 (EPA-453/R-07-006), Page 3.

[11] Ibid, Page 5.

using a precalciner, a method which allows for more fuel to be burned at the calcining temperature rather than the higher peak flame temperature within the kiln, thereby reducing thermal NO_X formation as well.

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 Dacotah kiln are summarized in Table 6-1.

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

NO_x Control Technologies	
Combustion Controls	Low NO_x Burners (LNB) (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 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.

6.1.1. Combustion Controls

6.1.1.1. 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 resulting from the staged combustion lower flame temperatures and reduce thermal NO_X formation. 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.[12]

The facility currently operates a low-NO_X burner in its cement kiln, and low-NO_X burners are therefore not considered as an additional available NO_X emission control measure for this facility. Baseline emissions are based on the operation of this Low-NO_X burner. All alternative methods of NO_X control in this analysis will assume that the kiln continues to operate this burner.

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

6.1.2. Post Combustion Controls

6.1.2.1. 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:

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

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

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.[13] 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. The application of SCR is extremely limited in the U.S. cement industry, as only one cement plant has installed SCR (in 2015) and the specifics of its installation, use, and success remain confidential.

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.[14] 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 U.S. EPA Control Cost Manual indicates that SNCR requires a higher temperature range than SCR of between approximately 1,550˚F and 1,950˚F,[15] 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

[13] 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.

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

[15] Ibid, Page 1-6

range of temperatures. At higher temperatures, NO_X reduction rates decrease.[16] In addition, a greater residence time is required for lower temperatures.

In cement kilns, SNCR can be applied in certain combustion zones of kilns to facilitate SNCR in a non-tailpipe mode. However, there are several complications that can occur when attempting to identify and successfully implement the controls in these ideal temperature zones, resulting in significant variability among the reduction efficiencies achieved with SNCR in cement kilns around the country.[17] In other words, SNCR on cement kilns has achieved varying and sometimes poor success, often due to the injection zone temperatures diverging from optimal.

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

Efficient operation of an SCR process requires fairly constant exhaust temperatures (usually ± 200°F).[18] 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 further ammonia slip. Other emissions possibly affected by SCR include increased particulate matter (PM) emissions (from ammonia salts in a detached plume) and increased SO_3 emissions (from oxidation of SO_2 on the catalyst). Each of these emissions are of greater concern in the cement industry, compared to the application with industrial boilers or even the cement industry in Europe, due to the increased sulfur content found in the processed raw material.

To reduce fouling in the catalyst bed with the PM in the exhaust stream, an SCR unit could be located downstream of the particulate matter control device (PMCD). However, due to the low exhaust gas temperature exiting the PMCD (approximately 250°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. Given the operational challenges GCC Dacotah has faced optimizing the upgraded Kiln 6 system, further optimization of the kiln could result in an even lower outlet temperature. 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.[19] Therefore, in addition to storage and handling equipment for the ammonia, the required equipment for the SCR system would include a catalytic reactor, heat exchanger

---

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

[17] SNCR control efficiencies as low as 10% have been reported for some European kilns, with efficiencies as high as 85% for other kilns, per the U.S. EPA, Alternative Control Techniques Document Update – NO_X Emissions from New Cement Kilns. EPA-453/R-07-006 Section 2.6, Page 7.

[18] Ibid, Page 2-11

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

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 due to the increase in required pitch size (which reduces the surface-area to volume ratio for the catalyst), as well as 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, which result in significant additional capital costs.

Only one cement kiln in the U. S. is using SCR for NO_X emissions control, and the details of its installation, use, and success 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.[20] This effect directly and negatively impacts SCR effectiveness for NO_X 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.[21]

In the U.S. 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 U.S. 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:

> *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*

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

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

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 semi-dust SCR's are not considered technically feasible for this facility.

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 1,550°F and 1,950°F)[22]. When temperatures at the injection point for this technology exceed 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 NO formation condition would likely be the case if ammonia was directly injected into the kiln tube, as high temperatures are required for product quality. Furthermore, at temperatures below the required range, appreciable quantities of un-reacted ammonia will be released to the atmosphere via ammonia slip. This ammonia slip can form PM that is 2.5 microns in size or smaller ($PM_{2.5}$) (most commonly ammonium sulfates and ammonium nitrates) in the atmosphere, resulting in increased visibility impairment. The ammonia slip emissions can cause adverse health effects directly from both the NH_3 and from $PM_{2.5}$. Based on the U.S. EPA's report on NO_X emissions and controls from new cement kilns, ammonia slip at levels of 25 ppm or greater can result in direct health impacts to the community.[23] In the case of cement kilns, and preheater and precalciner kilns in particular, the optimal location for injection occurs in the combustion zone in the calciner, the oxidation zone of the upper air inlet before the deflection chamber, or in the area after the mixing chamber before the inlet to the bottom cyclone.[24]

The potential for ammonia slip emissions from SNCR to result in formation of $PM_{2.5}$ is directly tied to an additional significant concern for the Rapid City community. The Rapid City area has historically faced issues with high particulate levels. From 1978 to 1986, Rapid City was classified as nonattainment for total suspended particulate (TSP) before being designated as "unclassifiable" for PM that is 10 microns in size or smaller (PM_{10}).[25] The exceedances that have occurred over the last several decades coincide with high wind events, and thus the Natural Events Action Plan (NAEP) was developed in 1998 to provide measures that limit PM emissions. When unreacted ammonia passes through the kiln, it has the potential to form particulate matter through the formation of ammonium sulfate and other ammonium salts. Given GCC's experience with the installation of SNCR on other kilns at several GCC plants, the potential for substantial ammonia slip is a paramount concern when attempting to achieve substantial

---

[22] Air Pollution Control Cost Manual, Section 4, Chapter 1, Selective Non-Catalytic Reduction, NOx Controls, EPA/452/B-02-001, Page 1-5.

[23] U.S. EPA, Office of Air Quality Planning and Standards. Alternative Control Technologies Document Update – NOx Emissions from New Cement Kilns. EPA-453/R-07-006, Page 53.

[24] Ibid, Page 49.

[25] South Dakota Department of Environment & Natural Resources, Natural Events Action Plan – Particulate Matter Background History. https://denr.sd.gov/des/aq/neap/neapabout.aspx

levels of NO_X control using SNCR. In GCC's experience, ammonia slip rates over 50 ppm have been necessary to achieve required NO_X reduction.

Detached plumes are opaque, visible emissions formed away from the stack. According to a study conducted by the U.S. EPA of detached plume formation from cement production plants, the majority of detached plumes created by the cement production process is composed of ammonia-based particulate matter.[26] When sufficiently high ammonia concentrations exist in the exhaust from the kiln, the ammonia can react with other products, namely HCl and SO_2, to form particulate matter. In the case of the rapid city area, PM_{10} emissions are relatively close to exceeding the National Ambient Air Quality Standard (NAAQS), with a current concentration of 124 $\mu g/m^3$ compared to the standard of 150 $\mu g/m^3$.[27]

Given Rapid City's historical challenges with PM air concentrations in the area, the potential for increased PM from ammonia means the installation of SNCR on the GCC Dacotah kiln in particular could negatively impact local efforts to maintain compliance with air quality standards.

Despite the technical and adverse environmental impacts detailed above, the installation of SNCR is considered technically feasible for GCC Dacotah's cement kiln 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 kiln and their associated control efficiencies.

Table 6-2. Ranking of NO_X Control Technologies by Effectiveness

Pollutant	Control Technology	Potential Control Efficiency (%)
NO_X	SNCR	50[a]
	Low NO_x Burner	Base Case

[a] Approximately the average control efficiency for SNCR, per the U.S. EPA Control Cost Manual Table 1.2, "SNCR NO_X Reduction Efficiency by Industry and Reagent Type."

[26] Cheney, et al. "Formation of a Detached Plume from a Cement Plant," Environmental Sciences Research Laboratory. EPA-600/S3-83-102, December 1983. Accessed from: https://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=2000TSQW.TXT.

[27] Rapid City pollutant concentration data (for 2018) obtained from the U.S. EPA Air Quality Statistics Report: https://www.epa.gov/outdoor-air-quality-data/air-quality-statistics-report.

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.

6.4.1.1. 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 ($/yr)	Baseline Emission Level (tons)	NO_X Reduction (%)	Emission Reduction (tons)	Cost Effectiveness ($/ton removed)
SNCR	$693,165	1,394	30	331[1]	$2,093

[1] Emission reduction assumes a 90% control technology uptime.

6.4.2. Timing for Compliance

GCC Dacotah believes that reasonable progress compliant controls are already in place. However, if the DENR 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).

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 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.

The use of NO_X reduction methods that incorporate ammonia injection leads to increased health risks and adverse environmental impacts to the local community from ammonia slip emissions, especially through the formation of $PM_{2.5}$, a pollutant that the Rapid City area has struggled with historically.

Environmental agencies around the country have acknowledged the significance of ammonia slip and the potential increases in $PM_{2.5}$ that can result from the introduction of excess ammonia slip into the atmosphere. The Texas Commission on Environmental Quality (TCEQ), for example, concludes the following in their "Assessment of NO_X Emissions Reductions Strategies for Cement Kilns – Ellis County," an evaluation of several NO_X reductions methods including SNCR and SCR:

> *Presence of "slip" ammonia reagent is expected to form sulfate and nitrate fine particles closer to the stack and may cause increased opacity at the stack. However, this is not a "new" pollutant in that the precursor pollutants released by cement kilns will tend to form fine particles in the atmosphere using atmospheric ammonia. The excess ammonia from SCR and SNCR will cause formation to occur closer to the stack. Excess opacity with the raw mill off-line may be exacerbated using SNCR.*

For jurisdictions that struggle with meeting PM standards, the California Environmental Protection Agency Air Resources Board's guidance document[28] 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 $PM_{2.5}$.*"

In the case of South Dakota specifically, anthropogenic area sources represented the largest increase in ammonia emissions between 2002 and 2011, per the 5-Year Progress Report.[29] The use of SNCR or SCR for NO_X control introduces the risk of excessive ammonia slip emissions, which can directly increase PM concentration in a region already struggling to meet the national standard.

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

SNCR is assumed to have a remaining useful life of 20 years, per U.S. EPA and DENR guidelines. The kiln is assumed to have a remaining useful life of at least 20 years as well.

---

[28] 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

[29] South Dakota's Regional Haze State Implementation Plan, 5-Year Progress Report, January 27, 2016. Page 24. https://denr.sd.gov/des/aq/aqnews/RH5YearReport.pdf

6.5. NO_X CONCLUSION

The facility currently uses a low NO_X burner in its kiln to lower NO_X emissions, in addition to having dual four-stage preheaters and a precalciner that limit NO_X emissions from the kiln. Low NO_X burners are commonly determined to be BACT in recent permitting decisions for new rotary preheater kilns, and the kiln achieves PSD BACT NO_X limits as currently operated. SCR is not a technically feasible control option for this kiln. While SNCR *may* represent a cost-effective option for NO_X emissions reduction, the introduction of substantial ammonia slip has the potential to cause adverse environmental impacts immediately relevant to the Rapid City community. In an area already struggling with PM emissions, the injection of the ammonia necessary for substantial reductions in NO_X emissions has the potential to lead to the formation of ammonia salts that would contribute directly to the PM issues in the city. The ammonia and $PM_{2.5}$ emissions both have the potential to cause direct health impacts for those in the area, and the storage and transportation of ammonia present additional safety concerns. Furthermore, significant capital expense has gone into upgrading the kiln recently. As a result of the upgrades to the kiln and recent upgrades to the calciner burner, not only is the GCC Dacotah kiln projected to have emission levels of NO_X (lb/ton basis) below historic levels, but preliminary data indicate that NO_X emissions may be even lower than the expected projected actual levels. Despite being over a decade old, the GCC Dacotah kiln is achieving a NO_X emission rate on a lb/ton of clinker produced basis that is comparable to PSD BACT levels set on modern kilns.[30] There are two instances of kilns that have SNCR installed which have an associated PSD BACT limit greater than the baseline emission rate for the GCC Dacotah kiln. Therefore, additional add-on controls for NO_X emissions reductions are not necessary on the GCC Dacotah kiln.

[30] See RBLC search results in Appendix C.

APPENDIX A : SO_2 CONTROL COST CALCULATIONS

Wet Scrubber Cost Calculations

Direct Costs per Kiln			
Purchased Equipment Costs			
Wet Scrubber Unit[1]	Equipment Costs (EC)	$	15,500,000.00
Instrumentation[2]	10% of EC	$	1,550,000.00
Sales Tax[2]	3% of EC	$	465,000.00
Freight[2]	5% of EC	$	775,000.00
Subtotal, Purchased Equipment Cost (PEC)		$	18,290,000.00
Total Direct Cost		$	18,290,000.00

Indirect Installation Costs per Kiln[2]			
Engineering	10% of PEC	$	1,829,000.00
Construction and Field Expenses	10% of PEC	$	1,829,000.00
Contractor Fees	10% of PEC	$	1,829,000.00
Start-up	1% of PEC	$	182,900.00
Performance Test	1% of PEC	$	182,900.00
Contingencies	3% of PEC	$	548,700.00
Total Indirect Cost		$	6,401,500.00

Total Capital Investment (TCI) per Kiln		**$**	**24,691,500.00**

Direct Annual Costs per Kiln			
Hours per Year[3]	Kilns run near continuously. Down less than 15% of selected time period		6817
Operating Labor			
Operator[4]	0.5 hr/shift, 3 shifts/day, 365 d/yr, $33.34/hr	$	18,253.65
Supervisor[2]	15% of operator	$	2,738.05
Subtotal, Operating Labor		$	20,991.70
Maintenance			
Labor[4]	0.5 hr/shift, 3 shifts/day, 365 d/yr, $37.94/hr	$	20,772.15
Material[2]	100% of Maintenance Labor	$	20,772.15
Subtotal, Maintenance		$	41,544.30
Utilities per Kiln			
Electricity			
Scrubber Electrical Rating[5]	kW		224.31
Cost[6]	$/kW-hr	$	0.08
Subtotal, Electricity		$	121,711.91
Limestone Slurry			
Amount Required[5]	ton/yr		400.16
Cost[7]	$/ton	$	11.90
Subtotal, Lime		$	4,761.86
Water			
Amount Required[5]	gpm		9.37
Cost[8]	$/1000 gallons	$	-
Subtotal, Water		$	-
Sludge Disposal			
Amount Generated[5]	tpy		830.41
Disposal Fee[9]	$/ton	$	32.00
Subtotal, Sludge		$	26,573.23
Subtotal, Utilities		$	153,047.00
Total Direct Annual Cost		$	215,583.00

Indirect Annual Costs per Kiln[2]			
Overhead	60% of sum of operating, supervisor, maintenance labor & materials	$	37,521.60
Administrative	2% of TCI	$	493,830.00
Property Tax	1% of TCI	$	246,915.00
Insurance	1% of TCI	$	246,915.00
Capital Recovery	20 year life, 7% interest	$	2,330,702.93
Total Indirect Annual Cost		$	3,355,884.52

Total Annualized Cost per Kiln		**$**	**3,571,467.52**

1) Wet scrubber unit equipment costs based on cost estimate from Bridge Gap Engineering Group for the cement kilns at the GCC Tijeras plant. Estimate includes reactor vessel, cyclones, storage bins, structural steel, and installation. The cost estimate is assumed to not include indirect installation costs.

2) Table 1.3 and Table 1.4 of the EPA Control Cost Manual 6th Edition, Section 5.2, Chapter 1

3) Based on average run time of Kilns #1 and from 2016 to 2018.

4) Labor time and percentages taken from Table 1.4 of the EPA Control Cost Manual 6th Edition, Section 5.2, Chapter 1. Labor costs are specific to GCC.

5) Utility usage rates obtained from quote provided to GCC Pueblo in 2000. Values are scaled by the annual emission rate of SO_2.

6) Cost of electricity EIA electricity database. Refer to webpage (https://www.eia.gov/electricity/data/browser/#/topic/7?agg=0,1&geo=g&endsec=vg&linechart=ELEC.PRICE.US-ALL.A~ELEC.PRICE.US-RES.A~ELEC.PRICE.US-COM.A~ELEC.PRICE.US-IND.A&columnchart=ELEC.PRICE.US-ALL.A~ELEC.PRICE.US-RES.A~ELEC.PRICE.US-COM.A~ELEC.PRICE.US-IND.A&map=ELEC.PRICE.US-ALL.A&freq=A&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0)

7) Cost of limestone from USGS 2019 mineral yearbook, Crushed Stone, Page 158. Refer to webpage (http://prd-wret.s3-us-west-2.amazonaws.com/assets/palladium/production/atoms/files/mcs2019_all.pdf)

8) There are no direct costs associated with water use, as there is a well constructed on site.

9) Site-specific cost for solid waste disposal to landfill.

Semi-Dry Scrubber Cost Calculations

Direct Costs per Kiln			
Purchased Equipment Costs			
Wet Scrubber Unit[1]	Equipment Costs (EC)	$	13,000,000.00
Instrumentation[2]	10% of EC	$	1,300,000.00
Sales Tax[2]	3% of EC	$	390,000.00
Freight[2]	5% of EC	$	650,000.00
Subtotal, Purchased Equipment Cost (PEC)		$	15,340,000.00
Total Direct Cost		$	15,340,000.00

Indirect Installation Costs per Kiln[2]			
Engineering	10% of PEC	$	1,534,000.00
Construction and Field Expense	10% of PEC	$	1,534,000.00
Contractor Fees	10% of PEC	$	1,534,000.00
Start-up	1% of PEC	$	153,400.00
Performance Test	1% of PEC	$	153,400.00
Contingencies	3% of PEC	$	460,200.00
Total Indirect Cost		$	5,369,000.00

Total Capital Investment (TCI) per Kiln	**$**	**20,709,000.00**

Direct Annual Costs per Kiln			
Hours per Year[3]	Kilns run near continuously. Down less than 15% of selected time period		6816.662225
Operating Labor			
Operator[4]	0.5 hr/shift, 3 shifts/day, 365 d/yr, $33.34/hr	$	18,253.65
Supervisor[2]	15% of operator	$	2,738.05
Subtotal, Operating Labor		$	20,991.70
Maintenance			
Labor[4]	0.5 hr/shift, 3 shifts/day, 365 d/yr, $37.94/hr	$	20,772.15
Material[2]	100% of Maintenance Labor	$	20,772.15
Subtotal, Maintenance		$	41,544.30
Utilities per Kiln			
Electricity			
Scrubber Electrical Rating[5]	kW		224.31
Cost[6]	$/kW-hr	$	0.08
Subtotal, Electricity		$	121,711.91
Limestone Slurry			
Amount Required[5]	ton/yr		400.16
Cost[7]	$/ton	$	11.90
Subtotal, Lime		$	4,761.86
Water			
Amount Required[8]	gpm		7.00
Cost[9]	$/1000 gallons	$	-
Subtotal, Water		$	-
Sludge Disposal			
Amount Generated[5]	tpy		830.41
Disposal Fee[10]	$/ton	$	32.00
Subtotal, Sludge		$	26,573.23
Subtotal, Utilities		$	153,047.00
Total Direct Annual Cost		$	215,583.00

Indirect Annual Costs per Kiln[2]			
Overhead	60% of sum of operating, supervisor, maintenance labor & materials	$	37,521.60
Administrative	2% of TCI	$	414,180.00
Property Tax	1% of TCI	$	207,090.00
Insurance	1% of TCI	$	207,090.00
Capital Recovery	20 year life, 7% interest	$	1,954,783.10
Total Indirect Annual Cost		$	2,820,664.70

Total Annualized Cost per Kiln	**$**	**3,036,247.69**

1) Semi-dry scrubber unit equipment costs based on cost estimate from Bridge Gap Engineering Group for the cement kilns at the GCC Tijeras plant. Estimate includes reactor vessel, cyclones, storage bins, structural steel, and installation. The cost estimate is assumed to not include indirect installation costs.

2) Table 1.3 and Table 1.4 of the EPA Control Cost Manual 6th Edition, Section 5.2, Chapter 1

3) Based on average run time of Kilns #1 and from 2016 to 2018.

4) Labor time and percentages taken from Table 1.4 of the EPA Control Cost Manual 6th Edition, Section 5.2, Chapter 1. Labor costs are specific to GCC.

5) Utility usage rates obtained from quote provided to GCC Pueblo in 2000. Values are scaled by the annual emission rate of SO_2.

6) Cost of electricity EIA electricity database. Refer to webpage (https://www.eia.gov/electricity/data/browser/#/topic/7?agg=0,1&geo=g&endsec=vg&linechart=ELEC.PRICE.US-ALL.A~ELEC.PRICE.US-RES.A~ELEC.PRICE.US-COM.A~ELEC.PRICE.US-IND.A&columnchart=ELEC.PRICE.US-ALL.A~ELEC.PRICE.US-RES.A~ELEC.PRICE.US-COM.A~ELEC.PRICE.US-IND.A&map=ELEC.PRICE.US-ALL.A&freq=A&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0)

7) Cost of limestone from USGS 2019 mineral yearbook, Crushed Stone, Page 158. Refer to webpage (http://prd-wret.s3-us-west-2.amazonaws.com/assets/palladium/production/atoms/files/mcs2019_all.pdf)

8) Water usage rates are obtained from the vendor quote provided to GCC's Pueblo plant for a wet scrubber. The difference in water usage between a wet scrubber and a semi-dry scrubber is scaled by the difference provided in the "Preliminary Economic Analysis of a Lime Spray Dryer FGD System," U.S. EPA Industrial Environmental Research Laboratory. EPA-600/7-808-050, March 1980. Pages 44, 46. https://nepis.epa.gov/Exe/ZyPDF.cgi/9101FOIG.PDF?Dockey=9101FOIG.PDF. The water

Wet Scrubber (Limestone Slurry Process):	99670	kgal
Semi-dry Scrubber (Lime Spray Dryer):	74440	kgal

8) There are no direct costs associated with water use, as there is a well constructed on site.

9) Site-specific cost for solid waste disposal to landfill.

APPENDIX B : NO_X CONTROL COST CALCULATIONS

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 ($SNCR_{cost}$) =	$1,636,063 in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,487,469 in 2018 dollars
Total Capital Investment (TCI) =	$5,360,592 in 2018 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 ($SNCR_{cost}$) =	$1,636,063 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}) =	$0 in 2018 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}) =	$2,487,469 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$242,071 in 2018 dollars
Indirect Annual Costs (IDAC) =	$451,094 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$693,165 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 =	$80,409 in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$128,688 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$9,638 in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$3,122 in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$18,536 in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$1,678 in 2018 dollars
Direct Annual Cost =		$242,071 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,412 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$448,682 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$451,094 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$693,165 per year in 2018 dollars
NOx Removed =	331 tons/year
Cost Effectiveness =	$2,093 per ton of NOx removed in 2018 dollars

APPENDIX C : RBLC SEARCH RESULTS

RBLC ID	Facility Name	Facility State	Permit Number	Permit Issuance Date	Process Name	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Average Time Condition	Case-By-Case Basis	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Average Time Condition	Standard Emission Limit	Standard Emission Limit Unit	Standard Limit Average Time Condition	Pollutant Compliance Notes
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CO	98PB0893	9/25/2000	PREHEATER/PRECALCINER, KILN	Nitrogen Oxides (NOx)	MULTI-STAGE COMBUSTION AND RECIRCULATION. EMISSION LIMIT IN LB/T OF CLINKER. LB/T LIMIT IS 12-MO ROLLING AVG.	2.32	LB/T		BACT-PSD	1100	T/YR		2.32	LB/T		
FL-0139	SUWANNEE AMERICAN CEMENT COMPANY, INC.	FL	1210465-001-AC	6/1/2000	IN LINE KILN & RAW MILL	Nitrogen Oxides (NOx)	MULTI-STAGE COMBUSTION W/SEPARATE LINE CALCINER COMBUSTION CHAMBER.	2.9	LB/T	CLINKER	BACT-PSD	0			0			
FL-0267	THOMPSON S. BAKER-CEMENT PLANT (FRI)	FL	PSD-FL-350; 0010087-013-AC	11/5/2004	IN LINE KILN/RAW MILL WITH ESP AND SNCR	Nitrogen Oxides (NOx)	SNCR	1.95	LB/TON CLINKER	30 DAY	BACT-PSD	243.75	LB/H	30 DAY	0			FOR THE FIRST 180 DAYS AFTER INITIAL START UP, NOX EMISSIONS SHALL NOT EXCEED 2.45 LB/TON CLINKER.
FL-0268	BROOKSVILLE CEMENT PLANT (FCS)	FL	PSD-FL-351; 0530021-009-AC	12/20/2004	125 TPH CLINKER KILN AND ASSOCIATED EQUIPMENT	Nitrogen Oxides (NOx)	SNCR	1.95	LB/TON CLINKER	30 DAY	BACT-PSD	243.75	LB/H	30 DAY	0			FOR 180 DAYS AFTER INITIAL STARTUP, NOX EMISSIONS SHALL NOT EXCEED 2.4 LB/TON CLINKER.
FL-0271	BRANFORD CEMENT PLANT (SUWANNE)	FL	1210465-014-AC; PSD-FL-352	3/30/2006	KILN W/IN LINE RAW MILL W/ SNCR AND BAGHOUSE	Nitrogen Oxides (NOx)	SNCR	1.95	LB/TON CLINKER	CEMS 30 DAYS ROLLING AVERAGE	BACT-PSD	247.7	LB/H	CEMS 30 DAYS ROLLING AVERAGE	0			FOR INITIAL START UP NOX EMISSIONS SHALL NOT EXCEED 3 LB/TON
FL-0297	NORTH BROOKSVILLE CEMENT PLANT	FL	PSD-FL-384	6/27/2007	KILN NO. 3 WITH PREHEATER, CALCINER, IN-LINE RAW MILL AND AIR HEATER	Nitrogen Oxides (NOx)	THE SELECTIVE NON-CATALYTIC REDUCTION (SNCR) PROCESS, THE SELECTIVE CATALYTIC REDUCTION (SCR) PROCESS OR ANY COMBINATION THEREOF	1.5	LB/T CLINKER	30-DAYS ROLLING	BACT-PSD	0			0			241 LB/H ____________ NOX CONTROLS A) LOW-NOX BURNERS AND INDIRECT FIRING: THE MAIN KILN AND CALCINER WILL BE EQUIPPED WITH LOW NOX BURNERS THAT WILL CREATE DISTINCT COMBUSTION ZONES WITHIN THE FLAME. AN INDIRECT FIRING SYSTEM WILL BE USED TO REDUCE THE AMOUNT OF PRIMARY AIR INJECTED WITH THE FUEL USED IN THE MAIN KILN BURNER. B) STAGED COMBUSTION IN THE CALCINER (SCC): INTRODUCTION OF FUEL, AIR AND MEAL TO THE CALCINER WILL BE STAGED OR SEQUENCED FOR THE REDUCTION OF NOX EMISSIONS. C) AMMONIA INJECTION SYSTEM (AIS): AN AIS SHALL BE DESIGNED, CONSTRUCTED AND OPERATED TO ACHIEVE THE PERMITTED LEVELS FOR NOX
GA-0134	HOUSTON AMERICAN CEMENT PLANT	GA	3241-153-0056-P-01-0	6/19/2007	MAIN KILN STACK ST35	Nitrogen Oxides (NOx)	STAGED AND CONTROLLED COMBUSITON (SCC), SNCR, LOW NOx BURNER AND INDIRECT FIRING.	1.95	LB/T CLINKER	30 DAY ROLLING AVG	BACT-PSD	243.8	LB/H		1.95	LB/T CLINKER	30 DAY ROLLING AVG	
GA-0136	CEMEX SOUTHEAST, LLC	GA	3241-153-0003-V-04-3	1/27/2010	MAIN KILN STACK K218	Nitrogen Oxides (NOx)	STAGED & CONTROLLED COMBUSTION (SCC), SNCR, LOW NOx BURNER AND INDIRECT FIRING.	1.95	LB/T CLINKER	30-DAY ROLLING AVG. BASED ON NOX CEMS	BACT-PSD	312	LB/H		1.95	LB/T CLINKER	30-DAY ROLLING AVG. BASED ON NOX CEMS	

RBLC ID	Facility Name	Facility State	Permit Number	Permit Issuance Date	Process Name	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Average Time Condition	Case-By-Case Basis	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Average Time Condition	Standard Emission Limit	Standard Emission Limit Unit	Standard Limit Average Time Condition	Pollutant Compliance Notes
IA-0070	LEHIGH CEMENT COMPANY - MASON CITY PLANT	IA	17-01-005	12/11/2003	KILN/CALCINER/PREHEATER	Nitrogen Oxides (NOx)	SNCR, LOW NOX BURNERS, COMBUSTION CONTROLS, AND PROPER KILN DESIGN.	2.85	LB/T	LB/T OF CLINKER	BACT-PSD	1496	T/YR		0			THE LB/TON BACT LIMIT IS A 30 DAY ROLLING AVG THAT DOES NOT INCLUDE EMISSIONS FROM STARTUP, SHUTDOWN, OR MALFUNCTION (SSM). THE T/YR LIMIT INCLUDES ALL EMISSIONS INCLUDING SSM. THERE IS A NAAQS LIMIT OF 427.5 LB/H (CALENDAR MONTH AVG).
IL-0111	UNIVERSAL CEMENT	IL	8120011	12/20/2011	KILN WITH IN-LINE RAW MILL	Nitrogen Oxides (NOx)	STAGED COMBUSTION AND SNCR	1.5	LB/TON CLINKER	30-DAY ROLLING AVERAGE	LAER	1.2	LB/TON CLINKER	30-DAY ROLLING AVERAGE	0			THE 1.5 LB/T LIMIT APPLIES DURING THE FIRST 395 OPERATING DAYS AFTER INITIAL STARTUP; THEREAFTER, THE 1.2 LB/T LIMIT APPLIES. LIMITS DO NOT APPLY DURING EMISSION TESTING TO CALIBRATE PM CEMS. NOX CEMS REQUIRED.
IN-0312	LEHIGH CEMENT COMPANY LLC	IN	093-40198-00002	6/27/2019	Kiln	Nitrogen Oxides (NOx)	low NOx burners and selective non-catalytic reduction (SNCR)	1.5	LB/TON CLINKER	30-DAY ROLLING AVERAGE	BACT-PSD	0			0			
SC-0132	ARGOS HARLEYVILLE PLANT	SC	0900-0004-EF-R2	12/14/2007	PREHEATER/PRECALCINER KILN 1	Nitrogen Oxides (NOx)	SELECTIVE NON-CATALYTIC REDUCTION (SNCR), STAGED COMBUSTION, INDIRECT FIRING, AND LOW NOX BURNERS	2.65	LB/TON CLINKER	30 DAY ROLLING AVERAGE	BACT-PSD	0			0			CEM ON MAIN STACK. DURING SHAKEDOWN (UP TO 12 MONTHS), A NOX EMISSION RATE OF 3.5 LB/TON OF CLINKER IS ALLOWED. THE EMISSION LIMIT IS FOR THE TOTAL COMBINED NOX EMISSIONS FROM THE MAIN KILN STACK AND THE PRECALCINER COAL MILL STACK.
SC-0132	ARGOS HARLEYVILLE PLANT	SC	0900-0004-EF-R2	12/14/2007	PREHEATER/PRECALCINER KILN 2	Nitrogen Oxides (NOx)	SELECTIVE NON-CATALYTIC REDUCTION (SNCR), STAGED COMBUSTION, INDIRECT FIRING, AND LOW NOX BURNERS	1.95	LB/TON CLINKER	30 DAY ROLLING AVERAGE	BACT-PSD	0			0			CEM TO BE INSTALLED. DURING SHAKEDOWN (UP TO 12 MONTHS), A NOX EMISSION RATE OF 3.0 LB/TON CLINKER IS ALLOWED.
SC-0133	HOLCIM US INC. HOLLY HILL PLANT	SC	1860-0005-CO-CU	12/22/1999	CEMENT KILN SYSTEM	Nitrogen Oxides (NOx)	LOW NOX BURNERS, BURNER OPTIMIZATION, KILN OPTIMIZATION, MULTI-STAGE COMBUSTION IN THE PRECALCINER	4.48	LB/TON CLINKER	FIRST YEAR OF OPERATION	BACT-PSD	4.33	LB/TON CLINKER	AFTER FIRST YEAR OF OPERATION	0			30 DAY ROLLING AVERAGE - SUM OF BOTH MAIN KILN STACK AND COAL MILL STACK CEMS INSTALLED IN BOTH MAIN KILN STACK AND COAL MILL STACK TO MONITOR EMISSIONS
TX-0822	CEMENT PLANT	TX	7369, PSDTX120M4, AND GHGPSDTX	6/30/2017	Portland Cement Kiln - Kiln KL-870	Nitrogen Oxides (NOx)	Good combustion practices, SNCR	1.5	LB/TON	30-DAY AVERAGE	BACT-PSD	0			0			NSPS F, MACT LLL
AZ-0052	ARIZONA PORTLAND CEMENT	AZ	38592	12/16/2008	KILN	Sulfur Dioxide (SO2)		0.16	LB/T CLINKER	30 DAY AVERAGE	BACT-PSD	0			0			
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CO	98PB0893	9/25/2000	PREHEATER/PRECALCINER, KILN	Sulfur Dioxide (SO2)	RAW MATERIALS QUARRY WILL BE MANAGED FOR OPTIMUM SULFUR CONTENTS. SO2 WILL BE ABSORBED IN 5-STAGE PRECALCINER/PREHEATER/KILN AND RAW MILL. EMISSION LIMIT IN LB/T OF CLINKER, 12 MO ROLLING AVG.	1.99	LB/T		BACT-PSD	0			1.99	LB/T		

RBLC ID	Facility Name	Facility State	Permit Number	Permit Issuance Date	Process Name	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Average Time Condition	Case-By-Case Basis	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Average Time Condition	Standard Emission Limit	Standard Emission Limit Unit	Standard Limit Average Time Condition	Pollutant Compliance Notes
FL-0139	SUWANNEE AMERICAN CEMENT COMPANY, INC.	FL	1210465-001-AC	6/1/2000	IN LINE KILN & RAW MILL	Sulfur Dioxide (SO2)	LOW SULFUR MATERIALS & PROCESS CONTROL	0.27	LB/T	CLINKER	BACT-PSD	0			0			
FL-0267	THOMPSON S. BAKER-CEMENT PLANT (FRI)	FL	PSD-FL-350; 0010087-013-AC	11/5/2004	IN LINE KILN/RAW MILL WITH ESP AND SNCR	Sulfur Dioxide (SO2)	PROCESS CONTROL AND RAW MATERIALS IN FLORIDA	0.28	LB/TON CLINKER	24 HR		35	LB/H	24 HR	0			
FL-0268	BROOKSVILLE CEMENT PLANT (FCS)	FL	PSD-FL-351; 0530021-009-AC	12/20/2004	125 TPH CLINKER KILN AND ASSOCIATED EQUIPMENT	Sulfur Dioxide (SO2)	PROCESS CONTROL AND RAW MATERIALS	0.23	LB/TON CLINKER	24-HR	BACT-PSD	28.8	LB/H	24-HR	0			
FL-0271	BRANFORD CEMENT PLANT (SUWANNE)	FL	1210465-014-AC; PSD-FL-352	3/30/2006	KILN W/IN LINE RAW MILL W/ SNCR AND BAGHOUSE	Sulfur Dioxide (SO2)	RAW MATERIALS AND PROCESS CONTROL	0.2	LB/TON CLINKER	CEMS 24-HR ROLLING AVERAGE	BACT-PSD	25.4	LB/H	CEMS 24-HR ROLLING AVERAGE	0			
FL-0297	NORTH BROOKSVILLE CEMENT PLANT	FL	PSD-FL-384	6/27/2007	KILN NO. 3 WITH PREHEATER, CALCINER, IN-LINE RAW MILL AND AIR HEATER	Sulfur Dioxide (SO2)		0.2	LB/T	24-HR ROLLING CEMS	BACT-PSD	0			0			32.1 LB/H
GA-0134	HOUSTON AMERICAN CEMENT PLANT	GA	3241-153-0056-P-01-0	6/19/2007	MAIN KILN STACK ST35	Sulfur Dioxide (SO2)	JUDICIOUS SELECTION/USE OF RAW MATERIALS AND , AS NECESSARY, USE OF HYDRATED LIME INJECTION.	1	LB/T CLINKER	30 DAY ROLLING BASED ON SO2 CEMS	BACT-PSD	1.25	LB/H		1	LB/T CLINKER	30 DAY ROLLING AVG BASED ON SO2 CEMS	
GA-0136	CEMEX SOUTHEAST, LLC	GA	3241-153-0003-V-04-3	1/27/2010	MAIN KILN STACK K218	Sulfur Dioxide (SO2)	JUDICIOUS SELECTION/USE OF RAW MATERIALS AND , AS NECESSARY, USE OF HYDRATED LIME INJECTION.	1	LB/T CLINKER	30-DAY ROLLING AVG.	BACT-PSD	160	LB/H		1	LB/T CLINKER	30-DAY ROLLING AVG.	
IA-0070	LEHIGH CEMENT COMPANY - MASON CITY PLANT	IA	17-01-005	12/11/2003	KILN/CALCINER/PREHEATER	Sulfur Dioxide (SO2)	WET SCRUBBER.	1.01	LB/T	LB/T OF CLINKER	BACT-PSD	530.3	T/YR		0			THE LB/TON BACT LIMIT IS A 30 DAY ROLLING AVG THAT DOES NOT INCLUDE EMISSIONS FROM STARTUP, SHUTDOWN, OR MALFUNCTION (SSM). THE TON/YR BACT LIMIT IS FOR ALL EMISSIONS INCLUDING SSM. THE ADDITION OF THE WET SCRUBBER WILL REDUCE THE OVERALL SO2 EMISSIONS AT THE PLANT BY ABOUT 5,400 TONS/YR. THERE IS ALSO A NAAQS LIMIT OF 458.17 LB/HR (3 HR AVG)
IL-0111	UNIVERSAL CEMENT	IL	8120011	12/20/2011	KILN WITH IN-LINE RAW MILL	Sulfur Dioxide (SO2)	ABSORPTION IN CLINKER AND KILN DUST AND AN ADD-ON CIRCULATING FLUIDIZED BED ABSORBER OR EQUIVALENT.	0.4	LB/TON CLINKER	30-DAY ROLLING AVERAGE	LAER	0			0			LIMIT DOES NOT APPLY DURING EMISSION TESTING TO CALIBRATE THE PM CEMS.
MO-0085	CONTINENTAL CEMENT COMPANY - ILASCO PLANT	MO	072007-008	7/24/2007	Preheater/Precalciner Kiln System	Sulfur Dioxide (SO2)	Inherent scrubbing when the raw mill is operating	0.89	LB/TON OF CLINKER	30-DAY ROLLING AVERAGE	BACT-PSD	1.15	LB/TON OF CLINKER	30-DAY ROLLING AVERAGE	1.41	LB/TON OF CLINKER	30-DAY ROLLING AVERAGE	Tiered limits based on the limestone raw mix combination. Emission 1 is applied when the raw mix contains <= 20% Kimmswick limestone; Emission 2 when raw mix is>20%, but <=40%; Emission 3 when raw mix is >40%, but <=60%; 1.67 lb/ton of clinker when >60%, but <=80%; 1.93 lb/ton of clinker when >80% Kimmswick limestone.
SC-0132	ARGOS HARLEYVILLE PLANT	SC	0900-0004-EF-R2	12/14/2007	PREHEATER/PRECALCINER KILN 1	Sulfur Dioxide (SO2)		0.9	LB/TON CLINKER	30 DAY ROLLING AVERAGE	BACT-PSD	1.6	LB/TON CLINKER	24 HOUR ROLLING AVERAGE	0			THE EMISSION LIMITS ARE FOR THE TOTAL COMBINED SO2 EMISSIONS FROM THE MAIN KILN STACK AND THE PRECALCINER COAL MILL STACK. CEMS TO BE INSTALLED ON MAIN STACK.

RBLC ID	Facility Name	Facility State	Permit Number	Permit Issuance Date	Process Name	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Average Time Condition	Case-By-Case Basis	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Average Time Condition	Standard Emission Limit	Standard Emission Limit Unit	Standard Limit Average Time Condition	Pollutant Compliance Notes
SC-0132	ARGOS HARLEYVILLE PLANT	SC	0900-0004-EF-R2	12/14/2007	PREHEATER/PRECALCINER KILN 2	Sulfur Dioxide (SO2)		0.9	LB/TON CLINKER	30 DAY ROLLING AVERAGE	BACT-PSD	1.6	LB/TON CLINKER	24 HOUR ROLLING AVERAGE	0			CEM TO BE INSTALLED
TX-0822	CEMENT PLANT	TX	7369, PSDTX120M4, AND GHGPSDTX	6/30/2017	Portland Cement Kiln - Kiln KL-870	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES	0.4	LB/TON	30-DAY AVERAGE	BACT-PSD	0			0			
MO-0072	CONTINENTAL CEMENT COMPANY, L.L.C.	MO	072006-003	7/11/2006	PORTLAND CEMENT KILN	Sulfur Oxides (SOx)	INHERENT RAW MILL SCRUBBING IS CONSIDERED TO BE BACT	1.93	LB/T	CLINK 30-DAY ROLLING AVERAGE	BACT-PSD	265.38	LB/T	30-DAY ROLLING AVERAGE	0			

APPENDIX D

SOUTH DAKOTA REGIONAL HAZE STATE IMPLEMENTATION PLAN: PETE LIEN AND SONS FOUR FACTOR ANALYSIS

RAPID CITY, SD LIME PLANT

Four Factor Analysis - NO_x

Prepared for:

Pete Lien & Sons, Inc.

October 2019

Four Factor Analysis - NOx

Prepared for:
Pete Lien & Sons, Inc.

Rapid City, SD

This document has been prepared by SLR International Corporation (SLR). The material and data in this report were prepared under the supervision and direction of the undersigned.

Tim Quarles, P.E.

Manager, US Air Program

Jamie Christopher

Principal Engineer

CONTENTS

FIGURES

TABLES

APPENDICES

1. INTRODUCTION AND BACKGROUND

On July 18, 2019 the South Dakota Department of Natural and Environmental Resources (DENR) sent a letter requesting that Pete Lien & Sons (PLS) perform a four-factor analysis (4FA) of its Rapid City, South Dakota Lime Plant operations for oxides of nitrogen (NO_x). This request was based on a screening analysis (Q/D), which is an early step in DENR's required process to update their Regional Haze state implementation plan (RHSIP) for July 2021. The results of DENR's screening analysis indicated that PLS' Rapid City Lime Plant operations may be impacting two Prevention of Significant Deterioration (PSD) Class I areas (Wind Cave and Badlands National Parks).

The State of South Dakota is required by EPA to submit an updated Regional Haze SIP by July 2021. This SIP must implement a long-term strategy (LTS) to ensure the Regional Haze Rule (RHR) requirements are on track. In July 2016, EPA issued the following draft guidance: *Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period* (Draft Guidance). Final guidance was due to be provided by Spring 2019. It should be noted that this second planning period for the RHR will be a new process, and is a departure from the first planning period that was based on the Best Available Retrofit Technology (BART) regulations. EPA made changes to the RHR in 2016 and is still working to provide final guidance and data to meet the regulatory schedule of the second planning period. Therefore, some ambiguity in the process remains.

The Draft Guidance provides an overview of the expected steps that states and RPOs will take in order to meet the July 2021 deadline. These include:

1. Ambient data analysis (of measured visibility data);
2. Screening of sources;
3. Four-factor analyses for selected sources;
4. Develop long-term strategy;
5. Regional-scale modeling; and
6. Demonstrate progress and glidepath check.

The first step is used to determine current visibility in the Class I areas, its relationship to the expected visibility reduction glidepath, the determination of 20% most impaired days, and the 20% clearest days over the previous five years. The determination in the 20% impaired/clearest must now include a determination of daily anthropogenic impairment. As part of this analysis, information about the anthropogenic extinction budgets at Class I areas will be determined, which can help to provide information about source attribution, changes to emission levels, and transport patterns.

The second step in this process is source screening, by which DENR will identify sources that must perform a 4FA. The draft guidance provides states with significant latitude on how this screening is performed and interpreted. Specific screening thresholds are not recommended by EPA nor have any been provided by DENR. Rather, EPA recommends that states should include (screen in) sufficient facilities so that at least 80% of the state emissions are required to perform a 4FA. However, EPA also notes that this 80% inclusion approach may not be appropriate if Q/D is used as the screening analysis. DENR used Q/D, and the results indicated that PLS may be impacting the two PSD Class I areas mentioned previously (Wind Cave and Badlands National Parks).

The third step in this process is the 4FA, which considers the following four factors:

1. The cost of compliance;
2. Time necessary for compliance;
3. Energy and non-air environmental impacts; and
4. Remaining useful life of the source.

SLR International Corporation (SLR) was retained by PLS to prepare a Round II Regional Haze State Implementation Plan Determination's (Round II Determination) four-factor analysis for the control of NO_x emissions from Kiln #1 and Kiln #2 from PLS' Rapid City, SD Lime Plant. The evaluation is in response to the South Dakota DENR's formal letter dated July 18, 2019. The evaluation includes an assessment of potentially available emission reduction measures for the four statutory factors listed above and in 40 CFR 51.308(f)(2), and takes into consideration EPA's Draft Guidance mentioned previously.

This document provides the results of the 4FA for NO_x emissions from the two lime kilns operating at the Rapid City, SD lime manufacturing plant. Section 2 contains information describing the facility, site location, and existing equipment. Details of the baseline emissions used to conduct the analysis presented herein can be found in Section 3. Section 4 provides a discussion of 4FA methodology. The 4FA can be found in Section 5 and identifies potentially available emission control technologies, evaluates each control option for technical feasibility and cost effectiveness of technically feasible control options. Section 5 also provides typical timelines required to design, engineer, procure and install the technically feasible control options, and identifies the energy and non-air quality environmental impacts associated with the technically feasible control options. A discussion of the planned remaining useful life of Kiln #1 and Kiln #2 is also discussed in Section 5. Section 6 provides a summary and conclusion.

2. FACILITY DESCRIPTION

Pete Lien & Sons, Inc. (PLS) owns and operates a lime manufacturing plant located in Rapid City, South Dakota. The existing facility consists of two direct-fired preheater-type rotary kilns (Kiln #1 and Kiln #2), along with associated limestone quarry operations and stone processing operations, a hydrate plant, and ready mix operation. The facility is currently operation under Permit No. 28.1143-02. The NO_x 4FA is being conducted for Kiln #1 and Kiln #2.

The Kiln #1 and Kiln #2 preheaters, located above the kilns are used to preheat the limestone (using hot gases from the kilns) and to control the feed rate to the kilns. The preheater improves the thermal efficiency by using heat from the kilns that might otherwise be lost. Burning fuel enters the cylinder from the lower end, and the pre-heated limestone that is added to the upper end of the kilns is subjected to heat and a gentle tumbling action. As the limestone is introduced into the kilns, it is chemically altered by exposure to heat generated from the combustion of coal/coke in the kilns. This heating action converts the limestone ($CaCO_3$) to lime (CaO) and carbon dioxide (CO_2) according to the following ideal chemical reaction:

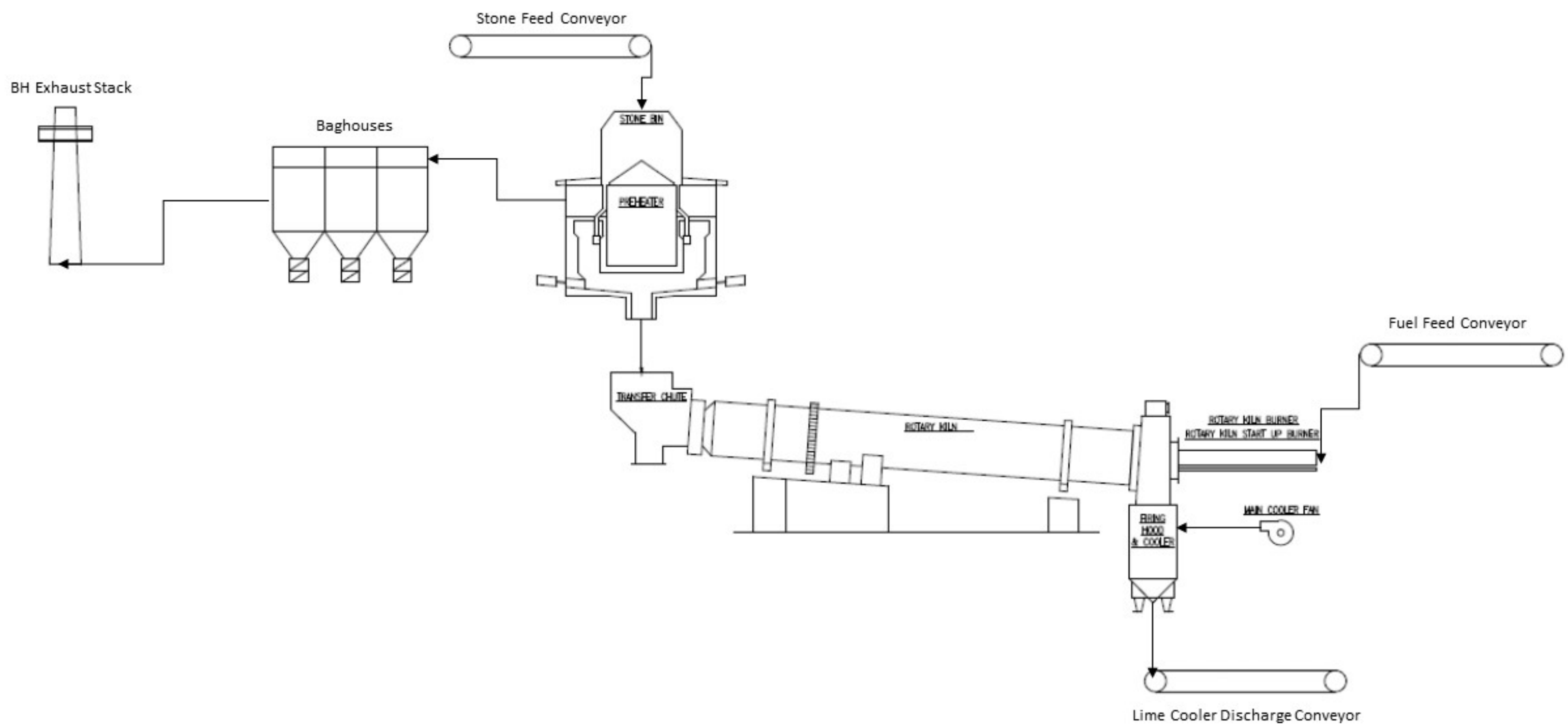
$$CaCO_3 \text{ (Limestone)} + \text{HEAT} \rightarrow CaO \text{ (High Calcium Lime)} + CO_2$$

Once the limestone is calcined (converted to lime), the lime enters a counter flow cooler where it is cooled and conveyed to an associated bucket elevator for product storage and loadout. Exhaust gas particulates from the preheaters, coolers and kilns are controlled by a baghouse. SO_2 emissions are controlled by the use of the preheater type kiln and the neutralizing ability of the kilns and baghouses (inherent scrubbing). NO_x, CO, and VOC emissions are controlled by the preheater kilns' design & efficient combustion controls. As stated, the preheater kiln design preheats the incoming limestone, reducing fuel usage and fuel generated emissions by approximately 30% compared to conventional rotary kilns. Fuels are natural gas for start-up, and coal and petroleum coke (coke) as the primary fuels. **Figure 2-1** is a simplified process flow diagram representative of both Kiln #1 and Kiln #2 operations.

The following table provides the design parameters used for the PLS Kiln #1 and Kiln #2 four factor analysis. The parameters are for each Kiln.

	KILN #1	KILN #2
Design	Direct-Fired Preheater Type Rotary Kiln	Direct-Fired Preheater Type Rotary Kiln
Year Installed	1994	2010
Design Rate	480 ton/day Lime Produced 960 ton/day Stone Feed	600 ton/day Lime Produced 1,200 ton/day Stone Feed
Baseline NO_x Emissions	310.3 tons per year	204.1 tons per year
Fuel	Coal / Pet Coke	Coal / Pet Coke
PM Control	Baghouse	Baghouse
NO_x Control	Good Combustion Practice / Preheater	Good Combustion Practice / Preheater

Figure 2-1 Kiln #1 / Kiln #2 Simplified Process Flow Diagram



3. BASELINE EMISSIONS – OXIDES OF NITROGEN (NO_x)

3.1 GENERAL

This section summarizes the baseline NO_x emissions rates used for Kiln #1 and Kiln #2 for the 4FA. DENR's letter dated July 18, 2019 does not indicate what baseline emission year(s) was(were) used for the screening analysis (Q/D) which indicated PLS operations may be impacting the two PSD Class I areas. The letter references that information on the 4FA may be found in EPA's "Draft Regional Haze Guidance July 2016.pdf" document (RH Guidance Document), which states the following:

> *"The State must identify the baseline emissions inventory on which its strategies are based. The baseline emissions inventory year shall be the most recent year for which the State has submitted emission inventory information to the Administrator in compliance with the triennial reporting requirements of subpart A of this part unless the State adequately justifies the use of another inventory year."*

Discussions with the DENR indicate that the triennial years they evaluated were 2014 and 2017. However, they did not indicate which year they used and/or if they established a worst-case or average of these years. The RH Guidance Document also refers to EPA's 2005 Regional Haze Rule BART guidelines, in which EPA described baseline emissions as follows:

> *"The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period. When you project that future operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice."*

Note the baseline description provided above only addresses annual baseline emissions that are used to establish a benchmark for determining tons reduced in the annual cost effectiveness analysis (the cost of compliance). Baseline emission rates are actually needed in several steps of the BART analysis and/or for the updated Regional Haze SIP by July 2021. Baseline emission rates representing the maximum 24-hour emissions are needed to establish the baseline visibility impairment from which the visibility improvement can be evaluated in Step 5 (Regional Scale Modeling) of the Draft Guidance. Annual baseline emission rates are also needed as part of evaluating the annual tons reduced in the cost of compliance analysis conducted in Step 1 of the 4FA. Finally, baseline emission rates (lb/ton stone feed [lb/tsf]) can be reviewed for establishing limits and for comparing existing emission levels to controlled emission levels that can be achieved based on the application of certain control devices.

DENR has indicated that the baseline emissions used in the 4FA should be representative of normal operation of each of the kilns at the Rapid City Lime Plant.

In an effort to establish baseline emissions from the kilns that represent normal operations, PLS reviewed emissions for Kiln #1 and Kiln #2 for the years 2013 through 2018. **Table 3-1** provides a summary of the emissions data for the years 2013 through 2018 for both kilns and includes the annual emissions (tpy), hours of operation (hr/yr), annual stone feed (ton SF/yr), and short-term emissions in pounds per hour (lb/hr) and pounds per ton of stone feed (lb/tsf).

Based on the information presented in **Table 3-1**, PLS determined that the normal operations would be best represented by using the average of the years 2017 and 2018 for both Kiln #1 and Kiln #2.

3.2 KILN #1 NO_x BASELINE EMISSION RATE

As discussed above, Kiln #1 NO_x baseline emissions were determined from the average actual emissions for the years 2017 and 2018, and are summarized below:

KILN #1	**96.60 LB/HR**	**4.36 LB/TSF**	**310.3 TPY**

3.3 KILN #2 NO_x BASELINE EMISSION RATE

As discussed above, Kiln #2 NO_x baseline emissions were determined from the average actual emissions for the years 2017 and 2018, and are summarized below:

KILN #2	**49.09 LB/HR**	**1.29 LB/TSF**	**204.1 TPY**

Table 3-1 Pete Lien & Sons, Inc. – Kiln #1 and Kiln #2 Actual NOx Emissions for 2013 to 2018

Year	Kiln #1 [1]					Kiln #2 [2]				
	Hours	Emission Factor		Stone Feed	NO_x Emissions	Hours	Emission Factor		Stone Feed	NO_x Emissions
2013	5,429 hr/yr	68.71 lb/hr	2.62 lb/ton SF	142,394.0 tons SF/yr	186.5 tpy	8,199 hr/yr	56.10 lb/hr	1.35 lb/ton SF	341,413.0 tons SF/yr	230.0 tpy
2014	8,278 hr/yr	68.69 lb/hr	2.55 lb/ton SF	223,274.0 tons SF/yr	284.3 tpy	8,118 hr/yr	59.13 lb/hr	1.38 lb/ton SF	348,667.0 tons SF/yr	240.0 tpy
2015	6,676 hr/yr	68.69 lb/hr	2.53 lb/ton SF	181,192.0 tons SF/yr	229.3 tpy	8,127 hr/yr	61.28 lb/hr	1.43 lb/ton SF	348,152.0 tons SF/yr	249.0 tpy
2016	5,007 hr/yr	68.70 lb/hr	2.38 lb/ton SF	144,731.0 tons SF/yr	172.0 tpy	8,253 hr/yr	46.74 lb/hr	1.28 lb/ton SF	300,456.0 tons SF/yr	192.9 tpy
2017	6,056 hr/yr	96.60 lb/hr	4.25 lb/ton SF	137,523.0 tons SF/yr	292.5 tpy	8,210 hr/yr	45.86 lb/hr	1.19 lb/ton SF	315,805.0 tons SF/yr	188.2 tpy
2018	6,792 hr/yr	96.60 lb/hr	4.48 lb/ton SF	146,598.0 tons SF/yr	328.1 tpy	8,406 hr/yr	52.33 lb/hr	1.39 lb/ton SF	316,771.0 tons SF/yr	220.0 tpy
AVG (2013 - 2018)	***6,373 hr/yr***	***78.00 lb/hr***	***3.13 lb/ton SF***	***162,618.7 tons SF/yr***	***248.8 tpy***	***8,219 hr/yr***	***53.57 lb/hr***	***1.34 lb/ton SF***	***328,544.0 tons SF/yr***	***220.0 tpy***
AVG (2017 / 2018)	***6,424 hr/yr***	***96.60 lb/hr***	***4.36 lb/ton SF***	***142,060.5 tons SF/yr***	***310.3 tpy***	***8,308 hr/yr***	***49.09 lb/hr***	***1.29 lb/ton SF***	***316,288.0 tons SF/yr***	***204.1 tpy***

[1] No NO_x Limits for Kiln 1. 1999 performance test (68.70 lb/hr) used for 2103 - 2016. 2017 Performance test (96.60 lb/hr) used for 2017-2018.

(lb/hr) (hr/yr) (ton/2,000 lb) = tpy

(ton/yr) / (ton SF/yr) (2,000 lb/ton) = lb/ton SF

[2] NO_x Limits for Kiln 2:

100 lb/hr - 24-hr Rolling Avg.; 2.0 lb/ton Stone Feed 24-hr Rolling Avg.; 438.0 ton/12-month Rolling Avg.

CEMs data used for annual (tpy) emissions.

(ton/yr) / (hr/yr) (2,000 lb/ton) = lb/hr

(ton/yr) / (ton SF/yr) (2,000 lb/ton) = lb/ton SF

4. FOUR FACTOR ANALYSIS METHODOLOGY

4.1 GENERAL

As discussed previously, the results of DENR's screening analysis (Q/D) indicated that PLS' Rapid City Lime Plant operations may be impacting two PSD Class I areas (Wind Cave and Badlands National Parks). As a result, a 4FA must be performed to determine if there are any "reasonable" controls available for reducing visibility impairing emissions. The 4FA considers the following four factors:

1. The cost of compliance;
2. Time necessary for compliance;
3. Energy and non-air environmental impacts; and
4. Remaining useful life of the source.

The following steps must be followed in conducting the four-factor analysis:

- Identify all available control technologies;
- Eliminate technically infeasible options;
- Rank the remaining options based on effectiveness;
- Analyze the most effective measure and document the results; and
- Establish federally enforceable emission limits and/or other requirements.

4.2 FACTOR 1 – COST OF COMPLIANCE

4.2.1 COST EFFECTIVENESS METHODOLOGY

The basis for comparison in the economic analysis of the control scenarios is the cost effectiveness; that is, the value obtained by dividing the total net annualized cost by the tons of pollutant removed per year for each control technique. Annualized costs include the annualized capital cost plus the financial requirements to operate the control system on an annual basis, including operating and maintenance labor, and such maintenance costs as replacement parts, overhead, raw materials, and utilities. Capital costs include both the direct cost of the control equipment and all necessary auxiliaries as well as both the direct and indirect costs to install the equipment. Direct installation costs include costs for foundations, erection, electrical, piping, insulation, painting, site preparation, and buildings. Indirect installation costs include costs for engineering and supervision, construction expenses, start-up costs and contingencies

To accurately estimate the total annualized cost of a particular control technology, a conceptual design must be developed in sufficient detail to quantify all of the direct capital and operating costs. All costs are then expressed as an annualized cost as well as calculated cost-effectiveness values. This approach of amortizing the investment into equal end-of-year annual costs is termed the Equivalent Uniform Annual Cost (EUAC) (Grant, Ireson and Leavenworth 1990). It is very useful when comparing the costs of two or more alternative control systems and is the USEPA-recommended method of estimating control costs. The EUAC costs and estimating methodology used in this report are directed toward a "study" estimate of ±30 percent accuracy that is described in the USEPA's OAQPS Control Cost Manual (USEPA 2002/2019b). According to the Chemical Engineer's Handbook (Perry and Chilton 2008), a study estimate is "...used to estimate the economic feasibility of a project before expending significant funds for piloting, marketing, land surveys, and acquisition... [however] it can be prepared at relatively low cost with minimum data." Capital and annual cost estimating methodology is described below.

4.2.2 CAPITAL COSTS

A number of methods with varying degrees of accuracy are available for estimating capital costs of pollutant control devices. Cost estimating techniques range from the simple "survey method" whereby the total installed costs are equated to a basic operating parameter (e.g., gas flow rate) to detailed cost estimates based on preliminary designs, systems drawings, and contractor quotes. Survey method cost algorithms are derived from industry surveys of overall capital costs of installed equipment, and represent the average cost of many installations. Since there are no provisions that permit normalization of the many site-specific parameters which affect both equipment and installation costs, survey methods provide accuracies, at best, on the order of +50 percent to -30 percent (Vatavuk and Neveril 1980).

Detailed cost estimates on the other hand, including obtaining detailed vendor quotations against detailed engineering bid packages, will provide better accuracies that are commensurate to the level of design detail obtained and included in the bid package (i.e. 15/30/60/90/100% level). Each higher level of design will require substantially more engineering work to develop with the cost rising accordingly. Detailed designs are not generally obtained for BACT analyses due to the substantial costs occurred and the speculative nature of the project. Generally, the approach taken in a BACT analysis is to obtain vendor-supplied control equipment cost estimates for similar facilities and apply a factored approach for estimating ancillary equipment and installation costs to obtain reasonably accurate installed capital costs for controls.

4.2.3 ANNUALIZED COSTS

Annualized costs are comprised of the direct operating costs of materials and labor for maintenance, operation, supervision and utilities and waste disposal, and the indirect operating charges, including plant overhead, general and administrative, and capital charges. These generalized factors may in some cases be modified to provide more accurate, site-specific values. Utility costs for the control device and auxiliary equipment are based on the total annual consumption, unit costs, and vendor estimates. The cost of electrical power is based on $0.09/kW-hr.

Indirect operating costs include the cost of plant overhead, general and administrative (G&A), and capital charges. G&A is a direct function of the total capital cost. Overhead is a function of both labor (payroll and plant) and project capital cost. The capital recovery cost, or capital charge, is based on the operational life of the system, interest and capital depreciation rates, and total capital cost. These charges are based on the capital recovery factor (CRF) defined as:

$$CRF = i\,(1 + i)^n / [(1 + i)^n - 1]$$

where: i = the annual interest rate; and
n = equipment life (years).

For this economic analysis, the capital recovery factor was calculated as 0.08024, which assumes that the equipment life is 20 years and the average annual interest rate is 5 percent. The interest rate was determined by averaging the United States Treasury rates for the first 6 months of 2019, adding two points to the percentage rate and rounding up to the next highest integer. This approach is consistent with guidance provided by the Bay Area Air Quality Management District. Based on the above cost estimating procedures, capital and annualized costs have been estimated for each potential emission control alternative studied. These costs are budgetary estimates, provided for comparative purposes only, and are not final costs. The estimated capital and operating costs do not include all components that are encountered in a project of this nature; therefore the costs presented are conservative. Specific capital and annualized cost calculations (if applicable) are discussed in the cost of compliance evaluation.

The basis for comparing the economic impacts of control scenarios is cost effectiveness. This value is defined as the total net annualized cost of control, divided by the actual tons of pollutant removed per year, for each control technique. Annualized costs include the capital cost plus the financial requirements to operate the control system on an annual basis, including operating and maintenance labor, replacement parts, overhead, raw materials, waste disposal and utilities. Capital costs include both the direct and indirect costs to install the equipment. Direct installation costs include costs for foundations, erection, electrical, piping, insulation, painting, site preparation, and buildings. Indirect installation costs include costs for engineering and supervision, construction expenses, startup costs and contingencies.

4.3 FACTOR 2 – TIME NECESSARY FOR COMPLIANCE

Factor 2 involves the evaluation of the amount of time needed for full implementation of the different control strategies. The time for compliance will need to be defined and should include the time needed to develop and implement the regulations, as well as the time needed to install the necessary control equipment. The time required to install a retrofit control device includes time for capital procurement, device design, fabrication, and installation. The Factor 2 analysis should also include the time required for staging the installation of multiple control devices at a given facility if applicable.

4.4 FACTOR 3 – ENERGY AND OTHER IMPACTS

Energy and environmental impacts analyzed as part of this step generally include the following but are not limited to and/or need to be included in the analysis:

Energy Impacts

- Electricity requirement for control equipment and associated fans
- Steam required
- Fuel required

Environmental Impacts

- Waste generated
- Wastewater generated
- Additional carbon dioxide (CO_2) produced
- Reduced acid deposition
- Reduced nitrogen deposition

Non-air environmental impacts (positive or negative) can include changes in water usage and waste disposal of spent catalyst or reagents. EPA recommends that the costs associated with non-air impacts be included in the Cost of Compliance (Factor 1). Other effects, such as deposition or climate change due to greenhouse gases (GHGs) do not have to be considered.

For this analysis we evaluated the direct energy consumption of the emission control device, solid waste generated, wastewater discharged, acid deposition, nitrogen deposition, any offsetting negative impacts on visibility from controls operation, and climate impacts (e.g., generation and mitigation of greenhouse gas emissions).

In general, the data needed to estimate these energy and other non-air pollution impacts were obtained from the cost studies which were evaluated under Factor 1. These analyses generally quantify electricity requirements, steam requirements, increased fuel requirements, and other impacts as part of the analysis of annual operation and maintenance costs.

Costs of disposal of solid waste or otherwise complying with regulations associated with waste streams were included under the cost estimates developed under Factor 1, and were evaluated as to whether they could be cost-prohibitive or otherwise negatively affect the facility.

Indirect energy impacts were not considered, such as the different energy requirements to produce a given amount of coal versus the energy required to produce an equivalent amount of natural gas.

4.5 FACTOR 4 – REMAINING EQUIPMENT LIFE

Factor 4 accounts for the impact of the remaining equipment life on the cost of control. Such an impact will occur when the remaining expected life of a particular emission source is less than the lifetime of the pollution control device that is being considered.

In this case, the capital cost of the pollution control device can only be amortized for the remaining lifetime of the emission source. Thus, if a control device with a service life of 15 years is being evaluated for a boiler with an expected remaining life of 10 years, the shortened amortization schedule will increase the annual cost of the control device.

In general a lime kiln has a design life of 50 years, and they are typically designed to allow component and subcomponents that allow independent change-outs. This can significantly extend the life of the kiln. Industrial processes often refurbish lime kilns to extend their lifetime. As such the remaining lifetime of the equipment is expected to be longer than the projected lifetime of the pollution control technologies that were analyzed for this 4FA.

5. FOUR FACTOR ANALYSIS – NO_x

5.1 INTRODUCTION

This section describes the 4FA for the control of NO_x emissions from the two existing lime kilns (Kiln #1 and Kiln #2) currently operating at the PLS Rapid City Lime Manufacturing Plant. As discussed and outlined in Section 4.1, the 4FA considers the following four factors:

1. The cost of compliance;
2. Time necessary for compliance;
3. Energy and non-air environmental impacts; and
4. Remaining useful life of the source.

The following steps must be followed in conducting the four-factor analysis:

- Identify all available control technologies;
- Eliminate technically infeasible options;
- Rank the remaining options based on effectiveness;
- Analyze the most effective measure and document the results; and
- Establish federally enforceable emission limits and/or other requirements.

5.2 NO_x RACT/BACT/LAER CLEARINGHOUSE REVIEW

An important consideration in reviewing potential control technologies and emission limits is past determinations for similar sources. A review of the RACT/BACT/LAER database (RBLC) on the U.S. EPA TTN web site was performed to identify previous control technology determinations for lime kilns (USEPA 2019a). This database contains information reported by state and local agencies on RACT (Reasonably Available Control Technology), BACT (Best Available Control Technology), and LAER (Lowest Achievable Emission Rate) determinations made on a case-by-case basis during permit application reviews. Results of this search are summarized in **Table 5-1**. Emission rates range from 1.8 lb/ton stone feed (lb/tsf) to 45.6 lb/tsf (3.5 lb/ton Lime to 90 lb/ton Lime), and BACT is defined as low NO_x burner and limit excess air, good combustion practices (GCP), and GCP and preheater kiln design, or some similar control techniques. No add-on controls have been determined as RACT, BACT, or LAER to date.

5.3 FORMATION OF NO_x

In the lime manufacturing process, conditions are very favorable for the formation of NO_x because of the high temperatures required. Essentially all NO_x emissions associated with lime manufacturing are generated in the lime kilns. In the lime kilns, NO_x emissions can be formed during fuel combustion by two primary mechanisms, of which both are similar to that occurring in any other combustion device:

- Oxidation of the molecular nitrogen present in the combustion air which is termed "thermal NO_x"; and
- Oxidation of the nitrogen compounds present in the fuel which is termed "fuel NO_x".

Thermal NO_x is formed by the homogeneous reaction of oxygen and nitrogen in the gas phase at high temperatures, following the overall reaction mechanism proposed by Zeldovich (Zeldovich 1946):

$N_2 + O \leftrightarrow NO + N$; $K_f = 2 \times 10^{14\ e\ (076500/RT)}$

$N + O_2 \leftrightarrow NO + O$; $K_f = 6.3 \times 10^{9\ e\ (-6300/RT)}$

The overall mechanism is extremely dependent on the gas-phase temperature and residence time, and is also dependent to a lesser extent upon the gas-phase concentrations of O_2 and N_2. The excess air used during fuel combustion can substantially affect NO formation by determining the amount of oxygen and nitrogen available for NO reaction. Virtually all thermal NO_x is formed in the region of the flame at the highest temperatures, approximately 3,000 to 3,600°F.

Fuel NO_x is formed by the conversion of nitrogen present in the fuel used. However, studies have found that thermal NO_x is the dominant NO_x formation mechanism in kilns, and that coal-fired kilns produce only one third the NO_x of a gas-fired kiln due to their cooler flame temperature (Hilovsky 1977).

5.4 AVAILABILITY AND EVALUATION OF NO_x CONTROL TECHNOLOGIES

NO_x emission control technologies which may be available for use on lime kilns are shown in **Table 5-2**. In general, NO_x control approaches applicable to lime kilns can be grouped into two categories:

- Combustion process modifications and control to reduce the formation of NO_x by minimizing (1) the amount of fuel combusted per ton of product, (2) the factors which contribute to NO_x formation, or both, and;
- Post-combustion control approaches which destroy the NO_x after it is formed in the combustion process.

Control of the process to reduce the formation of NO_x could include the use of the newer preheater process. Use of this technology or good combustion control has generally been selected as BACT for NO_x control on new lime kilns, according to the RBLC (USEPA 2019a). Both of the lime kilns at PLS' Rapid City Lime Plant are direct-fired preheater type lime kiln design with inherent reduction in fuel consumption and emissions. The preheater kiln design consumes 30% less fuel than a conventional rotary kiln per ton of lime product produced. This reduction in fuel consumption and the corresponding air (and its nitrogen content) needed for combustion results in a 30% reduction in NO_x generated per ton of lime produced. In addition, both of the kilns have incorporated features such as "proper kiln design and operation", or "good combustion practices" which were approved as BACT for all other lime kiln projects listed in **Table 5-1**.

5.4.1 EVALUATION OF COMBUSTION CONTROLS

Other combustion process NO_x controls which might be available for a direct-fired preheater kiln system include feed composition changes, kiln fuel changes, low NO_x burners, flue gas recirculation, and good combustion practices. These are discussed below.

5.4.1.1 Kiln Fuel Changes

Modification of the kiln fuel will have only a small effect on calcination NO_x emissions since this change would only affect the formation of fuel NO_x, which is a relatively minor contributor to NO_x emissions which are dominated by thermal NO_x. Solid fossil fuels, such as coal and petroleum coke, are known to produce significantly lower emissions of NO_x from lime kilns than gaseous fuels (USEPA 1994). Coal and coke are burned as the primary fuels in both kilns with natural gas a backup fuel hence both kilns have already incorporated a certain degree of NO_x reduction through burning coal and coke as the primary fuels. Switching to a fuel with a higher heating value and lower nitrogen content may reduce NO_x emission in a lime kiln. Coke has lower nitrogen content per million Btu than coal and is more uniform in terms of heat value, lower in volatile matter content and burns with a lower flame temperature (USEPA 1994). Although it is infeasible to accept emission limits that would require the use of alternative fuels (local availability varies and is not in PLS' control), PLS is committed to maximizing their use to assist in the reduction of NO_x at the plant. Both kilns are designed for the ability to use from 100% coal to 100% petroleum coke when available. The kilns typically burn a mixture of these two fuels.

5.4.1.2 Low NO_x Burners

Low NO_x burners (LNB) attempt to create two combustion zones, primary and secondary, at the end of the main burner pipe. In the high-temperature primary zone, combustion is initiated in a fuel-rich environment in the presence of a less than stoichiometric oxygen level. The sub-molar level of oxygen at the primary combustion site minimizes NO_x formation. The presence of CO in this portion of the flame also chemically reduces some of the NO_x that is formed.

In the secondary zone, combustion is completed in an oxygen-rich environment. The temperature in the secondary zone is much lower than in the first; therefore, lower NO_x formation is theoretically achieved as combustion is completed.

Although some burners are marketed specifically as LNBs, there is no specific definition of what qualifies a burner as an LNB. The U.S. EPA's *"Alternative Control Techniques Document Update - NO_x Emissions from New Cement Kilns"* indicates that burners specifically marketed as LNBs "typically use 5 to 7 percent primary air." (USEPA 2007) Reduced primary air is one characteristic of a LNB.

EPA has indicated that a 20 to 30 percent reduction in NO_x emissions may be anticipated in cement kilns by switching from a direct-fired standard burner to an indirect-fired LNB. However, EPA has determined that "the [emission reduction] contribution of the low-NO_x burner itself and of the firing system conversion [from direct to indirect] cannot be isolated from the limited data available.

In lime manufacturing, direct and indirect firing describe the manner in which pulverized fuel is conveyed from the fuel-grinding mill to the burner (NLA 2005).

Direct Firing Systems. In the direct firing configuration, fuel is pneumatically conveyed directly from the coal mill to the burner. The quantity of air introduced to the primary combustion zone is dictated by the minimum sweep air requirements of the coal mill and the conveyance system rather than by the optimum flame requirements.

Indirect Firing Systems. In the indirect firing system, the coal is pulverized in the coal mill and pneumatically transported to a storage tank. The pulverized fuel is then conveyed to the burner with the quantity of air that is optimum for flame considerations. This combustion air is completely independent of the sweep air requirements of the coal milling system. There have been no controlled studies conducted on lime kilns that verify that this method of burning solid fuels reduces the formation of NO_x.

As stated, LNBs are capable of reducing emissions by 20 to 30% on indirect-fired cement kilns reducing flame turbulence, delaying fuel/air mixing, and establishing fuel-rich zones for initial combustion. However, both of the lime kiln systems at the lime plant are direct-fired kilns and these burners cannot be used. As such, LNBs are not considered a technically feasible control option for the lime kilns and will not be considered further in this 4FA.

5.4.1.3 Flue Gas Recirculation

Flue gas recirculation (FGR) is intended to reduce the oxygen content of the primary combustion air used for the main burner pipe, thereby lowering the peak flame temperature in the burning zone. FGR is practiced in the electric utility industry. In a preheater kiln application, oxygen-deficient gases from the preheater tower exit would be used as primary combustion air to blow powdered fossil fuel (e.g., a coal/coke blend) into the burning zone. PLS is not aware of FGR ever being successfully applied to a lime kiln or a cement kiln for that matter.

As applied to the lime industry, the FGR control option would require extensive ducting to bring a relatively small amount of oxygen-deficient gas from the top of the preheater tower to the main burner pipe to serve as primary air.

Nearly all of the combustion air in a lime kiln (secondary air) must come from the cooler to maximize energy efficiency of the system and to supply as small a volume of combustion air as possible. The use of oxygen-deficient gas for combustion requires the processing of larger gas volumes and results in unacceptably inefficient equipment design and potential process problems. Using oxygen-deficient gas for combustion air in a lime kiln is simply impractical.

Implementation of FGR for the main burner pipe will lower the peak flame temperatures and lengthen the flame shape. The longer/lazier flame will affect lime quality and produce unstable kiln operations. Localized reducing conditions caused by oxygen deficiency are detrimental to maintaining lime quality. Therefore, FGR is not considered a technically feasible control option for the lime kilns and will not be considered further in this 4FA.

5.4.1.4 Staged Combustion Air

NO_x is primarily formed due to oxidation of nitrogen in the combustion air at high temperatures. Combustion modifications attempt to reduce NO_x formation by reducing combustion temperatures or limiting the availability of nitrogen in the high temperature flame to achieve reductions up to 45%. Similar to a cement kiln, a high flame temperature and an oxidizing atmosphere in a lime kiln are process requirements to produce a quality product. Staged combustion air refers to the practice of limiting the amount of available oxygen in the combustion zone to create an oxygen-lean condition. With low levels of oxygen available for combustion, NO_x formation in the combustion zone is inhibited. However, this oxygen-lean condition also leads to reduced fuel efficiency and higher levels of CO. The reduced flame temperatures and reducing condition techniques possible in a boiler are not compatible with lime production. Staged combustion has been used in the cement industry, where initial combustion occurs in a fuel-rich zone and secondary combustion is carried out in a fuel-lean zone. However, lime kilns do not operate in this two-stage manner so staged combustion is not applicable. Reduction in combustion temperatures in the lime kiln will influence kiln productivity and quality of the lime by increasing carry-over of unburned carbon to the lime product. This unburned fuel will prevent the lime product from being used in many applications. Therefore, this technology is not considered as a technically feasible control option for the lime kilns and will not be considered further.

5.4.1.5 Good Combustion Practices

A properly designed and operated stone feed processing system will produce a stone feed material that is uniform in chemical composition and fineness. In turn, a uniform kiln stone feed material significantly contributes to smoother kiln operation and more efficient conversion of raw materials to lime (quicklime). Since the generation of NO_x is directly related to heat input (fuel and the needed combustion air), a stone feed requiring less heat input results in lower NO_x emissions. Uniform quality fuels are also important in reducing process variability that tends to increase NO_x emissions. Solid fossil fuels, such as coal and coke, are known to produce significantly lower emissions of NO_x from lime kilns than gaseous fuels.

The Kiln #1 and Kiln #2 systems both use currently available practices to reduce NO_x emissions while still maintaining the quality of lime produced. To minimize fuel consumption and NO_x emissions, the PLS plant produces the most uniform stone feed possible through the application of proper milling and blending practices. The kiln systems utilize solid fossil fuels (i.e., coal and petroleum coke) as the primary source of energy. The plant has coal/coke blending facilities to assure a uniform quality of blend for the kiln systems. Natural gas is used as a secondary fuel during start-up and other anomalous operating conditions.

5.4.2 EVALUATION OF POST COMBUSTION NO_x CONTROLS

Post combustion controls potentially available include selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR).

5.4.2.1 Selective Non-Catalytic Reduction

This technology has been determined to be technically or economically infeasible in all BACT determinations for lime kilns to date. The selective non-catalytic reduction (SNCR) process is based on a gas-phase homogeneous reduction reaction between an ammonia-containing solution and NO_x in the preheater tower within the optimum temperature range of 1,600 - 2,000°F. The ammonia-containing solution may be supplied in the form of anhydrous ammonia, aqueous ammonia or urea. The primary reactions include:

$$NH_3 + OH^- \rightarrow NH_2 + H_2O$$

$$2\ NH_3 + O_2^- \rightarrow 2\ NH_2 + H_2O$$

$$NH_3 + H^+ \rightarrow NH_2 + H_2$$

Whereupon NH_2 has been formed by any of the above mechanisms, reduction of NO occurs:

$$NH_2 + NO \rightarrow N_2 + H_2O$$

At temperatures lower than 1,600°F, the reaction rates are slow, and there is potential for significant amounts of ammonia to exit or “slip” through the system. This ammonia slip may result in a detached visible plume at the main stack, as the ammonia will combine with sulfates and chlorides in the exhaust gases to form inorganic condensable salts. The condensable salts can become a significant source of condensable $PM_{10}/PM_{2.5}$ emissions that cannot be controlled with the baghouse.

At temperatures within the optimal temperature range, the above reactions proceed at normal rates. However, as noted in the literature as well as by vendors, a minimum of 5 ppm ammonia slip will still occur as a side effect of the SNCR process.

At temperatures above 2,000°F, the necessary reactions do not occur. In this case, the ammonia or urea reagent will oxidize and result in even greater NO_x emissions. In addition, SNCR side reactions can form a precipitate, resulting in additional reagent usage and kiln upset. Ammonia reagent may react with sulfur in kiln gases to form ammonium sulfate. Ammonium sulfate in the preheater can create a solids buildup. Ammonium sulfate in the kiln baghouse dust recycle stream may adversely affect the lime quality and the kiln operation.

There are two possible locations where the reagent (urea or ammonia) could be injected where this temperature profile (1,600 - 2,000°F) could be achieved: after the air pollution control device (in most cases a baghouse), or within the kiln. Regarding the first option, flue gas exhaust temperatures from lime kilns (generally about 450°F) are substantially below the SNCR operating range. Consequently, the exhaust gases would need to be reheated. Recent BACT analyses estimate that the **cost of reheating alone** -- excluding reagent cost -- would result in an average cost/ton of NO_x removed greater than \$8,000. If more current prices were assumed, this cost would exceed \$15,000 to \$20,000/ton of NO_x removed. Reheating exhaust gases would also result in additional pollutants being formed from the combustion products from the fuel used to reheat the exhaust gases (NLA 2005).

Turning to the second option, several RBLC analyses address the infeasibility of injecting the reagent within the kiln. For a straight rotary kiln, temperatures in the reagent injection region would result in increased NO_x formation. For a preheater kiln (as are both of these kilns), the regions where optimum temperatures exist in a lime kiln contain either large stone or have exceedingly short residence times. Large stone would either damage spray nozzles, or the sprays would impinge on the stone, wetting the stone but not entraining the reagent in the gas stream. As stated, SNCR requires an operating temperature range of 1,600 to 2,000°F and sufficient residence time for NO_x reduction to occur. Temperatures at the discharge of the kiln where fuel is burned are greater than 2,200°F. In preheater cement kilns, the temperatures at the cooler end of the rotating kiln, in the riser duct, and in the lower section of the cyclone preheater tower have made cement kilns good candidates for application of SNCR technology. However, lime kilns operate at a different temperature profile than cement kilns. In the lime kiln, the limestone is heated until it is calcined and CO_2 is released. In the cement kiln, raw materials continue to be heated until liquid and formation of clinker. A series of high temperature cyclones follow a cement kiln allowing an opportunity for ammonia reactions with the flue gas. Temperatures in the preheater following a lime kiln quickly decrease due to the tight packing of the incoming limestone, as such this does not provide for a suitable location for ammonia injection.

Another concern raised in control technology analyses with using SNCR is the presence of unreacted ammonia or urea that will react with sulfur oxides in the flue gas in the presence of water to form ammonium bisulfite (NH_4HSO_4), a sticky compound that can cause corrosion, fouling, and blockages downstream of the injection point. This would create serious problems with the preheater, ductwork, baghouses, and fans; reduce kiln draft; and cause excessive outages. Furthermore, ammonia slip from such systems would increase formation of secondary fine particulate (ammonia sulfate and nitrate salts) in the atmosphere. This fine particulate matter formed is a known contributor to visibility degradation and would therefore act to offset to some extent of any visibility improvement obtained by reducing NO_x. Finally, ammonia absorption into the lime kiln dust collected in the baghouse would seriously impact, if not eliminate the ability to sell this byproduct. Not only maintaining but also increasing the sale of these byproducts is a key industry strategy in meeting PLS' CO_2 intensity reductions under DOE's Climate Vision Program. For all of the above reasons, PLS believes SNCR is not a feasible NO_x control strategy for the lime industry.

SNCR was apparently determined as Best Available Retrofit Technology (BART) in 2014 for two lime kilns at the Nelson Arizona Lime Plant (USEPA 2014). NO_x reductions of 50% were estimated (claimed) for the SNCR applications, and the final BART emission limits were 3.8 lb/ton lime (1.9 lb/tsf) for Kiln 1 and 2.61 lb/ton lime (1.31 lb/tsf) for Kiln 2 on a 30-day rolling basis. However, EPA acknowledges in their September 3, 2014 response to comments on the FIP that SNCR has never been installed on a lime kiln to their knowledge, that comparison of lime kilns to Portland cement kilns is inappropriate, and because of these facts, they acknowledge that it will certainly be a challenge for the Nelson plant to utilize SNCR for significant NO_x reductions.

As a result, the EPA gave the Nelson Arizona Lime Plant three years to comply with the BART emission limits and 18 months to optimize the SNCR system. EPA also acknowledged that they recognized commenter's efforts to substantially inflate their baseline emissions estimates, stating "…it represents a conservatively high estimate of baseline emissions, and potentially overstates the anticipated emission reductions and visibility benefit from the evaluated control options". Baseline hourly average emissions from the two kilns were reported by the Nelson Arizona Lime Plant at a very high 7.6 lb/ton lime and 5.2 lb/ton lime during a three-month test period to determine facility baseline emissions. This inflated baseline has the effect of making it possible to comply with the annual and monthly BART emission limits proposed as an equivalent of 50% control (from baseline) by operating with a control efficiency well lower than 50%. EPA's response to comments on the Nelson Arizona Lime Plant BART requirements in the September 3, 2014 Federal Register notice include the following statements in rejecting further control and rejecting further expediting of the SNCR installation (USEPA 2014):

- There are multiple operational and design differences between cement and lime production. Cement and lime production processes are sufficiently different that it is not appropriate to assume that SNCR installation times for cement kilns are directly transferable to the application of SNCR on lime kilns.

- To our knowledge, SNCR has never been installed on a lime kiln. Given that this control technology will be retrofitted to a new source category for the first time, it is not unreasonable to expect unforeseen challenges and delays.

- As explained in further detail in our TSD, we consider LNA's general approach appropriate, but also note that it represents a conservatively high estimate of baseline emissions, and potentially overstates the anticipated emission reductions and visibility benefit from the evaluated control options. (from 2/18/14 FR notice of proposed rule).

However, since it appears that at least one lime kiln may be successfully utilizing SNCR, PLS has evaluated the cost effectiveness of SNCR for each of the two lime kilns at the Rapid City lime plant. PLS still believes that SNCR is likely infeasible for a lime kiln at significant control efficiency, but has prepared a cost analysis for SNCR with control efficiencies ranging from 10% to a maximum of 25% control.

5.4.2.2 Selective Catalytic Reduction

SCR is a process that utilizes ammonia in the presence of a catalyst to selectively reduce NO_x emissions from exhaust gases. The catalyst is typically vanadium pentoxide, zeolite, or titanium dioxide. The NO_x containing exhaust gas is injected with anhydrous ammonia and passed through a catalyst bed to initiate the catalytic reaction. As the catalytic reaction is completed, NO_x is reduced to nitrogen and water. The critical temperature range required for the completion of this reaction is 570 - 840°F, which is higher than the typical lime kiln baghouse exit gas temperature. Hence, an SCR system would have to be located prior to each of the kilns' main baghouses.

Efficient operation of a 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 NO_x emissions and appreciable ammonia emissions. If the temperature is too high, oxidation of the NH_3 to NO can occur. Other emissions potentially generated 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).

The most prohibitive disadvantage of the SCR process is fouling of the SCR catalyst. The high dust loading in lime plant exhaust streams may plug the catalyst and render it ineffective. Minor impurities in the gas stream, such as compounds or salts of sulfur, arsenic, calcium, and alkalis, may deactivate the catalyst very rapidly, strongly affecting the efficiency and system availability as well as increasing the waste catalyst disposal volume. Continual fouling of the SCR catalyst would render it inoperative as a NO_x control option. Ammonia injected to a SCR system with a fouled catalyst would pass unreacted through the system (i.e., ammonia slip). As discussed in section 5.4.2.1, the unreacted ammonia will combine with sulfates and chlorides in the exit gases, forming inorganic condensable salts, which result in a detached visible plume and a significant increase in condensable $PM_{10}/PM_{2.5}$ emissions.

To avoid fouling the catalyst bed with the PM in the exhaust stream, an SCR unit would need to be located downstream of the particulate matter control device. However, due to the low exhaust gas temperature exiting air pollution control devices at lime plants (in most cases, a baghouse), a heat exchanger system would be required to reheat the exhaust stream to the desired reaction temperature. Just the cost of exhaust gas reheat alone would be prohibitive ($8,000 to $20,000/ton), as with the SNCR systems noted previously (NLA 2005).

Although SCR is being used in the utility industry, there are significant differences between the exhaust streams generated by the two industries that account for the difference in the application of the technology. A utility boiler's exhaust gas stream does not vary over time. That is, the gas stream characteristics do not change greatly, whereas, the lime kiln exhaust gas stream temperature has a high degree of fluctuation.

Low temperature SCR systems were also evaluated for feasibility. SCR catalysts can be formulated to operate at low temperatures, even below 450°F. However, these systems can only be operated on natural gas combustion sources. The flue gas must be ultra clean (free of sulfur) to prevent the formation of ammonium bisulfate which fouls and deactivates the catalyst. For an operating temperature of 450°F the flue gas would have to have SO_2 concentrations of 5 ppmvd or lower and less than 0.05 ppmvd SO_3.

Therefore, since SCR has not been demonstrated on a lime kiln and the exhaust gas characteristics create significant chemical and physical problems in the application of SCR, SCR cannot be considered a technically feasible control option for the lime kilns and will not be considered further.

5.4.3 TOP DOWN EVALUATION OF CONTROLS

NO_x control technologies that were found to be technically available are summarized in **Table 5-3**. The only control option identified as technically feasible is good combustion practices and use of a preheater lime kiln. It should be noted that since 1999, BACT analyses of NO_x controls have been prepared for 15 new commercial lime plants with kilns that have been thoroughly reviewed by U.S. EPA, state and local agencies, and the public. They all reached the conclusion that add-on controls for NO_x for new lime kilns define BACT as efficient combustion practices, minimization of fuel consumption (preheater type kiln), and excess air for the combustion process, or similar control techniques (NLA 2006). PLS firmly believes SNCR is not a feasible NO_x control strategy for the lime kilns. However, since it appears that at least one lime kiln may be utilizing SNCR it will be evaluated further for each of the two lime kilns at the plant.

Since good combustion practices and use of a preheater lime kiln is the current control for each lime kiln, only SNCR will be evaluated further.

5.5 FACTOR 1 – COST OF COMPLIANCE

5.5.1 SELECTIVE NON-CATALYTIC REDUCTION

PLS firmly believes that SNCR is likely infeasible for a lime kiln at significant control efficiency, but has prepared an analysis for SNCR with control efficiencies ranging from 10% to a maximum of 25% control.

5.5.1.1 Economic Impacts

The capital and annual costs summary for SNCR for each of the kilns (Kiln #1 & Kiln #2) are presented in **Table 5-4** and **Table 5-7**. Capital costs were previously obtained from Combustion Components Associates, Inc. (CCA) in 2014 for a BACT determination included in a 2014 PSD permit application for a 600 ton per day direct-fired preheater-type rotary kiln (coal and pet coke) owned and operated by PLS in Laramie, Wyoming. The permit was issued in February 2015 (PLS 2015) and BACT was determined to be preheater kiln and good combustion practices (2 lb/tsf). The costs have been updated to 2019 dollars using the annual consumer price index (CPI). The total installed capital costs were estimated at $2,092,456.

Total annualized costs are shown in **Table 5-5** and **Table 5-7** for Kiln #1 and Kiln #2 respectively. Costs were prepared for control efficiencies between 10% and 25%. PLS believes it is unlikely that greater than 10% control efficiency could be obtained. Tons per year of NO_x removed range from 31 tpy at 10% control to 78 tpy at 25% control for Kiln #1 and from 20 tpy at 10% control to 51 tpy at 25% control for Kiln #2. As shown in **Table 5-5** and **Table 5-7**, annualized costs range from $2.1 million (10% control) to over $3 million (25% control) for the kilns. Annualized costs for SNCR include reagent consumption, lime kiln dust (LKD) product sales loss (> $1.1 million for Kiln #1 and > $1.4 million for Kiln #2), utilities, parts and maintenance, and labor costs for technicians to operate and monitor the SNCR operating controls. Operating and maintenance labor is estimated at 1 hour per shift. Reagent requirements were provided by CCA at 10 gallons per hour at $4.42/gallon (twice the current cost to account for the historically high variability of this reagent cost) for a 10% control system. Reagent usage for the other control levels was based on a linearity scale from the 10% control ammonia usage. These are very high annual costs and primarily the result of the high reagent cost and substantial loss of revenue due to the contamination of the lime kiln dust.

Total cost effectiveness ranges from $34,860 per ton ($/ton) at 25% control level to $68,430/ton at 10% control for Kiln #1 and from $58,830/ton at 25% control level to $118,620/ton at 10% control for Kiln #2, which are clearly excessive.

5.6 FACTOR 2 – TIME NECESSARY FOR COMPLIANCE

The time necessary for compliance is generally defined as the time needed for full implementation of the technically feasible control options. This includes the time needed to develop and implement the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. Therefore, compliance deadlines must consider the time necessary for compliance by setting a compliance deadline that provides a reasonable amount of time for the source to implement the control measure.

Sources are generally given between two and five years to implement changes for compliance with new regulations. MACT standards typically allow three years for compliance and BART emission limitations require compliance no more than five years after regional haze SIP approval by the EPA. Under the NO_x SIP Call for Phases I and II, EPA allowed for three and a half and two years, respectively, after the SIP submittal date for compliance. Post-combustion NO_x controls require significant time for engineering, construction, and facility preparedness. After SIP submittal, a two year period is assumed to be adequate for pre-combustion controls and a three year period for post combustion control installation.

The Institute of Clean Air Companies (ICAC) has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_x control (ICAC 2006). However, state regulators' experience indicates that closer to 18 months is required to install this technology (Ghoreishi 2007). PLS has indicated that a minimum of 18 months is required to design, procure, build and install for a single source (PLS 2019). In the Clean Air Interstate Rule (CAIR) analysis, EPA estimated that approximately 30 months is required to design, build, and install SO_2 scrubbing technology for a single emission source (USEPA 2005). The analysis also estimated that up to an additional 12 months may be required for staging the installation process if multiple sources are to be controlled at a single facility.

5.7 FACTOR 3 - ENERGY AND NON-AIR ENVIRONMENTAL IMPACTS

The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, increased emissions of other criteria or non-criteria pollutants, increased water consumption, and land use impacts from waste disposal.

5.7.1 ENERGY IMPACTS

The use of SNCR will have an energy penalty in terms of electricity needed to operate the SNCR system. The electricity requirement for the SNCR system is approximately 71 kw per hour (621,960 kW/yr) which equates to $62,196 per year.

5.7.2 ENVIRONMENTAL IMPACTS

Another concern with using SNCR is the formation of unreacted ammonia or urea that will react with sulfur oxides in the flue gas in the presence of water to form ammonium bisulfate (NH_4HSO_4), ammonium sulfate [$(NH_4)_2SO_4$], ammonium bisulfite (NH_4HSO_3), and ammonium chloride (NH_4Cl). The first three compounds are sticky compounds that can cause corrosion, fouling, and blockages downstream of the injection point. This would create serious problems with the preheater, ductwork, baghouses, and fans; reduce kiln draft; and cause excessive outages. Furthermore, ammonia slip from such systems would increase formation of secondary fine particulate in the atmosphere. The fine particulates created by ammonia slip are the result of the in-transit, secondary formation of ammonium sulfate and ammonium nitrate [$(NH_4)NO_3$]. The free ammonia will react with emitted or ambient concentrations of SO_2 and NO_x to form ammonium particulates, which absorb and scatter light, and as a result, reduce visibility. These secondarily-formed, fine particulates comprise a significant portion of the measured haze at Class I areas. Finally, ammonia absorption into the lime kiln dust collected in the baghouse would eliminate the ability to sell this byproduct, which would result in an economic penalty of over $1.1 million and $1.4 million for Kiln #1 and Kiln #2 respectively as discussed above and shown in **Table 5-5** and **Table 5-7**. Not only maintaining but also increasing the sale of these byproducts is a key industry strategy in meeting our CO_2 intensity reductions under DOE's Climate Vision Program.

Finally, note that the DENR has implemented a Natural Events Action Plan (NEAP) in response to exceedances of the PM_{10} NAAQS that were related to natural events. The NEAP requires implementation of PM_{10} BACT controls for certain sources, included the PLS facility. Any increase in secondary particulates associated with the ammonia slip would be counterproductive to the DENR's efforts to achieve and maintain compliance with the PM_{10} NAAQS.

5.8 FACTOR 4 – REMAINING USEFUL LIFE OF SOURCE

Kiln No. 1 was installed in 1994 and has been operational for 25 years. Kiln No. 2 was installed in 2010 and has been operational for almost 10 years. The remaining useful lifetime of both Kiln No. 1 and Kiln No. 2 is expected to be longer than the projected lifetime of the pollution control technology (SNCR) which has been analyzed for these sources. As such the remaining useful life of the kilns does not impact the annualized costs of SNCR because the remaining useful life of both kilns is anticipated to be at a minimum as long as the capital cost recovery period, which is 20 yrs.

5.9 CONCLUSION

The four factor analysis prepared for PLS NO_x reductions indicates that the SNCR control option is cost prohibitive for both Kiln #1 and Kiln #2. At a cost effectiveness ranging from $34,860 to $68,430/ton of NO_x removed for Kiln #1 and $58,830 to $118,620/ton of NO_x removed for Kiln #2, SNCR clearly is not a cost effective control technology. Although control efficiencies between 10% and 25% were reviewed, PLS believes it is unlikely that greater than 10% control efficiency could be obtained. High reagent cost and substantial loss of revenue due to the contamination of the lime kiln dust are the primary contributors to the high cost. In addition to the serious economic impacts associated with SNCR, there are significant environmental drawbacks which outweigh the benefits of NO_x reduction. These include emissions of toxic air contaminants by "ammonia slip" through the SNCR unit. Ammonia slip would also result in the formation and emissions of secondary particulates, and counterproductive to the DENR's efforts to achieve and maintain the PM_{10} NAAQS in Rapid City. There is also a potential for generation of corrosive acid gases contributing to increased opacity which in turn creates negative impacts on visibility. There are inherent hazards in transportation, handling, and storing large quantities of ammonia. Assuming SNCR is actually technically feasible which PLS firmly believes it is not, because of the severe economic costs of SNCR, the many energy and environmental drawbacks, the ammonia transportation and handling hazards associated with SNCR, and it not being a proven technology on lime kilns in the U.S., SNCR is not considered a cost effective control technology for either of the lime kilns.

PLS has determined that the only cost-effective and viable control technology for Kiln #1 and Kiln #2 is the existing control options consisting of efficient combustion practices, minimization of fuel consumption (preheater type kiln), and excess air for the combustion process, or similar control techniques.

Table 5-1 U.S. EPA NO_x RACT/BACT/LAER Clearinghouse – Lime Kilns

RBLC ID	Company / Facility	(Permit Issued) Last Update	Kiln Type / Size	Fuel Type	Emission Limit	Control Technology	Basis
WY-????	PLS Jonathon Lime Plant	(02/05/2015)	Rotary Kiln PH / 600 tpd Lime	Coal / Coke	2 lb/stf; 100 lb/hr; 438 tpy	GCP; PH Kiln	BACT-PSD
WI-0250	Graymont (WI) LLC	(02/06/2009) 10/26/2009	Rotary Kiln Preheater / 1,296 tpd stone feed	Coal / Coke	98.8 lb/hr – 3-hr avg. 1.83 lb/tsf – 24 hr avg.	Good Combustion Practice (GCP)/Optimization	BACT-PSD
OH-0321	Martin Marietta Materials / Magnesia Specialties, LLC	(11/13/2008) 02/10/2009	Rotary Kiln Preheater (PH) / 900 tpd Lime	Coal / Coke	4.1 lb/ton lime (~2.1 lb/tsf), 673.4 tpy	None Listed	BACT-PSD
SD-????	PLS Rapid City Lime Plant	(10/30/2008)	Rotary Kiln PH / 600 tpd Lime	Coal / Coke	2 lb/stf; 100 lb/hr; 438 tpy	GCP; PH Kiln	BACT-PSD
WI-0233	Cutler Magner Company / Superior	(08/16/2006) 12/21/2006	Rotary Kiln PH / 650 tpd Lime	Coal / Coke	98.8 lb/hr - 3-hr; 1.83 lb/tsf - 24 hr	GCP; PH Kiln	BACT-PSD
AR-0082	Arkansas Lime Company	11/03/2005	Rotary Kiln	Coal / Coke	3.6 lb/ton lime (~1.8 lb/tsf)	GCP	BACT-PSD
PA-0241	Graymont Western US, Inc. / Bellefonte Plant	(07/09/2004) 10/25/2004	Rotary Kiln #7 / 1,050 tpd	Coal / Coke	179 lb/hr; 709 tpy	None Listed	Other
MI-0383	Western Lime Corporation	(01/30/2004) 09/14/2007	Rotary Kiln PH / 1,680 tpd Stone Feed	Coal / Coke	132.6 lb/hr; 1.83 lb/tsf; 532 tpy	LNB & limit excess air	BACT-PSD
TX-0452	Austin White Lime Co. – McNeil Plant	(11/19/2003) 08/02/2007	Rotary Kiln #1 & #2	Coal / Coke	106.1 lb/hr; 437.3 tpy (each)	None Listed	BACT-PSD
			Rotary Kiln #3	Coal / Coke	118.3 lb/hr; 425.7 tpy	None Listed	BACT-PSD
OH-0270	Carmeuse Lime – Maple Grove Facility	(10/14/2003) 07/18/2005	(2) Rotary Kilns / 650 tpd each Stone Feed	Coal / Coke	1,234.9 lb/hr; 45.6 lb/tsf; 5,409 tpy (each)	None Listed	BACT-PSD
IL-0084	Vulcan Materials	(10/28/2002) 09/17/2003	Rotary Kiln / 1,296 tpd stone feed	Not Listed	4.5 lb/tsf; 242.5 lb/hr	GCP	BACT-PSD
MT-0020	Graymont Western US, Inc.	09/23/2003	Rotary Kiln	Coal	100 lb/hr	GCP	BACT-PSD
AR-0034	Arkansas Lime Company	(05/18/2000) 02/10/2003	Rotary Kiln / 600 tpd Lime	Nat Gas	3.65 lb/ton lime (~1.83 lb/tsf); 399.3 tpy	None Listed	BACT-PSD
AR-0028	Arkansas Lime Company	(09/14/1999) 02/18/2001	Rotary Kiln / 625 tpd Lime	Coal / Coke	3.65 lb/ton lime (~1.83 lb/tsf); 91.2 lb/hr	Proper Design & Operation of Kiln	BACT-PSD
TX-0360	Texas Lime	(08/02/1999) 01/04/2005	Rotary Kiln #4 / 850 tpd	Coal	104.3 lb/hr; 393 tpy	None Listed	Other
			Rotary Kiln #6 / 850 tpd	Coal	197.1 lb/hr; 639.5 tpy	None Listed	Other

Table 5-2 Identified Air Pollution Control Technologies - NO_x

Combustion Controls	Exhaust Treatment
Kiln Fuel Changes	Selective non-catalytic reduction (SNCR)
Low NOx Burner	Selective catalytic reduction (SCR)
Flue Gas Recirculation	
Staged Combustion Air	
Good Combustion Practices	

Table 5-3 Technical Feasibility of NO_x Control Technologies

Controls	Status / Feasibility	Technically Feasible?
Kiln Fuel Changes	Part of normal operation and current design (Pet Coke) – but not mandatory or considered control option	No
Flue Gas Recirculation (FGR)	Never Demonstrated on a Lime Kiln, Oxygen Deficiency Detrimental to Lime Quality	No
Low NO_x Burner (LNB)	Available for indirect-fired kiln only	No
Staged Combustion Air	Never Demonstrated on a Lime Kiln	No
Good Combustion Practices	Available	Yes
SNCR	Never Demonstrated on a Lime Kiln	No
SCR	Never Demonstrated on a Lime Kiln	No

Table 5-4 Selective Non-Catalytic Recovery (SNCR) Capital Costs – Kiln #1

DIRECT COSTS (DC):	
(1) Purchased Equipment Costs:	
(a) Basic Equipment and Auxiliaries (A)	$753,971
(b) Instrument and Controls [0.1 (a)]	$0
(c) Freight [0.05 (a)]	$37,699
(d) Taxes [0.06 (a)]	$45,238
Total Equipment Cost (B)	$836,908
(2) Direct Installation Costs	
(a) Foundations and Supports [0.04 (B)]	$33,476
(b) Erection and Handling [0.5(B)]	$418,454
(c) Electrical [0.08 (B)]	$66,953
(d) Piping [0.01 (B)]	$8,369
(e) Insulation [0.07 (B)]	$58,584
(f) Painting [0.02 (B)]	$16,738
Total Direct Installation Costs	$602,574
Total Direct Costs, TDC (B + Direct Installation Costs)	$1,439,482
INDIRECT COSTS (IDC):	
(4) Engineering and Supervision [0.10 (B)]	$83,691
(5) Construction and Field Expenses [0.20 (B)]	$167,382
(6) Construction Fee [0.10 (B)]	$83,691
(7) Start-up [0.02 (B)]	$16,738
(8) CEMS	$215,420
(9) Performance Test [0.03 (B)]	$25,107
Total Indirect Costs, TIDC	$592,029
Total Direct Costs + Total Indirect Costs	$2,031,511
Contingency (3% of TDC + TIDC)	$60,945
TOTAL INSTALLED CAPITAL COSTS (TCC)	**$2,092,456**

Sources: USEPA 2002/2019b; Vatavuk and Neveril 1980; CCA/Ferenco 2014 (Adjusted for 2019 Consumer Price Index).

Table 5-5 Selective Non-Catalytic Recovery (SNCR) Annualized Costs – Kiln #1

DIRECT COSTS:	Percent Control			
	25%	**20%**	**15%**	**10%**
(1) Operating Labor: 1 hr/shift @ $36,462/yr ($17.53/hr) (C)	$19,195	$19,195	$19,195	$19,195
(2) Supervisory Labor [0.15 (C)]	$2,879	$2,879	$2,879	$2,879
(3) Maintenance Labor: 1 hr/shift @ $40,102/yr ($19.28/hr)	$21,112	$21,112	$21,112	$21,112
(4) Parts and Materials [100 percent of maintenance labor + 0.10(A)]	$96,509	$96,509	$96,509	$96,509
(5) Utilities				
(a) Electricity ($0.09/kW-hr, 71 kW, 8,760 hr/yr)	$55,976	$55,976	$55,976	$55,976
(b) CEMS Operating Costs (includes annual RATA)	$35,000	$35,000	$35,000	$35,000
(6) LKD loss sales penalty [480 tpd x 5.7% 348 days/yr x $125/ton (sell price - disposal price)]	$1,190,160	$1,190,160	$1,190,160	$1,190,160
(7) Urea Reagent (10 gal/hr per 10% control @ $4.42 /gal; usage linearity assumed)	$967,980	$774,384	$580,788	$387,192
Total Direct Costs	$2,388,811	$2,195,215	$2,001,619	$1,808,023
INDIRECT COSTS:				
(8) Overhead [0.80 (1.15C + 0.04 TDC)]	$63,723	$63,723	$63,723	$63,723
(9) Property Tax (0.01 TCC)	$20,925	$20,925	$20,925	$20,925
(10) Insurance (0.01 TCC)	$20,925	$20,925	$20,925	$20,925
(11) G&A Charges (0.02 TCC)	$41,849	$41,849	$41,849	$41,849
(12) Capital Recovery (CRF * TCC)	$167,904	$167,904	$167,904	$167,904
(a) Capital Recovery Factor (CRF) [5% ROR, 20-year life]	0.08024	0.08024	0.08024	0.08024
Total Indirect Costs	$315,326	$315,326	$315,326	$315,326
TOTAL ANNUALIZED COSTS	**$2,704,137**	**$2,510,541**	**$2,316,945**	**$2,123,349**
Tons/year of NO_x Removed	77.6	62.1	46.5	31.0
COST EFFECTIVENESS ($/ton NO_x removed)	**$34,860**	**$40,460**	**$49,780**	**$68,430**

Sources: USEPA 2002/2019b; Vatavuk and Neveril 1980; CCA/Ferenco 2014 (Adjusted for 2019 Consumer Price Index).

Table 5-6 Selective Non-Catalytic Recovery (SNCR) Capital Costs – Kiln #2

DIRECT COSTS (DC):	
(1) Purchased Equipment Costs:	
(a) Basic Equipment and Auxiliaries (A)	$753,971
(b) Instrument and Controls [0.1 (a)]	$0
(c) Freight [0.05 (a)]	$37,699
(d) Taxes [0.06 (a)]	$45,238
Total Equipment Cost (B)	$836,908
(2) Direct Installation Costs	
(a) Foundations and Supports [0.04 (B)]	$33,476
(b) Erection and Handling [0.5(B)]	$418,454
(c) Electrical [0.08 (B)]	$66,953
(d) Piping [0.01 (B)]	$8,369
(e) Insulation [0.07 (B)]	$58,584
(f) Painting [0.02 (B)]	$16,738
Total Direct Installation Costs	$602,574
Total Direct Costs, TDC (B + Direct Installation Costs)	$1,439,482
INDIRECT COSTS (IDC):	
(4) Engineering and Supervision [0.10 (B)]	$83,691
(5) Construction and Field Expenses [0.20 (B)]	$167,382
(6) Construction Fee [0.10 (B)]	$83,691
(7) Start-up [0.02 (B)]	$16,738
(8) CEMS	$215,420
(9) Performance Test [0.03 (B)]	$25,107
Total Indirect Costs, TIDC	$592,029
Total Direct Costs + Total Indirect Costs	$2,031,511
Contingency (3% of TDC + TIDC)	$60,945
TOTAL INSTALLED CAPITAL COSTS (TCC)	**$2,092,456**

Sources: USEPA 2002/2019b; Vatavuk and Neveril 1980; CCA/Ferenco 2014 (Adjusted for 2019 Consumer Price Index).

Table 5-7 Selective Non-Catalytic Recovery (SNCR) Annualized Costs – Kiln #2

DIRECT COSTS:	Percent Control 25%	20%	15%	10%
(1) Operating Labor: 1 hr/shift @ $36,462/yr ($17.53/hr) (C)	$19,195	$19,195	$19,195	$19,195
(2) Supervisory Labor [0.15 (C)]	$2,879	$2,879	$2,879	$2,879
(3) Maintenance Labor: 1 hr/shift @ $40,102/yr ($19.28/hr)	$21,112	$21,112	$21,112	$21,112
(4) Parts and Materials [100 percent of maintenance labor + 0.10(A)]	$96,509	$96,509	$96,509	$96,509
(5) Utilities				
(a) Electricity ($0.09/kW-hr, 71 kW, 8,760 hr/yr)	$55,976	$55,976	$55,976	$55,976
(b) CEMS Operating Costs (includes annual RATA)	$35,000	$35,000	$35,000	$35,000
(6) LKD loss sales penalty [600 tpd x 5.7% 348 days/yr x $125/ton (sell price - disposal price)]	$1,487,700	$1,487,700	$1,487,700	$1,487,700
(7) Urea Reagent (10 gal/hr per 10% control @ $4.42 /gal; usage linearity assumed)	$967,980	$774,384	$580,788	$387,192
Total Direct Costs	$2,686,351	$2,492,755	$2,299,159	$2,105,563
INDIRECT COSTS:				
(8) Overhead [0.80 (1.15C + 0.04 TDC)]	$63,723	$63,723	$63,723	$63,723
(9) Property Tax (0.01 TCC)	$20,925	$20,925	$20,925	$20,925
(10) Insurance (0.01 TCC)	$20,925	$20,925	$20,925	$20,925
(11) G&A Charges (0.02 TCC)	$41,849	$41,849	$41,849	$41,849
(12) Capital Recovery (CRF * TCC)	$167,904	$167,904	$167,904	$167,904
(a) Capital Recovery Factor (CRF) [5% ROR, 20-year life]	0.08024	0.08024	0.08024	0.08024
Total Indirect Costs	$315,326	$315,326	$315,326	$315,326
TOTAL ANNUALIZED COSTS	**$3,001,677**	**$2,808,081**	**$2,614,485**	**$2,420,889**
Tons/year of NO_x Removed	51.0	40.8	30.6	20.4
COST EFFECTIVENESS ($/ton NO_x removed)	**$58,830**	**$68,790**	**$85,400**	**$118,620**

Sources: USEPA 2002/2019b; Vatavuk and Neveril 1980; CCA/Ferenco 2014 (Adjusted for 2019 Consumer Price Index).

6. SUMMARY AND CONCLUSIONS

At the request of DENR, a four factor analysis was prepared for PLS' Kiln #1 and Kiln #2 for use in their Round II Determination. The analysis identified technically feasible NO_x control options for the kilns, and evaluated each of the control measures for the following four statutory factors:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

The cost of compliance evaluation (Statutory Factor 1) prepared for NO_x controls indicates that, from baseline emission rates, the average annual cost effectiveness of the technically feasible NO_x control options for Kiln #1 ranges from $34,860/ton (25% control) to $68,430/ton NO_x removed (10% control), and for Kiln #2 ranges from $58,830/ton (25% control) to $118,620/ton NO_x removed (10% control) from historical baselines.

The time necessary for compliance for the NO_x control options, the time necessary for compliance ranges from 18 months to 42 months.

An evaluation of energy impacts and non-air environmental impacts (Statutory Factor 3) indicates that the use of SNCR will have an energy penalty in terms of electricity needed to operate the SNCR system. Collateral environmental impacts include emissions of toxic air contaminants by "ammonia slip" through the SNCR unit. Ammonia slip would also result in the formation and emissions of secondary particulates, and counterproductive to the DENR's efforts to achieve and maintain the PM_{10} NAAQS in Rapid City. There is also a potential for generation of corrosive acid gases contributing to increased opacity which in turn creates negative impacts on visibility. There are also inherent hazards in transportation, handling, and storing large quantities of ammonia.

Regarding remaining useful life (Statutory Factor 4), the remaining useful lifetime of both Kiln No. 1 and Kiln No. 2 is expected to be longer than the projected lifetime (20 years) of the pollution control technology (SNCR) which has been analyzed for these sources. Therefore, the remaining useful life has no impact on the annualized cost of control under the current regulatory framework.

The four factor analysis prepared for PLS' NO_x reductions indicates that SNCR control is cost prohibitive (assuming it is even technically feasible). The control cost evaluation indicates that the average cost effectiveness levels exceed $34,000/ton NO_x removed. PLS is proposing that the existing control options consisting of efficient combustion practices, minimization of fuel consumption (preheater type kiln), and excess air for the combustion process, or similar control techniques on Kiln #1 and Kiln #2 represent appropriate controls for the Round II Determination, therefore no change to the current Title V Operating Permit is proposed for NO_x emissions at PLS.

7. REFERENCES

CCA/Ferenco. 2014. Personal communication with C. Shaw (Ferenco) and J. Feehan (PLS) via email regarding capital cost for SNCR from Combustion Components Associates, Inc. (CCA) E. Schindler. November 21, 2014.

Gard. 1978. Capital and Operating Costs of Selected Air Pollution Control Systems. United States Environmental Protection Agency. 450/55 80 002

Ghoreishi. 2007. Personal communication, Time required to install add-on control measures for NO_x, Wisconsin Department of Natural Resources, April 27, 2007.

Grant, E. L., Ireson, W. G., and Leavenworth, R. S. Principles of Engineering Economy, Eighth Edition, John Wiley & Sons, New York, 1990.

Hilovsky, R.J.. 1977. NO_x Reductions in the Portland Cement Industry With Conversion to Coal-Firing. Presented at the 1977 U.S. EPA Emission Inventory/Factor Workshop. Raleigh, NC. September 13-15, 1977.

ICAC 2006. Institute of Clean Air Companies (2006), Typical Installation Timelines for NO_x Emissions Control Technologies on Industrial Sources. http://www.icac.com/files/public/ICAC_NOx_Control_Installation_Timing_120406.pdf.

National Lime Association (NLA). 2005. Comments on Vista's Draft Regional Haze Modeling Protocol. October 21, 2005.

_____. 2006. Comments on Ozone Transport Commission's Draft NO_x Control Measure Summary for Lime Kilns. March 30, 2006

Perry, Robert. H. and Chilton, Cecil. H., editors. 2008. *Perry's Chemical Engineers Handbook*. 8th Edition. McGraw-Hill.

Pete Lien & Sons, Inc. 2019. Personal communication between J. Christopher (SLR) and C. Beck (PLS) via email. September 24, 2019.

_____. 2015. Wyoming Department of Environmental Quality Air Quality Permit CT-16003, issued to Pete Lien & Sons, Inc. to construct a lime manufacturing plant, nominal capacity of 600 tons per day, issued February 5, 2015.

United States Environmental Protection Agency (USEPA). 2017. Office of Air Quality Planning and Standards Control Cost Manual. Office of Air Quality Planning and Standards, Economic Analysis Branch, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina. November. (Chapter 2, updated November, 2017)

_____. 2019a. BACT/RACT/LAER Clearinghouse - Compilation of Control Technology Evaluations.

_____. 2019b. Office of Air Quality Planning and Standards Control Cost Manual. Office of Air Quality Planning and Standards, Economic Analysis Branch, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina. Section 4 – NO_x Controls, Chapter 1 – Selective Non-Catalytic Reduction (updated April 25, 2019)

_____. 2007. Alternative Control Techniques Document Update -- NO_x Emissions from Cement Manufacturing. Emission Standards Division, U.S. Environmental Protection Agency. Research Triangle Park, North Carolina. EPA-453/R-07-006. November 2007.

_____. 2014. Arizona Regional Haze and Interstate Visibility Transport Federal Implementation Plan. Final Rule. 79 FR 52419. October 3, 2014.

_____. 2005. Boilermaker Labor Analysis and Installation Timing – Technical Support Document for the Final Clean Air Interstate Rule. OAR-2003-0053, U.S. EPA, Washington, DC. www.epa.gov/cair/technical.html#final.

_____. 1994. Alternative Control Techniques Document -- NO_x Emissions from Cement Manufacturing. Emission Standards Division, U.S. Environmental Protection Agency. Research Triangle Park, North Carolina. EPA-453/R-94-004. March 1994.

Vatavuk, W. M. and Neveril, R. B. "Estimating Costs of Air Pollution Control Systems - Part I: Parameters for Sizing Systems," Chemical Engineering. October 6, 1980, pp 165-168.

Zeldovich, J. 1946. The oxidation of nitrogen in combustion and explosions. ACTA Physico Chimica, URSS Volume 21:4, pp. 577-628.

APPENDIX A

ECONOMIC SUPPORT DATA

Four Factor Analysis - NO_x

Pete Lien & Sons, Inc.

Rapid City, SD

October 2019

Jamie Christopher

From:	Craig Shaw <craigs@ferenco.com>
Sent:	November 21, 2014 2:27 PM
To:	Jim Feehan
Subject:	FW: NOX Control for Lime Kilns

Jim:

I just received this from CCA.

Looks like supply and install is $700,000 + $400,000 = $1,100,000.

Operating costs would be the power for the 75 HP compressor and the two pumps at 10 HP each.
Electrical costs would be 95 HP x .746KW/HP = 71 KW x 24 hours/day x $0.10/KWh x 365 days = $62,196 per year.
Plus the cost of the reagent.
At 10 GPH x 24 hours/day x 365 days/yr. = 87,600 GPY x $2.21 = $193,596 per year.
Total Power and reagent = $62,196 + 193,596 = $255,792 per year.
This is for a 10% reduction.

This seems consistent with the GCC number you were quoting me on Thursday.

If the effect is linear you would need $255,792 x 5 = $1,278,960 per year for a 50% reduction.

The email from CCA stated 10 GPM but after we questioned it they corrected it to 10 GPH.

The EPA Guidebook as a way to formulate these costs as well.
We will put these numbers into the format and see if we get higher results.

No feedback from anyone else yet.

Yours truly

Craig

From: Ed Schindler [mailto:ESchindler@peerlessmfg.com]
Sent: Friday, November 21, 2014 12:00 PM
To: Craig Shaw
Cc: Nathan Schindler
Subject: RE: NOX Control for Lime Kilns

Craig
The equipment supply includes:
a) Heated urea storage tank
b) 7 injectors and connecting hoses
c) Pump skid with valves (dual pumps)

d) Air compressor
e) Metering rack for flows to each injector

supply budget cost is $700,000.00
install budget cost is $400,000.00

We would also like to know the power consumption for the air compressor and pumps (ballpark).
Compressor is 75 HP pumps area about 10 HP each for water and urea.

As well the reagent present costs and consumption rate assuming the same 10% NOX reduction rate.

Reagent has not changed much as it is based on natural gas prices. Recent quotes are $2.21 delivered per gallon.

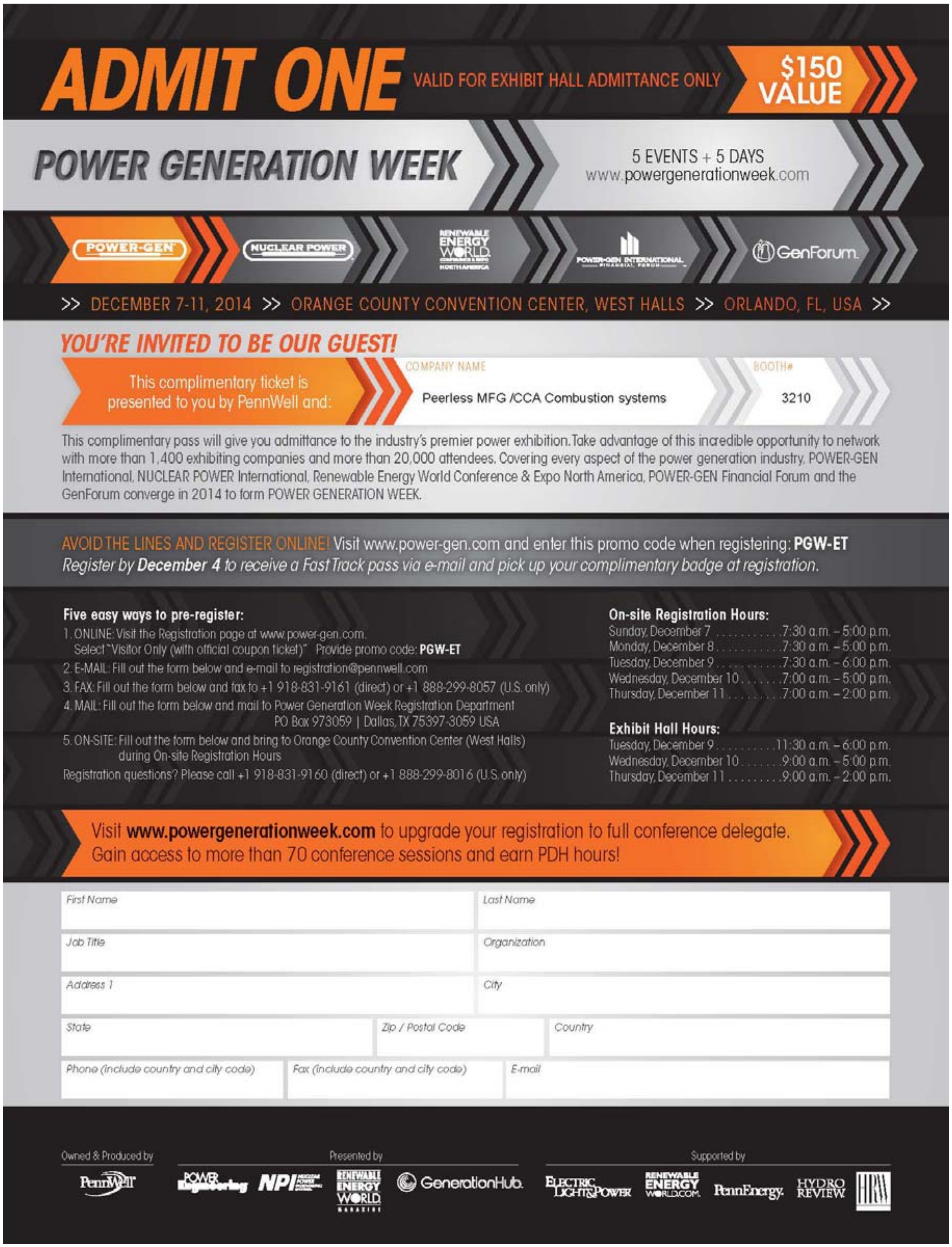
If you only want 10% reduction you probably only need 3 injectors.

If the kiln is the same and the temperature is 100F lower you may need less urea but for now let's say 10 gpm for 10% reduction.

Send the paper if you have it.

Thanks for your interest.

Ed Schindler
Director, Sales
Please visit us at Power-Gen December 9-11, 2014 Booth 3210 See free admission below Orange County Convention



Center Orlando, FL
"CCA Combustion Systems, a division of Peerless Mfg. Co. "
My Contact information is:
Email: eschindler@peerlessmfg.com **note new email.**
Phone: 203 268 3139 x117
Fax: 203 261 7697
Cell: 203 733 5863
Web site: www.CCA-INC.net
Address:
Combustion Components Associates, INC.
884 Main Street
Monroe, CT 06468

From: Craig Shaw [mailto:craigs@ferenco.com]
Sent: Thursday, November 20, 2014 3:22 PM
To: Nathan Schindler
Subject: NOX Control for Lime Kilns

Nathan:

Thank you for taking the time to speak to me today about NOX Control.

As we discussed we are presently trying to gather ballpark cost information related to NOX control on lime kilns.
We were directed to your company by our client who had read a presentation by Unimim whereby they listed your company as the supplier of equipment they used.
In that presentation the final installation was commissioned in October of 2010.

The final results where that Unimim were getting a 10% NOX reduction with 8 gal/hour using 50% Urea with an acidic additive (NOxOUT A).
The presentation also listed that it was possible to get up to a 50% reduction in NOX before ammonia slip occurs.
The injection point was at the interface between the kiln and the preheater with gas temperatures around 2100 F.
Prices for NOxOUT A were listed at $2.20/gal back in Oct 2011.
The capital costs for the equipment was listed at $500,000.

Our application is very similar.
The injection point would be the same with the temperature at approximately 2000 F.
The flue gas flow rate at this location is 147,500 lbs./hour.
The plant is coal fired.

We would be looking for either a ballpark equipment supply cost or a turnkey supply / installation cost in US Dollars.
It looks like the equipment supply includes:

a) Heated urea storage tank
b) 7 injectors and connecting hoses
c) Pump skid with valves
d) Air compressor
e) Metering rack for flows to each injector

We would also like to know the power consumption for the air compressor and pumps (ballpark).

As well the reagent present costs and consumption rate assuming the same 10% NOX reduction rate.

We hope that your company's previous work makes gathering this information easier.
Your assistance is greatly appreciated.

Yours truly
FERENCO INDUSTRIAL (CANADA) INC.

Craig A. Shaw P.Eng.
President

APPENDIX E

SOUTH DAKOTA REGIONAL HAZE STATE IMPLEMENTATION PLAN: THE WRAP MODELLING DELAYS MEMO

Via E-Mail

February 8, 2021

Mary Uhl
Executive Director
Western Air Resources Council (WESTAR)
3 Caliente Road #8
Santa Fe, New Mexico 87508
(505) 954-1160
maryuhl@westar.org

Subject: Explanations for Delay in Western States Regional Haze Modeling

Dear Mary:

This letter documents and provides reasons for delays in the chronology of Ramboll's completion and delivery of the Regional Haze (RH) photochemical modeling results since late 2018, for the western states on the WRAP Technical Support System (TSS). The TSS is our delivery target since western states and other WRAP partners use it for Round 2 RH State Implementation Plans (SIPs) due July 2021. This work for WESTAR-WRAP has been done mainly under WESTAR Contract 19-01. First and foremost, I want to emphasize how much we value WESTAR-WRAP membership and the western states in particular as important clients and these delays in no way indicate a lack of commitment by Ramboll or us not placing this work as highest priority. This is the most important project that I and my staff have right now, and we are trying to finish delivery of high quality RH technical work products as quickly as we can.

The WRAP western state RH CAMx source apportionment is quite complex and complicated integrating numerous sources of data (e.g., 2014NEI, WRAP states data, EPA 2016v1 platform, natural and international emissions, data products of WRAP workgroups and projects etc.), because the vast majority of emissions affecting RH planning are out of the control of the states, but must be thoroughly assessed with photochemical modeling per EPA RH planning guidance. The work tasks in Contract 19-01 involved a lot of moving parts and pieces of data that needed to be properly implemented presenting multiple opportunities for mistakes. However, that is not an excuse as Ramboll has a reputation and track record on performing such complicated and high-quality air quality modeling studies.

In my over 40 years as an air quality consultant, I have never had a project that had so many setbacks for so many different reasons. Ramboll is not blameless in this as some delays are our fault and we have taken a financial penalty by all the re-running of modeling scenarios, not to mention the emotional and stressful aspects of these delays. But many of the delays have been unique and due to unforeseen circumstances that were out of our control, including:

- Federal government shut-down in December 2018 and January 2019 delayed getting EPA's 2014 modeling platform at the outset of the project.

- EPA's 2014 GEOS-Chem simulation that we planned to use for Boundary Conditions (BCs) was flawed with June & July SO2/SO4 overestimation and year-round ozone overestimation. As a result, we had to conduct our own unplanned 2014 GEOS-Chem simulation to correct it that took several months.

- Delays and data processing decisions at EPA in releasing the National Emissions Inventory Collaborative (NEIC) 2016v1 modeling platform and 2023 and 2028 future year emission projections caused delays in getting future year emissions, as well as errors in the data, as noted below.

- Ramboll modeling computer servers for this work are located in northern California. The Pacific Gas & Electric utility instituted Public Service Power Shutoffs (PSPS) to prevent wildfires that shut down the power to the computers doing the modeling during portions of September-October 2019.

- In November 2019, California Air Resources Board discovered errors in the 2014v2/RepBase fugitive dust emissions they provided that caused delays while we re-processed the emissions and re-ran model simulations.

- COVID-19 Shelter-in-place from March 2020 to the present disrupted and slowed down the modeling. It took a while to figure out how to work effectively remotely. Also with no one in the office, when a computer goes down, hangs or there is a need to mount a new disk to make disk space, there are longer delays than normal as someone has to make a trip to the office.

- In June 2020 we found that some anthropogenic state-controllable sources for RH planning were both incorrect and/or double-counted in the NEIC 2016v1 modeling platform data, in both of the key scenarios for RH planning, the already-completed RepBase and 2028OTBa projection scenarios in the WESTAR-WRAP modeling effort, that caused a 3-month delay (Jun-Jul-Aug 2020). The emissions had to be reviewed by Ramboll and the states for corrections, updated and fixed and SMOKE emissions modeling of re-done so new RepBase2 and 2028OTBa2 could be done.

- Because of the problems and reprocessing required for the NEIC 2016v1 and 2028 emissions, technical decisions were made by WESTAR-WRAP members in RH work groups, to change some of the emissions sector datasets to be used in the new RepBase2 and 2028OTBa2 scenarios from what was in Ramboll's contract necessitating re-processing and some additional delays. The effect of these decisions was non-zero in terms of Ramboll effort, but were timely and improved the representativeness of the RepBase2 and 2028OTBa2 modeling results for RH planning.

- Unprecedented wildfires in Northern California August through November 2020 interfered with staff working as $PM_{2.5}$ concentrations in excess of 200 µg/m^3 blanketed the region making going outdoors and travel dangerous. Many staff were on-call prepared for evacuation and worked much less efficiently under stressful conditions.

- Coding errors in the Ramboll CAMx model caused two re-runs of the CAMx RepBase2 and 2028OTBa2 source apportionment simulations in late 2020. As these runs take ~28 days to run, each re-run can cause a 1-2 month delay as we have to debug what the error is, fix it and re-run.

Ramboll was originally teamed with a Subcontractor whose role was to do most of the SMOKE emissions modeling. The same Subcontractor had a similar role when Ramboll developed the WRAP WestJumpAQMS 2008 and IWDW-WAQS 2011 modeling platforms and performed well.

Attachment 1 has a chronology of events that occurred and caused delays in delivering products on schedule. Below we discuss how some of these specific events delayed some of the key project deliverables.

- The schedule for the first big deliverable was WRAP-WAQS Shake-Out 2014v1 CMAQ and CAMx platforms, model evaluation and Close-Out meeting by March 2019. The Close-Out meeting occurred in April 2019 and delivery of the 2014v1 platform to IWDW in May. The causes for these delays are as follows:
  - Initial contract award was received December 11, 2018, affecting the proposed schedule from Ramboll. If we have started December 1, 2018 as originally planned we likely would have noticed the missing files for EPA's 2014 platform on their ftp site before the unexpected government shut-down.
  - Federal government shut-down December 22, 2018 through January 25, 2019 that delayed getting the EPA 2014 modeling platform by over a month as the EPA ftp site did not include all of the files and EPA staff were unavailable to provide them.
  - In February 2019 we found that the EPA 2014 GEOS-Chem had overestimation issues and in March 2019 EPA re-ran June and July to fix one of the problems so that final 2014v1 CMAQ/CAMx simulations, MPE and database transfer were delayed from the March target timeframe until April-May 2019.
- The next big deliverables, as identified in the May 29, 2019 WESTAR 19-01 Amendment#2 (A2), was 2014v2 emissions modeling, 2014 GEOS-Chem modeling and 2014v2 CMAQ/CAMx modeling to be completed by July 2019 and Representative Baseline (RepBase) modeling to be completed by August 2019. In reality, the first CAMx 2014v2 simulation was not completed until September 2019 and a series of emission updates were made so that the final 2014v2 CAMx base case was not completed until early December 2019. The first RepBase run was not completed until January 2020. The reasons for the delays of the final 2014v2 and initial RepBase simulations are as follows:
  - The July 2019 deadline for the 2014v2 platform was probably overly ambitious, but August should have been doable.
  - A key update in the 2014v2 platform was 2014 emissions for California that CARB provided to the SMOKE emissions Subcontractor in May 2019. In July the Subcontractor started asking questions and needing updates to the 2014 California inventory, so it appears they sat on and didn't look at the data for two months. 2014v2 SMOKE emissions processing was delayed as the Subcontractor's SMOKE modeler had many trips, such as to Korea (June), South America (July) and the EPA Emissions Inventory Conference in Dallas (August). Ramboll finally received the disk drive with the 2014v2 emissions on August 29, 2019. Note that Ramboll has worked very well with this Subcontractor in past studies (e.g., 2008 and 2011 platforms), but personnel

changes appear to have affected their ability to deliver in a timely fashion. Ramboll ultimately took over the SMOKE emissions modeling so that it could be performed in a more timely manner.

- Ramboll's initial CAMx 2014v2 simulation in September 2019 produced high ozone in northeast Wyoming that was traced to an emissions modeling error that allocated all the annual average O&G emissions to January in some counties.

- The Subcontractor corrected the 2014v2 O&G emissions and a revised CAMx 2014v2 simulation was conducted in October 2019.

- The California Air Resources Board informed us in November 2019 that there were errors in California's 2014v2/RepBase fugitive dust emissions and sent corrections that were incorporated into the RepBase emissions delaying the RepBase CAMx simulation until January 2020.

- Also in November 2019, we discovered errors in the RepBase fire emissions files provided by the WRAP Fire & Smoke Work Group (FSWG) contractor that produced negative $PM_{2.5}$ emissions that had to be corrected by the FSWG contractor. Identification of these sort of issues for fire and many other source categories is a common and required task for assembly of air quality modeling scenarios in a platform. The evaluation and correction of the fire emissions files was another delay in the sequence to assemble RepBase.

- Errors in EPA's proprietary and lightly documented AMET MPE Tool that EPA did not fix until January 2020 (and only EPA can fix), that we use to calculate performance statistics to be in compliance with EPA modeling guidance, meant that some of the model performance evaluation (MPE) products for the 2014v2 simulations were delayed.

* WESTAR Contract 19-01 Amendment#5 (A5) dated November 22, 2019 had several deliverables with the key ones as follows: (1) 2002 Dynamic Evaluation (2002DE) CAMx simulation completed by February 2020; (2) 2028OTB CAMx done by February 2020; and (3) CAMx 2028 source apportionment done by March 2020. There were numerous iterations in these simulations so that they were not finally completed until January 2021 for the following reasons:

  - After these milestones were set in the contract and in discussion with Regional Technical Operations Work Group Co-Chairs and WESTAR-WRAP staff and to meet objectives (e.g., obtain separate fire and U.S. anthropogenic emission contributions), the RepBase, 2028OTBa and 2002DE were turned into source apportionment simulations each of which takes ~28 days to run. Thus, the original schedule in A5 as the awarded contract required was physically impossible to meet given the changes in the run times from a CAMx standard model run (~5 days) to a source apportionment run (~28 days).

  - The delays in the 2014v2 and RepBase simulations meant that A5 modeling could not start until January 2020 instead of November 2019 as originally envisioned. This meant that the 2028OTB emissions and first CAMx 2028OTB simulations and visibility projections were completed in March-April instead of February 2020.

- In March 2020, shelter-in-place orders were mandated due to the COVID-19 pandemic that caused a slow-down in the modeling for several reasons:

  - People had to move their work stations from the office to home where they do not have as efficient a work space (e.g., copier machines, access to computers, etc.).

  - It took some time for people to figure out how to work from home effectively and efficiencies suffered.

  - Schools and day cares closed so parents had full time responsibility for their children and had to assist teaching from home.

  - When the high performance Linux computers in the office went down, hung or we needed to mount disks for backups to make more disk space, someone had to physically come in to the office and there were restrictions on how that could be done.

- The 2002 Dynamic Evaluation emissions development to backcast 2014 emissions to 2002 turned out to be a much bigger task than originally scoped by Ramboll and as awarded in the contract. It was deemed less critical than the 2028OTB modeling so was de-emphasized compared to getting the 2028 visibility projections done.

- How to treat fires in the 2028 MID projections caused some delays as there were modeled fires on some days in the IMPROVE MID; MID are selected in part to limit fire contributions.

- Double-counted and/or incorrect anthropogenic state-controllable sources for RH planning were discovered in the NEIC 2016v1 modeling platform due in part to EPA emissions processing of the 2016v1 files having O&G sources in the Non-EGU Point files instead of in the O&G files. Several WESTAR-WRAP region states also identified incorrect emissions rates in the 2016v1 files. This caused a series of state-by-state review and correction actions and a 3-4 month delay at a critical point in the regional haze modeling. This was probably the single biggest issue that caused delays in the project and required the following corrective action:

  - Ramboll conducts intensive review of the EPA 2016v1 platform emissions to identify the problems.

  - Western states review and update their RepBase and 2028OTBa emissions to now be RepBase2 and 2028OTBa2 inputs.

  - The WESTAR-WRAP project manager decides not to continue to use the NEIC 2028 projections for some source sectors (e.g., WRAP non-EGU Point), in response to requests from the WESTAR-WRAP region states, in 2028OTBa2 modeling and use 2014 instead.

  - Ramboll creates harmonized emission inventories for RepBase2 and 2028OTBa2 and conducts SMOKE modeling.

  - Re-run RepBase2 and 2028OTBa2 source apportionment simulations.

- WESTAR Contract 19-01 Amendment#10 (A10) provided funding for updating the RepBase2 and 2028OTBa2 emissions to address the EPA double counting issue and had a detailed schedule: (1) CAMx RepBase2 H-L SA run done by Nov 17, 2020; (2) CAMx 2028OTBa2 H-L SA run done by Nov 28, 2020; (3) CAMx 2028OTBa2 L-L SA run done by Dec 30, 2020. In reality, the final RepBase2 and 2028OTBa2 H-L SA runs were not done until January 2021 due to multiple re-runs:
    - The RepBase2 and 2028OTBa2 H-L SA simulations take approximately 28 days to run. The first RepBase2 and 2028OTBa2 H-L SA runs were completed within the A10 schedule (Nov 2020), but a series of issues were discovered that caused re-runs as follows:
        - The way lightning NOx emissions were treated was changed from millions of virtual point sources to a netCDF 3-D input to be more computationally efficient. However, a coding error in the CAMx v7.0 model caused the netCDF 3-D inputs not to work correctly and it adversely affected the source apportionment results necessitating going back to the virtual point source input approach.
        - The second round of RepBase2 H-L SA runs was performed in December 2020, but was invalid due to missing New Mexico Non-EGU Point emissions (Ramboll's fault).
        - A third set of RepBase2 and 2028OTBa2 simulations were conducted the end of December 2020 into January 2021 and another coding error was discovered in CAMx v7.0 that dropped point source SO2 emissions.
        - The fourth set of RepBase2 and 2028OTBa2 H-L SA simulations finished in late January 2021 and were post-processed and transferred to the TSS by end of January.

I hope you find this letter useful in helping to explain why the regional haze modeling for the WESTAR-WRAP region is delayed. I believe these issues are behind us and the regional haze modeling results are now being populated onto the WRAP TSS. I do not foresee any remaining modeling or data delivery issues for the remaining tasks over the next 2-3 months, and Ramboll is closely coordinating with WESTAR-WRAP staff and the RTOWG Co-Chairs.

If you need more information or want me to personally talk to EPA or any of the States with WESTAR-WRAP staff in attendance, please let me know as I am always available and always try to live up to my commitments and responsibilities.

Best Regards,

Ralph E. Morris
Managing Principal
Central West Business Unit (CA-UT-CO)
Ramboll Environment and Health
(415) 899-0708
rmorris@ramboll.com

cc. Tom Moore

Attachment 1. Timeline of events that caused delays in the WRAP western states regional haze modeling.

Approximate Date	Event
Dec 11, 2018	Initial WESTAR Contract 18-12 to development 2014 Shake-Out platform was received 10 days after project start date (Dec 1, 2018)
Dec 2018-Jan 2019	Federal government shut-down Dec 22, 2018 – Jan 25, 2019 caused over a month plus delay in getting all files from EPA's 2014 modeling platform as the 2014 platform files on the EPA ftp site were incomplete.
Feb 2019	Found that EPA's 2014 GEOS-Chem run that was planned to be used for BCs was flawed as it had too high SO2/SO4 in Jun & Jul and overstated O3 year-round. This meant Ramboll had to perform an unplanned 2014 GEOS-Chem run that took several months to complete.
Mar 2019	EPA re-runs GEOS-Chem for Jun & Jul without volcano eruption fixing Jun & Jul SO2/SO4 overestimation problem in BCs but causing delays in delivering the 2014v1 Shake-Out modeling platform in March 2019.
Jun – Aug 2019	2014v2 SMOKE emissions modeling delayed 3 months due to unavailability of Subcontractors SMOKE modeler.
Sep 2019	Corrections needed for error in SMOKE emissions modeling of 2014v2 (overstates Wyoming Jan O&G emissions) caused another month delay.
Sep – Oct 2019	PG&E Public Service Power Shutoffs (PSPS) cut-off power to Ramboll's Linux computers in their Novato, CA office shutting down progress on 2014v2, RepBase2 and 2028OTB modeling.
Nov 2019	California Air Resources Board informs us that California Fugitive Dust emissions are in error in 2014v2/RepBase and sends update that caused delays.
Nov 2019	The RepBase fires from the FSWG have errors that produce negative $PM_{2.5}$ emission that need to be fixed
Dec 2019	EPA's AMET MPE tool does not work right and does not generate all the MPE products that are needed. EPA AMET contact goes on holiday and issue is not fixed until after they come back in Jan 2020.
Jan 2020	Modeling for 2028OTB and 2002DE that was supposed to start in November 2019 started in Jan 2020 instead due to delays and finishing up 2014v2 and RepBase modeling.
Mar 2020 - present	COVID-19 shelter-in-place disrupts modeling as people can no longer go to the office and must work from home. That reduces efficiency and modeling takes longer due to more computer down time.
Apr – May 2020	Extra time to determine how to treat modeled fires in visibility projections for the MID that are not supposed to have any episodic fire.
Jun – Sep 2020	Double counted sources in EPA's 2016v1 modeling platform caused a stop of the modeling and have Ramboll and the states re-work the emissions, fix them and redo the SMOKE modeling causing a 3-4 month delay.
Jun – Sep 2020	Given problems with EPA 2016v1 platform 2028 emission projections, WRAP decides to change what emissions are being used in 2028OTB emission scenarios from what was in Ramboll's contract.
Aug – Nov 2020	Massive wildfires in California caused extremely high $PM_{2.5}$ concentrations, limited travel in the region and caused inefficiencies in work.
Nov 2020	RepBase2 and 2028OTBa2 H-L SA runs have to be re-done due to coding error in CAMx v7.0 treatment of netCDF 3-D lighting NOx inputs.
Dec 2020	Second RepBase2 H-L SA run has to be re-done due to missing New Mexico non-EGU point source emissions.
Dec 2020 – Jan 2021	Third RepBase2 and 2028OTBa2 H-L SA runs have to be re-done due to coding error in source apportionment species mappings that dropped point source SO2 emissions.
Jan 2021	Fourth RepBase2 and 2028OTBa2 H-L SA runs have satisfied all the QA checks and appear correct so that 2028 visibility projections and other data will be transferred to the WRAP TSS by the end of January 2021.

APPENDIX F

SOUTH DAKOTA REGIONAL HAZE STATE IMPLEMENTATION PLAN: SOUTH DAKOTA’S MEMORANDUMS OF UNDERSTANDING WITH THE US FOREST SERVICE AND WITH THE CITY OF RAPID CITY, SOUTH DAKOTA

Memorandum of Understanding

between

United States Forest Service – Black Hills National Forest

and

South Dakota Department of Environment and Natural Resources – Air Quality Program

I. BACKGROUND

The United States Forest Service uses prescribed fire to reduce hazardous fuels, protecting communities from extreme fires. Prescribed fire also provides forage for wildlife, recycles nutrients back to the soil; and promotes the growth of tree, wildflowers, and other plants. The Forest Service manages prescribed fires to benefit natural resources and reduce the risk of unwanted wildfires in the future.

Smoke from prescribed fires in western South Dakota has caused exceedances of the National Ambient Air Quality Standards for Particulate Matter 2.5 (PM2.5) and Particulate Matter 10 (PM10). It is critical that prescribed burners in the Black Hills Forest Fire Protection District conduct burns during times of optimum smoke dispersion, based on values that are in the Green (Good) or Yellow (Moderate) level on the Air Quality Index on DENR's website, to avoid exceedances of the National Ambient Air Quality Standards and avoid a non-attainment designation. It is also important to avoid allowing excessive smoke into cities and towns for the health and safety of the citizens.

II. PURPOSE

This Memorandum of Understanding establishes the procedures for cooperation and coordination between the Black Hill National Forest (Forest Service) and the South Dakota Department of Environment and Natural Resources (DENR).

The purpose of this agreement is to maintain a responsive and proactive air resource and interagency smoke management and coordination program by land management agencies in South Dakota. The vision of the agencies is to maintain excellent communications, collaboration, and coordination in air and smoke resources to avoid difficulties and impediments that may hinder individual or joint programs and to assist South Dakota in maintaining its National Ambient Air Quality Standards.

This Memorandum of Understanding will improve communication between the partners and will help establish guidelines for when burning should take place by following the listed items:

- Contact Air Quality staff in Pierre (Rick Boddicker) at (605) 773-6706 or Rapid City (Jon Epp) at (605) 394-2229 or email at rick.boddicker@state.sd.us and jon.epp@state.sd.us the day prior to ignition.

- Monitor the Air Quality Index on DENR's website to be sure the values are in the Green (Good) or Yellow (Moderate) level before igniting. http://denr.sd.gov/des/aq/aarealtime.aspx

- Attempt to halt ignitions by 2:00 pm MST to allow large fuels to burn out and smoke to disperse prior to sundown. If additional ignitions are needed after 2:00 pm MST due to the size of a burn or for safety reasons, the Forest Service should contact DENR and get concurrence prior to 1:30 pm MST.

In addition to following the steps above, DENR recommends that the Forest Service continue to follow their existing Prescribed Burn Plans.

III. WITHDRAWAL FROM THIS MEMORANDUM OF UNDERSTANDING

Any signatory may withdraw from this Memorandum of Understanding by giving thirty days written notice to all signatories.

IV. EFFECTIVE DATE AND REVISION OF MEMORANDUM OF UNDERSTANDING

This Memorandum of Understanding becomes effective upon signature of each respective agency. Revision of the Memorandum of Understanding may take place at any time with the agreement of the signatories. The term of the Memorandum of Understanding will be five years from the date last signed and is renewable at the end of each five-year period by approval of the parties involved and by completing a new signature page. Amendments to this Memorandum of Understanding may be made at any time, subject to the written concurrence and approval of both agencies.

IT IS MUTUALLY UNDERSTOOD AND AGREED BY AND BETWEEN THE PARTIES THAT:

1. FREEDOM OF INFORMATION ACT (FOIA). Any information furnished to the Forest Service or DENR under this instrument is subject to the Freedom of Information Act (5 U.S.C. 552) and / or the public records provisions set forth in SDCL §1-27.

2. PARTICIPATION IN SIMILAR ACTIVITIES. This instrument in no way restricts the Forest Service from participating in similar activities with other public or private agencies, organizations, and individuals.

3. AMENDMENT AND MODIFICATION. Amendments to this MOU or modifications within the scope of the instrument may be made by mutual consent of the parties, upon the issuance of a written amendment signed by all parties

4. COMMENCEMENT/EXPIRATION/TERMINATION. This Memorandum of Understanding takes effect upon the signature of both parties and shall remain in effect for 5 years from the date of execution. This Memorandum of Understanding may be extended upon written agreement of the parties signed by both parties. Either of the parties may terminate this Memorandum of Understanding with a 30-day written notice to the other.

5. RESPONSIBILITIES OF PARTIES. Both parties and their respective agencies and office will handle their own activities and utilize their own resources, including the expenditure of their own funds, in pursuing these objectives. Each party will carry out its separate activities in a coordinated and mutually beneficial manner.

6. PRINCIPAL CONTACTS. The principal contacts for this instrument are:

Andrew Johnson Acting Forest Supervisor Black Hills National Forest 605-673-9200 Andrew.johnson@usda.gov	Rick Boddicker Environmental Manager I Air Quality Program South Dakota - DENR 605-773-6706 Rick.boddicker@state.sd.us
Jason Virtue Fire Management Officer Black Hills National Forest 605-673-9261 Jason.virtue@usda.gov	Jon Epp Environmental Engineer III Air Quality Program SD-DENR 605-394-5313 Jon.epp@state.sd.us

7. ESTABLISHMENT OF RESPONSIBILITY. This Memorandum of Understanding is not intended to, and does not create, any right, benefit, or trust responsibility, substantive or procedural, which would be enforceable against the other.

8. AUTHORIZED REPRESENTATIVES. By signature below, the cooperator certifies that the individuals listed in this document as representatives of the cooperator are authorized to act in their respective areas for matters related to this agreement.

The following signatories agree to abide by this MEMORANDUM OF UNDERSTANDING:

By______________________________ Date 1/28/20

Andrew Johnson, Acting Forest Supervisor

Black Hills National Forest

By______________________________ Date 2/12/2020

Hunter Roberts, Secretary

South Dakota Department of Environment and

Natural Resources

Memorandum of Understanding

between

City of Rapid City

and

South Dakota Department of Environment and Natural Resources – Air Quality Program

I. BACKGROUND

Smoke from prescribed fires in western South Dakota has caused exceedances of the National Ambient Air Quality Standards for Particulate Matter 2.5 (PM2.5) and Particulate Matter 10 (PM10). It is critical that prescribed burners in the Black Hills Forest Fire Protection District conduct burns during times of optimum smoke dispersion to avoid exceedances of the National Ambient Air Quality Standards and avoid a non-attainment designation. It is also important to avoid allowing excessive smoke into cities and towns for the health and safety of the citizens.

II. PURPOSE

This Memorandum of Understanding establishes the procedures for cooperation and coordination between the City of Rapid City (RC) and the South Dakota Department of Environment and Natural Resources (DENR).

The purpose of this agreement is to maintain a responsive and proactive air resource and interagency smoke management and coordination program by land management agencies in South Dakota. The vision of the agencies is to maintain excellent communications, collaboration, and coordination in air and smoke resources to avoid difficulties and impediments that may hinder individual or joint programs and to assist South Dakota in maintaining its National Ambient Air Quality Standards.

This Memorandum of Understanding will improve communication between the partners and will help establish guidelines for when burning should take place by following the listed items:

- Contact Air Quality staff in Pierre (Rick Boddicker) at (605) 773-6706 or Rapid City (Jon Epp) at (605) 394-2229 or email at rick.boddicker@state.sd.us and jon.epp@state.sd.us the day prior to ignition.

- Monitor the Air Quality Index on DENR's website to be sure the values are in the Green (Good) or Yellow (Moderate) level before igniting. http://denr.sd.gov/des/aq/aarealtime.aspx

- Attempt to halt ignitions by 2:00 pm MST to allow fires to burn out and smoke to disperse prior to sundown.

In addition to following the steps above, DENR recommends that the City of Rapid City continue to follow their Fuel Reduction Pile Burn Guidelines already in place with the Rapid City Fire Department.

III. WITHDRAWAL FROM THIS MEMORANDUM OF UNDERSTANDING

Any signatory may withdraw from this Memorandum of Understanding by giving thirty days written notice to all signatories.

IV. EFFECTIVE DATE AND REVISION OF MEMORANDUM OF UNDERSTANDING

This Memorandum of Understanding becomes effective upon signature of each respective agency. Revision of the Memorandum of Understanding may take place at any time with the agreement of the signatories. The term of the Memorandum of Understanding will be five years from the date last signed and is renewable at the end of each five-year period by approval of the parties involved and by completing a new signature page. Amendments to this Memorandum of Understanding may be made at any time, subject to the written concurrence and approval of both agencies.

IT IS MUTUALLY UNDERSTOOD AND AGREED BY AND BETWEEN THE PARTIES THAT:

1. FREEDOM OF INFORMATION ACT (FOIA). Any information furnished to the City of Rapid City or DENR under this instrument is subject to the Freedom of Information Act (5 U.S.C. 552) and / or the public records provisions set forth in SDCL §1-27.

2. PARTICIPATION IN SIMILAR ACTIVITIES. This instrument in no way restricts the City of Rapid City from participating in similar activities with other public or private agencies, organizations, and individuals.

3. AMENDMENT AND MODIFICATION. Amendments to this MOU or modifications within the scope of the instrument may be made by mutual consent of the parties, upon the issuance of a written amendment signed by all parties

4. COMMENCEMENT/EXPIRATION/TERMINATION. This Memorandum of Understanding takes effect upon the signature of both parties and shall remain in effect for 5 years from the date of execution. This Memorandum of Understanding may be extended upon written agreement of the parties signed by both parties. Either of the parties may terminate this Memorandum of Understanding with a 30-day written notice to the other.

5. RESPONSIBILITIES OF PARTIES. Both parties and their respective agencies and office will handle their own activities and utilize their own resources, including the expenditure of their own funds, in pursuing these objectives. Each party will carry out its separate activities in a coordinated and mutually beneficial manner.

6. PRINCIPAL CONTACTS. The principal contacts for this instrument are:

Tim Weaver Lieutenant, Rapid City Fire Department Wildfire Mitigation 605-394-5233 Tim.weaver@rcgov.org	Rick Boddicker Environmental Manager I Air Quality Program South Dakota - DENR 605-773-6706 Rick.boddicker@state.sd.us
Jon Epp Environmental Engineer III Air Quality Program SD-DENR 605-394-5313 Jon.epp@state.sd.us	

7. ESTABLISHMENT OF RESPONSIBILITY. This Memorandum of Understanding is not intended to, and does not create, any right, benefit, or trust responsibility, either substantive or procedural, which would be enforceable against the other.

8. AUTHORIZED REPRESENTATIVES. By signature below, the cooperator certifies that the individuals listed in this document as representatives of the cooperator are authorized to act in their respective areas for matters related to this agreement.

The following signatories agree to abide by this MEMORANDUM OF UNDERSTANDING:

By Rod Seals Date FEB. 7, 2020

Rod Seals, Fire Chief

City of Rapid City Fire Department

By Hunter Roberts Date 2-12-2020

Hunter Roberts, Secretary

South Dakota Department of Environment and

Natural Resources