Ohio Environmental Protection Agency

Division of Air Pollution Control
Response to Comments

Draft Regional Haze State Implementation Plan for the Second Implementation Period – Federal Land Manager (FLM) Consultation Period

Agency Contact for this Package

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On January 6, 2021, Ohio EPA provided a draft Regional Haze State Implementation Plan (SIP) for the second implementation period to the federal land managers (FLMs) to satisfy the consultation requirements of CFR Section 51.308(i)(2). This document summarizes the comments and questions received during the consultation period, which ended on February 17, 2021.

Ohio EPA reviewed and considered all comments received during the consultation period. By law, Ohio EPA has authority to consider specific issues related to protection of the environment and public health.

In an effort to help you review this document, the questions are grouped by topic and organized in a consistent format. The name of the commenter follows the comment in parentheses.

General Comments

Comment 1: Comments were received from the National Park Service (NPS) and the Forest Service (FS). The full comment letters can be found in Appendices L1 through L3. (David Pohlman, NPS; Shawn Cochran, FS)

Response 1: Thank you for your comments. Excerpts from specific comments along with Ohio EPA's responses may be found below.

Comment 2: "The National Park Service (NPS) appreciates the opportunity to review the Ohio Environmental Protection Agency's January 2021 draft of the Ohio Regional Haze State Implementation Plan (SIP) for the Second Implementation Period (2018-2028). This email summarizes the consultation call we had in coordination with the other Federal Land Management agencies on February 1st, 2021 as well as our staff to staff email correspondence and detailed analysis of several SIP components. As such, this email and supplementary attachments serve as documentation of NPS conclusions and recommendations resulting from formal regional haze consultation as required by 42 U.S.C. §7491(d).

While Ohio does not contain any NPS managed Class I areas, emissions from sources in the state can affect visibility at Shenandoah National Park in Virginia, Mammoth Cave National Park in Kentucky, and Great Smoky Mountains National Park in North Carolina and Tennessee. We appreciate your continued involvement in LADCO and commitment to reducing pollutants in the region to help improve visibility in all Class I areas. We commend Ohio for putting together a well laid out and detailed SIP, and for engaging early in the process with the Federal Land Managers. We would like to express our particular thanks for responding to earlier NPS feedback on the source selection process and adjusting selection criteria to consider facility wide emissions. This resulted in additional analysis of emission reduction opportunities for Haverhill Coke.

We are satisfied with the list of sources that Ohio considered for reasonable progress four-factor analysis but disagree with the Ohio conclusion that no new emissions controls from any of these sources are warranted in this planning period. Further, we are not convinced that some of the identified sources that were screened from four-factor analysis because of “effective controls” have adequately demonstrated that they are effectively controlled. We urge Ohio to review our feedback and to require reasonable pollution controls that would advance clean air and clear views in NPS Class I areas in this planning period.

During our call, a number of concerns and potential areas for Ohio draft SIP improvement were discussed.” (David Pohlman, NPS)

Response 2: Thank you for your comments. Ohio’s responses to the specific concerns and issues raised are provided below.

Comment 3: “Overall the plan is very comprehensive and well organized. It is logically sequenced and generally well explained. We recognize the significant emission reductions of nitrogen oxides (NOx) and sulfur dioxide (SO_2) made in Ohio since 2005 due to economic and regulatory drivers.
We specifically appreciate:

- the very nice comparison made between the 2017 National Emissions Inventory and 2018 state emissions inventory to the 2016 collaborative inventory used as the basis for most of the technical work.
- that Ohio did not categorically exclude any sources subject to Best Available Retrofit Technology (BART) requirements during the first implementation period during the source selection process for the second implementation period
- that Ohio addressed all sources included on list of sources submitted by the Forest Service” (Shawn Cochran, FS)

Response 3: Thank you for your comments.

<u>Source Selection</u>

Comment 4: "The choice of an emissions/distance (Q/d) threshold value produces a number of emission sources for further analysis that is unique to the particular circumstances in each state. Our overriding concern is that a sufficient number of sources is selected. Therefore, the Q/d values used by Ohio produced an outcome that is unique based its distribution of sources and their emissions. It resulted in the selection of 72% of the total Q/d for all Ohio sources. In a draft of EPA's Regional Haze Guidance, 80% of each state's overall impact was suggested as appropriate. We find this approach acceptable." (Shawn Cochran, FS)

Response 4: Thank you for your comments.

<u>Enforceability</u>

Comment 5: "Enforceability and documentation – Assertions regarding source and emission unit operation relied on in the SIP must be federally enforceable. This is especially relevant to source shut down dates, operational limits, and pollution control equipment efficiency used to designate specific units as effectively controlled and exempt them from four factor analysis. For example, facilities running air pollution control equipment installed prior to the first implementation period may not be achieving the 90% efficiency recognized as "effective control" in the 2019 EPA regional haze guidance." (David Pohlman, NPS)

"We note and reenforce Ohio's statement on page 11 regarding the need for assumptions relating to the shutdown of facilities to be made enforceable. We also extend this to assumptions regarding the operation of sources and emission units that are relied on in the plan, including:
• operating scenarios for emission units that represent a reduced capacity, for example a reduced number of operating hours per year,
• pollution control equipment efficiency used to designate unit as "effectively controlled." (Shawn Cochran, FS)

"For facilities being shutdown, ensure there are enforceable conditions in place." (Shawn Cochran, FS)

Response 5: Ohio has ensured the measures in Ohio's Long-Term Strategy (LTS) that are being relied on for reasonable progress in the second implementation period are federally enforceable. These measures include on-the-books and on-the-way controls as described in Ohio's LTS, including the permanent shutdowns of coal-fired boilers at Miami Fort Power Station and Zimmer Power Station by 2028, which are made enforceable through Director's Final Findings and Orders (DFFOs).

Ohio is not relying on any existing measures for sources evaluated but not selected for four-factor analysis, or for sources selected for four-factor analysis but where new additional measures were found not to be necessary, as part of the LTS to make reasonable progress in the second implementation period.

Ohio does not agree that the Regional Haze Rule requires enforceable limits commensurate with existing operations (including reduced operating capacity or pollution control efficiency) for sources which were evaluated in screening and determined to be currently effectively controlled, or for sources where a four-factor analysis was performed but where new additional measures were found not to be necessary.

40 CFR 51.308(f)(2) states “The long-term strategy must include the enforceable emissions limitations, compliance schedules, and other measures **that are necessary to make reasonable progress**, as determined pursuant to (f)(2)(i) through (iv).” (emphasis added)

Ohio agrees that once a measure is determined necessary, enforceable limits are applicable. Ohio has determined that measures are not necessary for these sources; therefore, enforceable limitations are not required.

Further, an interpretation that enforceable limitations are required for all sources that were evaluated during the screening or four-factor processes is inconsistent with requirements under the first round of Regional Haze and with other Clean Air Act (CAA) and National Ambient Air Quality Standards (NAAQS) programs. Programs related to the NAAQS (such as the SO_2 Data Requirements Rule) allow facilities to be screened out of requirements without establishing enforceable limits on the conditions that led to the exclusion.

Additionally, Ohio believes establishing enforceable limitations on all sources that were evaluated during the screening or four-factor processes is unnecessary. All Class I areas impacted by sources in Ohio are below, or well, below, the glidepath. In addition, significant pressures and incentives already exist to deter the source from increasing emissions in the future, including compliance with other rules (e.g. MATS, CSAPR/CSAPR Update/Revised CSAPR Update).

Finally, such an approach would provoke extreme opposition from the regulated community. It would be seen as “punishing” good actors that have already minimized emissions to the extent possible.

In sum, Ohio has ensured the measures being relied on for reasonable progress are federally enforceable, but is not relying on existing measures for all sources evaluated during the screening process or four-factor analyses. Ohio finds that enforceable limits commensurate with existing operations for all sources evaluated is unnecessary and would be inconsistent with the federal regulations and past practice.

Uniform Rate of Progress (URP) Glidepath

Comment 6: "We agree with Ohio that "The Regional Haze Guidance further indicates that projected visibility conditions in 2028 below the URP may serve to demonstrate that, after a state has gone through its source selection and control measure analysis, it has no "robust demonstration" obligation per 40 CFR 51.308(f)(3)(ii)(A) and/or (B)." On the other hand, we do not agree that just because a class I area is below the glidepath it relieves a source impacting this area from performing a four-factor analysis and installing cost effective controls. We point out which sources use this argument below." (Shawn Cochran, FS)

Response 6: Ohio is not claiming that just because a Class I area is below the glidepath it relieves a source impacting this area from performing a four-factor analysis and installing cost effective controls. However, as part of a broader weight of evidence approach, we find it important to recognize that all Class I areas impacted by sources in Ohio are below the glidepaths and therefore visibility targets are being met (while acknowledging that this is not a reason, on its own, to not consider additional controls).

Definition of Effectively Controlled

Comment 7: "Ohio discusses examples of what they believe are effective controls. We would also like to offer some additional examples.

- Presumptive BART for EGUs[1]
    - 0.15 pounds per million BTU, or 95% control of SO_2,
    - boiler specific NO_x controls,
    - if unit already has existing SCR/SNCR but only runs it for part of the year - use it all year.
- Control scenarios run by LADCO during the 1st round of RH
    - EGU 1 - SO_2 limited to 0.15 (lb/million-BTU), NO_x limited to 0.10 (lb/million-BTU),
    - EGU 2 - SO_2 limited to 0.10 (lb/million-BTU), NO_x limited to 0.07 (lb/million-BTU).
- In their recent Regional Haze Plan submittal Texas performed four-factor analyses on SO_2 sources that had post-combustion controls performing less than 95% control." (Shawn Cochran, FS)

Response 7: Thank you for providing these examples.

[1] FR 7/6/2005, p. 39172

Cardinal Power Plant

Comment 8: "Cardinal #1 installed its FGD on March 1, 2008 which is during the first implementation period. Prior to installation of the FGD, CAM data indicate an uncontrolled SO_2 emission rate of 2.60 lb/mmBtu. Over 2016 – 2020, SO_2 emissions averaged 0.21 lb/mmBtu and control efficiency is 92%. **Cardinal #1 is effectively controlled for SO_2 and a 4-factor analysis for SO_2 is not warranted.**

Cardinal #1 installed its SCR on June 1, 2003 which is outside the first implementation period. Prior to installation of the SCR, CAM data indicate an uncontrolled NO_X emission rate of 1.00 lb/mmBtu. Over 2016 – 2020, NO_X emissions averaged 0.08 lb/mmBtu and control efficiency is 92%. Despite the age of its SCR, we agree that **Cardinal #1 is effectively controlled for NO_X and a 4-factor analysis for NO_X is not warranted.**

Cardinal #2 installed its FGD on December 1, 2007 which is outside the first implementation period. Prior to installation of the FGD, CAM data indicate an uncontrolled SO_2 emission rate of 2.36 lb/mmBtu. Over 2016 – 2020, SO_2 emissions averaged 0.24 lb/mmBtu and control efficiency is 87%. **Cardinal #2 is not effectively controlled for SO_2 and a 4-factor analysis for SO_2 is warranted.**

Cardinal #2 installed its SCR on May 1, 2003 which is outside the first implementation period. Prior to installation of the SCR, CAM data indicate an uncontrolled NO_X emission rate of 1.11 lb/mmBtu. Over 2016 – 2020, NO_X emissions averaged 0.08 lb/mmBtu and control efficiency is 93%. Despite the age of its SCR, we agree that **Cardinal #2 is effectively controlled for NO_X and a 4-factor analysis for NO_X is not warranted.**

Cardinal #3 installed its FGD on December 30, 2011 which is within the first implementation period. Prior to installation of the FGD, CAM data indicate an uncontrolled SO_2 emission rate of 1.32 lb/mmBtu. Over 2016 – 2020, SO_2 emissions averaged 0.15 lb/mmBtu and control efficiency is 89%. **Cardinal #3 is not effectively controlled for SO_2 and a 4-factor analysis for SO_2 is warranted.**

Cardinal #3 installed its SCR on May 1, 2003 which is outside the first implementation period. Prior to installation of the SCR, CAM data indicate an uncontrolled NO_X emission rate of 0.53 lb/mmBtu. Over 2016 – 2020, NO_X emissions averaged 0.08 lb/mmBtu and control efficiency is 85%. **Cardinal #3 is not effectively controlled for NO_X and a 4-factor analysis for NO_X is warranted.**" (David Pohlman, NPS)

Response 8: Cardinal Power Plant provided the following additional information regarding actual control efficiency from 2016-2020 for the units above where the commenter concluded that the units are not effectively controlled (that is, Cardinal #2 for SO_2, and Cardinal #3 for SO_2 and NOx).

<u>SO_2</u>
For SO_2, there are continuous emissions monitors on the inlet and the outlet of the FGD of each unit. This data is stored in the CEMS software, RegPerfect. Additionally, SO_2 percent removal is calculated in the RegPerfect software. Data for 2016-2020 for Units 2 and 3, excluding startup/shutdown hours which constitute less than 5% of the operating hours, is shown below. Both units are achieving an SO_2 control efficiency of greater than 90% using actual operating data and are effectively controlled.

FGD Efficiency %		
Year	Cardinal 2	Cardinal 3
2016	94.4	97.1
2017	93.0	97.1
2018	95.7	97.3
2019	92.5	97.3
2020	94.6	96.3

<u>NOx</u>
For NOx, there is a continuous emissions monitor on the stack for Part 75 compliance that monitors outlet NOx. There are 2 monitors on the SCR inlet that monitor NOx before the SCR. Data for these monitors is stored in RegPerfect. The NOx percent removal was calculated from an average of the 2 inlet monitors and the monitor on the stack, again excluding startup/shutdown hours. While this unit is achieving 83-86% control efficiency using actual operating data, it is important to also note that it is achieving an NOx emission rate of 0.09 lb/MMBtu. Therefore, Ohio continues to believe this unit is effectively controlled for NOx and a four-factor is not warranted.

SCR Efficiency %	
Year	Cardinal 3
2016	85.1
2017	86.6
2018	85.1
2019	82.6
2020	82.8

Comment 9: "These boilers were excluded from a four-factor analysis based on a design efficiency of their pollution control equipment of 90/95%. Please ensure there are enforceable conditions in place to ensure that the pollution control equipment is operated so this rate is achieved continuously in actual operations." (Shawn Cochran, FS)

Response 9: Please see Response 5 above.

Orrville

Comment 10: "Are there enforceable conditions in place that ensure B001 remains a limited use boiler?" (Shawn Cochran, FS)

Response 10: Yes, the conversion of B001 to limited use boiler was incorporated into permit PTI no. P0124959, effective December 24, 2018; and permit Title V no. P0125633, effective March 16, 2020. Conversion back to full time use would require first applying for and obtaining modified permits under the new source review program. As this conversion was part of a strategy to comply with Boiler Maximum Achievable Control Technology (Boiler MACT) requirements and the Data Requirements Rule (DRR) for the SO_2 NAAQS designation process, return to full time use would jeopardize compliance with those programs and is highly unlikely.

Bay Shore

Comment 11: "We believe that the 90/95% control effectiveness criteria for SO_2 does not apply internally to the circulating fluidized bed boiler, therefore post-combustion controls should be evaluated." (Shawn Cochran, FS)

Response 11: Ohio is not relying on a strict interpretation of the 90/95% SO_2 control efficiency example for Bay Shore Plant. U.S. EPA's Regional Haze Guidance clearly indicates that the examples are meant to be illustrative but not exhaustive. Therefore, Ohio has also excluded some sources which do not squarely fit the specific example scenarios included in the Regional Haze Guidance, based on a reasoned argument.

In this case, we believe it is irrelevant where the reductions are being realized (internally or via post-combustion controls). We believe this case-specific scenario demonstrates that, given the operational nature of the process at this unit in which SO_2 and NOx are inherently controlled and/or there is low formation potential, resulting in 94% removal of SO_2 along with low SO_2 and NOx emissions rates, it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would result in the conclusion that no further controls are necessary.

Haverhill Coke

Comment 12: "The waste gas stack was excluded from a four-factor analysis based on design efficiency of their pollution control equipment of 90/95%. Please ensure there are enforceable conditions in place to ensure that the pollution control equipment is operated so this rate is achieved continuously in actual operations." (Shawn Cochran, FS)

Response 12: Please see Response 5 above.

Kyger Creek

Comment 13: "Kyger Creek #1: According to EPA's Clean Air Markets Database (CAMD), in 2020 Kyger Creek #1 emitted 710 tons of SO_2 and 1027 tons of NO_X. Prior to installation of the FGD, CAM data indicate an uncontrolled SO_2 emission rate of 2.71 lb/mmBtu. Over 2016 – 2020, SO_2 emissions averaged 0.12 lb/mmBtu and control efficiency is 95%. **Kyger Creek #1 is effectively controlled for SO_2 and a 4-factor analysis for SO_2 is not warranted.** CAM data indicate an uncontrolled NO_X emission rate of 0.78 lb/mmBtu prior to installation of SCR. Over 2016 – 2020, NO_X emissions averaged 0.16 lb/mmBtu and control efficiency is 80%. **Kyger Creek #1 is not effectively controlled for NO_X and a 4-factor analysis for NO_X is warranted.**

Kyger Creek #2: According to CAMD, in 2020 Kyger Creek #2 emitted 698 tons of SO_2 and 971 tons of NO_X. Prior to installation of the FGD, CAM data indicate an uncontrolled SO_2 emission rate of 2.08 lb/mmBtu. Over 2016 – 2020, SO_2 emissions averaged 0.12 lb/mmBtu and control efficiency is 94%. **Kyger Creek #2 is effectively controlled for SO_2 and a 4-factor analysis for SO_2 is not warranted.** CAM data indicate an uncontrolled NO_X emission rate of 0.78 lb/mmBtu prior to installation of SCR. Over 2016 – 2020, NO_X emissions averaged 0.16 lb/mmBtu and control efficiency is 79%. **Kyger Creek #2 is not effectively controlled for NO_X and a 4-factor analysis for NO_X is warranted.**

Kyger Creek #3: According to CAMD, in 2020 Kyger Creek #3 emitted 589 tons of SO_2 and 662 tons of NO_X. Prior to installation of the FGD, CAM data indicate an uncontrolled SO_2 emission rate of 2.03 lb/mmBtu. Over 2016 – 2020, SO_2 emissions averaged 0.14 lb/mmBtu and control efficiency is 93%. **Kyger Creek #3 is effectively controlled for SO_2 and a 4-factor analysis for SO_2 is not warranted.** CAM data indicate an uncontrolled NO_X emission rate of 0.77 lb/mmBtu prior to installation of SCR. Over 2016 – 2020, NO_X emissions averaged 0.17 lb/mmBtu and control efficiency is 78%. **Kyger Creek #3 is not effectively controlled for NO_X and a 4-factor analysis for NO_X is warranted.**

Kyger Creek #4: According to CAMD, in 2020 Kyger Creek #4 emitted 647 tons of SO_2 and 992 tons of NO_X. Prior to installation of the FGD, CAM data indicate an uncontrolled SO_2 emission rate of 2.06 lb/mmBtu. Over 2016 – 2020, SO_2 emissions averaged 0.14 lb/mmBtu and control efficiency is 93%. **Kyger Creek #4 is effectively controlled for SO_2 and a 4-factor analysis for SO_2 is not warranted.** CAM data indicate an uncontrolled NO_X emission rate of 0.77 lb/mmBtu prior to installation of SCR. Over 2016 – 2020, NO_X emissions averaged 0.18 lb/mmBtu and control efficiency is 77%. **Kyger Creek #4 is not effectively controlled for NO_X and a 4-factor analysis for NO_X is warranted.**

Kyger Creek #5: According to CAMD, in 2020 Kyger Creek #5 emitted 676 tons of SO_2 and 1028 tons of NO_X. Prior to installation of the FGD, CAM data indicate an uncontrolled SO_2 emission rate of 2.07 lb/mmBtu. Over 2016 – 2020, SO_2 emissions averaged 0.14 lb/mmBtu and control efficiency is 93%. **Kyger Creek #5 is effectively controlled for SO_2 and a 4-factor analysis for SO_2 is not warranted.** CAM data indicate an uncontrolled NO_X emission rate of 0.99 lb/mmBtu prior to installation of SCR. Over 2016 – 2020, NO_X emissions averaged 0.17 lb/mmBtu and control efficiency is 83%. **Kyger Creek #5 is not effectively controlled for NO_X and a 4-factor analysis for NO_X is warranted.”** (David Pohlman, NPS)

Response 13: Kyger Creek has provided additional information and clarification regarding their SO_2 and NOx controls (please see attachment 1). This supplemental information confirms that the units are effectively controlled for SO_2.

Although the SCRs do not meet a strict interpretation of the “FGD/SCR with at least 90% effectiveness” example in the Regional Haze Guidance, Ohio EPA continues to conclude based on a case-by-case evaluation of the control efficiency, emission rate, year-round control operation, and operational improvements described further in the attachment that it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would result in the conclusion that no further controls are necessary.

Comment 14: **“**These boilers were excluded from a four-factor analysis based on design efficiency of their pollution control equipment of 90/98%. Please ensure there are enforceable conditions in place to ensure that the pollution control equipment is operated so this rate is achieved continuously in actual operations. In particular, the SCR controls appear to be performing at about 80% control efficiency.” (Shawn Cochran, FS)

Response 14: Please see Response 5 above.

Four-Factor Analyses - General

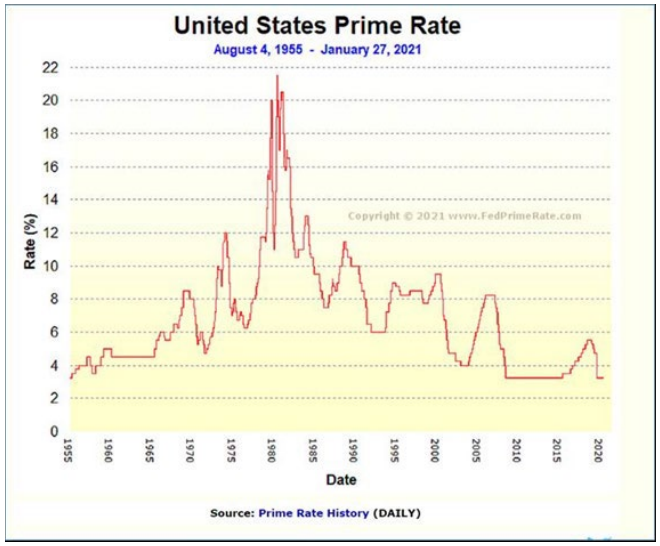
Comment 15: "Inflated cost analyses – Control cost analyses presented in 4-factor analyses as part of the Ohio draft SIP are generally too high. The latest sections of the EPA Cost Control Manual outline accepted methods for estimating the costs of pollution controls and we recommend that these guidelines be followed unless clear and compelling source-specific documentation is presented. Factors contributing to inflated cost analyses include:

a. Interest rate – Cost analyses should be based on the current bank prime rate of 3.25%.
b. Equipment life – Standard equipment life for control equipment is defined in the EPA cost control manual. Use of a shorter life may be justified in the case of an enforceable shut-down date for a given facility.
c. Control Efficiency – Standard efficiency rates from the cost control manual should be used unless there are well documented source specific circumstances.
d. Retrofit Factors – If used, retrofit factors require thorough justification based on parameters defined in the EPA Control Cost Manual (7th ed., Section 5, Chapter 1, 2.6.4.2 Retrofit Cost Considerations)." (David Pohlman, NPS)

Response 15: The four-factor analyses have been revised to use an interest rate of 3.25% unless justification for another firm-specific rate has been provided. Likewise, standard control equipment life, control efficiencies and average retrofit factors have been used, except were a case-specific justification is provided for alternate values.

Comment 16: "We identified several issues with the source-specific four-factor analyses in Ohio's plan that we expect will not be unique to Ohio. It is our hope that EPA will ensure that there is consistency across the country in their application.

- The interest rate used to annualize the capital costs of control equipment
  - Section 1, Chapter 2 of the EPA Control Cost Manual (7th ed.) says on page 15 "For permit applications, if firm-specific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates"



- Over the past 10 years the bank prime rate has hovered around 3% except for a brief spike to less than 6%.
- The analysis for Avon Lake references Office of Management and Budget (OMB) circular A-4 when using 7%.
    - The 7% figure in Circular A-4 is actually a citation from a different document - Circular A-94 - dated 1992. The 7% figure was realistic relative to 1992 as you can see in the graph, but not in 2021.
    - Circular A-94 suggests for future years to look at the annual updates (Appendix C) that are made by OMB for nominal and real discount rates. The most recent issue for 2020 shows rates well below 3% for the 20-year and 30-year time periods applicable to our analyses.
- In summary, the use of 7% is not supported, 3% seems to be more realistic.

- Control equipment life
    - EPA Control Cost Manual, 7th ed., Section 5, Chapter 1, 1.1.5 Equipment Life - "Gas scrubbers are relatively simple and reliable systems that have been demonstrated to be exceedingly durable. The EPA has generally used equipment life estimates of 20 to 30 years for gas scrubbers, although these estimates are recognized to be low for many installations. Many FGD systems installed in the 1970s and 1980s have operated for more than 30 years…and some scrubbers may have lifetimes that are much longer. Manufacturers reportedly design scrubbers to be as durable

as boilers, which are generally designed to operate for more than 60 years."
    - Most analyses in Ohio's plan used 20 years, we encourage looking into the sensitivity of the cost calculations to the use of 30 years.

- Retrofit factor
    - A couple of items to consider from EPA Control Cost Manual, 7th ed., Section 5, Chapter 1, 2.6.4.2 Retrofit Cost Considerations.
        - A 30% increase is already assumed for "average" retrofits within the cost calculations - "Cost calculations in the IPM are based primarily on data for retrofits. However, retrofits are typically 30% more than for new units of the same size and design. To adjust for the additional costs associated with retrofits, we have included a retrofit factor in the TCI equations"
        - "Since each retrofit installation is unique, no general factors can be developed. Nonetheless, if necessary, some general information can be given concerning the kinds of system modifications one might expect to be considered in developing a retrofit factor:"
            1. Handling and erection.
            2. Site Preparation.
            3. Off-Site Facilities.
            4. Limited Space for Staging Equipment.
            5. Transportation.
            6. Lost Production.
        - Often the only justification for the use of an inflated retrofit factor is a Google Earth picture of the facility with no additional explanation. EPA suggests describing the retrofit issues in terms of the specific modifications listed above. For example, many of these issues can be noted on the picture, such as overlaying the footprint of the potential new air pollution control equipment on it. Please provide more specific information concerning the retrofit factors used by the sources.

- Affordability ($/ton)
  Although Ohio has not indicated what threshold they would consider for air pollution controls to be cost effective, we can look at similar analyses to get a general idea of an appropriate value.
    - The only source-specific BART determination made by Ohio during the last round was for the P. H. Glatfelter facility. Although it ended up converting its boilers to natural gas as

an alternative to BART, the original BART determination for the installation for SO2 controls was reported as $2700 per ton ($2007).[2]

- The CSAPR rule substituted for BART for EGUs in Ohio. In the final CSAPR rules and EPA used a cost effectiveness threshold of $3400 per ton ($2011)[3]
- In its recent regional haze plan submittal for the second round, Texas chose a cost threshold of $5000 per ton for NOx and SO2 emissions.[4]
- A survey of BART and reasonable progress determinations from the first round reveal the top end of the range of cost effectiveness determined by EPA and the states was (most of these evaluations all occurred around 2011)[5]:
  - NOx: $6300 per ton
  - SO2: $3000 to 5000 per ton

  Some specific examples include:
  - PGE Boardman (OR): $5500 to $7300 per ton for NOx and SO2 ($2010)[6]
  - Craig Unit 2 (CO): for $6299 per ton NOx ($2016)[7]
  - Electrical generating units in North Dakota: $3100 per ton for NOx and $2466 per ton for SO2 ($2009)[8]
  - San Juan Generating Station (NM): from $3494 per ton for NOx ($2011)[9]
  - Four Corners Power Plant (NM) - EPA R9 determined that costs as high as $6,170 per ton are cost-effective in evaluating addition of SCR ($2010)[10]
  - J.E. Corette power plant (MT) - ($2012), $3490 per ton to control SO2 and $4,491 per ton for NOx[11]

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[2] Regional Haze State Implementation Plan for Ohio, Appendix G, BEST AVAILABLE RETROFIT TECHNOLOGY (BART) Engineering Analysis, P.H. Glatfelter Company - Chillicothe Facility, Chillicothe, Ohio, Prepared by: BE&K Engineering, November 2007

[3] USEPA, *Regulatory Impact Analysis of the Cross-State Air Pollution Rule (CSAPR) Update for the 2008 National Ambient Air Quality Standards for Ground-Level Ozone*, EPA-452/R-16-004, September 2016.

[4] Texas Commission on Environmental Quality, 2021 Regional Haze State Implementation Plan Revision, Project Number 2019-112-SIP-NR, Proposal, October 7, 2020

[5] Available upon request

[6] Oregon Department of Environmental Quality Memo, “Agenda item K, Action item: Revisions to DEQ Regional Haze BART Rules for the PGE Boardman Power Plant,” December 9-10, 2010.

[7] https://www.colorado.gov/pacific/sites/default/files/AP_PO_Regional-Haze-State-Implementation-Plan-Dec-2016.pdf

[8] FR, Vol. 76, No. 183, September 21, 2011 and FR, Vol. 77, No. 67, April 6, 2012.

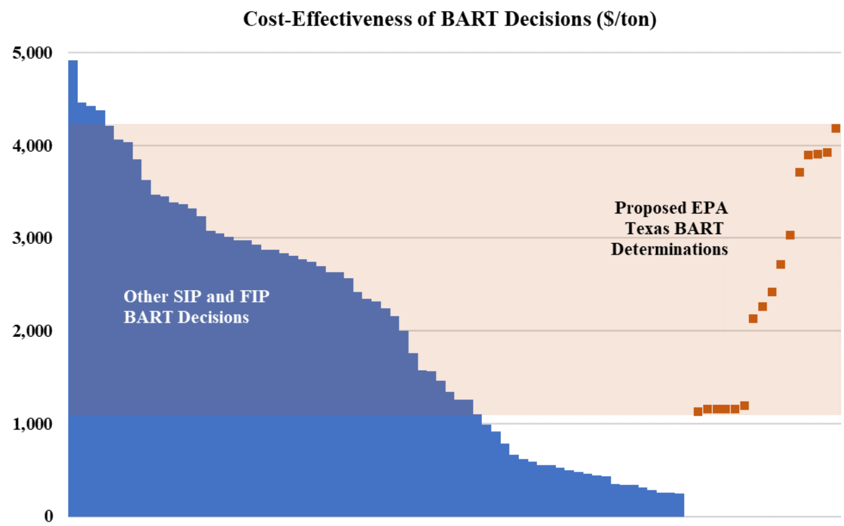
[9] New Mexico Environment Department, Air Quality Bureau, BART Determination, Public Service Company of New Mexico, San Juan Generating Station, Units 1-4, February 28, 2011

[10] FR, Vol. 75, No. 201, October 19, 2010

[11] FR, Vol. 77, No. 181, September 18, 2012

- Georgia Pacific Broadway Mill (WI) - $1500 per ton for SO2, $1900 per ton for NOx ($2011)[12]
- Multiple BART sources (MN) – $3900 per ton for SO2, $3201 per ton for NOx ($2009)[13]
- EPA NewPage Paper (MI) - $1500 per ton for NOx[14]

○ The following graphic is from the Federal Regional Haze Plan for Texas that summarizes BART determinations across the US[15]



- New economic analysis - cost/sales ratio
  ○ The four-factor analysis for Carmeuse and Dover Light and Power include a cost/sales ratio analysis. This analysis is not discussed in the regional haze guidance and as far as we are aware, has not been used with the Regional Haze Rule. The inputs to these calculations are confidential business information and can't be independently verified. Until EPA offers guidance as to how to verify this analysis and interpret it, we believe it has little value." (Shawn Cochran, FS)

Response 16: The four-factor analyses have been revised to use an interest rate of 3.25% unless justification for another firm-specific rate has been provided. Likewise, standard control equipment life, control efficiencies and average

[12] Regional Haze State Implementation Plan for Wisconsin, Appendix F, BART Technical Support Document for Non-EGUs
[13] Minnesota Regional Haze State Implementation Plan, Appendix 9.4: BART Determinations by MPCA – EGU, December 2009.
[14] FR, Vol. 77, No. 232, December 3, 2012
[15] EPA-R06-OAR-2016-0611, https://beta.regulations.gov/document/EPA-R06-OAR-2016-0611-0083

retrofit factors have been used, except were a case-specific justification is provided for alternate values.

Additional background and discussion regarding the affordability analyses based on cost/sales ratio has been added to the document.

Avon Lake

Comment 17: "We disagree with the following statement "As explained below, because the visibility impacts attributable to the Avon Lake Power Plant are negligible, further controls and/or lower emission limits, even if technically and economically feasible, would not yield material visibility benefits at any of the regional Class I." See related comment on this issue above.

- We disagree with several of the cost assumptions used in this analysis:
  - The emission reductions cited are largely due to the facility running well below capacity – there appears to be no requirement that it run this way in the future. This reduced capacity also significantly reduces the cost effectiveness of controls.
  - The analysis assumes the use of new fuels based on the switch made in 2017. Is this fuel switch enforceable?
  - A 20-year control equipment life and 7% interest rate are not appropriate, as noted above.
  - The 1.2 retrofit factor used for SO2 controls is unjustified. See comment above regarding the use of retrofit factors.
  - Owner's Costs and Allowance for Funds Used During Construction (AFUDC) are not allowed by the Control Cost Manual.
- If you change items 1 through 4 to: 8000 hours per year, 30 years, 3%, and 1; the cost per ton is changed significantly:
  - for NOx, the value goes from over $10,000 per ton to less than $1000 per ton for selective non-catalytic reduction (SNCR).
  - for SO2, the value goes from over $20,000 per ton to less than $2000 per ton for a wet scrubber
- As noted above, presumptive BART prescribes that if you have an SNCR unit that is already running for part of the year, it should run year around." (Shawn Cochran, FS)

Response 17: Ohio has included the visibility benefit analysis as additional weight of evidence to be weighed along with the other factors in accordance with the Regional Haze Guidance.

Please see Response 5 above regarding enforceable limits commensurate with existing operations.

Avon Lake has provided case-specific justification that a 7% interest rate is very conservative based on comparisons with recently financed projects at other independent coal plant projects in the area.

Although we believe a remaining useful life of 20 years and a retrofit factor of 1.2 for FGD, SDA and SCR are appropriate and justified in this case, the costs were also calculated based on a remaining useful life of 30 years and a retrofit factor of 1.0 to show the sensitivity of costs to these parameters.

The EPA Control Cost Manual, Chapter 2 (Cost Estimation: Concepts and Methodology), Page 11 notes that AFUDC is considered a cost item within the electric power industry.

Avon Lake does not currently have an operating SNCR unit. A temporary demonstration unit was installed in 2005 and was last operated during the summer of 2009. There is very little remaining from the old, temporary system and the remaining items would need significant upgrades to be repurposed. Therefore, reuse is likely to be more costly than a new, replacement system.

<u>Carmeuse Lime – Maple Grove</u>

Comment 18: "The four factor analysis considered dry sorbent injection (DSI), conditioning tower slurry injection, wet scrubbing, and fuel switching as potential options for reducing SO2 emissions. Fuel switching was determined to be infeasible, but the other three options were carried forward for analysis. We reviewed the cost analyses for DSI and wet scrubbing, as these two technologies were assessed to have higher SO2 removal efficiencies than slurry injection. Our review indicates that the cost per ton in the four factor analysis for these controls is overestimated for these reasons:

-- A retrofit factor of 1.2 was applied to the capital investment cost for DSI. According to the EPA Control Cost Manual, Section 5, Chapter 1 (July 2020 draft), p. 1-23, the cost estimation method already assumes an increase of 30% over the cost of a new installation. Retrofit factors higher than one should be documented and justified. The four factor analysis says the higher factor was chosen because of "uncertainties and difficulties likely to be encountered during handling and erection and site preparation (e.g., limited space at existing site), staging of equipment, and projected losses in production related to unexpected issues associated with retrofit installation" and "significant modifications to existing equipment, namely ductwork, for each installation" (p. 4-3) but does not offer specifics. Accordingly, we chose a retrofit factor of 1.

-- An interest rate of 7% was used. The Control Cost Manual 7th Edition, Section 1, Chapter 2, page 15, says "if firm-specific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates given the potential difficulties in eliciting accurate private nominal interest rates since these rates may be regarded as confidential business information or difficult to verify." As no firm-specific interest rate has been provided, we used the current bank prime rate of 3.25%. The bank prime rate has been below 7% since 2008.

-- The analysis assumed a control lifetime of 20 years. Regarding the equipment life for SO2 scrubbers, the Control Cost Manual, 7th edition (draft July 2020), Section 5, Chapter 1, page 1-5, says: "The EPA has generally used equipment life estimates of 20 to 30 years for gas scrubbers, although these estimates are recognized to be low for many installations. Many FGD systems installed in the 1970s and 1980s have operated for more than 30 years (e.g., Coyote Station; H.L. Spurlock Unit 2 in Maysville, KY;, East Bend Unit 2 in Union, KY; and Laramie River Unit 3 in Wheatland, WY) and some scrubbers may have lifetimes that are much longer. Manufacturers reportedly design scrubbers to be as durable as boilers, which are generally designed to operate for more than 60 years." Accordingly, we used an equipment life of 30 years for our analysis.

-- The analysis assumed a removal efficiency of 50%. The Control Cost Manual, 7th edition (draft July 2020), Section 5, Chapter 1, page 1-8 indicates that the removal efficiency for DSI systems varies from 50-70% (page 1-8) and for web scrubbers from 90-99% (page 1-19). We used an efficiency of 65% for DSI and 80% for wet scrubbing to estimate cost effectiveness; assuming 90% removal efficiency for a wet scrubbing system would reduce the cost for that technology further.

-- The analysis included costs for sales and property tax. According to the Ohio EPA web site, there is a tax exemption for pollution control equipment (Tax Exemption Program (ohio.gov)). We used a 0% rate for sales and property taxes.

Using these adjustments, we estimate the cost per ton for a DSI system at approximately $4,000 and for a wet scrubbing system at approximately $2,200, which demonstrates both technologies would be cost effective for reducing SO2 emissions. Our cost estimates are detailed in the attached Excel spreadsheet titled Carmeuse SO2." (David Pohlman, NPS)

Response 18: Additional support has been added to the four-factor analysis for the use of a retrofit factor or 1.2, interest rate of 7%, remaining useful life of 20 years and removal efficiency of 50%.

Ohio typically includes taxes in cost analyses conducted as part of our permitting program. Although the Ohio Department of Tax runs a program that exempts tax for pollution control equipment, the owner/operator must submit a request and it must be approved. Since we are not certain if a tax exemption will be requested or approved at the time of our review, our normal process is to include these costs in the analysis. Ohio believes the approach taken for permitting is also appropriate for these purposes.

Comment 19: "The four factor analysis concludes that there are no additional controls that are technologically feasible for NOx reduction. We have not identified a lime kiln using SNCR that does not have a preheater. However, tail-end SCR should be technologically feasible as it is unlikely that there would be sufficient contaminants remaining in the exhaust stream from the baghouse to poison or foul the SCR catalyst. While it may be necessary to reheat the gas stream, this would still be technically feasible and should be evaluated to determine if it would be cost effective." (David Pohlman, NPS)

"A tail-end SCR system located downstream of the baghouse should be technically feasible, as it is very unlikely that there would be sufficient contaminants remaining in the exhaust stream to poison or foul the SCR catalyst. It may be necessary to reheat the gas stream, but this would not be an issue of technically feasibility but rather economic feasibility. Tail-end SCR should be evaluated to determine if it would be cost effective." (Shawn Cochran, FS)

Response 19: To ensure a thorough and conservative analysis, the four-factor analysis for Carmeuse Lime – Maple Grove has been revised to include the addition on tail-end SCR, despite reasonable concerns about technical feasibility of this control.

Comment 20: "Wet scrubbers are described as too costly based on assumptions of 50% control efficiency, a 7% interest rate and 20-year control equipment life.

- If you change the inputs to 75%, 3% and 30 years the cost per ton goes from $4064 per ton to $2270 per ton. We find both of these cost values within the cost effective range described above." (Shawn Cochran, FS)

Response 20: As noted in Response 18, additional support has been added for these inputs.

<u>Dover Municipal Light</u>

Comment 21: "It is noted that VISTAS identified four emissions sources in Ohio which strongly contribute to regional haze in their Class I areas which did not include the City of Dover. Therefore, it is concluded that City of Dover is not a significant source.

  - We disagree. All the report shows is that VISTAS thought Dover was not one of the top 4 impacting sources from Ohio at the time of their analysis. We note that one of these sources (Zimmer) has committed to shut down since the VISTAS analysis was done.

- The highest impacts from this facility is at Dolly Sods and it is projected to be below the URP. Therefore, additional emission reductions "are not required." Please see note our comment above concerning the significance of the glideslope.
- Use of cost/sales ratio – see comments above." (Shawn Cochran, FS)

Response 21: The text regarding the VISTAS modeling has been changed to clarify that the City of Dover was not one of the four most significant sources shown to have a sulfate or nitrate impact on a Class I area.

Ohio finds it important to recognize that the Class I areas impacted by sources in Ohio are below the glidepath and therefore visibility targets are being met, while acknowledging that this is not a reason, on its own, to not consider additional controls.

Additional background and discussion regarding the affordability analyses based on cost/sales ratio has been added to the document.

<u>Gavin Power Plant</u>

Comment 22: "It is our understanding that a wet FGD using magnesium-enhanced lime as the reagent is typically more efficient than a limestone-based system. **We recommend that OEPA evaluate switching back to magnesium-enhanced lime to reduce SO_2 emissions."** (David Pohlman, NPS)

Response 22: As recommended, Gavin evaluated switching back to magnesium-enhanced lime. The following has been added to the four-factor analysis "The historical supplier of magnesium-enhanced lime, the Carmeuse Lime and Stone Maysville mine, is no longer producing magnesium-enhanced lime. A potential supply for magnesium-enhanced lime has not been identified, however, the system is already optimized as the FGD system has achieved 95% removal efficiency with limestone. At these collection / control levels, the Plant's solids handling capabilities are at their design limits."

Comment 23: "Not only were the SCR systems at Gavin installed prior to the first implementation period, they do not appear to be achieving 90% control and are not eligible for exemption from a 4-factor analysis. **We recommend that OEPA conduct a 4-factor analysis on the feasibility of improving SCR efficiency."** (David Pohlman, NPS)

Response 23: Gavin Power Plant has provided additional information and clarification regarding their NOx controls (please see attachment 2). This supplemental information confirms that the units are effectively controlled for NOx as they are achieving a control efficiency of 91% when considered along with the low-NOx burners.

The supplemental information provided by Gavin shows that the SCRs are well-maintained, including routine replacement of the catalyst layers. In addition, Gavin operates its control systems in concert to maximize the efficiencies in reducing all pollutants, and must maintain an operational balance between objectives, including MATS compliance. Further, the supplemental information provided by Gavin shows the visibility impacts of NOx emissions at Gavin are minimal, as determined from CAMx modeling performed for the VISTAS/SESARM Regional Planning Organization.

Ohio EPA continues to conclude that it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would result in the conclusion that no further controls are necessary.

Comment 24: "These boilers were excluded from a four-factor analysis based on design efficiency of their pollution control equipment of 90/95%. Please ensure there are enforceable conditions in place to ensure that the pollution control equipment is operated so this rate is achieved continuously in actual operations. In particular, the selective catalytic reduction (SCR) controls appear to be performing at about 80% control efficiency." (Shawn Cochran, FS)

Response 24: Please see Responses 5 and 24 above.

Visibility Benefit Analysis

Comment 25: "Visibility Benefit – The visibility benefit of emissions reductions is not one of the four statutory factors that are required for consideration under reasonable progress. Visibility improvement in Class I areas depends on the cumulative effects of regional emission reductions and can be most appropriately evaluated in the context of natural conditions. The Ohio analysis does not use accepted modeling protocol or reflect EPA guidance and misapplies the visibility metrics." (David Pohlman, NPS)

"We have several concerns regarding the visibility benefit analysis included in the draft Ohio Regional Haze State Implementation Plan for the Second Implementation Period.

Overview

Policy considerations

1. As defined in the CAA (§169A (g)(1)), four-factor analyses for reasonable progress do not include consideration of visibility benefit.
2. Perceptibility is not a requirement for reasonable progress.

Technical

1. Per the 2019 EPA guidance if visibility benefit analyses are undertaken, they should reference a clean background.

2. It may not be appropriate to:
    a. Use PSAT modeled visibility impacts for a specific source to represent different sources.
    b. Scale PSAT modeled visibility impacts to reflect different emission scenarios from those that were modeled.
3. The Ohio visibility benefit analysis misinterprets the relationship between the deciview and inverse megameter visibility metrics.

Details

Policy

First, Ohio did not need to conduct a visibility benefit analysis and has not established a visibility benefit threshold for reasonable progress determination in the draft SIP. As defined in the Clean Air Act §169A (g)(1), the four factors that **must** be taken into consideration in determining reasonable progress for individual sources are:

- Cost of compliance
- Time necessary for compliance
- Energy and non-air environmental impacts
- Remaining useful life of the source

Second, in the 2019 Regional Haze Guidance, EPA allows for consideration of visibility benefits to inform the determination of whether it is appropriate to require a certain measure while clearly indicating that perceptibility is not a requirement for reasonable progress. The incremental improvements in visibility that Ohio could achieve through emission reductions would have meaningful cumulative benefits for reasonable progress.

EPA 2019 RH Guidance (page 38, §II.B.5.a)…

> *"Visibility benefits* – If a state uses a visibility benefit threshold to evaluate control measures, it must explain how its approach is consistent with the requirement to consider the statutory factors in making reasonable progress determinations. Additionally, EPA has previously explained that, ***because regional haze results from a multitude of sources over a broad geographic area, a measure may be necessary for reasonable progress even if that measure in isolation does not result in perceptible visibility improvement***.[70]
>
> [70] See Response to Comment Document, Final Rule: Protection of Visibility: Amendments to Requirements for State Plans, 82 FR 3078, January 10, 2017 at 268-69 (explaining that ***a measure may be necessary for reasonable progress even if it does not result in a perceptible visibility improvement because progress will require addressing many relatively small contributions to impairment***); see, also, 77 FR 57864, 57883 (September 18, 2012) (citing 70 FR 39104, 39129 (July 6, 2005)) (perceptibility of visibility impairment is not dispositive in BART context "because regional

haze is produced by a multitude of sources and activities which are located across a broad geographic area").”

Technical

First, EPA 2019 RH Guidance states that “…a state should not use the difference in projected 2028 visibility with and without the control measure (e.g., the effect on the 2028 RPG) as its only characterization of the visibility benefit of the measure.” (§II.B.4.g)

The potential visibility benefit of emission reductions is much larger when compared to a clean background condition (e.g. 2064 end point). By basing the visibility benefit analysis on the VISTAS 2028 modeling run, Ohio is using a “dirty” reference condition for comparison which mutes or understates the true long-term visibility benefit of emission reductions.

> <u>EPA 2019 RH Guidance (page 38, §II.B.4.g):</u>
> “The discussion in Section II.B.3.b of this document regarding the use of a natural background light extinction value when expressing baseline source impacts in delta deciview units applies when expressing visibility benefits in delta deciview units. In particular, ***a state should not use the difference in projected 2028 visibility with and without the control measure (e.g., the effect on the 2028 RPG) as its only characterization of the visibility benefit of the measure.***[66]
> [66]In the first implementation period and in comments submitted in the rulemaking for the 2017 revisions to the Regional Haze Rule, some stakeholders stated that, when considering visibility benefits as one of the five statutory factors for BART or when considering visibility along with the four statutory factors for reasonable progress, it is appropriate to consider only the amount by which a potential measure or combination of measures would change the projected overall ambient deciview index value as of the end of the implementation period, i.e., the incremental effect on the RPGs. The Rule requires RPGs to represent the expected actual overall visibility conditions at the end of the implementation period. The RPGs are values that will be compared in a progress report to actual visibility conditions. ***In contrast, estimates of the visibility benefits of emission control measures have a different purpose, which is to help guide decisions on the control of individual sources. In this context, relying solely on a quantification of visibility benefits relative to “dirty background” (i.e., conditions with greater impairment than natural background visibility conditions) obscures the full potential benefits of control measures and makes it less likely that a measure would appear reasonable from a visibility benefit perspective.*** EPA has used a natural background light extinction value when expressing baseline source impacts in delta deciview units in the North Dakota (77 FR 20894, April 6, 2012),

Montana (77 FR 57864, September 18, 2012), Arizona (79 FR 52420, September 3, 2014), and Texas (81 FR 296, January 5, 2016) FIPs and partial disapprovals of North Dakota (77 FR 20894, April 6, 2012) and Texas (81 FR 296, January 5, 2016) SIPs that relied on modeling employing high-deciview ambient background conditions. This approach has been upheld by the Eighth Circuit. North Dakota v. EPA. 730 F.3d 750, 764-766 (8th Cir. 2013) ("Although the State was free to employ its own visibility model and to consider visibility improvement in its reasonable progress determinations, it was not free to do so in a manner that was inconsistent with the CAA. Because the goal of § 169A is to attain natural visibility conditions in mandatory Class I Federal areas, see 42 U.S.C. § 7491(a)(1), and EPA has demonstrated that the visibility model used by the State would serve instead to maintain current degraded conditions, we cannot say that EPA acted in a manner that was arbitrary, capricious, or an abuse of discretion by disapproving the State's reasonable progress determination based upon its cumulative source visibility modeling."

Second, the details of the analysis methods used by Ohio to estimate visibility benefits are not well described and may not be appropriate. It is not standard practice to use modeled visibility impacts for a specific source to represent different sources. Likewise, it is not standard to scale modeled visibility impacts to reflect different emission scenarios from those that were modeled. Differences in meteorological conditions from place to place and complex atmospheric chemistry generally preclude substitution of emission data as a replacement or even proxy for robust modeling.

As currently described the visibility benefit analysis conducted by Ohio lacks the scientific rigor of a true visibility modeling analysis.
Finally, the Ohio visibility benefit analysis misinterprets the relationship between the inverse megameter and deciview and visibility metrics which need to considered relative to a background condition. Per Scott Copeland, USFS visibility expert:

In order to calculate the deciview impact of a source, the correct calculation is to determine the deciview of the source plus background extinction and subtract the deciview of the background extinction as:

- Delta dv = 10*ln((Bbackgound + Bsource)/10) - 10*ln((Bbackgound)/10)

This can be simplified to the standard form of source impact calculation:

- Delta dv = 10*ln ((Bsource+Bbackground)/Bbackground)

Thus, the delta deciview for any source can never be negative. As a simple exercise in scale, the described cumulative impact of 2.9 Mm-1, if added to the default 2064 endpoint extinction at Shining Rock Wilderness of 28.9 Mm-1, yields nearly 1.0 dv change which is very significant in the context of making progress towards the 2064 goal.

The haze metrics converter on the IMPROVE webpage is a useful tool for exploring the relationship between extinction and deciviews relative to baseline conditions. (http://vista.cira.colostate.edu/Improve/haze-metrics-converter/)

This is a significant concern in the Ohio draft SIP because it serves to downplay the true effect and benefit of emission reductions for visibility." (David Pohlman, NPS)

"Although EPA's 2019 Regional Haze Guidance allows for the consideration of visibility in determining whether emissions control measures are necessary for making reasonable progress, the guidance also states that "because regional haze results from a multitude of sources over a broad geographic area, a measure may be necessary for reasonable progress even if that measure in isolation does not result in perceptible visibility improvement." Widespread emissions controls, particularly for SO2 and NOx, are essential for making reasonable progress at Class I areas both near to, and more distant from, emissions sources. Further, small visibility improvements, even those that may be imperceptible by themselves, are essential for making progress towards the national goal of restoring natural conditions at Class I areas by 2064." (Shawn Cochran, FS)

"We want to clarify a section on page 44:

- The paragraph describing deciview impacts should be revised to correctly describe the relationship between *changes* in light extinction and *changes* in deciview. In order to calculate the deciview impact of a source, the correct calculation is to determine the deciview of the source plus background extinction and subtract the deciview of the background extinction as:
    - Delta dv = 10*ln((Bbackgound + Bsource)/10) - 10*ln((Bbackgound)/10)

  This can be simplified to the standard form of source impact calculation:
    - Delta dv = 10*ln ((Bsource+Bbackground)/Bbackground)

- Thus the delta dv for any source can never be negative. As a simple exercise in scale, the described cumulative impact of 2.9 Mm-1, if added to the default 2064 endpoint extinction at Shining Rock Wilderness of 28.9 Mm-1, yields about a 1 dv change which is very significant in the context of making progress towards the 2064 goal." (Shawn Cochran, FS)

Response 25: Ohio agrees that the visibility benefit analysis is not one of the required four statutory factors. This analysis is included in the SIP as additional weight of evidence. While the approach taken in scaling the VISTAS modeling for other sources has limitations, it is the best available information we have before us at this time and serves to provide a rough estimate of the visibility benefit of potential controls under consideration.

Ohio recognizes we initially misinterpreted the relationship between the delta deciview and inverse megameter metrics, which resulted in technical inaccuracy of statements regarding the 'de facto' metric of 10 Mm-1. Therefore, discussion on this point has been removed.

Ohio continues to present the visibility benefit analysis in terms of inverse megameters (Mm^{-1}) rather than delta deciviews in order to be consistent with recommendations in U.S. EPA's Regional Haze Guidance. However, some of the sources elected to include a visibility benefit analysis in the four-factor analysis and presented their analyses in terms of both light extinction (Mm^{-1}) and delta deciviews. These analyses have been revised to reference the adjusted 2064 endpoint to represent natural visibility conditions (i.e. 'clean' background), consistent with U.S. EPA's Regional Have guidance (see Appendices F and I).

Both the NPS and FS comments provided the following comment: "As a simple exercise in scale, the described cumulative impact of 2.9 Mm-1, if added to the default 2064 endpoint extinction at Shining Rock Wilderness of 28.9 Mm-1, yields about a 1 dv change which is very significant in the context of making progress towards the 2064 goal." Ohio does not believe it is appropriate to use the natural background of a *single* Class I area to convert a *cumulative* visibility benefit (at all four facilities considered across all Class I areas) to delta deciviews. This significantly overestimates the impact that could be realized should the controls be implemented. Any determination of the delta deciview for a cumulative visibility benefit should account for the cumulative background for all Class I areas considered.

Ohio finds that the visibility benefit as estimated from this analysis would not be significant, whether considered in isolation for each source and Class I area, or whether considered cumulatively across multiple sources and all Class I areas.

<u>Other</u>

Comment 26: "It would be helpful if Ohio would share which sources were subject to the SO_2 Data Requirements Rule and what the outcome was for each." (Shawn Cochran, FS)

Response 26: This information is available on our website at https://www.epa.ohio.gov/dapc/sip/SO2, specifically in the July 1, 2016 Letter of DRR Sources with chosen air quality characterization pathway, and the Nonattainment Area Recommendations table which has information for each round of designations.

End of Response to Comments

REGIONAL HAZE SIP – SECOND IMPLEMENTATION PERIOD
RESPONSE TO FLM COMMENTS

ATTACHMENT 1
SUPPLEMENTAL INFORMATION PROVIDED BY KYGER CREEK STATION

OVEC Response to FLM comments regarding the Kyger Creek Generating Station

March 30, 2021

We appreciate the comments provided by FLM regarding the above-referenced facility and its analysis of the facility performance relative to Regional Haze and the State Implementation Plans (SIPs) for the Second Implementation Period.

We recognize that the non-binding guidance document USEPA issued to assist states in the preparation of SIPs provides valuable insight and recommendations on factors that States can consider during SIP plan development. States can use this document along with a whole range of circumstances in evaluating whether a four-factor analysis may be warranted for any facility. Factors such as a facility's emissions profile and performance, distance to the nearest Class I areas (Kyger Creek Station is near the outer limit of 300 km to the nearest area), the status of the Class I areas relative to reasonable progress goals, other factors such as actual and planned emissions source retirements within a state, and these include the four statutory factors and five voluntary factors that can be used to evaluate the need on a holistic level to consider whether additional reductions or a full four-factor analysis is needed for the Kyger Creek Station.

Scrubber Performance and SO_2 removal efficiency:

OVEC agrees with the FLM conclusion that the two FGD Scrubbers serving all five units at the Kyger Creek Station are effectively controlling SO_2 emissions; however, OVEC wants to clarify details of the scrubber design and performance factors that show even better removal efficiency than the data cited by FLM in their comments.

As part of Kyger Creek's interim strategy to meet compliance obligations under the Acid Rain Program and the CAIR program, the facility temporarily relied on fuel switching to a lower sulfur coal blend not designed to be used in the facility boilers to lower SO_2 emissions for the period during the facility's transition toward scrubber installation. The resulting emission rate is reflected in the "uncontrolled" SO_2 emission rate provided in the FLM comments based on CAMD data showing a pre-scrubber emission rate of 2.71 lb/mmBtu. That emission rate was reflective of a reduced sulfur eastern bituminous and sub bituminous (Powder River Basin) blend that the Kyger Creek Plant was using as it transitioned toward scrubber installation. That coal blend temporarily used during that time is not what the boilers were originally designed to use, and it is not the sulfur content that the scrubbers were designed to scrub. The FGD scrubbers were designed for using the traditional local fuel source for the plant boilers - a Northern Appalachian Coal with up to a 7.5# SO_2 content. Accordingly, a correct "uncontrolled" emission rate is greater than 97% for the scrubbers.

In addition, OVEC wants to clarify that two scrubbers were installed. One scrubber is for the combined flue gas from Units 1 and 2, and the second scrubber is for the combined flue gas from Units 3, 4 and 5. The certified CEMS monitoring equipment used to demonstrate compliance with US EPA regulations are installed on the common flues for each scrubber in accordance with US EPA siting criteria. Factoring in this information, the actual control efficiency for the Jet-bubbling reactor FGD scrubbers at Kyger Creek Station is consistently greater than 97%. This removal efficiency is clearly greater than the 95% or higher removal efficiency that, as referenced in the footnote on pg. 24 of USEPA's RHR guidance document, EPA expects scrubbers installed under the CAA since 2007 would achieve. Further, Kyger

Creek Station has been using the FGD scrubbers to separately demonstrate compliance with the applicable alternative SO_2 emission limit in the 2012 Mercury Air Toxics Standards (MATS) Rule applicable to power plants. The applicable SO_2 30-day rolling average emission limit under that rule is 0.2 lb/MMBtu for coal-fired EGUs and 0.3 lb/MMBtu for EGUs fired with oil-derived solid fuel. Based on US EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, dated August 20, 2019, EPA concludes that, "…it is unlikely that an analysis of control measures for a source already equipped with a scrubber and meeting one of these limits would conclude that even more stringent control of SO_2 is necessary to make reasonable progress." (pg. 23 of RHR guidance document).

In addition, the Kyger Creek Plant JBR scrubber design provides a co-benefit by removing additional particulate matter beyond the removal efficiency achieved by the electrostatic precipitators installed on each unit upstream from the common scrubbers. The JBR scrubber design and PM removal efficiency are effective enough that the facility has installed and certified PM monitors on each of the two flue-gas stacks and separately demonstrates compliance with the alternative PM emission limit in the 2012 Mercury Air Toxics Standards (MATS) Rule applicable to coal-fired EGUs. The applicable PM emission limit under that rule is 0.03 lb/MMBtu as a 30-day rolling average.

In conclusion, while OVEC agrees with the FLM suggestion that a four-factor analysis and SO_2 emissions at Kyger Creek Station, the facts presented above show additional rationale on why that is appropriate.

SCR and over-fire air performance and NO_x removal efficiency: OVEC disagrees with the FLM analysis of NO_x emissions on all units at the Kyger Creek Station, and that the facility should undergo a four-factor analysis. The FLM comments are missing important details that OVEC believes support Ohio EPA drawing a different conclusion in the SIP. First, the baseline emission rate for Kyger Creek Station boilers prior to SCR installation as defined in 40 CFR Section 76.6, is an emission rate of 0.84 lb/mmBtu. This is the NO_x emission rate established under the Acid Rain Program for Group 2 wet bottom wall fired boilers with installed over-fire air controls for NO_x. All five of the Kyger Creek Station boilers meet this designation.

Second, FLM pulled post-SCR installed unit-specific emission rates from CAMD. While this data is directionally accurate, none of the CAMD data is unit-specific CEMS certified monitor data. This facility has two flues in a common concrete stack. One flue exhausts the combined scrubbed flue gas from Units 1 and 2 and the second flue exhausts the combined scrubbed flue gas from Unit 3, 4 and 5. As a result, the CAMD data apportionment is estimated on a unit basis. OVEC is not certain how CAMD made the allocations between the units so we cannot validate the accuracy of the unit-specific emission rates provided.

Third, when analyzing Kyger Creek certified emissions data from the past four consecutive ozone seasons, the data shows an average facility wide NOx emission rate between 70-90% removal efficiency from the 0.84 lb/mmBtu baseline. The Kyger Creek Station has also recently enhanced its preventative maintenance and operator training programs and has also made process improvements to the urea injection system that are expected to improve year-round NO_x control urea injection reliability.

Finally, the Kyger Creek Station also depends on the catalyst reactivity available in the four catalyst layers in each of the SCRs to not only reduce NO_x emissions but to oxidize the trace amounts of mercury in the local coal used at the facility. Oxidizing the mercury in the SCR catalyst layers converts the mercury into a form that can be removed from the flue gas in the scrubber. This is necessary for the facility to also consistently demonstrate compliance with the MATS mercury emission limit of 1.2 lb/TBtu as a 30-day rolling average on each of the two plant stacks. As a result, the facility needs to retain some operational balance between NO_x removal and Hg oxidation to effectively remove both pollutants at levels necessary to comply with both the annual and ozone season NO_x regulations applicable to this facility as well as the stack specific “not to exceed” Hg emission limits required under MATS regulations.

This facility has improved seasonal NO_x removal efficiency since the CSAPR Update went into effect in 2017, and is working on system and process improvements to improve urea injection reliability year-round while balancing MATS compliance obligations. Given these facts, and when taking a holistic view of the facility’s overall emissions performance, OVEC thinks that the OEPA has reasonably concluded for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls are necessary for this facility. OVEC also believes that that EPA’s Regional Haze Guidance places this sort of decision squarely in Ohio EPA’s hands.

OVEC believes that this conclusion is complemented by the following external facts.

- Ohio has had several sources of NOx emissions that have recently retired and additional coal-fired EGUs have announced plans to retire prior to 2028. Announced and actual unit retirements will further reduce emissions from the state that contribute to regional haze, and these retirements are factors that states can consider under both EPA guidance and rules.
- U.S. EPA, consistent with a court ordered mandate, promulgated additional regulations targeting NOx emissions in a 12-state region that includes Ohio that will put additional regional and facility constrains on NOx emissions beginning with the 2021 ozone season. This regulation, entitled, “***Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS***” was signed by EPA Administrator Michael Regan on March 15, 2021, will become effective 60-days after publication in the Federal Register, and the associated regional NO_x emission caps will apply beginning in 2021. Consideration of reductions from other CAA mandated programs is also something states can consider under EPA’s Regional Haze rules and guidance, and
- The Class I areas that the Kyger Creek Station could contribute to are already below the glide path goals established under the RHR for the Second Implementation Period.

REGIONAL HAZE SIP – SECOND IMPLEMENTATION PERIOD
RESPONSE TO FLM COMMENTS

ATTACHMENT 2
SUPPLEMENTAL INFORMATION PROVIDED BY GAVIN POWER PLANT

Gavin Power Plant

Current NOx Emissions and Haze Impacts

May 4, 2021

1. Introduction

Lightstone Generation LLC owns and operates the General James M. Gavin Power Plant (Gavin Power Plant). In December 2020, the Gavin Power Plant submitted to Ohio Environmental Protection Agency (Ohio EPA), a four-factor analysis for sulfur dioxide (SO_2) emissions from Units 1 and 2. The National Park Service and Federal Land Managers (NPS/FLM) have commented to Ohio EPA that the Gavin Power Plant should also conduct a four-factor analysis for nitrogen oxides (NOx) controls, notwithstanding the fact that the Gavin Power Plant currently operates the best available retrofit technology available for the control of NOx emissions – selective catalytic reduction (SCR), as well as low-NOx burners. The NPS/FLM claim that those state-of-the-art controls should be disregarded because they were installed prior to 2007 and because the Gavin Power Plant allegedly does not achieve a 90% control efficiency. Ohio EPA therefore has requested additional technical information on the Gavin Power Plant's NOx controls on Units 1 and 2 and their current actual emission rates to support their decision of not requiring a four-factor analysis for NOx.

As will be discussed further below, a four-factor analysis for NOx is redundant and inappropriate for the Gavin Power Plant. As a preliminary matter, the fact that the Gavin Power Plant was an early adopter of SCR systems should not be held against it when evaluating whether the plant meets United States Environmental Protection Agency's (USEPA's) criterion of a "well-controlled source".[1] Although the NPS/FLM claim that the plant is achieving less than an 80% NOx removal efficiency, the available emissions information supports the conclusion that the low-NOx burners and the SCRs together achieve greater than 90% NOx removal efficiency. Therefore, consistent with the USEPA Regional Haze Rule (RHR) guidance[1], nothing more should be required.

Even more importantly, Gavin operates all of its control systems in concert to maximize the efficiencies in reducing ***all*** pollutants. Although for a short time from 2009-2012, Gavin was able to achieve slightly higher control efficiencies from its SCRs through injection of additional ammonia, those marginal improvements in NOx emissions came with significant corollary environmental disbenefits – including higher mercury emissions, compromised ash quality and reduced plant output and efficiency (thereby increasing total emissions of all pollutants, including greenhouse gases). Moreover, the additional ammonia injection resulted in air heater pluggages that necessitated additional major plant outages and/or significant plant capacity derating.

The closest Class I areas to the Gavin Power Plant (Dolly Sods, James River Face, and Otter Creek Wilderness Areas in West Virginia) are more than 200 km from the plant. Additionally, the available data for those Class I areas demonstrate that they are each significantly *ahead* of the USEPA-established glide path for achieving the nation's visibility goals and that additional NOx reductions at the Gavin Power Plant will result in negligible visibility improvement at those areas.

[1] US EPA; "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" in August 2019. Available at https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

The NPS/FLM have the option of evaluating air pollutants in isolation, focusing only on the issues of concern to them, i.e., visibility at Class I areas. But Ohio EPA – and Gavin – are obligated to look at all of the environmental impacts associated with the plant's operations, including the adverse impacts that would result from increased ammonia injection and the imperceptible impacts on visibility that would result from the slightly improved NOx emission rates. Viewed in that light, it is clear that Ohio EPA should not mandate further NOx reductions from the Gavin Power Plant, thus a four-factor analysis is not necessary.

2. NOx Emissions

USEPA RHR guidance[2] states that a source may already have effective controls in place as a result of a previous regional haze SIP or to meet another Clean Air Act requirement. In addition, for well-controlled sources, the USEPA guidance indicates that it may be reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls are necessary. For a source meeting the specific USEPA examples for well-controlled sources, the practice widely accepted by states, USEPA, and other interested parties has been to not require a four-factor analysis.

Emissions of NOx at the Gavin Power Plant Units 1 and 2 are controlled by low-NOx cell burners and SCR systems. The cell burners, installed in 1999, resulted in a 50% reduction in NOx emissions. The SCR systems, installed in 2001, are operated in accordance with the following terms of the facility's Title V operating permit:

> ""Continuously operate" or "continuous operation" means that when an SCR, FGD, DSI, ESP or other NOx pollution controls are used at an emissions unit, except during a malfunction, they shall be operated at all times such emissions unit is in operation, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for such equipment and the emissions unit so as to minimize emissions to the greatest extent practicable. For this source, the "continuously operate" or "continuous operation" definition applies to the operational restrictions in c)(1) and c)(2), the monitoring and recordkeeping requirements in d)(1) and d)(2) and the reporting requirements in e)(1)."[3]

The NPS/FLM claim that those state-of-the-art controls, which are – and are required to be – operated "so as to minimize emissions to the greatest extent practicable," should be disregarded because they were installed prior to 2007. We disagree. The Gavin Power Plant should not be penalized for being an early adopter of SCR technology, so long as those state-of-the-art controls are well-maintained and operated, as they demonstrably are, and are required to be. This conclusion is especially valid for sources using SCR to control NOx because the catalyst layers are routinely replaced with layers that may have updated catalyst types that provide for lower SO_2 oxidation as well as better mercury oxidation and NOx control.

Units 1 and 2 were designed and constructed to burn bituminous coal using cell burners. For bituminous coal, AP-42 emission factors[4] are:

- 31 lb/ton (approx. 1.24 lb/MMBtu) for cell burners;
- 22 lb/ton (approx. 0.88 lb/MMBtu) for wall fired units; and
- 15 lb/ton (approx. 0.60 lb/MMBtu) for tangential fired units.

[2] US EPA; "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" in August 2019, Pages 22 and 23. Available at https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.
[3] Title V Operating Permit No. P0089258 (Expiration date – May 6, 2025), Page 31.
[4] https://www.epa.gov/sites/production/files/2020-09/documents/1.1_bituminous_and_subbituminous_coal_combustion.pdf

Therefore, well-controlled sources using cell burners are expected to have higher NOx emissions than sources with other firing configurations.

Actual emissions and annual capacity factors for Units 1 and 2 for the 1997 – 1998 period and the 2017 through 2019 period are summarized in **Table 2-1**. During the years 1997 and 1998, Units 1 and 2 operated with cell burners. Based on USEPA Air Markets Program Data[5], overall average emissions during this 2-year period were 1.164 lb/MMBtu. In 1999, new low-NOx cell burners were placed in service as the first step of a NOx reduction program. In 2001, SCR systems were placed in service on both units. Average NOx emissions during the 2016 through 2019 period were at 0.105 lb/MMBtu, which is a 91% reduction from the pre-control emission rate of 1.164 lb/MMBtu.

Table 2-1 Gavin Power Plant – Units 1 and 2 Actual Annual Operation and NOx Emissions

Time Period	Unit	Annual Operating Hours [(a)]	Power Output [(a)]	Capacity Factor based on MW [(b)]	Annual Fuel Use [(a)]	NOx Emissions [(a)]	
		(hr/yr)	(MWh)	%	(MMBtu/yr)	(ton/yr)	(lb/MMBtu)
1997 - 1998	1	6,568	8,042,557	64.20%	80,764,153	50,185	1.243
	2	7,289	8,795,068	70.21%	86,728,570	47,254	1.090
	Average	6,928	8,418,813	67.21%	83,746,362	48,720	1.164
	Total	----	16,837,625	----	167,492,724	97,439	----
2017-2019	1	7,102	8,026,519	62.8%	73,806,437	3,807	0.103
	2	7,309	8,453,514	66.1%	74,131,407	3,931	0.106
	Average	7,206	8,240,017	64.4%	73,968,922	3,869	0.105
	Total	----	16,480,033	----	147,937,844	7,738	----
Emission Reduction						**92.0%**	**91.0%**

(a) EPA Air Markets Program Data (https://ampd.epa.gov/ampd/)

(b) Rated capacity for Unit 1 is 1,430 MW, gross and that for Unit 2 is 1,460 MW, gross.

3. SCR Systems on Units 1 and 2

Unit 1 and Unit 2 each have their own SCR systems for control of NOx emissions. Each SCR unit has 4 catalyst layers. Catalyst activity is monitored by periodic sampling and analyses by Cormetech. Catalyst sampling occurs every 2 years. Each catalyst layer change-out requires a 35-day outage of the affected unit. On each unit, one layer of catalyst is changed during that unit's scheduled major outage. Major outages are scheduled based on operation and have been done biennially since 2010. That is, one major scheduled outage occurs for each unit every other year. The old catalysts are cleaned before being moved. Cleaning is done using an industrial vacuum truck to vacuum off as much fly ash as possible before removing them. After the catalysts have been cleaned, they are removed using a rail-based hoist and rail cart system. The hoist and rail car system are used to transport the catalysts to a crane that lowers them down to the ground to be transported to the temporary storage area. The spent catalysts are covered with plastic to protect them from the elements and prevent any environmental releases. The

5 EPA Air Markets Program Data (https://ampd.epa.gov/ampd/)

spent catalysts are then processed for recycling or disposal in an appropriate class landfill. The same crane, hoist and rail cart system is then used for the installation of the new catalyst(s).

Ammonia (NH_3) slip is monitored in the ducts at the catalyst outlet. NOx emission control is limited by acceptable NH_3 slip. Current actual NH_3 slip is less than 1 ppm. SCR catalyst chemistry and operation are balanced to both reduce NOx to N_2, and oxidize mercury to form water-soluble Hg compounds. Oxidized mercury is well-controlled by wet FGD systems like the ones in place at the Gavin Power Plant. Non-oxidized (i.e., elemental) mercury essentially passes through the scrubber with minimal mercury capture being achievable. High levels of ammonia, which is a reducing agent, reduce mercury oxidation, returning it to its elemental state. These high levels of ammonia therefore adversely affect the ability of the wet FGD system to capture and control the mercury, in turn jeopardizing MATS[6] compliance. Therefore, the dual function of the SCR system for both NOx reduction and Hg oxidation must be optimized. The Gavin Power Plant cannot inject addition ammonia to increase NOx reduction without jeopardizing its ability to control mercury emissions.

In addition, higher ammonia slip adversely affects air heater performance. Unreacted ammonia reacts with the sulfur oxides resulting in the formation of ammonium sulfate and ammonium bisulfate. Deposition of ammonium sulfate and ammonium bisulfate causes air heater fouling and eventually pluggage. Even low levels of ammonia slip for short periods of time are sufficient to result ammonium sulfate and bisulfate formation, causing heater fouling and pluggage. The pluggage is detected by fan or duct back-pressure. As the fans reach maximum capacity due to fouling and pluggage, the plant capacity must be derated, sometimes significantly, until a major outage can be scheduled with the system operator to allow for a complete cleaning of the air heaters. This reduction in plant output and efficiency in turn increases all air emissions, including greenhouse gases, as more fuel is needed to generate the same amount of electricity. For this reason as well, the plant has to be extremely careful to avoid ammonia slip and cannot simply inject additional ammonia to enhance NOx removal efficiencies.

As noted previously, in the 2009 to 2012 time period, the prior owner/operator of the Gavin Power Plant attempted to lower NOx emissions by injecting more ammonia. That effort was ultimately abandoned because of recurring issues with high ammonia slip that decreased mercury control levels and caused air heater pluggage. Indeed, the pluggage issues were so significant that they required repeated major plant outages to clean the air heater. During the 2009 to 2012 period, these air heater washes were required, at a minimum, twice a year – as well as more limited cleaning occurring every time there was any forced outage, no matter how short.

Lastly, high NH_3 slip adversely affects ash quality which renders the ash unsuitable for beneficial reuse.[7] Specifically, the concrete will carry an ammonia odor and emit ammonia vapors, potentially impacting the air quality of the immediate area. As such, ammonia slip also increases the waste generated at the plant, as fly ash must be landfilled rather than beneficially reused. Ash is periodically sampled for NH_3 content to manage this issue.

4. NOx Visibility Impacts

The goal of the RHR is to improve visibility in federal Class I areas. Accordingly, when evaluating possible emissions reduction projects or programs, it is appropriate to consider the degree to which control projects might contribute towards that goal. As explained below, because the visibility impacts attributable to NOx emissions at the Gavin Power Plant are low, further NOx controls and/or lower

[6] Mercury and Air Toxics Standards (40 CFR 63, Subpart UUUUU)

[7] Fly ash is combined with the wet FGD sludge prior to landfilling. Beneficial reuse of the fly ash is its use in concrete.

emission limits, even if technically and economically feasible, would yield only negligible visibility benefits at any of the regional Class I areas.

Class I areas in the eastern United States near Ohio are shown in **Figure 4-1**. There are no Class I areas within 100 km of the Gavin Power Plant. The closest Class I areas to the Gavin Power Plant are Dolly Sods, James River Face, and Otter Creek Wilderness Areas in West Virginia which are more than 200 km but less than 300 km from the plant. Other Class I areas within 400 km of the Gavin Power Plant are also shown in the figure.

The state of Ohio is a member of the Lake Michigan Air Directors Consortium (LADCO) Regional Planning Organization. LADCO assists its member states by conducting modeling analyses, including photochemical grid modeling, to assess visibility impacts from emission sources. This is especially helpful in determining the haze impact of the current emissions from sources being considered for SO_2 and NOx controls. A modeling result for this assessment is best obtained for a photochemical grid modeling analysis for which the source's emissions are "tagged" for purposes of determining the source's sulfate and nitrate haze contributions at each Class I area under consideration.

LADCO is currently conducting photochemical grid modeling that will assist member states to assess impacts from sources in states and industry sectors (e.g., electric generating stations). However, the LADCO modeling had not been completed as of the time of this report. It is expected that when the modeling results are available, they will be consistent with independent modeling assessments that have already been completed by other Regional Planning Organizations (RPOs), as discussed below.

The next sub-section discusses available CAMx modeling for some Ohio EGUs conducted by the southeastern states Regional Planning Organization, VISTAS / SESARM.[8]

The impact of NOx emissions to Class I area visibility can be determined by analyzing the results of visibility modeling conducted by the VISTAS / SESARM Regional Planning Organization that included emissions for some Ohio power plants. The VISTAS modeling was conducted by Alpine Geophysics and utilized advanced CAMx modeling including modeling particulate matter simulations and source apportionment studies. Determinations of the haze contributions of specified large sources was accomplished by "tagging" the selected sources for determining their contribution to impairment at each Class I area of interest. Gavin Power Plant is a tagged source in the VISTAS analysis.

Visibility impairment is commonly expressed using two parameters to characterize the visibility impairment:

- **Light Extinction (b_{ext})** is the reduction in light due to scattering and absorption as it passes through the atmosphere. Light extinction is directly proportional to pollutant particulate and aerosol concentrations in the air and is expressed in units of inverse megameters or Mm-1.

- **Deciview (DV)** is a unitless metric of haze which is proportional to the logarithm of the light extinction. Deciview correlates to a person's perception of a visibility change, with a change of 1 deciview being barely perceptible. The "no degradation" value of 0.1 DV stated in the 1999 Regional Haze Rule is only 10% of this perceptibility threshold.

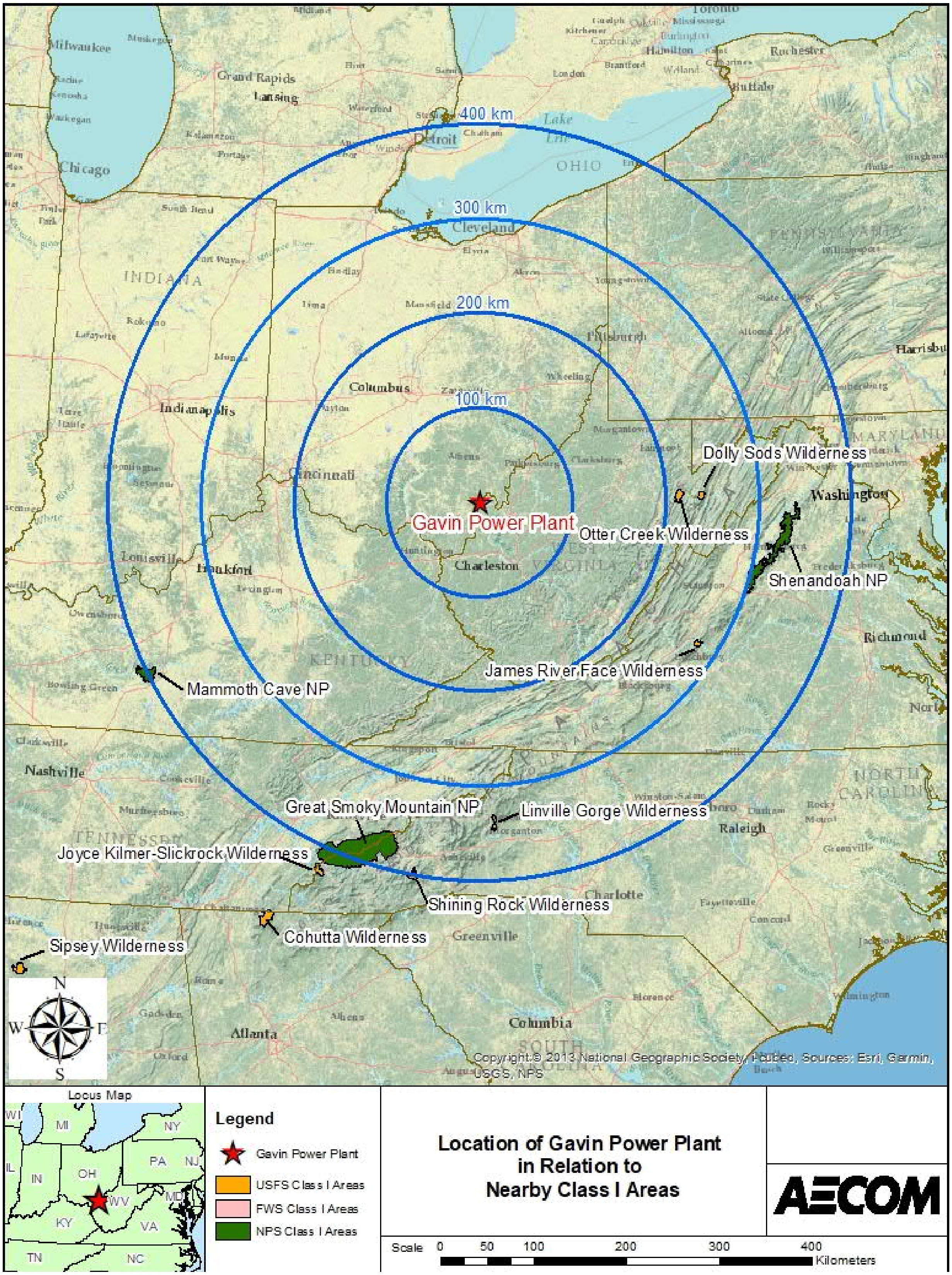
Both metrics are helpful in understanding changes to visibility impairment. While the deciview is the best parameter to relate the significance of a perceived visibility change, modeling produces results in the form of light extinction using the new IMPROVE equation that converts particulate concentrations to visibility impairment.

[8] "VISTAS" is an acronym for Visibility Improvement-State and Tribal Association of the Southeast and "SESARM" stands for Southeastern States Air Resource Managers, Inc. Their web site for Regional Haze Rule modeling results is https://www.metro4-sesarm.org/content/vistas-regional-haze-program.

In response to comments received from the Federal Land Managers for Ohio's draft State Implementation Plan submittal earlier in 2021, the Ohio EPA requested that the conversion between deciviews and extinction should reference the natural conditions endpoint visibility conditions. Ohio has indicated that it is permissible to reference the natural conditions endpoint adjusted for international haze contributions. These adjusted endpoints are available from USEPA's 2019 visibility modeling document[9], Appendix E.

[9] Available at https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf.

Figure 4-1 Class I Areas in the Vicinity of Gavin Power Plant



A review of the natural conditions endpoint deciviews published by USEPA, adjusted for the influence of international contributions to haze, indicates that the cleanest background is at Dolly Sods and Otter Creek Wilderness Areas, with a deciview value of 11.07. The visibility metrics converter available at https://vista.cira.colostate.edu/Improve/haze-metrics-converter/ can be used to determine the extinction in inverse megameters for a deciview value of 11.07, as well as 10.97 and 11.17 (0.1 dv increments). At that deciview level, a change of 0.1 dv is equivalent to an extinction change of 0.3 Mm^{-1}. This conversion is used in the discussion provided below.

Charts shown in **Figures 4-2** and **4-3** are taken from the VISTAS Regional Haze modeling project webinar updated on September 10, 2020 (after being originally presented on May 20, 2020). They show, in units of deciview, the actual visibility measurements and projected modeling results of visibility for most impaired days at the Dolly Sods Wilderness Area and the James River Face Wilderness Area where the Gavin Power Plant's NOx emissions have the greatest visibility impacts.

Figure 4-2 Visibility Trends at Dolly Sods Wilderness Area

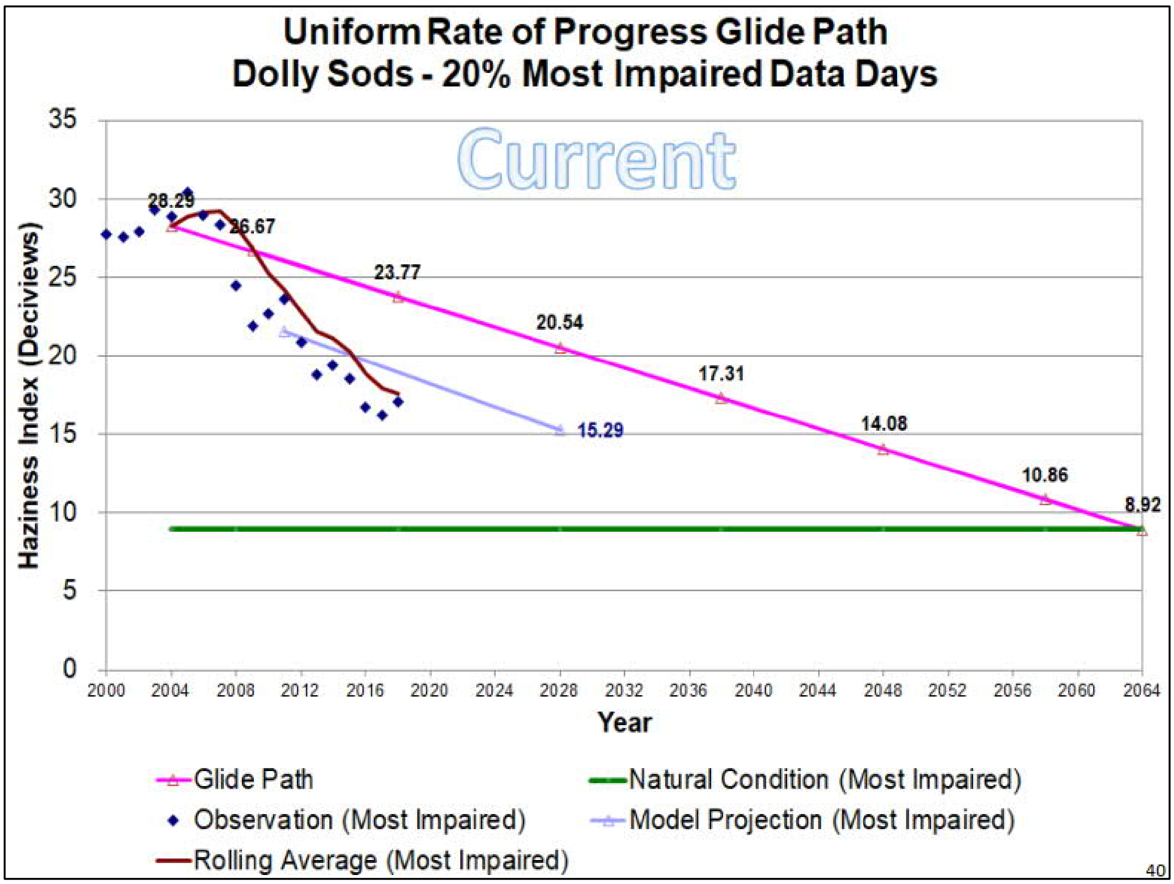
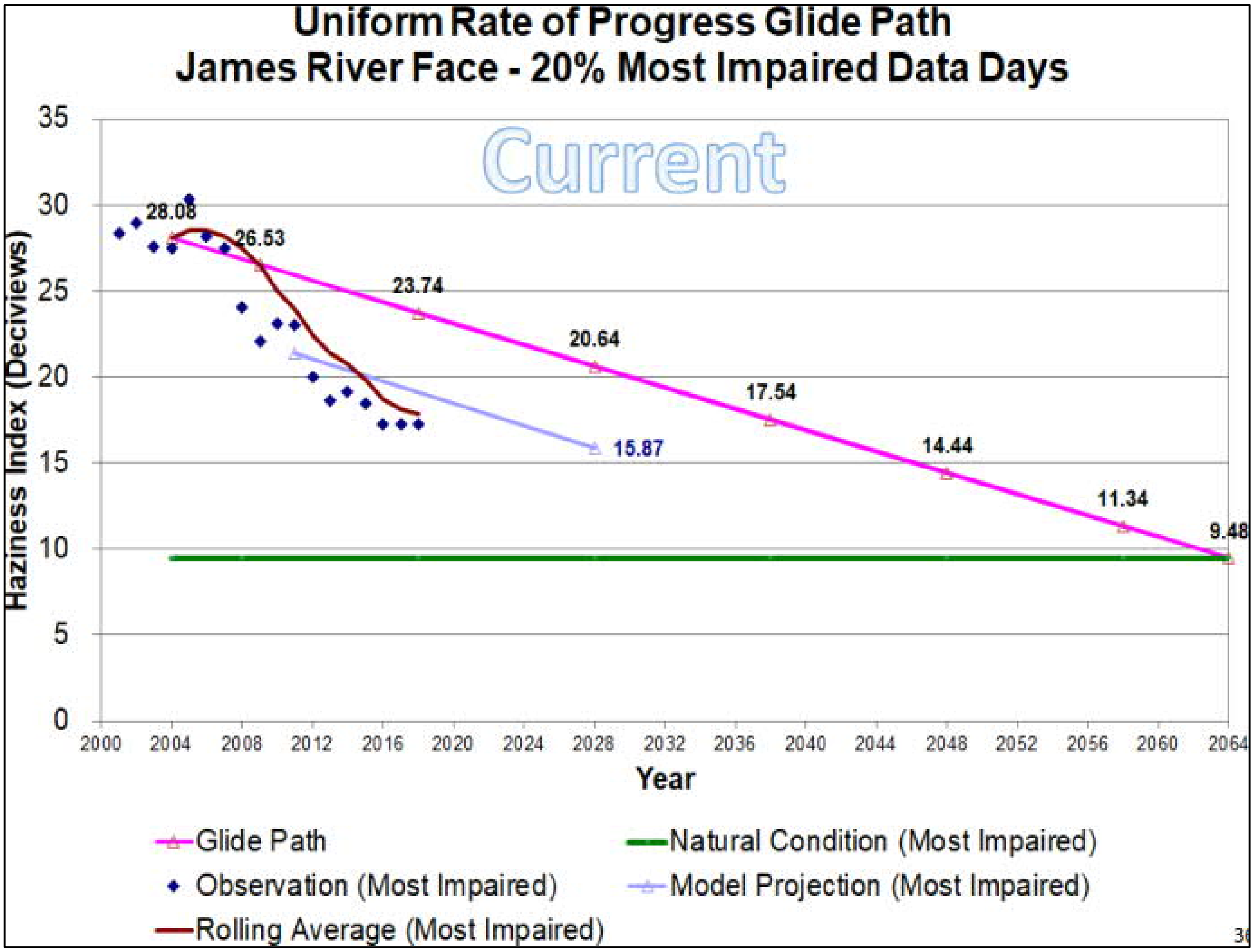


Figure 4-3 Visibility Trends at James River Face Wilderness Area



Figures 4-2 and **4-3** show that actual visibility measurements (the diamonds) confirm a strong trend of improved visibility in the past 10 years from about 28 DV to 16 DV in Dolly Sods WA and from 30 DV to about 17 DV in James River Face WA. These rates of actual improvement are much faster than the RHR target to maintain a "uniform rate of progress" or "glide path" (the pink line), which could be revised to a less-steep revised glide path to account for internationally-caused haze. However, VISTAS believes that since the Class I areas in this region are so far ahead of projections, that refinement is not necessary at this time.[10] Additionally, VISTAS modeling of the expected emissions reductions in the coming years (on-the-books / on-the-way controls) projects (the blue line) that visibility should continue to significantly improve, reaching 15.3 DV and 15.9 DV by the next RHR milestone year of 2028 for Dolly Sods and James River Face, respectively. These charts show that visibility in these Class I areas is currently running ***at least 10 to 20 years ahead of the RHR targets*** and is expected to continue to do so. VISTAS modeling of other regional Class I areas shows very similar trends and all areas are far ahead of their glide path targets. Therefore, no additional emissions reductions at any regional facilities, beyond those already planned, are needed to continue to meet the RHR interim goals.

[10] VISTAS/SESARM response during Q&A of VISTAS Regional Haze modeling webinar presented on May 20, 2020.

4.1 Impact of Gavin NOx Emissions

The VISTAS modeling used 2011 actual annual emissions to estimate the projected 2028 emissions for modeling, and these values can be scaled to current representative NOx emissions for the Gavin Power Plant. Ohio EPA has stipulated that 2017 through 2019 average emissions should be considered as a representative baseline for this analysis. The Gavin Power Plant's current emissions of NOx (7,738 ton/yr) can be compared to its modeled emissions (7,983 ton/yr) to develop, with linear scaling, estimates of visibility impacts of the current NOx emissions. **Table 4-1** presents the visibility impacts of the Gavin Power Plant's current NOx emissions.

Table 4-1 Visibility Impact of Current NOx Emissions

Class I Areas Nearest to the Gavin Power Plant	Total Haze Impacts of Current NOx Emissions	
	Mm^{-1}	DV*
Dolly Sods WA	0.0086	0.0029
James River Face WA	**0.0152**	**0.0051**
Shenandoah NP	0.0210	0.0070
Linville Gorge WA	0.0019	0.0006
Great Smoky Mountain NP	0.0029	0.0010
Mammoth Cave NP	0.0057	0.0019

** Potential Improvement in DV is listed for the 20% most impaired days for each Class I area. Conversion between deciviews and extinction is based upon the discussion in Section 3.0: 0.1 dv is equivalent to 0.3 Mm^{-1} for extinction.*

Unit 1 and 2's current actual annual emissions of NOx result in estimated visibility impacts that are less than 0.05% of the projected 2028 visibility at the nearest Class I areas (Dolly Sods and James River Face). In addition, both these Class I areas are currently running at least 10 to 20 years ahead of the RHR glide path targets and are expected to continue to do so. Therefore, no further NOx reductions at the Gavin Plant are required for Ohio EPA to meet its regional haze reasonable progress goals. Indeed, visibility improvements from any additional NOx reductions are likely to be imperceptible.

5. Conclusion

In conclusion, a Gavin Power Plant four-factor analysis is unnecessary. The Gavin Power Plant currently operates the best available retrofit technology available for the control of NOx emissions –, low-NOx burners with SCRs, a system that together achieves greater than 90% NOx removal efficiency. Mandating additional NOx removal would upset the careful balance the Gavin Power Plant has achieved in reducing emissions of all pollutants and in preventing other corollary environmental disbenefits, including higher mercury emissions, compromised ash quality, reduced plant output and efficiency (thereby increasing total emissions of all pollutants, including greenhouse gases) and air heater pluggage resulting in major outages and/or significant plant capacity derating. Indeed, the closest Class 1 areas are more than 200 km away ***and*** are already well ahead of the EPA-established glide path for achieving the nation's visibility goals. Moreover, the impact of Gavin's current NOx emissions on the closest Class I area is 0.0051 DV, and any additional NOx reductions at the Gavin Power Plant would merely result in an imperceptible incremental improvement in visibility in those areas. Under these circumstances, it is entirely appropriate for Ohio EPA to conclude that the Gavin Power Plant is a well-controlled source for NOx and nothing further should be required to meet its regional haze obligations.