Appendix W

RH SIP NPS Comments

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National Park Service (NPS) Regional Haze SIP feedback for the Indiana Department of Environmental Management (IDEM)

July 23, 2021

Contents

1 Source Selection

Indiana sources for the four-factor[1] analyses required by the Clean Air Act (CAA) were identified by the Indiana Department of Environmental Management (IDEM) using the Q/d methodology developed by the Lake Michigan Area Air Directors Consortium (LADCO). The analysis of annual emissions (Q) expressed in tons per year divided by distance in kilometers (d) from the Class I areas, known as Q/d, was used to screen emissions source impacts at downwind receptors in lieu of air quality modeling results. IDEM evaluated its sources with higher nitrogen oxides (NO_x) and/or sulfur dioxide (SO_2) emissions taken from a 2018 inventory which could potentially have visibility impacts on surrounding Class I areas. A screening threshold Q/d value of 5 was established in order to screen out sources with either low emissions or located at far distances from Class I areas that were less likely to have visibility impacts.[2] Sources with a Q/d value of 5 or above were selected for evaluation based on the four-factors listed in the CAA to determine if emission controls were necessary. The sources in Indiana that exceeded the Q/d threshold value of 5 are shown in the following table.

Indiana Sources Exceeding the Q/d Threshold Value (Q/d > 5)

County	County ID	Plant ID	Name	Q/d Value
Floyd	043	00004	Duke - Gallagher	15.0
Gibson	051	00013	Duke - Gibson	134.8
Jasper	073	00008	NIPSCO - R M Schahfer	16.1
Jefferson	077	00001	IKEC - Clifty Creek	65.7
Lake	089	00383	Cokenergy	10.7
Lake	089	00316	ArcelorMittal - Indiana Harbor East	10.5
Lake	089	00121	US Steel - Gary Works	6.3
Lake	089	00382	ArcelorMittal - Indiana Harbor West	5.3
Lawrence	093	00002	Lehigh Cement - Mitchell	15.7
Pike	125	00002	AES - Petersburg	83.7
Porter	127	00001	ArcelorMittal Burns Harbor	42.8
Posey	129	00010	SIGECO - AB Brown	34.5
Posey	129	00002	SABIC - Mt Vernon	5.3
Putnam	133	00002	Lone Star Industries	6.7
Spencer	147	00020	AEP - Rockport	259.5
Sullivan	153	00005	Hoosier Energy - Merom	23.6
Vermillion	165	00001	Duke - Cayuga	36.4
Warrick	173	00007	Alcoa Warrick Operations	80.9
Warrick	173	00002	Alcoa Warrick Power Plant	31.3
Warrick	173	00001	SIGECO - F. B. Culley	25.3

[1] The four factors are: The costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements.

[2] Eight other states used a Q/d threshold of five or lower. LADCO recommended Q/d = 4 which was used by MI and MN.

We recommend that IDEM identify the specific Class I area that was the basis for each of its Q/d calculations.

We agree that IDEM has identified a reasonable group of facilities for four-factor analyses (4FA). IDEM says:

> The source listings included Electricity Generating Units (EGUs) and non-EGUs (steel mills, cement and plastics manufacturers, and aluminum smelter and electric services operations) emission sectors. These sources had the largest NO_x and SO_2 emissions in the state and were screened to have the greatest potential to impact visibility in surrounding Class I areas. Sources above the screening threshold value were required by IDEM to conduct a four-factor analysis with the exception of EGUs.

1.1 Exemption of EGU Sources from Four-Factor Analysis

The EGUs warrant consideration in this planning period for several reasons. First, the IDEM facility selection process and the exemption of EGUs from 4FA is internally inconsistent. Of the non-EGU facilities required by IDEM to conduct 4FA, Alcoa Warrick Operations had the highest Q/d = 80.9. However, IDEM's Q/d analysis identified three EGU facilities with higher Q/d than Alco Warrick Operations:

- AEP Rockport (Q/d =259.5)
- Gibson (Q/d =134.8)
- AES Petersburg (Q/d = 83.7)

These facilities have the highest potential to impair visibility at a Class I area according to the IDEM source selection analysis and were not required to conduct 4FA. The issue of excluding the sources that may cause the most visibility impairment from four-factor analyses is addressed in the EPA July 8th, 2021 clarification memo:

> Similarly, a threshold that excludes a state's largest visibility impairing sources from selection is more likely to be unreasonable.

Of the facilities required by IDEM to conduct 4FA, SABIC – Mt. Vernon had the lowest Q/d = 5.3. All of the EGUs identified by IDEM source selection methodology had higher Q/d values and were exempted from 4FA. This is an inconsistent application of the regional haze requirements.

Second, IDEM's rationale for exempting EGUs is not in accordance with the rule requirements or the EPA Guidance. IDEM has misconstrued the EPA Guidance. IDEM (correctly) cites EPA's 2019 Regional Haze Guidance "key flexibility of the RH program is that a state is not required to evaluate all sources of emissions in each implementation period." However, that guidance does not give IDEM unfettered authority to exempt an entire source sector with major emissions without a reasonable rationale. IDEM's rationale is stated as:

> Indiana surmises the EGU sector was evaluated in great detail for the first implementation period of the RH Rule. Based on industry-wide emission control measures mandated by strict regulations and far less reliance on coal over the past decade or more due to alternative power generation; numerous shutdowns and fuel conversions

> of boilers has occurred to which tens of thousands of tons of NO_x and SO_2 emissions have been reduced in just Indiana alone. Emission trends for both NO_x and SO_2 have shown dramatic decreases in emissions and as a result, IDEM is not requiring four-factor analyses for its EGUs.

On the contrary, Indiana's EGUs were not "…evaluated in great detail for the first implementation period of the RH Rule." Instead, Indiana's EGUs were subject to the Clean Air Interstate Rule (CAIR) and its successor, the Cross-State Air Pollution Rule (CSAPR). Under CAIR/CSAPR, individual EGUs were not evaluated for their contribution to haze in individual Class I areas as the rule was concerned with the health-based standards rather than regional haze. IDEM adopted this approach in its first-round SIP:

> IDEM identified several EGUs subject to BART. However, as provided by the federal rule, IDEM assumed NO_x and SO_2 BART requirements are met by the participation of these sources in the CAIR NO_x and SO_2 trading program.

Finally, we acknowledge and appreciate that large emission reductions have come from the EGU sector in the past decade. However, this is not a valid rationale for failing to consider reasonable progress opportunities for individual sources of haze-causing emissions in this planning period. From the EPA's July 8th, 2021 clarification Memo:

However, a state should generally not reject cost-effective and otherwise reasonable controls merely because there have been emission reductions since the first planning period owing to other ongoing air pollution control programs or merely because visibility is otherwise projected to improve at Class I areas. More broadly, we do not think a state should rely on these two additional factors to summarily assert that the state has already made sufficient progress and, therefore, no sources need to be selected or no new controls are needed regardless of the outcome of four-factor analyses. Doing so would be similar in principle as relying on URP as a safe harbor, which we have consistently stated does not comport with the RHR, as noted in Section 5.4. We do think states can consider these factors in a more tailored manner, for instance in choosing between multiple control options when all are reasonable based on the four statutory factors.

The CAA explicitly omits visibility as a "fifth factor" in reasonable progress analyses because SIPs should evaluate all reasonable measures in order to continue progress toward the national visibility goal.

Nevertheless, IDEM highlights their intent to postpone evaluation of EGU emissions:

> IDEM intends to conduct a review of the EGU sector for the January 31, 2025 progress report, pursuant to 40 CFR 51.308 (g). If necessary, IDEM will evaluate EGUs more in depth for the third implementation period of the RH Rule, to be submitted in 2028. As such, Indiana has focused its visibility impact analyses on non-EGU sources, such as steel mills, cement kilns, plastic manufacturing facilities, and aluminum smelter and electric services operations.

Reasonable progress requires that sources identified for four-factor analysis should be analyzed for reasonable emission control opportunities. As highlighted in section 2.3 of the EPA July 8th, 2021 clarification memo:

> The August 2019 Guidance provides that a source that otherwise would undergo a four-factor analysis (e.g., because it exceeds a threshold of emissions divided by distance or Q/d, visibility, or other source-selection threshold) may forgo a full four-factor analysis if it is already "effectively controlled." While this flexibility has the potential to streamline states' planning processes, states that identify "effectively controlled" sources need to explain why it is reasonable to assume that a four-factor analysis would likely result in the conclusion that no further controls are reasonable.

IDEM has made no such demonstration and we request that IDEM complete four-factor analyses for the EGU sources identified through their source selection methodology in this planning period.

1.2 Planned Retirements and Shutdowns for Coal Fired EGUs at Indiana Power Plants

IDEM cites several potential retirements of coal-fired EGUs:

> Coal fired EGUs are now becoming less financially viable for most companies. New commitments to renewable energy generation are growing each year. Many of these retirements are projected to take place between 5-10 years in the future and are not based on a court order or a permit condition. While the plans for those EGUs with planned retirements of their boilers are a mixture of court ordered requirements and power plants' Integrated Resource Plan (IRP) projections, the overall trend is clear that Indiana is making reasonable progress. Table 8-5 shows the expected unit retirements by 2028 for many of the EGUs in Indiana.

Consistent with RH guidance, IDEM must make any retirements upon which it is basing its SIP decision to forgo a four-factor analysis federally enforceable . From the EPA's July 8th, 2021 clarification Memo:

> Therefore, on-the-way measures, including anticipated shutdowns that are relied on to forgo a four-factor analysis or to shorten the remaining useful life of a source, are necessary to make reasonable progress and must be included in a SIP.

Table 8-5 Indiana EGUs and Expected Unit Retirements by 2028

County	County ID	Plant ID	Name	Expected Unit Retirements by January 1, 2028, and not in the Modeling
Floyd	43	4	Duke Energy Indiana, LLC – Gallagher	Units 2 & 4 per the 2019 IRP for Duke and verified with source for a June2021 retirement.
Gibson	51	13	Duke Energy Indiana, LLC – Gibson	Unit 4 per the 2019 Duke IRP and verified with source by 2026.
Jasper	73	8	NIPSCO - R M Schahfer	Units 14, 15, 17 & 18 per the 2018 IRP and was added to the October 2020 NEEDS update from CAMD, verified with source for 2023 for units 17 and 18. Source stated that units 14 and 15 are accelerating retirement now by the end of 2021.
Jefferson	77	1	Indiana-Kentucky Electric Corporation Clifty Creek	None announced.
Pike	125	2	AES Indiana - Petersburg	AES Indiana Petersburg will retire units 1 and 2 before 2028. A determination was made to retire those units in the modeling in 2021 and 2023, respectively. This decision was made based on AES Indianan determining in their 2019 Integrated Resource Plan (IRP) that retiring those units was the "preferred low-cost option", in addition these units were identified in U.S. EPA's 2020 NEEDS update from CAMD as retiring. Finally, the source confirmed the expected retirements.
Posey	129	10	SIGECO - AB Brown	Units 1 & 2 are set to retire in 2023 per the 2019-2020 IRP and the dates were verified with the source.
Spencer	147	20	AEP Indiana Michigan Power Company dba American Electric Power - Rockport Plant	Rockport Plant, which is owned by AEP Indiana Michigan Power Company, AEP Generating Company, and a group of unaffiliated financial investors is operated by AEP Indiana Michigan Power Company. Under the terms of the Fifth Modification of the AEP System Eastern Fleet NSR Consent Decree signed on July 17, 2019, Rockport Plant must install and operate Enhanced Dry Sorbent Injection Systems by June 1, 2020, on Unit 2 and by December 31, 2020 on Unit 1. SO_2 was further limited to 10,000 tons per year from both units combined starting in 2021 through 2028 and reduced to 5,000 tons per year beginning in 2029, concurrent with the required retirement of Unit 1 by December 31, 2028. The modification requires compliance with a 0.15 lb/MMBtu 30 day rolling average SO_2 emission rate on the combined stack beginning with the 30th SO_2 operating day on the combined stack after January 1, 2021. The modification further required the installation and operation of SCR on Unit 2 by June 1, 2020 (SCR was installed on Unit 1 in 2017). In addition, the modification requires compliance with a 0.09 lb/MMBtu 30 day rolling average NO_x emission rate on the combined stack beginning with the 30th NO_x operating day on the combined stack after January 1, 2021. Both units at Rockport are included in the modeling for 2028.
Sullivan	153	5	Hoosier Energy Rec Inc - Merom	In the October 2020 NEEDS update from CAMD (IPM v5.15 CSAPR update retired by 2024). Retirements are also in the 20-year plan and included in the November 2020 IRP for projected retirement in 2023.
Vermillion	165	1	Duke Energy Indiana LLC - Cayuga	Unit 1 &2 to retire per the 2019 Duke IRP. Verified with the source for a 2028 retirement.
Warrick	173	2	Alcoa Warrick Power Plant - AGC Division	Per 2019-2020 Vectren IRP exit agreement to purchase power in 2023. Unit will still operate in some capacity beyond 2023.
Warrick	173	0	SIGECO - F. B. Culley	Unit 2 projected to retire in 2023 per 2019-2020 Vectren IRP and the date was verified with source.

1.3 LADCO Source Apportionment Modeling

IDEM appears to be relying upon LADCO modeling to argue that the impacts of its EGUs upon visibility are insignificant:

> While the percent contribution from all Indiana EGUs on nitrate and sulfate impacts range up to 5% for the nitrate portion at the Class 1 areas, and up to 12.5% for sulfate, Indiana's total EGU portion of its contribution to the Class I area total light extinction is small with impacts less than 7% at Mammoth Caves and less than 4% at all other Class 1 areas modeled. Total EGU visibility impacts are reduced from the previous 1st implementation period and additional emission reductions from federal mandates and retirement of EGUs will help to diminish visibility impacts even more in the future, re-enforcing the reasonable progress of visibility benefits on all surrounding Class 1 areas.

There are several technical problems with IDEM's argument which we will discuss next. **LADCO's source apportionment modeling looked at the individual impacts from emission sectors within the state.** Due to its proximity to Indiana, Mammoth Cave National Park in Kentucky shows the greatest visibility impact from Indiana. Table 16-2 shows all Indiana EGUs contributions to total light extinction at all Class I areas modeled.

Table 16-2 Indiana EGU Visibility Impacts on Class I Areas

Class I Area	Total Class I Light Extinction (Mm^{-1})	IN EGU Nitrate Impact (Mm^{-1})	IN EGU Sulfate Impact (Mm^{-1})	Total IN EGU Impact (Mm^{-1})	Total IN EGU Impact (%)
Mammoth Cave	74.18	0.963	4.128	5.091	6.9%
Sipsey	60.97	0.276	1.936	2.212	3.6%
Great Smoky Mountains/ Joyce Kilmer-Slickrock	51.02	210.187	1.502	1.689	3.3%
Dolly Sods/Otter Creek	54.03	0.064	1.543	1.607	3.0%
Cohutta	51.8	0.099	1.387	1.486	2.9%
Shenandoah	50.63	0.071	1.338	1.409	2.8%
Mingo	69.67	0.414	1.189	1.602	2.3%
James River	53.42	0.053	1.103	1.156	2.2%
Linville Gorge	45.73	0.018	0.919	0.937	2.1%
Hercules Glades	59.43	0.088	0.724	0.813	1.4%
Shining Rock	41.42	0.014	0.530	0.545	1.3%
Upper Buffalo	54.35	0.068	0.647	0.715	1.3%
Seney	57.36	0.153	0.460	0.613	1.1%
Lye Brook	42.86	0.042	0.353	0.395	0.9%
Caney Creek	54.4	0.05	0.377	0.427	0.8%
Brigantine	69.4	0.037	0.445	0.482	0.7%
Swanquarter	48.52	0.031	0.325	0.356	0.7%
Isle Royale	48.62	0.049	0.214	0.263	0.5%
Voyageurs	41.03	0.014	0.054	0.068	0.2%
Boundary Waters	40.51	0.022	0.048	0.07	0.2%

IDEM's Table 16-2 contains values expressed in Light Extinction and percentage. The explanations below are from the IMPROVE website (http://vista.cira.colostate.edu/Improve/haze-metrics-converter/) and introduces the deciview.

Light Extinction (b_{ext}): The attenuation of light due to scattering and absorption as it passes through a medium. **Units**: inverse distance, e.g. inverse mega meters (Mm^{-1}). **Benefit**: Light extinction can be directly related to gaseous and aerosol concentrations. **Drawback**: Light extinction is non-linearly related to a person's perception of changes in haze. For example, a 10 Mm^{-1} increase in b_{ext} will have a larger perceived impact on a scene at b_{ext} = 20 Mm^{-1} than at b_{ext} = 100 Mm^{-1}

Deciview (DV): A metric of haze proportional to the logarithm of the atmospheric extinction (b_{ext}). **Units**: Unitless. **Benefit**: Under many circumstances a change in one deciview will be perceived to be the same on clear and hazy days. **Drawback**: Deciview is not easily related to gaseous and aerosol concentrations.

Additionally, while the deciview and percent contributions are relative to the degree of visibility impairment to which these parameters are applied, light extinction is an absolute value that is independent of impairment.

The IDEM analysis is unsubstantiated for the following reasons:

- The LADCO analysis evaluates percent contribution to an already impaired background which is counter to the overarching goal of the RH program. The goal of the regional haze program is to achieve natural visibility conditions by 2064. Natural visibility at Mammoth Cave NP on the 20% most-impaired days is 9.8 dv (26.64 Mm^{-1}). Contributions from Indiana's EGUs (5.091 Mm^{-1} = 1.75 dv) represent 19% of natural conditions at Mammoth Cave.
- A percent contribution approach provides less protection for the more-impacted Class I areas. When modeled impairment from a single source is divided by the total impairment at a given Class I area, the percentage (a.k.a. "contribution") will be smaller at a more impaired area than an area with less overall impairment. For example, from IDEM's Table 16-2, Indiana EGUs contribute 5.091 Mm^{-1} to light extinction at Mammoth Cave, and IDEM calculates that this represents 6.9% of the Total Light Extinction (74.18 Mm^{-1}) at the park. That same amount of impairment, if it were to occur at Shining Rock, would account for 12% of the Total Light Extinction (41.42 Mm^{-1}) there.
- Even when a percent contribution approach is used, the significance threshold should be relatively low (and applied to a fixed value). For example, the updated CSAPR applies a 1% contribution relative to the ozone National Ambient Air Quality Standard to determine if a <u>state</u> contributes significantly to ozone concentrations in a downwind state. Indiana's EGUs contribute to more than 1% of projected 2028 light extinction in 13 of the Class I areas in Table 16-2. One percent of the visibility goal at Mammoth Cave is 0.27 Mm^{-1} and Indiana sources would exceed that threshold by a factor of 19.

Because IDEM did not provide predicted visibility impacts from all the facilities it identified for potential 4FA, we relied upon results provided by Visibility Improvement State and Tribal Association of the Southeast (VISTAS). The table below is excerpted from the

Emissions/Distance Extinction Weighted Residence Time analysis conducted by VISTAS[3] as described below:

- Facility-level SO_2 and NO_x area of influence (AoI) analyses were performed for each Class I area to determine the relative visibility impact from each facility.
- The next step was to develop sulfate and nitrate extinction-weighted residence time (EWRT) plots. Each back trajectory was weighted by ammonium sulfate and ammonium nitrate extinction for that day and used to produce separate sulfate and nitrate EWRT plots.
- Extinction weighted residence times were then combined with 12-km gridded SO_2 and NO_x emissions from the 2028 emissions inventory.
- The grid cell total point SO_2 or NO_x emissions (Q, in tons per year) were divided by the distance (d, in kilometers) to the trajectory origin; for a final value (Q/d). This value was then multiplied by the sulfate or nitrate EWRT grid values (i.e., EWRT*(Q/d)) on a grid cell by grid cell basis.

[3] TASK 5 - AREA OF INFLUENCE ANALYSIS | Metro 4/SESARM (metro4-sesarm.org)

FACILITY NAME	d km	EWRT NO3	NO_x 2028	EWRT SO4	SO_2 2028	Combined SO4 NO3 2028 EWRT Q/d
INDIANA MICHIGAN POWER DBA AEP ROCKPORT	118	0.0078	8,807	0.0146	30,536	4.3553
Gibson	198	0.0043	12,280	0.0100	23,117	1.4333
INDIANAPOLIS POWER & LIGHT PETERSBURG	183	0.0037	10,665	0.0070	18,142	0.9050
ALCOA WARRICK POWER PLT AGC DIV OF AL	136	0.0047	11,159	0.0120	5,071	0.8353
Sigeco AB Brown South Indiana Gas & Electric	163	0.0063	1,579	0.0130	7,645	0.6698
SABIC INNOVATIVE PLASTICS MT. VERNON LLC	179	0.0040	1,752	0.0124	4,703	0.3633
ALCOA INC. - WARRICK OPERATIONS	136	0.0047	333	0.0120	3,898	0.3558
ESSROC CEMENT CORP	147	0.0025	2,365	0.0070	4,681	0.2651
INDIANA KENTUCKY ELECTRIC (Clifty Creek)	189	0.0014	6,188	0.0035	9,038	0.2118
HOOSIER ENERGY REC INC MEROM GENERA	246	0.0035	3,676	0.0063	5,437	0.1908
SIGECO - F.B. CULLEY GENERATING STATION	135	0.0047	948	0.0120	1,770	0.1902
LEHIGH CEMENT COMPANY LLC	180	0.0027	3,753	0.0061	2,881	0.1533
Duke Energy Indiana Inc Vermillion (Cayuga)	329	0.0017	5,755	0.0054	4,019	0.0951
Edwardsport	209	0.0025	1,605	0.0071	1,959	0.0853
ArcelorMittal Burns Harbor Inc.	507	0.0004	8,011	0.0028	12,004	0.0721
Whitewater Valley	316	0.0010	343	0.0036	6,130	0.0714
Citizens Thermal	292	0.0009	1,495	0.0038	4,531	0.0642
Countrymark Refining and Logistics LLC	180	0.0040	125	0.0124	551	0.0406
INDIANA UNIVERSITY	229	0.0041	231	0.0074	1,021	0.0373
ELI LILLY & COMPANY CLINTON LABS	308	0.0016	592	0.0041	1,757	0.0266
Indiana Harbor East	516	0.0008	4,387	0.0026	2,678	0.0198
NIPSCO R M SCHAHFER GENERATING STATI	460	0.0004	4,012	0.0017	2,567	0.0132
ESSROC Cement Corp	401	0.0007	2,054	0.0019	1,927	0.0130
Waupaca Foundry Inc	110	0.0048	92	0.0169	53	0.0122
BALL STATE UNIVERSITY	347	0.0008	179	0.0026	1,447	0.0111
INDIANA HARBOR COKE COMPANY	515	0.0008	859	0.0026	1,898	0.0107
TATE & LYLE, LAFAYETTE SOUTH (33)	365	0.0006	500	0.0016	2,221	0.0107
PURDUE UNIVERSITY -WADE UTILITY PLANT	371	0.0005	453	0.0018	2,070	0.0105
CITIZENS GAS - WORTHINGTON STATION	231	0.0034	-	0.0075	307	0.0100
MGPI of Indiana	246	0.0009	380	0.0035	555	0.0093
TATE & LYLE SAGAMORE OPERATION	373	0.0008	581	0.0027	1,028	0.0088
ISPAT INLAND STEEL COKENERGY LLC	517	0.0004	-	0.0009	4,892	0.0086

selected by IN but no 4FA

selected by IN with 4FA

IDEM selected Alcoa Warrick Operations for 4FA because it had a Q/d = 80.9; the VISTAS EWRT*Q/d value for this facility's impact at Mammoth Cave = 0.3558. VISTAS estimated that the Rockport, Gibson, Peterson, A.B. Brown, and Alcoa Warrick power plants would have greater impacts at Mammoth Cave than the Alcoa Warrick Operations facility.

To address consultation requests from Arkansas, Missouri, and VISTAS (which identified three Indiana sources as having possible visibility impacts on Class I areas within their state or region)

LADCO tagged individual sources as well as emission source categories to determine the visibility impacts from each. In this individual facility analysis, modeled visibility impacts on light extinction from Duke-Gibson and Rockport were evaluated at several Class I areas in Arkansas, Missouri, and VISTAS. AES Petersburg was not modeled in the source apportionment run; however, AES-Petersburg NO_x and SO_2 emissions were evaluated with the Rockport visibility impact to conservatively estimate its visibility impacts at selected Class I areas. We are addressing these three facilities in our separate discussions of them. In short, Gibson would contribute 0.37 dv, Rockport 0.45 dv, and Petersburg 0.38 dv impairment at Mammoth Cave versus natural conditions. We note that the visibility thresholds used in the first round of RH planning are not appropriate to use in this round of haze planning. This point is stressed in the EPA July 8th, 2021 clarification Memo:

> To this end, EPA is reiterating that visibility thresholds used for BART and other analyses in the first planning period (*e.g.*, 0.5 deciviews) are, in most cases, not appropriate thresholds for selecting sources or evaluating the impact of controls for reasonable progress in the second planning period. This is the case for several reasons. [Please refer to the rationale documented in the memorandum.]

1.4 Results & Conclusions

- IDEM initially selected a reasonable group of facilities for four-factor analyses (4FA) based upon Q/d > 5.
- IDEM's reasons for exempting all EGUs from 4FA are based on erroneous assertions of pervious RH planning efforts, internally inconsistent, and technically unsubstantiated.
- LADCO modeling results show that Indiana EGUs as a whole, and Gibson, Rockport, and Petersburg individually, contribute significantly to visibility impairment at multiple Class I areas.
- IDEM should make all EGU retirements on which it is depending federally enforceable.
- IDEM should require/conduct 4FAs for all EGUs contained in its original list that do not have federally enforceable retirement dates.

2 EGU Feedback

2.1 General EGU Feedback

We highlight several sources equipped with SCR that appear to have very low control efficiencies. We do not have the necessary information to determine the reason for this, but as a general comment note that existing SCR systems should be operated year-round to protect visibility in NPS Class I areas. If an SCR is only operated for a portion of the year, it is likely during the ozone season, which occurs during the warm, summer season in the eastern U.S. However, ammonium nitrate is playing an increasingly important role in visibility impairment at Class I areas throughout the region. Nitrate is particularly important at Mammoth Cave NP, where in 2018, nitrate comprised 45% of the extinction on the 20% most impaired days. The seasonal distribution demonstrates that days with high nitrate extinction generally occur in the cooler months of the year (outside of the ozone season). Therefore, it is inappropriate to conclude that an existing SCR is protective of visibility if it is only operated for a portion of the year.

2.2 AEP Rockport

2.2.1 Summary of NPS Recommendations and Requests for AEP Rockport

According to the Indiana source selection process and initial NPS evaluations, the Indiana Michigan Power Company, American Electronic Power (AEP) - Rockport Plant (Rockport) has the highest visibility impact (Q/d) of all Indiana sources for NPS Class I areas. Mammoth Cave National Park is most affected by this source. Rockport is subject to a Consent Agreement that will substantially reduce emissions by the end of this planning period. In addition, by the end of 2028:

- Unit 1 – Required by consent agreement to retire
- Unit 2 – AEP announced plans to retire. We note that this must be federally enforceable for inclusion in the SIP

If Unit 2 retirement is made federally enforceable and included in the SIP, haze causing emissions from this facility will no longer be a concern for the NPS. Otherwise, we recommend that Indiana undertake/require a four-factor analysis of potential NO_x and SO_2 emission reduction opportunities from AEP Rockport Unit 2.

2.2.2 AEP Rockport Background

Rockport is in Spencer County, in the southern portion of Indiana. Rockport has a maximum generating capacity of 2,774 gross megawatts with two identical Babcock & Wilcox pulverized coal opposed dry bottom wall fired steam generators identified as Units 1 and 2 with Boilers MB1 and MB2. These units (1,300 MW each net) were launched into service in December 1984 and December 1988. To minimize cost, AEP announced in February 2018 that Rockport would rely solely on coal from the Powder River Basin in Wyoming.

According to EPA's Air Markets Program (AMP) database, in 2020, the Rockport facility ranked #35 (out of 1167 facilities) for SO_2 emissions at 6,816 tons and #118 for NO_x emissions at 1,764 tons.

In July 2019, AEP announced that Rockport's Unit 1 will retire by the end of 2028. This was made in an agreement modification between AEP, the USEPA, several northeastern states, the Sierra Club, and other parties.[4] The agreement allows AEP to achieve emission reduction goals while also shutting down Unit 1 without adding costly pollution control systems.

2.2.3 AEP Rockport SO_2 Controls

Rockport is required under the Fifth Modification of the AEP Eastern System NSR Consent Decree, entered on July 17, 2019, to install and continuously operate dry sorbent injection systems on Units 1 and 2 by 2015, and enhanced dry sorbent injection systems on Unit 2 by June 1, 2020 and December 31, 2020 on Unit 1. Units 1 and 2 are required to meet a 30-day rolling average of 0.15 lb/MMBtu SO_2. For the first three months of 2021, Rockport has averaged 0.11 – 0.14 lb/mmBtu.

SO_2 emissions are also required to be capped plant-wide in the Fifth Modification at 10,000 tons on an annual basis in between 2021 and 2028. (2020 SO_2 emissions were 6,816 tons.) Beginning in 2029 that plant wide total cap is lowered to 5,000 tons per year, concurrently with the retirement of Unit 1 (MB1) by no later than December 31, 2028.

2.2.4 AEP Rockport NO_x Controls

In addition to the existing low-NO_x burner/Overfire Air Systems, Rockport was required to install and continuously operate SCR on Unit 1 (MB1) by December 31, 2017 and Unit 2 (MB2) by June 1, 2020; the SCRs shall maintain a 30-day rolling average NO_x emissions on the common stack of 0.09 lb/MMBtu beginning with the 30th stack operating day in 2021. Rockport appears to be meeting this limit.

Both units at Rockport are included in the ERTAC modeling for 2028.

In April 2021 AEP announced that Rockport's Unit 2 will also be retired by the end of 2028.

2.2.5 NPS Results, Recommendations & Conclusions for the AEP Rockport Facility

- Rockport is subject to a Consent Agreement that will substantially reduce emissions by the end of this planning period.

[4] Under the proposed Fifth Joint Modification to Consent Decree, the deadline for AEP to retrofit, refuel, or re- power Rockport Unit 1 is extended until December 31, 2028 and the requirement to retrofit, refuel, or re-power Rockport Unit 2 is removed. In exchange, AEP agrees to do the following: (1) Install enhanced dry sorbent injection technology to reduce SO_2 emissions on Rockport Unit 1 by December 31, 2020 and Rockport Unit 2 by June 1, 2020; (2) comply with a 30-day rolling average emission rate of 0.15 pounds of SO_2 per million British thermal units of heat input at the Rockport Units for years 2021 and beyond; (3) reduce the AEP Eastern System-wide annual tonnage limitations for SO_2 for years 2021 and beyond; (4) reduce the Rockport Plant- wide annual tonnage limitations for SO_2 for years 2021 and beyond; (5) install selective catalytic reduction NO_X control technology on Rockport Unit 2 by June 1, 2020; (6) comply with a 30- day rolling average emission rate of 0.09 pounds of NO_X per million British thermal units of heat input at the Rockport Units for years 2021 and beyond; (7) reduce the AEP Eastern System-wide annual tonnage limitations for NO_X for years 2018 and beyond; (8) provide the State Co-Plaintiffs with an additional $4 million in mitigation funding; (9) provide the Citizen Co- Plaintiffs with an additional $3.5 million in mitigation funding; and (10) retire Rockport Unit 1 by December 31, 2028.

- If AEP follows through on its announced closure of Unit 2 by the end of 2028, Rockport will no longer be a source of haze causing emissions. Shutdown of this unit should be made federally enforceable.

2.3 Gibson Generating Station

2.3.1 Summary of NPS Recommendations and Requests for the Gibson Generating Station

Projected 2028 emissions from Duke Energy, Inc - Gibson Generating Station (Gibson) affect at least 12 Class I areas with the most significant impacts at Mammoth Cave National Park. Four-factor analysis of NO_x and SO_2 emission reduction opportunities from this facility is warranted and should be undertaken/required by Indiana. We have the following recommendations for the Gibson Generating Station:

- The SO_2 scrubbers on Gibson Units #4 and #5 are not achieving the same levels of control as those on Units #1, #2, and #3 and we request that they be evaluated. Please provide source efficiency calculations for all five units.
- The 81% NO_x control efficiency cited for the SCR indicates the need for an analysis of why these controls are not achieving the expected efficiency level of 90%.
- Unit 4 is the only unit expected to retire before 2028; this retirement was included in 2028 modeling projections and should be made federally enforceable.

2.3.2 Background on Gibson Generating Station

Gibson is located at SR 64 W & CR 975, Princeton in Gibson County, in the southwestern portion of Indiana. It is a stationary electric utility generating station with a maximum generating capacity of 3,646 megawatts among five identical dry bottom, pulverized coal-fired boilers with wet limestone scrubbers for SO_2 and Low-NO_x Burner Technology w/ Overfire Air and Selective Catalytic Reduction. (All controls were installed prior to the first planning period.) Data below are from EPA's Air Markets Program (AMP) database for 2018–2020. Nationally, in 2020, the Gibson facility ranked #10 (out of 1,167 U.S. facilities) for SO_2 emissions at 13,393 tons and #5 for NO_x emission at 9,545 tons. (Additional information on these boilers is contained in the attached Excel workbook.)

Gibson 2018–2020 Averages				
Unit	Avg. SO_2 Rate (lb/MMBtu)	SO_2 (tons)	Avg. NO_x Rate (lb/MMBtu)	NO_x (tons)
1	0.101	1,305	0.146	1,879
2	0.099	1,593	0.130	2,079
3	0.091	1,266	0.131	1,828
4	0.222	3,005	0.129	1,745
5	0.441	5,922	0.132	1,776

IDEM states that (based on source calculations) SO_2 control efficiencies are above 93% and NO_X control efficiencies are above 81%. However, inspection of the AMP data indicates that the SO_2 scrubbers on Gibson Units #4 & #5 are not achieving the same levels of control as those on Units #1 to #3 and we would like to see the source efficiency calculations for all five units. The 81% control efficiency cited for SCR at each unit indicates the need for an analysis of why these controls are not achieving the expected 90% level.

Unit 4 is the only unit expected to retire before 2028. Again, this retirement should be federally enforceable**.** NO_x emissions are projected to be reduced from 2016 to 2028 by 35% or almost 4,600 tons while SO_2 emissions are estimated to be reduced by 13% or nearly 2,000 tons. The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028.[5] The overall emissions from each facility will be reduced because of the unit shutdowns but individual unit emissions may be slightly higher than their 2016 emissions due to power demand and limited coal-fired power generation capacity with retirements of other boilers. For Gibson's future emissions projections, Units 1, 2, 3, and 5 will be utilized more to meet the electricity demands without Unit 4. Gibson's unit utilization rates, both for base-year 2016 and future year 2028, are shown in IDEM's Table 4-1.

Table 4-1
Gibson Generating Station's 2016 and Projected 2028 Utilization Rates for Units 1-5

ORIS-ID	Unit ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028-ERTAC	Percentage Change in Utilization
6113	1	Gibson Generating Station	0.4701	0.5175	10.09%
6113	2	Gibson Generating Station	0.6340	0.7097	11.93%
6113	3	Gibson Generating Station	0.6157	0.6688	8.63%
6113	4	Gibson Generating Station	0.5483	Retired	-100.00%
6113	5	Gibson Generating Station	0.5726	0.6351	10.91%

Utilization rates will impact the 2028 emissions from each of the existing units; yet the overall NO_x and SO_2 emissions from the facility will decrease because of the retirement of Unit 4.

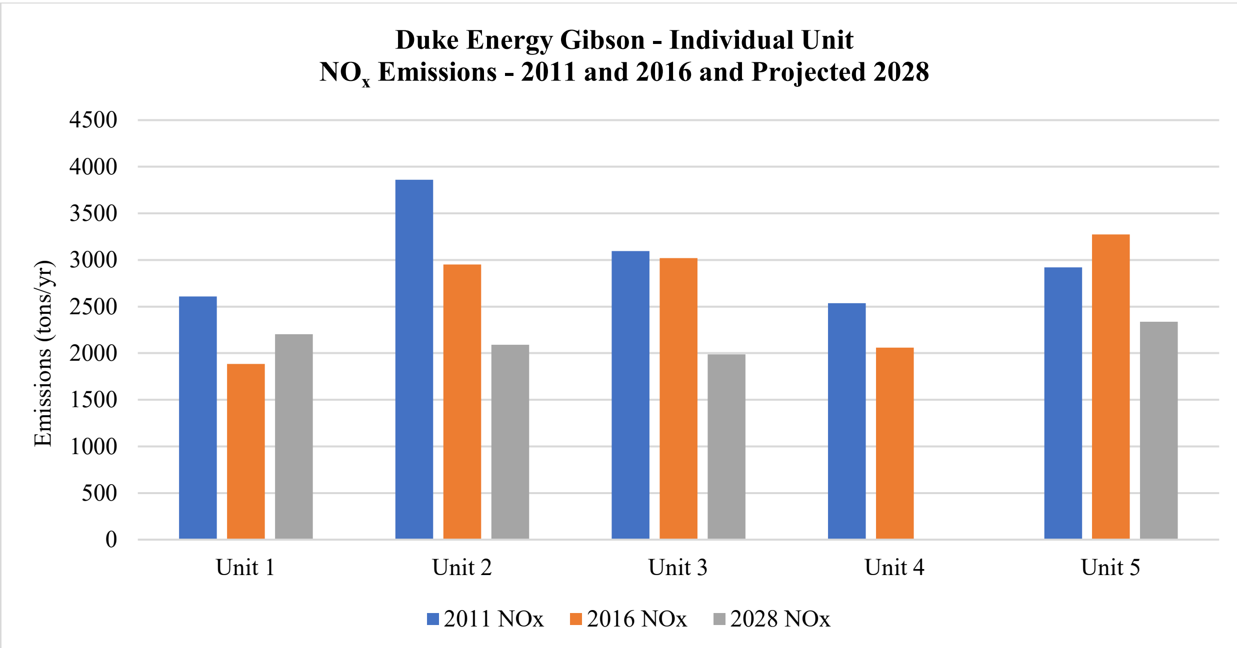
[5] In the ERTAC emissions tool, the utilization fraction as calculated from the 2016 base-year data will be used to determine dispatch order of electricity to the power grid for units that were operating in the base year. Utilization fraction is the ratio of the total average heat input to the maximum heat input for a unit. It is calculated using the following formula: total average annual heat input/(maximum hourly rated capacity * 8,760 hours/year). For future year emissions projections, the ERTAC tool will dispatch generation to the coal unit fuel type according to the hourly hierarchy order up to the maximum ERTAC annual utilization fraction for that fuel/unit type bin. In the case of coal, no unit will run above 90% utilization rate in the emission model. In the case of Gibson and the retirement of Unit 4, before the demand for additional power results in a need to make up electric generation within ERTAC's emissions model, the demand is met by other coal units at the facility based on the growth rates for coal. Gibson's future year utilization rates among Units 1, 2, 3 and 5 vary from the 2016 base-year to the 2028 projection year because of the retirement of Unit 4 to meet anticipated electricity demands based on less coal-fired power generation capacity.

Graph 4-2 shows the unit-by-unit comparison of NO_x emissions at the Duke Gibson power plant. According to IDEM:

Note the slight increase in emissions at each of the four remaining units, this demonstrates the increase in utilization based on Unit 4's retirement to meet anticipated power demand. As with SO_2, overall NO_x emissions at Gibson are projected to decrease by 35% from 2016 to 2028.

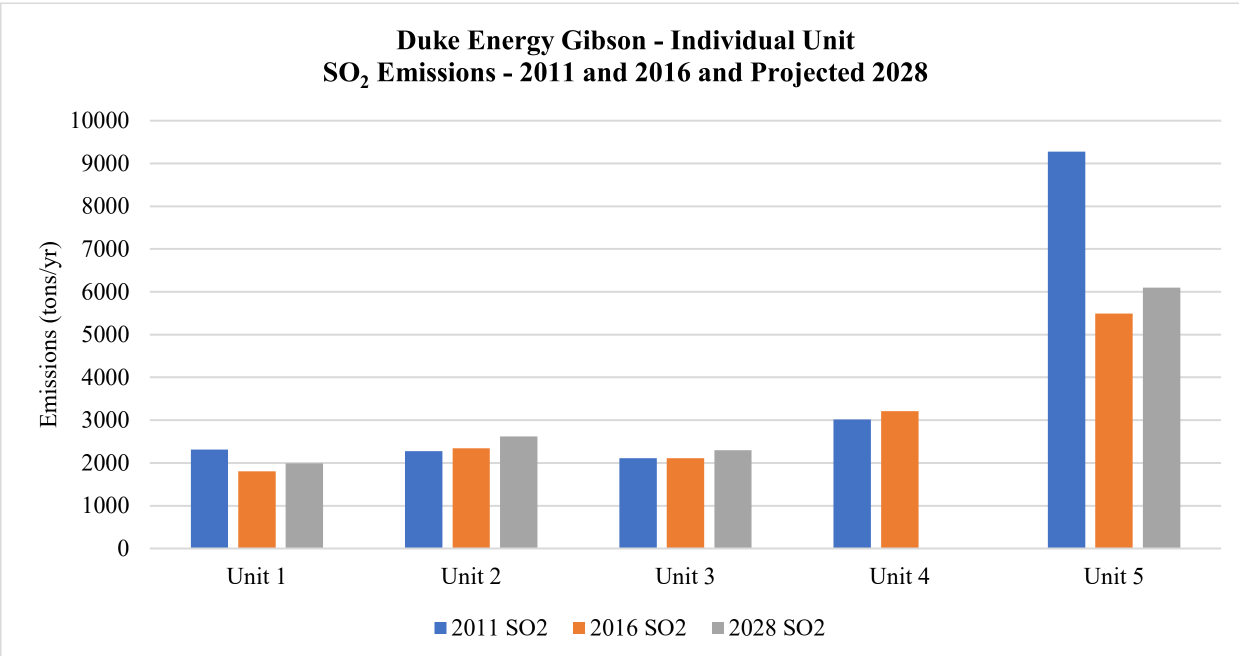
However, the graph appears to show that only Unit #1 shows a NO_x increase in 2028. Why would NO_x emissions decrease at any unit if utilization increases?

Graph 4-2
Unit Comparison of Duke Energy Gibson's NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 4-3 shows the unit-by-unit comparison of SO_2 emissions at the Duke Gibson power plant. Note the slight increase in emissions at each of the four remaining units, this demonstrates the increase in utilization based on Unit 4's retirement. Again, overall SO_2 emissions at Gibson are projected to decrease by 13% from 2016 to 2028.

Graph 4-3
Unit Comparison of Duke Energy Gibson's SO_2 Emissions - Actual 2011 and 2016, Projected 2028



To address consultation requests from Arkansas, Missouri, and VISTAS, which identified three Indiana sources as having possible visibility impacts on Class I areas within their state or region, LADCO tagged individual sources as well as emission source categories to determine the visibility impacts from each tagged source. Duke-Gibson was modeled individually and its modeled visibility impacts on light extinction were evaluated at several Class I areas in Arkansas, Missouri, and VISTAS. Table 16-4 shows the nitrate, sulfate, and overall visibility impacts on light extinction.

LADCO's source apportionment modeling looked at the individual impacts from emission sectors within the state. Due to its proximity to Indiana, Mammoth Cave National Park in Kentucky shows the greatest visibility impact from Gibson. IDEM appears to be relying upon LADCO modeling to argue that the impacts of its EGUs upon visibility are insignificant:

Gibson's sulfate impacts made up less than 3% of the total sulfate impact at each Class I area, while the nitrate impact from Gibson was less than 2% of the total nitrate impact on light extinction at each Class I area. When Gibson's overall visibility impacts were compared to each Class I area's total light extinction, Gibson's impact was less than 1.5% as shown below in Table 16-4.

Table 16-4 Duke Gibson - Nitrate and Sulfate Visibility Impacts for Selected Class I Areas

Class I Area	Gibson Nitrate Impact (Mm^{-1})	Total Class Nitrate Impact (Mm^{-1})	Gibson Nitrate Impact (%)	Gibson Sulfate Impact (Mm^{-1})	Total Class I Sulfate Impact (Mm^{-1})	Gibson Sulfate Impact (%)	Total Class I Light Extinction (Mm^{-1})	Gibson Total Impact (%)
MACA1	0.22	18.75	1.2%	0.79	33.02	2.4%	74.18	1.4%
GRSM1/ JOYC1	0.002	5.79	0.0%	0.26	22.80	0.2%	51.02	0.6%
SIPS1	0.04	11.49	0.4%	0.27	25.92	1.0%	60.97	0.5%
MING1	0.12	19.36	0.6%	0.25	24.08	1.0%	69.67	0.5%
COHU1	0.02	5.25	0.4%	0.17	24.08	0.7%	51.8	0.4%
DOSO1/ OTCR1	0.01	6.79	0.1%	0.18	27.64	0.6%	54.03	0.3%
HEGL1	0.02	14.87	0.1%	0.13	20.37	0.6%	59.43	0.3%
SHRO1	0.00	2.88	0.1%	0.08	18.19	0.4%	41.42	0.2%
UPBU1	0.01	11.20	0.1%	0.11	19.93	0.5%	54.35	0.2%
CACR1	0.01	8.31	0.2%	0.08	21.89	0.4%	54.4	0.2%

IDEM's percent contribution argument is misleading because impacts were compared to a dirty background and discriminate against more-impacted Class I areas like Mammoth Cave NP. However, the light extinction results are useful because they can be compared to light extinction for the 20% most-impaired days under natural conditions for example by using the IMPROVE haze metrics converter (http://vista.cira.colostate.edu/Improve/haze-metrics-converter/). For Mammoth Cave NP, the natural condition on most impaired days is 9.8 dv (26.64 Mm^{-1}).

Gibson contributes 1.01 Mm^{-1} which translates to 0.37 dv at Mammoth Cave NP when compared to the natural condition on 20% most-impaired days; this is a very significant contribution to impairment.[6]

2.3.3 Gibson Generating Station Results & Conclusions

- Gibson's projected 2028 impact at Mammoth Cave National Park is significant and a four-factor analysis is warranted.
- The SO_2 scrubbers on Gibson Units #4 & #5 are not achieving the same levels of control as those on Units #1 - #3 and should be evaluated; we would like to see the source efficiency calculations for all five units.
- The 81% control efficiency cited for the SCR at each of the units indicates the need for an analysis of why these controls are not achieving the expected 90% level.
- Unit 4 is the only unit expected to retire before 2028; this retirement was included in 2028 modeling projections and should be made federally enforceable.

[6] EPA 7/8/2021 Guidance: In many cases, the difference in the form of the modeled emissions and the visibility impact metrics alone could account for BART Guideline modeling impacts that are an order of magnitude, or more, higher than typical photochemical modeling impacts averaged over the 20 percent most impaired days for a single year.

2.4 Petersburg Generating Station

2.4.1 Summary of NPS Recommendations and Requests for the Petersburg Generating

AES Indiana (AES) Petersburg Generating Station's projected 2028 impact at Mammoth Cave National Park is significant. We request that Indiana:

- Make the retirement of Units #1 and #2 federally enforceable.
- Undertake/require a four-factor analysis of potential NO_x and SO_2 emission reduction opportunities for Units #3 and #4. (This is also needed for Units #1 and #2 unless their shutdown is made federally enforceable.)
- Provide source control efficiency calculations for all four units.

Our initial review finds that Petersburg Unit #4 lacks effective NO_x controls. Further, we find that addition of SCR to Petersburg Unit #4 is cost-effective and could reduce NO_x emissions by over 3,000 tons/yr at less than $4,500/ton.

2.4.2 Petersburg Generating Station Background

The Petersburg Generating Station (Petersburg) is in Pike County, in the southwestern portion of Indiana. It is a stationary electric utility generating station with a maximum generating capacity of 1,824 megawatts (2,146 MW nameplate capacity) among four coal/No. 2 fuel oil fired boilers:

- **Unit 1**: 281.6 MW in service 1967;
  - SO_2 controlled by Wet Limestone (Began May 01, 1996)
  - NO_x controlled by Low NO_x Burner Technology w/ Closed-coupled/Separated OFA (Began Nov 30, 1995)
- **Unit 2**: 523.3 MW in service 1969;
  - SO_2 controlled by Wet Limestone (Began May 01, 1996)
  - NO_x controlled by Low NO_x Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction (Began May 19, 2004)
- **Unit 3**: 670.9 MW in service 1977;
  - SO_2 controlled by Wet Limestone/Sodium based scrubbing
  - NO_x controlled by Selective Catalytic Reduction (Began May 08, 2004) Low NO_x Burner Technology w/ Closed-coupled OFA
- **Unit 4**: 670.9 MW in service 1986;
  - SO_2 controlled by Wet Limestone/Sodium based scrubbing
  - NO_x controlled by Low NO_x Burner Technology w/ Closed-coupled/Separated OFA (Began Dec 11, 2001)

All SO_2 and NO_x controls were operational prior to the first planning period.

IDEM says that the Flue Gas Desulfurization scrubbers have SO_2 control efficiencies above 94% and NO_x with control efficiencies on Units 3 and 4 are above 70% based on source estimates. AES should provide the control efficiency estimates with supporting calculations/documentation for inclusion in the SIP.

According to EPA's Air Markets Program (AMP) database, in 2020, the Petersburg facility ranked #49 (out of 1,167 U.S. facilities) for SO_2 emissions at 4,348 tons and #44 for NO_x emissions at 4,631 tons.

A consent decree[7] lodged August 31, 2020 in the UNITED STATES DISTRICT COURT FOR THE SOUTHERN DISTRICT OF INDIANA requires Indianapolis Power and Light (IPL) to reduce its plant's emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter (PM) and sulfuric acid mist (H_2SO_4). IPL (now AES Indiana) will install a Selective Non-Catalytic Reduction System (SNCR) on one of the plant's coal-fired units, upgrade its sulfuric acid mitigation system, and continually operate all of its pollution control equipment to meet levels that will achieve reductions in NO_x, SO_2, PM and H_2SO_4 emissions.[8] The agreement recognizes that IPL may permanently retire two of its Petersburg units earlier than it had planned. Retirement of those units would result in emission reductions significantly greater than any reductions achieved by installing and operating the SNCR. Thus, IPL may forego installing that control device if it in fact retires the two units prior to July 1, 2023, the deadline under the consent decree by which IPL must install the SNCR. Further, IPL will pay a total civil penalty of $1.525 million, of which $925,000 will go to the United States and $600,000 to the State of Indiana.

2.4.3 Petersburg Generating Station Review and Feedback

IDEM reports that Petersburg will retire Units 1 and 2 before 2028. AES Indiana made this decision based on the determination, in their 2019 IRP, that retiring those units was the "preferred low-cost option." In addition, both units were identified as retiring in EPA's 2020 National Electric Energy Demand System (NEEDS) update from CAMD. The source also confirmed the expected retirements of Units 1 and 2 with IDEM officials in November 2020.

While it is highly likely that these retirements will occur, in view of the Consent Decree and IPL statements, the retirements need to be made federally enforceable for inclusion in the regional haze SIP.

Petersburg's 2028 EGU NO_x emissions are projected to be reduced by 50.5% or 5,500 tons from 2016 emission levels and SO_2 emissions are estimated to be reduced by 26.6% or 3,400 tons from 2016 to 2028; primarily as a result of retirements at Units 1 & 2, shown in Graph 6-1.

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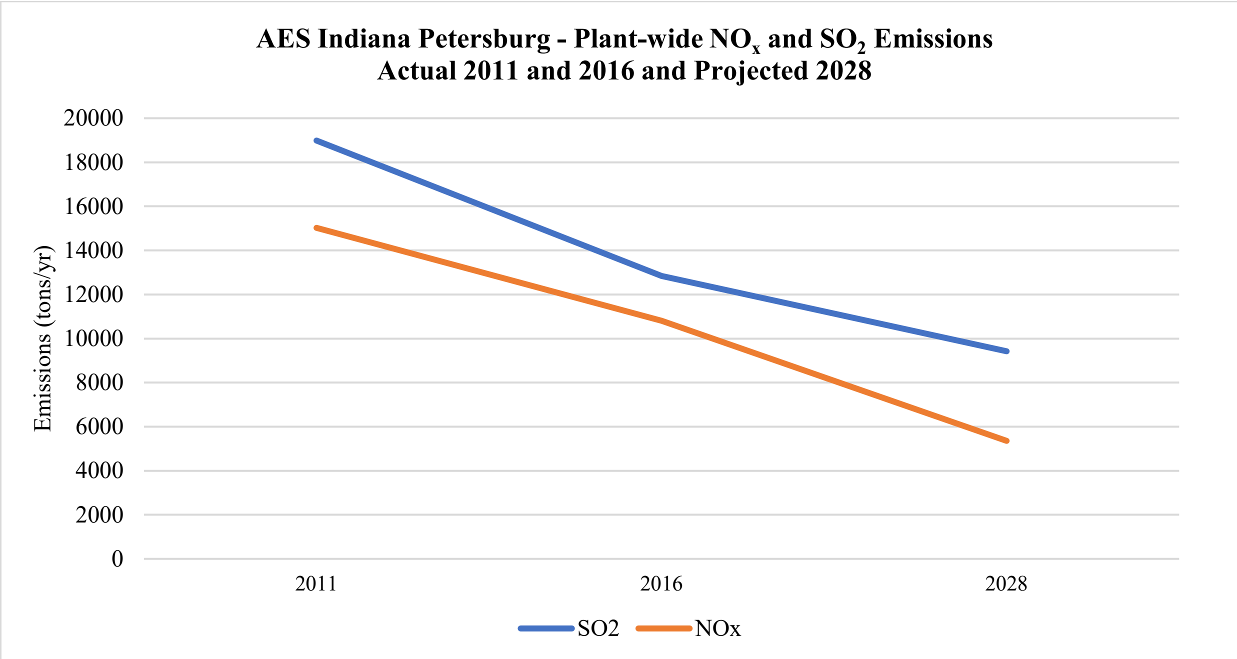
[7] Indianapolis Power & Light Company Consent Decree | Enforcement | US EPA

[8] UNITED STATES AGREES WITH POWER AND LIGHT COMPANY TO RESOLVE ALLEGED VIOLATIONS OF THE CLEAN AIR ACT | U.S. EPA News Releases | US EPA

Graph 6-1 AES Indiana Petersburg's NO_x and SO_2 Emissions Trends



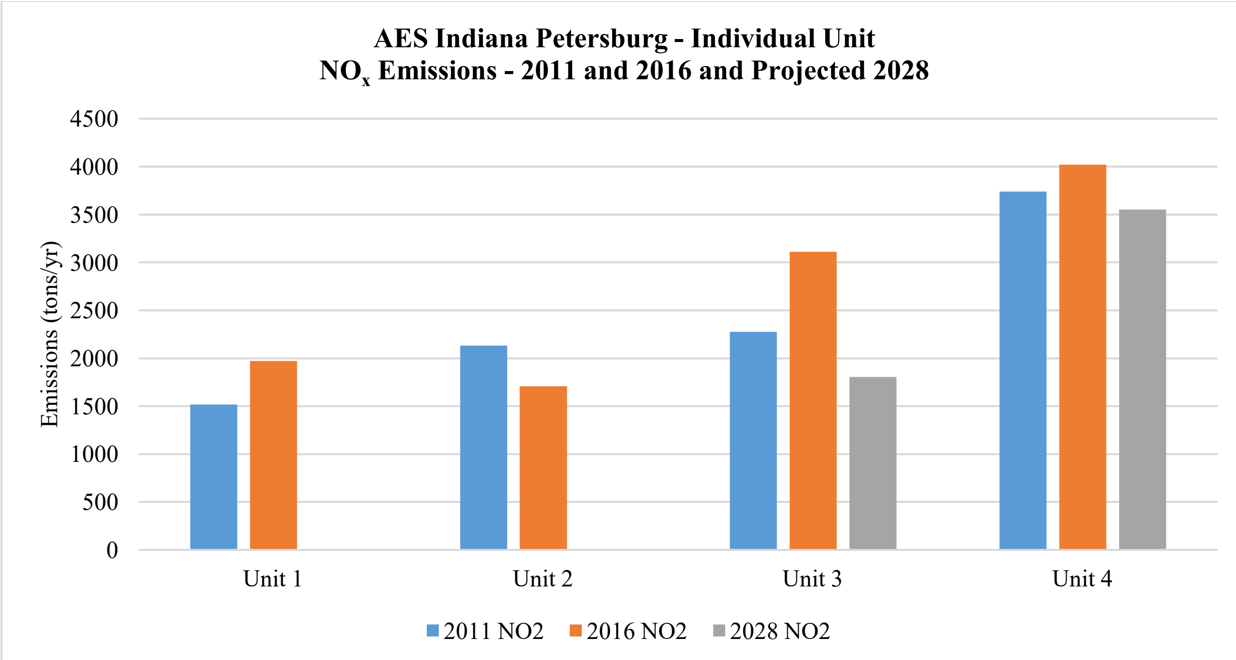
The emissions projections for 2028 were determined by ERTAC which allocates power generation from units that will be retired before 2028 to other existing units. The overall emissions from AES Indiana - Petersburg will be lower as a result of the unit shutdowns but Units 3 and 4 emissions may be slightly higher than 2016 due to power demand and limited coal-fired power generating capacity with retirements of Units 1 and 2. For Petersburg, Units 3 and 4 will need to be utilized more in order to meet the electricity demands. Petersburg's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 6-1.

Table 6-1 Petersburg Generating Station's 2016 and Projected 2028 Utilization Rates for Units 1-4

ORIS-ID	Unit ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028-ERTAC	Percentage Change in Utilization
983	1	Petersburg Generating Station	0.8075	Retired	-100.0%
983	2	Petersburg Generating Station	0.5979	Retired	-100.0%
983	3	Petersburg Generating Station	0.6478	0.7282	11.0%
983	4	Petersburg Generating Station	0.5991	0.6493	7.7%

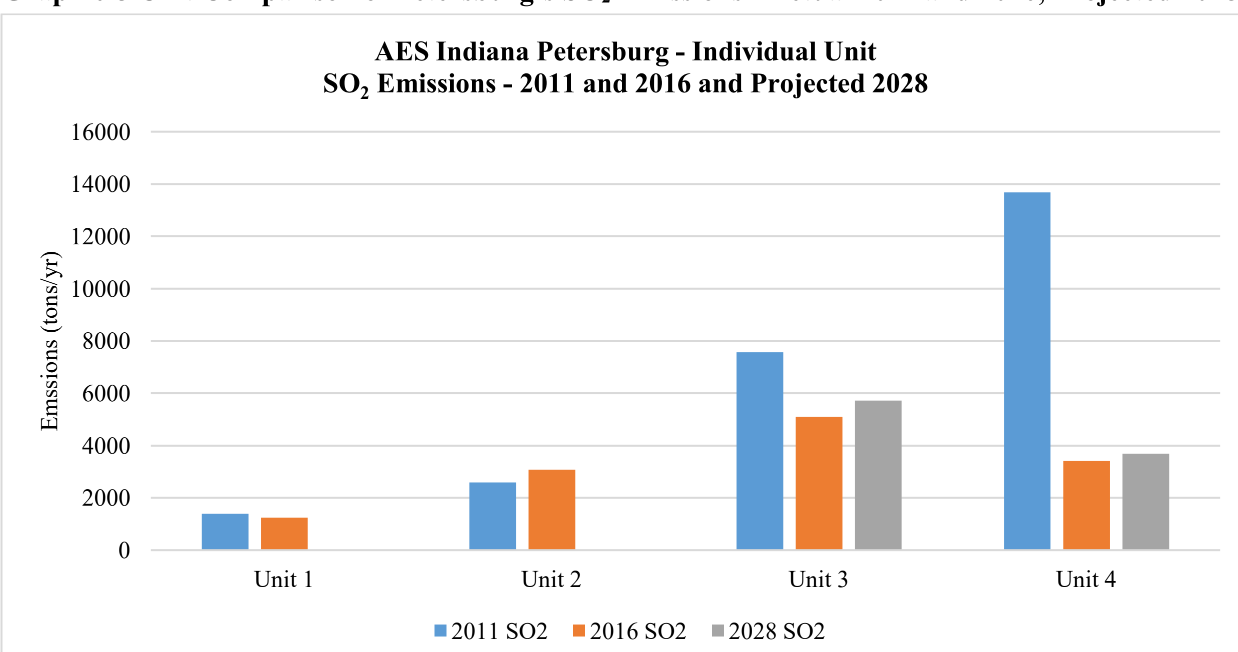
Graph 6-2 shows the unit-by-unit comparison of NO_x emissions at the Petersburg power plant. There are significant projected decreases in NO_x emissions with the retirement of Units 1 and 2 and modest NO_x emission reduction from Units 3 and 4 as observed from actual CAMD data for 2011 and 2016 and ERTAC's projected 2028 emissions.

Graph 6-2 Unit Comparison of AES Indiana Petersburg's NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 6-3 shows the unit-by-unit comparison of SO_2 emissions at the Petersburg power plant. With the retirements of both Units 1 and 2, overall SO_2 emissions decrease from actual CAMD data for 2011 and 2016 to ERTAC's projected 2028 emissions of zero. Note the slight increase in projected emissions at Units 3 and 4 in 2028. This demonstrates the slight increase in utilization based on projected electricity demand in the area due to power generation. These increases equate to 12.4% for Unit 3 and 8.4% increase at Unit 4. These increases are a result of the retirements of Units 1 and 2 so overall SO_2 emissions are expected to be reduced by 26.6 %.

Graph 6-3 Unit Comparison of Petersburg's SO_2 Emissions - Actual 2011 and 2016, Projected 2028



To address consultation requests from Arkansas, Missouri, and VISTAS, which identified three Indiana sources as having possible visibility impacts on Class I areas within their state or region, LADCO tagged individual sources as well as emission source categories to determine the visibility impacts from each tagged source. Duke-Gibson and Rockport were modeled, individually and their modeled visibility impacts on light extinction was evaluated at several Class I areas in Arkansas, Missouri, and VISTAS. AES-Petersburg was not included in the source apportionment modeling as a single EGU source but was accounted for in all other Indiana EGUs modeled. To determine the individual visibility impact from Petersburg, as requested by VISTAS, Petersburg's future year NO_x and SO_2 emissions were compared with Rockport and Gibson's future year NO_x and SO_2 emissions and ratioed. These ratios were then multiplied by the visibility impacts modeled for both Rockport and Gibson to estimate the modeled visibility impacts from Petersburg. This approach found that the best method was to ratio with the Rockport emissions and use the visibility impacts from Rockport to conservatively evaluate Petersburg's impacts on the Class I areas selected by VISTAS. Table 16-6 shows the nitrate, sulfate and overall visibility impacts calculated from Petersburg. Although the validity of this approach is questionable we note that the results show a significant impact from Petersburg at Mammoth Cave NP.

LADCO's source apportionment modeling looked at the individual impacts from emission sectors within the state. Due to its proximity to Indiana, Mammoth Cave National Park in Kentucky shows the greatest visibility impact from Gibson. IDEM appears to be relying upon LADCO modeling to argue that the impacts of its EGUs upon visibility are insignificant:

Table 16-6 shows the nitrate, sulfate and overall visibility impacts calculated from Petersburg. Like the results for Rockport and Gibson, nitrate impacts were less than 1% of the total nitrate contribution to visibility impacts at the selected Class I areas while sulfate impacts were less than 3% of the total sulfate contribution. Overall visibility impacts on the Class I areas were calculated to be 1.5% or less at all specified Class I areas.

Table 16-6 AES Petersburg - Nitrate and Sulfate Visibility Impacts for Selected Class I Areas

Class I Area	Petersburg Nitrate Impact (Mm^{-1})	Total Class I Nitrate Impact (Mm^{-1})	Petersburg Nitrate Impact (%)	Petersburg Sulfate Impact (Mm^{-1})	Total Class I Sulfate Impact (Mm^{-1})	Petersburg Sulfate Impact (%)	Total Class I Light Extinction (Mm^{-1})	Petersburg Total Impact (%)
MACA1	0.13	18.75	0.7%	0.91	33.02	2.7%	74.18	1.5%
SIPS1	0.04	11.49	0.3%	0.51	25.92	2.0%	60.97	0.9%

Note: Petersburg visibility impacts were estimated by future year projected emissions ratioed with Rockport projected emissions and then multiplied by Rockport modeled visibility impacts at selected Class I areas

IDEM's percent contribution argument is misleading because impacts were compared to a dirty background and discriminate against more-impacted Class I areas like Mammoth Cave NP. However, the light extinction results are useful because they can be compared to light extinction for the 20% most-impaired days under natural conditions; for Mammoth Cave NP, that value is 9.8 dv or 26.64 Mm^{-1}. Petersburg contributes 1.04 Mm^{-1} or 0.38 dv at Mammoth Cave NP when compared to the natural condition on 20% most-impaired days; this is a very significant contribution to impairment.[9]

Addition of SCR to Unit #4 is Cost-effective

In the absence of a 4FA for Unit #4, we applied EPA Guidance and its Control Cost Manual and estimate that, based upon IDEM's 2028 projected utilization increase and the past five years of EPA's Clean Air Markets/AMP data, addition of SCR could reduce NO_x emissions by over 3,000 tons/yr at less than $4,500/ton. (Our calculations are attached.)

2.4.4 Petersburg Generating Station Results & Conclusions

- Petersburg's projected 2028 impact at Mammoth Cave National Park is significant and a four-factor analysis is warranted.
- We would like to see the source control efficiency calculations for all four units.
- Units #1 & #2 are expected to retire before 2028; these retirements must be made federally enforceable for inclusion in the SIP.
- Unit #4 lacks effective NO_x controls. Addition of SCR is cost-effective and could reduce NO_x emissions by over 3,000 tons/yr at less than $4,500/ton.
- IDEM should explain why it expects NO_x emissions from Units 3 & 4 to decrease. Is there some IDEM "on-the-books" requirement that is driving this decrease? If not, would IDEM consider a requirement that EGUs make better utilization of emission controls?

2.5 Alcoa Warrick Power Plant

2.5.1 Summary of NPS Recommendations and Requests for the Alcoa Warrick Power Plant

Unit #4 at the Alcoa Power Generating INC – Warrick Power Plant (Warrick) is still in operation and plans to continue operations. This unit is a significant source of NO_x in the region and we recommend that Indiana undertake/require four-factor analysis of NO_x emission reduction opportunities from this facility.

Our initial review finds that the SCR NO_x controls at Warrick Unit #4 are only achieving 38% efficiency while modern systems are expected to achieve 90% efficiency. We find that both the total and incremental cost-effectives estimates for replacing the SCR are well within the range $4,000 - $10,000/ton now being considered by states for total cost effectiveness. We recommend that Alcoa replace (or upgrade) the existing SCR on Warrick Unit 4.

2.5.2 Alcoa Background

Warrick Generating Station was a 755 MW coal-fired electricity-generating station, located in Warrick County, Indiana. Alcoa Power Generating Inc - Warrick Power Plant (Alcoa) owns three of the four dry bottom, pulverized coal-fired units at the Warrick facility. The Power Plant is generally fueled by Illinois Basin coal that is mined from the nearby region. The generating station received about 2 million tons of coal each year from both rail and truck shipments.

[9] EPA 7/8/2021 Guidance: In many cases, the difference in the form of the modeled emissions and the visibility impact metrics alone could account for BART Guideline modeling impacts that are an order of magnitude, or more, higher than typical photochemical modeling impacts averaged over the 20 percent most impaired days for a single year.

- Boiler 1 came online prior to August 1962.
- Boiler 2: is classified as an industrial boiler and came online in January 1964; nominal heat input capacity of 1,589 MMBtu/hr; equipped with a low NO_x burner (LNB) and overfire air (OFA) in 2004
- Boiler 3: is classified as an industrial boiler and came online in October 1965; nominal heat input capacity of 1,589 MMBtu/hr; equipped with LNB and OFA in 2002

Boilers 1 – 3 appear to have ceased operation in 2018. We recommend that these shutdowns must be federally enforceable for inclusion in the SIP, if they are not already.

Construction of the 323 MW Boiler 4 started on March 16, 1968 and the unit was placed in operation in 1970. Boiler 4 is classified as an EGU, has a nominal heat input capacity of 2,958 MMBtu/hr and is jointly owned by Alcoa and Vectran. Boiler 4 was equipped with a LNB in 1998 and a selective catalytic reduction (SCR) system in 2004. Although Boiler 4 was subject to BART, because of CAIR/CSAPR, it was only evaluated for PM emissions.

Each boiler is equipped with an electrostatic precipitator (ESP) for PM control and Wet flue gas desulfurization (FGD) scrubbers were installed on all boilers in 2008.

According to the 2019-2020 Vectren Integrated Resource Plan, both companies will exit their agreement to purchase power in 2023 from Alcoa Unit 4. Therefore, this unit was not modeled as an EGU and was not included in the ERTAC future year emissions projections and was not modeled by LADCO. After modeling was concluded, the IDEM learned that the unit would continue operating as an EGU after 2023 with similar emissions. This unit will be added back to the next round of ERTAC modeling to correct this issue.

According to the EPA Clean Air Markets Database (CAMD)/Air Markets Program (AMP) NO_x emissions from Unit 4 in 2020 were 3,786 tons; Unit 4 ranked #18 out of 3,317 EGUs for NO_x emissions.

2.5.3 Alcoa Warrick Power Plant Review and Feedback

We investigated the economics of replacing the existing SCR which began operation in 2004. Based upon a comparison of CAMD emissions averaged over 1999 – 2003 versus 2016 -2020, this 17-year old SCR appears to be reducing NO_x by only 38%. The EPA Control Cost Manual (CCM) advises that modern SCR can reduce NO_x by 90% down to 0.04 lb/mmBtu.

We applied the CCM SCR workbook to the existing SCR as well as a new SCR and the results are tabulated below.

SCR Scenario	Current	New		Incremental
		New Unit Alone	New Unit + Indirect Costs of Existing	
Uncontrolled NO_x (lb/mmBtu)	0.472	0.472	0.472	
Controlled NO_x (lb/mmBtu)	0.294	0.0472	0.0472	
NO_x Control (%)	37.7	90.0	Totals	
Indirect Annual Cost	$ 5,661,927	$ 6,562,286	$ 12,224,213	$ 6,562,286
Direct Annual Cost	$ 1,350,708	$ 1,885,136	$ 1,885,136	$ 534,428
Total Annual Cost	$ 7,012,635	$ 8,447,422	$ 14,109,349	$ 7,096,714
NO_x Removed (ton/yr)	1,808	4,318	4,318	2,510
Cost Effectiveness ($/ton)		$ 1,956	$ 3,268	$ 2,828

We evaluated the existing SCR to estimate current annual indirect costs and determine the incremental change in direct and indirect annual costs. Therefore, we do not report total cost effectiveness for the existing SCR. We assumed that Alcoa would continue paying the Indirect Annual Cost of the existing SCR as well as for the new SCR. (At some time, it is likely that these costs would end.) We also assumed that the Direct Annual Costs for the existing SCR would end once it is taken out of service and only the new direct annual costs would be incurred. However, the increased Indirect Annual Costs would be relevant in the calculation of incremental costs and these were factored into the incremental costs.

The Total Annual Cost of the new SCR would be $14.1 million (including Indirect Costs from the existing SCR) to remove a total of 4,319 tons for cost-effectiveness of $3,268/ton. The Incremental Total Annual Cost would be $7.1 million to remove an additional 2,510 tons for incremental cost-effectiveness = $2,828/ton. Both the Total and Incremental cost-effectives estimates are well within the range of cost-effectiveness thresholds $4,000 - $10,000/ton now being considered by states.

2.5.4 Alcoa Warrick Power Plant Results & Conclusions

- Boilers 1–3 appear to have ceased operation in 2018. Shutdowns must be federally enforceable for inclusion in the SIP.
- Unit 4 will continue operating as an EGU after 2023 with similar emissions. NO_x emissions from Unit 4 in 2020 were 3,786 tons; Unit 4 ranked #18 out of 3,317 EGUs for NO_x emissions.
- Both the Total and Incremental cost-effectives estimates for replacing the SCR are well within the range $4,000 - $10,000/ton now being considered by states for Total Cost Effectiveness.
- Alcoa should replace (or upgrade) the existing SCR on Unit 4.

2.6 Clifty Creek Station

2.6.1 Summary of NPS Recommendations and Requests for the Clifty Creek Station

The Indiana Kentucky Electric Corporation (IKEC) and the Ohio Valley Electrical Corporation's[10] Clifty Creek Station (Clifty Creek) has six units that all appear to be effectively controlled for SO_2. However, none of the six units is effectively controlled for NO_x. Indiana should undertake/require four-factor analyses of NO_x emission reduction opportunities from this facility. Our initial review finds that addition of SCR to Unit #6 is cost-effective and would reduce NO_x emissions by over 1,000 ton/yr. The rationale for NO_x emissions decreases projected for 2028 is unclear and requires explanation.

2.6.2 Clifty Creek Background and Review

Clifty Creek is a 1,303.6 megawatts (MW) coal-fired power station located at 1335 Clifty Hollow Rd., in Madison, Jefferson County. The Clifty Creek Station operates six wet-bottom pulverized (Illinois Basin) coal-fired boilers, with each of its six generating units rated at 217.26 MW, for a total capacity of 1,303.6 MW.

Controls for NO_x and SO_2 are as follows:

- SO_2: Flue-Gas Desulfurization Systems began operation in 2013 on all units and they appear to be effectively controlled.
- NO_x: Overfire Air on all six units began operation from 1998–1999 and Selective Catalytic Reduction on Units 1 through 5 in began in 2013. Our evaluation of Clean Air Markets Data indicates that SCR efficiencies are 67–79%.

According to EPA's Air Markets Program (AMP) database, in 2020, the Clifty Creek facility ranked #80 (out of 1,167 U.S. facilities) for SO_2 emissions at 2,537 tons and #32 for NO_x emissions at 5,301 tons. Emissions from the individual emission units and their ranking (out of 3,317 U.S. EGUs) are shown in the table below.

Unit ID	Gross Load (MW-h)	SO_2 (tons)	SO_2 (tons) Rank	NO_x (tons)	NO_x (tons) Rank	Heat Input (MMBtu)
1	877,292	454	312	783	266	8,898,127
2	870,459	458	310	856	243	8,794,422
3	799,304	412	322	772	268	8,071,979
4	890,032	449	314	1,019	205	8,805,029
5	881,646	446	315	1,058	194	8,777,960
6	559,887	317	351	812	253	5,592,062

Clifty Creek 2028 EGU NO_x emissions are projected to be reduced by 59% or 5,534 tons from 2016 emission levels and SO_2 emissions are expected to increase slightly, by 6% or 286 tons

[10] Parent Company: American Electric Power (43.47%), Buckeye Power (18%), Duke Energy (9%), FirstEnergy (8.35%), Wolverine Power Cooperative (6.65%)[1], LG&E Energy 5.63%, AES (4.9%), Kentucky Utilities Company 2.5%, Vectren (1.5%).

from 2016 to 2028. The ERTAC model projects small increases in utilization at the facility for all six units.

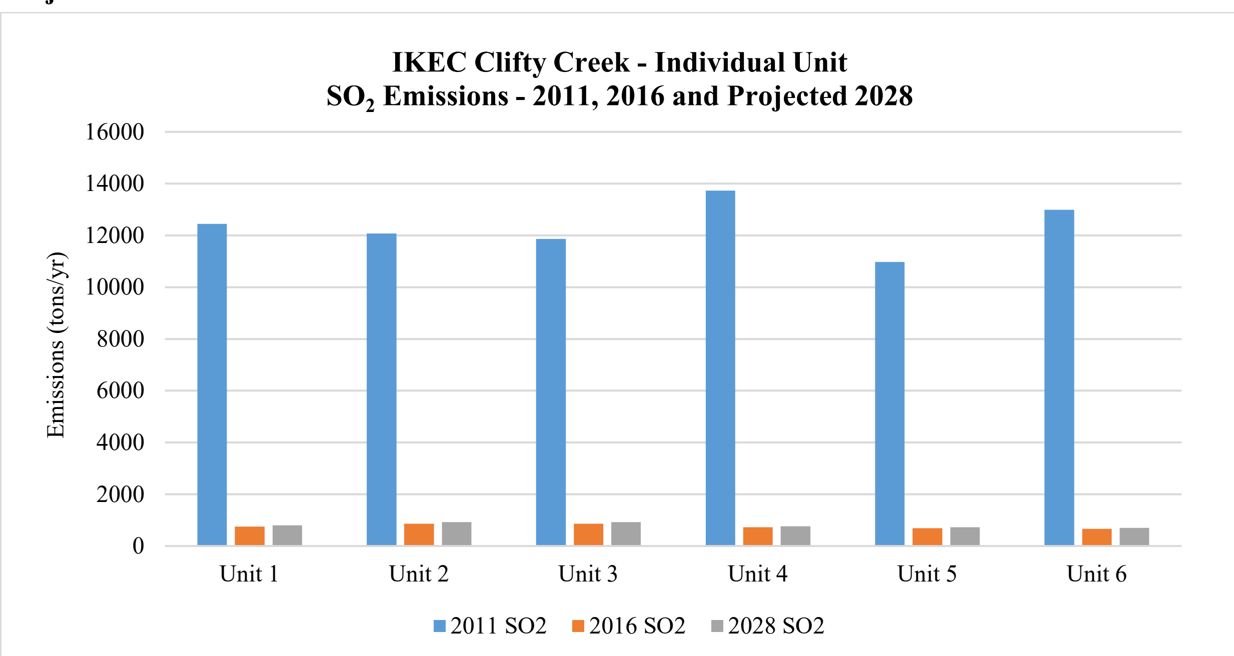
The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. For Clifty Creek's future emissions projections, Units 1–6 are anticipated to be utilized more to meet the electricity demands for the area. Clifty Creek's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 7-1.

Table 7-1 Clifty Creek Generating Station's 2016 and Projected 2028 Utilization Rates for Units 1-6

ORIS-ID	Unit ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028ERTAC	Percentage Change in Utilization
983	1	Clifty Creek Generating Station	0.4689	0.4997	6.2%
983	2	Clifty Creek Generating Station	0.5439	0.5829	6.7%
983	3	Clifty Creek Generating Station	0.5354	0.5705	6.1%
983	4	Clifty Creek Generating Station	0.5094	0.5377	5.3%
983	5	Clifty Creek Generating Station	0.4861	0.5099	4.7%
983	6	Clifty Creek Generating Station	0.4607	0.4913	6.2%

Graph 7-3 below shows the unit-by-unit comparison of SO_2 emissions at the Clifty Creek power plant. Note the slight increase in projected emissions at each of the six units. This demonstrates the slight increase in utilization based on projected electricity demand in the area due to power plants in the area reducing their generation or retiring their coal-fired boilers. *The overall* SO_2 *emissions increase at Clifty Creek from 2016 to 2028 is projected to be 6%.*

Graph 7-3 Unit Comparison of IKEC Clifty Creek SO_2 Emissions - Actual 2011 and 2016, Projected 2028

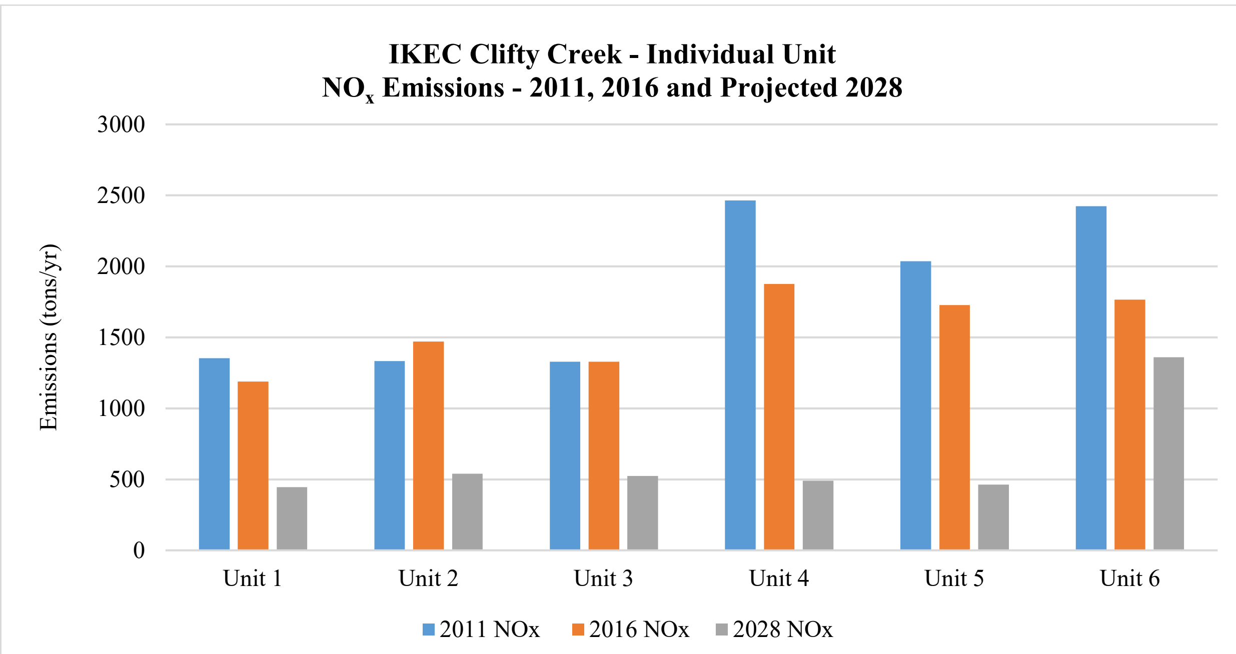


Graph 7-2 below shows the unit-by-unit comparison of NO_x emissions at the Clifty Creek power plant. There is a significant projected decrease in NO_x emissions at each of the six units from actual CAMD data for 2011 and 2016 to projected 2028 emissions by ERTAC.

According to IDEM:

The ERTAC model predicts very small increases in utilization for the Clifty Creek EGUs, an average plant- wide increase in utilization of only around 3%, which would result in increased NO_x and SO_2 emissions. However, IDEM surmises that while the higher utilization rates will result in small increases in SO_2, better control of NO_x from on-the-books control measures will result in much lower NO_x emissions. The SCRs on the Clifty Creek EGUs do not operate continuously, however the emissions trends based on CAMD reporting since 2016 does show that SCR controls on these units are being operated more frequently. This has resulted in NO_x emissions decreasing between 50 to 60 percent when comparing 2016 to 2019 NO_x emissions for the Clifty Creek EGUs.

Graph 7-2 Unit Comparison of IKEC Clifty Creek NO_x Emissions - Actual 2011 and 2016, Projected 2028



We applied EPA's Control Cost Manual (CCM) SCR workbook to recent AMP data for Unit 6 and estimate that addition of SCR could remove over 1,000 ton/yr NO_X at $6,100/ton.

2.6.3 Clifty Creek Review Results & Conclusions

- All six units appear to be effectively controlled for SO_2.
- None of the six units is effectively controlled for NO_x and four-factor analyses should be conducted for these units.

- IDEM should explain why it expects NO_x emissions to decrease. Is there some IDEM "on-the-books" requirement that is driving this decrease? If not, would IDEM consider a requirement that EGUs make better utilization of emission controls?
- Addition of SCR to unit 6 is cost-effective and would reduce NO_x emissions by over 1,000 ton/yr.

2.7 Culley Generating Station

2.7.1 Summary of NPS Recommendations and Requests for the Culley Generating Station

The Southern Indiana Gas and Electric Company – FB Culley Generating Station (Culley) retired Unit #1 in 2006 and is planning to retire Unit #2 in 2023. This retirement must be federally enforceable for inclusion in the SIP. Our review finds that Unit #3 is effectively controlled for SO_2 emissions but not for NO_x. Indiana should undertake/require four-factor analyses of NO_x emission reduction opportunities for Unit #3 (and for Unit #2 unless an enforceable shutdown requirement is included in the SIP).

2.7.2 Culley Background

The Culley Generating Station is a coal-fired power plant located at 3711 Darlington Rd southeast of Newburgh in Warrick County, Indiana.

Culley has two units still in service: a 104 MW Unit 2 (built in 1966) and a larger 265 MW Unit 3 (built in 1973). Unit 1 with 46 MW, began electricity generation in 1955. The unit closed in 2006 to comply with the Environmental Protection Agency's (EPA) Clean Air Interstate Rule. It was announced in February 2018 that F. B. Culley's Unit 2 will be shut down in 2023 when a natural gas plant in Posey County is completed.

2.7.3 Culley Review and Analysis

Emission controls include LNB for NO_x control and FGD system for SO_2 controls on Unit 2. Unit 3 has LNB and SCR for NO_x reduction and shares the FGD system for SO_2 controls with Unit 2. According to EPA's Air Markets Program (AMP) database, in 2020, the Culley facility ranked #80 (out of 1,167 U.S. facilities) for SO_2 emissions at 2,537 tons and #32 for NO_x emissions at 5,301 tons. Unit 3 ranked #279 (out of 3,317 EGUs) for SO_2 emissions at 585 tons and #323 for NO_x emissions at 586 tons. Our evaluation of AMP data indicates that the SCR on Cully Unit 3 is only achieving 75% control. Modern SCR systems are expected to achieve at least 90% efficiency.

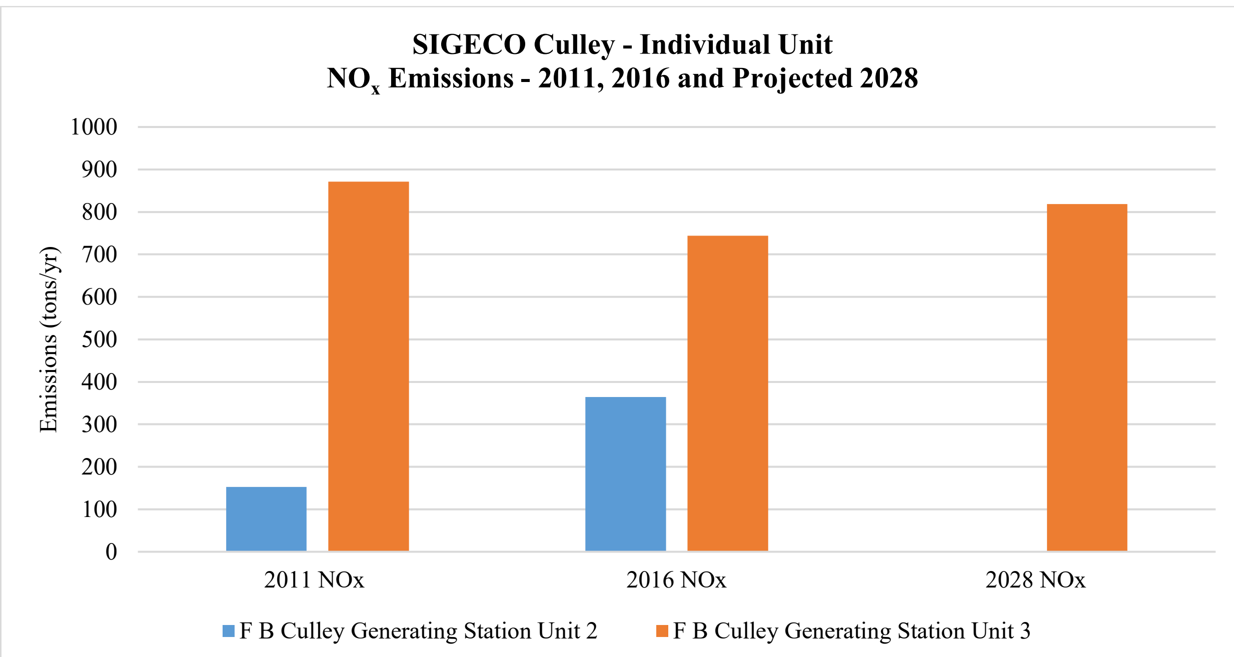
The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. For Culley's future emissions projections, Unit 2 coal-fired power generation is being replaced with renewables and NG-fired combustion turbines. The renewables filing was recently submitted with the Indiana Utility Regulatory Commission. Meanwhile, Unit 3 may be utilized more to meet the electricity demands with the retirement of Unit 2. Culley's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 11-1.

Table 11-1 Culley Generating Station's 2016 and Projected 2028 Utilization Rates for Units 2 and 3

ORIS-ID	Unit ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028-ERTAC	Percentage Change in Utilization
1012	2	F B Culley Generating Station	0.0999	Retired	-100.00%
1012	3	F B Culley Generating Station	0.3745	0.4114	11.93%

Graph 11-2 shows the unit-by-unit comparison of NO_x emissions at the Culley power plant. Note the slight increase in projected emissions at Unit 3. This demonstrates the slight increase in utilization based on projected increased electricity demand in the area due to the retirement of Unit 2. The overall NO_x emissions decrease at Culley from 2016 to 2028 is projected to be 26%.

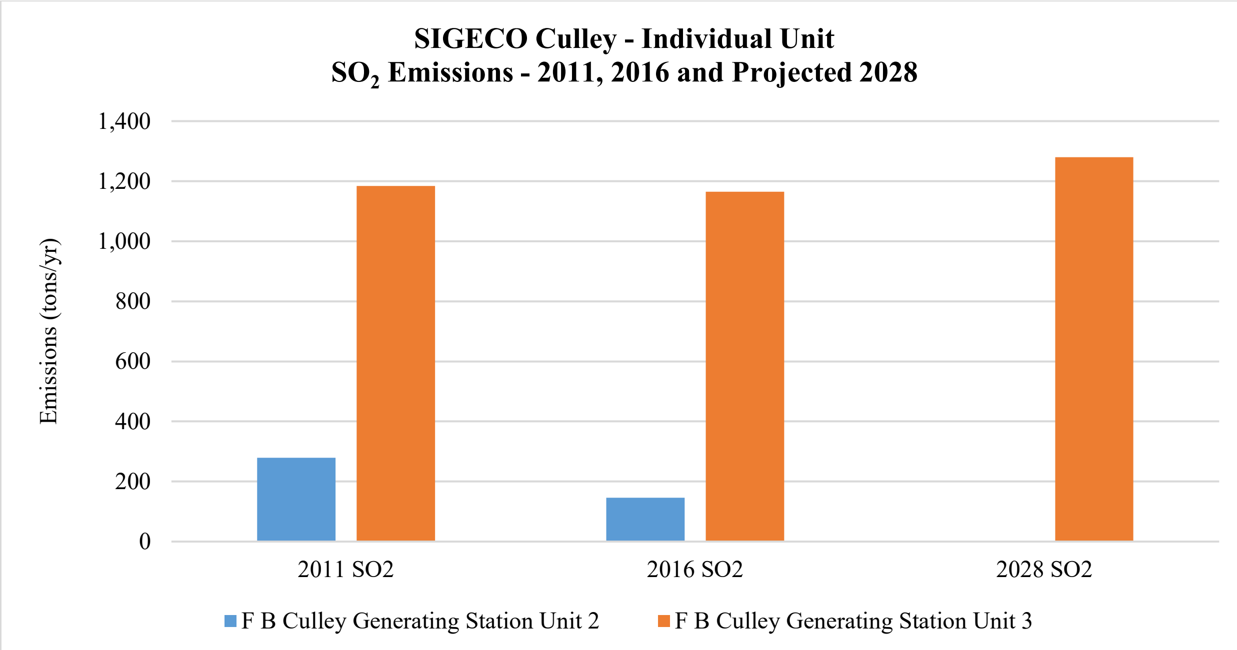
Graph 11-2 Unit Comparison of SIGECO Culley NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 11-3 shows the unit-by-unit comparison of SO_2 emissions at the Culley power plant.

Note the slight increase in projected emissions at Unit 3. This demonstrates the slight increase in utilization based on projected electricity demand in the area due to the retirement of Unit 2. The overall SO_2 emissions decrease at Culley from 2016 to 2028 is projected to be 2%.

Graph 11-3 Unit Comparison of SIGECO Culley SO_2 Emissions - Actual 2011 and 2016, Projected 2028



2.7.4 Culley Review Results & Conclusions

- Unit 2 retirement should be made federally enforceable .
- Unit 3 is effectively controlled for SO_2 but not for NO_X.
- A four-factor analysis should be conducted to determine if Unit 3 NO_X control can be improved in a cost-effective manner.

3 Non EGU Feedback

3.1 Alcoa Warrick Operations (Aluminum)

3.1.1 Summary of NPS Recommendations and Requests for Alcoa Warrick Aluminum Plant

- Notwithstanding the analysis issues noted below, the costs for adding a FGD system to control potline emissions appear to be very reasonable and IDEM agreed with this conclusion in the SIP yet determined that no controls were necessary. We recommend that controls should be considered based on the four-factors evaluated.
- The Alcoa four-factor analysis (4FA) is almost completely lacking in essential economic and emissions information. Please provide the necessary cost information in the SIP, including the Burns & McDonnell update of Babcock Power budgetary proposal, which was the basis of the Alcoa 4FA.
- The inflation adjustment used in the Alcoa analysis is too high. The EPA CCM recommends use of the CEPCI which increased by 13% since the original 2007 cost estimates. Instead, Burns & McDonnell assumed a 2.5% annual interest rate which inflated costs by 38%.
- The Alcoa 4FA assumed 70% control efficiency for the FGD. This seems low. What is the basis for this assumption? Note, a 95% control efficiency was assumed for the FGD in the BART analysis for the Warrick facility in the previous round of RH planning.

3.1.2 Alcoa Aluminum Analysis & Review Background:

Alcoa is a stationary aluminum production plant consisting of the Alcoa potlines and potlines support plant, paste production plant, and anode baking plant. The two emission unit groups selected for SO_2 four-factor analysis in IDEM's RFI are listed below and the source of each unit's SO_2 emissions and existing control measures are described in this section. According to IDEM's Appendix J, annual SO_2 emissions from the potlines are 3,000 tons with 139 tons from the anode baking ring furnace. NO_x four-factor analyses were not requested by IDEM for the two emission unit groups selected.

Potline Nos. 2, 3, 4, 5, and 6[11]

The Alcoa Potlines consists of the five center-worked prebake one (CWPB1) potlines each with 150 pots and a maximum aluminum production rate of 7.99 tons per hour. Primary emissions are controlled by A-398 pollution control system fluidized bed scrubbers (for potlines 2, 5, and 6), alumina injection and fabric filtration systems (for potlines 3 and 4). The SO_2 emissions are generated by the consumption of the carbon anode during the aluminum smelting process. Secondary emissions are uncontrolled and exhaust at roof monitors The facility's hourly SO_2 emissions limitations translate into a limit on the incoming sulfur content of the petroleum coke used to form the anode of ~2% sulfur, the lowest sulfur content of all aluminum smelters in the United States. Alcoa's coke supplier must import low sulfur calcined petroleum coke from South America in order to meet the ~2% limit, at a considerable cost to the facility. NO_x emissions have not been directly measured from this process.

Anode Baking Ring Furnace Description[12]

The Anode Baking Ring Furnace is an above-ground NG furnace that was constructed in 1981 and rebuilt in 2003. It has a capacity of 21.42 tons of green anodes per hour and it is equipped with an A-446 pollution control system. The A-446 pollution control system consists of three reactor sections with baghouses for PM and PM_{10} control and dry alumina scrubbers for total fluoride and SO_2 control. The system operates with a minimum of two reactor sections at any one time. SO_2 emissions from the anode baking ring furnace are primarily from the sulfur in the coal tar pitch, which is used to bind the petroleum coke together during the anode forming process. Pursuant to the facility's Title V air permit, the pitch sulfur content may not exceed

[11] The Alcoa Warrick smelter operates center-worked prebake (CWPB) cells. Prebake cells utilize carbon anodes, made from petroleum coke and coal tar pitch, which have been pre-formed into blocks, baked, and secured onto copper rods prior to being introduced into a cell. Pressing, baking and rodding take place on-site in the green carbon, carbon baking, and anode rodding processes respectively. In center-worked pots, the crust overlying the molten bath is broken and ore is fed by means of a puncher-feeder device located along the cell's centerline between the two rows of anodes. The individual cells are arranged in "potlines" which are rows of cells connected electrically in series. Air pollution control systems employed at Alcoa include the following: For potlines, primary emission control systems capture pot fumes. The systems consist of hoods and movable shields around each pot, and a system of ducts and fans which draw the fume from each pot to a centralized treatment system. The treatment system consists of two types of alumina dry scrubbers (referred to as either A-398 fluidized bed or alumina injection system) which use alumina to react with and remove hydrogen fluoride in the gas stream. The resulting aluminum fluoride is removed, along with other particulate matter, by a system of fabric filter containing baghouses prior to venting the treated gasses to the atmosphere. The aluminum fluoride particulate is recycled in the potroom process.

[12] For anode bake ovens, a dry alumina scrubber system, with fluidized bed alumina reactors and baghouses (A-446), treats bake oven gasses in a fashion similar to the A-398 system. Bake oven gasses consist of combustion products from natural gas and from volatile matter that is driven off the baking anodes and burned in the ovens, particulate matter from the packing coke surrounding the baking anodes, and fluoride present in spent anodes (anodes removed from the pot cells are crushed and returned to the anode mix). The alumina used in the scrubber is recycled as feedstock in the potrooms. For the green mill, a dry coke injection scrubber system (Procedair) is used for collecting and treating organic vapors and particulates in the carbon plant. In the green mill, petroleum coke and coal tar pitch are heated, mixed and pressed into anodes. Carbon particles and organic vapors are generated by these processes. The coke scrubber adsorbs volatile material onto calcined petroleum coke which is injected into the ductwork and waste gas streams, and a baghouse captures the resulting particles. The coke fines and adsorbed organic vapors collected by the baghouse are recycled back into the anode forming process.

0.8%. NO_x emissions, although not directly measured, are expected to be primarily from the combustion of NG.

3.1.3 Alcoa Four-Factor Analysis of Potential SO_2 Control Options

Alcoa chose a FGD system for Potlines 2-6 and the Anode Baking Ring Furnace and associated A-446 Dry Alumina Scrubbers. SO_2 emissions from these emission units are primarily due to the sulfur content in the materials used in the Potlines and Potlines Support and Anode Baking Ring Furnace and associated A-446 Dry Alumina Scrubbers operations. Since there are no pollution control devices associated with the potlines or anode baking ring furnace and Alcoa received a budgetary proposal for a FGD to control SO_2 emissions from the potlines, the FGD is evaluated for the potlines and the anode baking ring furnace.

Cost of Compliance for Potential SO_2 Control Options

In July 2007, Babcock Power Environmental (Babcock Power) provided Alcoa a budgetary proposal for a FGD system for the control of SO_2 emissions from Potlines 2 through 6. To estimate the capital cost of installing a FGD system to control SO_2 emissions from the potlines, Burns & McDonnell updated the budgetary cost in this proposal by escalating to reflect inflation from 2007 to 2020. An annual inflation rate of 2.5% was assumed over this time period based on information from the Chemical Engineering Plant Cost Index (CEPCI).

There are several problems here:

- EPA's control Cost Manual advises against using cost information that is more than five years old.
- We were not provided any of the cost information that is the basis for the company estimates.
- 2.5% inflation over 13 years is a 38% increase. The CEPCI in 2007 was 525.4 and for 2020 was 596.2 for a 13% increase.

The capital and annual O&M cost estimates for a new FGD system on the potlines and the Anode Baking Ring Furnace are summarized by IDEM in Table 1. Note all costs are in 2020 dollars and represent rough order-of-magnitude costs.

Table 1. FGD System Cost Estimate Summary

Scrubber	Capital	Annual O&M
Potline 2 through 6	$512,800,000	$5,300,000
Anode Baking Ring Furnace	$63,900,000	$700,000
Total	$576,700,000	$6,000,000

Burns & McDonnell developed a rough order-of-magnitude cost estimate for installing SO_2 controls on the Anode Baking Ring Furnace and associated A-446 Dry Alumina Scrubbers based on the escalated Babcock Power budgetary proposal. The budgetary cost estimate for the FGD for the potlines was scaled to represent a FGD system for the Anode Baking Ring Furnace based on the flue gas parameters provided by Alcoa.

The Alcoa Warrick primary aluminum operations were subject to BART in the first round of regional haze planning.[13] The excerpts below are from that analysis[14] which estimated a capital cost of $305 million (presumably in 2010$) and $15,000/ton cost-effectiveness for a wet FGD system.

Table 6-3. Summary of the Impacts Analysis for SO_2 Control Scenarios

Control Scenario	Control Technology Evaluated	Emission Rate (tons/year)	Emissions Reductions (tons/year)[a]	Installed Capital Cost ($000)	Total Annualized Control Costs ($000)	Cost Effectiveness($ per ton of pollutant removed)	Energy Impact (000 kW-hour/year)	Collateral Increase in other Pollutants	Non-Air Quality Environmental Impacts
1	3.0% Sulfur Coke with Potlines Wet Scrubber	393	3,662	$305,000	$55,000	$15,000	41,800	$PM_{2.5}$ 58 tons/year	21,633 tons/year of solid waste for disposal 312 million gallons/year makeup water usage
Current Potential Emissions	2.0% Sulfur Coke Potlines	4,055							

Time Necessary for Potential SO_2 Control Options Compliance

Alcoa estimates that a new FGD system typically requires 30 to 36 months for front end planning, design, procurement, installation, and commissioning. Alcoa's capital planning process would add 12 to 18 months to this timeframe.

Energy and Non-Air Impacts of Potential SO_2 Control Options

No unusual impacts were noted by Alcoa.

Remaining Useful Life for SO_2 Control Options

The Alcoa potlines have been in operation since 1960, and Alcoa continues to maintain them for continuous, reliable operation. The Anode Baking Ring Furnace was constructed in 1981 and rebuilt in 2008. Alcoa says, "The remaining life of each of the production units is based on economic factors and product demand, and therefore cannot be predicted at this time." Alcoa

[13] The 1999 RH Rule was issued to fulfill the requirements of Section 169A and 169B of the CAA. Section 169(B) of the CAA and 40 CFR 51.308 (e)(1)(ii)(B) required states to address the Best Available Retro-fit Technology (BART) requirement when developing their RH SIPs for the first implementation period. Under the CAA, BART is required for certain large stationary sources that a state determined "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area." The potlines at Alcoa were found to be subject to BART according to the criteria outlined in the BART Guidelines, so Alcoa proposed limiting the anode grade coke to 3.5% sulfur to satisfy BART. IDEM approved Alcoa's BART strategy since SO_2 emissions from the potlines can be controlled by limiting the sulfur content in the anode grade coke. The emission limits representing BART for the potlines were included in the first planning period RH SIP. The EPA published the final approval of Indiana's RH SIP for the first implementation period on Oct 7, 2019.

[14] BART DETERMINATION REPORT FOR ALCOA, INC. – WARRICK OPERATIONS NEWBURGH, INDIANA; Prepared for: Alcoa, Inc. – Warrick Operations, Newburgh, Indiana, Prepared by: URS Corporation, 1093 Commerce Park Drive, Suite 100, Oak Ridge, Tennessee 37830, and CH2M HILL, 1095 Lakeside Centre Way, Suite 200, Knoxville, Tennessee 37922, December 2008 (Amended July 2010)

should provide the interest rate and the remaining useful life it used to calculate capital recovery costs.

Alcoa Reasonable Level of Control for SO_2 Emissions

According to IDEM:

> The reasonable SO_2 emission control measure beyond what is currently installed and operated for Potlines 2-6 and Anode Baking Ring Furnace & A-446 Dry Alumina Scrubbers unit at Alcoa is FGD. The associated SO_2 cost-effectiveness values ($ per ton of emissions reduction) for the addition of FGD for Potlines 2-6 is $5,889 per ton of SO_2 emissions reduction and $16,787 per ton of SO_2 emissions reduction for the Anode Baking Ring Furnace & A-446 Dry Alumina Scrubbers unit (See Cost Effectiveness and Cost Estimate Spreadsheets in Appendix A of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis For Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J of this document).

Below is the table from IDEM's Appendix J (referenced above) for the Alcoa aluminum plant.

SO_2 Controls

Control Cost Summary	**Potlines 2-6**	**Anode Baking Ring Furnace & A-446 Dry Alumina Scrubbers**
	Flue Gas Desulfurization	**Flue Gas Desulfurization**
Total Capital Cost	$512,800,000	$63,900,000
Total Annual Cost (Capital & Operating)	$5,300,000	$700,000
Current Emissions (ton/yr)	3,000	139
Control Efficiency	70%	70%
New Emission Rate (tons/yr)	900	42
Emission Reductions (tons/yr)	2,100	97
Cost-Effectiveness ($/ton)	2,524	7,194

3.1.4 Alcoa Aluminum Results & Conclusions

- The Alcoa four-factor analysis (4FA) is almost completely lacking in essential economic and emissions information. The basis of the Alcoa 4FA is a Burns & McDonnell update of Babcock Power budgetary proposal, neither of which was provided.
- The EPA CCM recommends use of the CEPCI which increased by 13% since the original 2007 cost estimates. Instead, Burns & McDonnell assumed a 2.5% annual interest rate which inflated costs by 38%.
- Despite the dearth of vital information, if the Burns & McDonnell estimates are taken at face values, the cost-effectiveness of adding a FGD system to control potline emissions is very reasonable. Likewise, the IDEM table in its Appendix J shows the cost-effectiveness is even more reasonable.

- The Alcoa 4FA assumed 70% control efficiency for the FGD. This seems low. What is the basis for this assumption? Note, a 95% control efficiency was assumed for the FGD in the BART analysis for the Warrick facility in the previous round of RH planning.

3.2 Steel Mills

3.2.1 Summary of NPS Recommendations and Requests for Steel Mills

The Air Resources Division reviewed the four-factor analyses for the emissions units located at the four steel mills: Cleveland-Cliffs Steel - Indiana Harbor East (Indiana Harbor East), Cleveland-Cliffs Steel - Indiana Harbor West (Indiana Harbor West), Cleveland-Cliffs Burns Harbor, LLC (Burns Harbor), and United States Steel Corporation - Gary Works, (Gary Works). We provide the following Requests & Recommendations:

- We found several errors in the cost analyses provided for the steel mills and request that these errors are corrected. Once corrected, controls may be even more cost effective than estimated by IDEM.
- Notwithstanding the analysis issues highlighted here, IDEM still identified a number of cost-effective control options for the Burns Harbor facility that are within the range of $4,000-$10,000/ton cost thresholds being used by other states in their regional haze implementation plans. We request that IDEM include these cost effective controls in their RH SIP.
- We recommend the IDEM consider whether SNCR may be feasible for the Lime Plant Nos. 1 and 2 Preheater and Rotary Kilns at the Burns Harbor East Facility (see below).

3.2.2 Summary of Cost Analysis Issues

Where costs for pollution control equipment were estimated for specific units, such as the coke battery underfire units and power station boilers at Burns Harbor, the costs are likely overestimated for the following reasons:

- <u>Interest rate:</u> the analyses used an interest rate of 5.5% rather than the bank prime rate of 3.25%. The EPA Control Cost Manual 7th Edition, Section 1, Chapter 2, states that "if firm-specific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates" for use in cost estimation. As the analyses do not provide a justification for the use of the 5.5% rate, the bank prime rate should be used.
- <u>Retrofit factor:</u> several of the analyses used a retrofit factor greater than 1. A retrofit factor of 1 already accounts for costs that are approximately 30% higher than for installing equipment in a new facility. According to the Control Cost Manual 7th Edition, Section 5, Chapter 1: "For retrofits that are more complicated than average, a retrofit factor of greater than 1 can be used to estimate capital costs provided the reasons for using a higher retrofit factor are appropriate and fully documented." In the absence of documentation justifying the use of a higher retrofit factor, a value of 1 should be used.
- <u>Equipment useful life:</u> the analyses of costs for spray dry absorbers for the Burns Harbor units assumed a useful life of 20 years. According to the CCM Section 5 Chapter 1, "Acid gas scrubbers are relatively reliable systems that have been demonstrated to be exceedingly durable. In the past, the EPA has generally used equipment life estimates of

20 to 30 years for analyses involving acid gas scrubbers, although these estimates are recognized to be low for many installations. Many FGD systems installed in the 1970s and 1980s have operated for more than 30 years (e.g., Coyote Station; H.L. Spurlock Unit 2 in Maysville, KY; East Bend Unit 2 in Union, KY; and Laramie River Unit 3 in Wheatland, WY) and some scrubbers may have lifetimes that are much longer." Accordingly, a useful life greater than 20 years is appropriate for spray dry absorbers.

- <u>Sales tax:</u> should not be included for pollution control equipment. According to Indiana Code Title 6. Taxation § 6-2.5-5-30, "Machinery, equipment, and devices used to comply with governmental environmental quality laws, regulations or standards by manufacturers, processors, refiners, miners, farmers are exempt from sales/use tax. IC 6-2.5-5-30."

We have attached our calculations for SDA costs at the Burns Harbor battery #1 underfire and power station boiler #7 as examples, where we used an interest rate of 3.25% and assumed a 25 year equipment life.

In addition, we have questions regarding the purchased equipment costs for spray dry absorbers used in the Burns Harbor analyses. The analyses reference an EPA fact sheet (capital cost estimate based on mid-range of EPA spray dry fact sheet \$/(MMBtu/hr): https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf) to derive capital costs, but the footnotes (where included) seem to refer to the purchased equipment costs specifically, not the total capital costs. The SDA analyses include the other elements of the capital costs separately accompanied by the equations, but it is not clear how the purchased equipment costs were derived from the fact sheet. We would appreciate seeing a detailed explanation of how these costs were determined.

3.2.3 Summary of Review Conclusions for Steel Mills

The four-factor analysis for the Indiana Harbor East facility concluded that there are no technically feasible options for controlling NO_x emissions from the Lime Plant Nos. 1 and 2 Preheater and Rotary Kilns. However, SNCR has been successfully applied at some lime plants that have preheaters. One example is the Lhoist Nelson plant in Arizona (see attached permit). The facility should perform a four-factor analysis to determine if SNCR could be installed at the lime plant.

The Burns Harbor four-factor analysis estimates for some controls are cost effective, including spray dry absorbers for the battery #1 and #2 underfire units at \$6,300 and \$5,300, respectively, per ton of NO_x removed, and desulfurization for the clean coke oven gas line and flare at \$4,000/ton of NO_x. These values are within the range of \$4,000-\$10,000/ton being used by other states in their regional haze implementation plans as thresholds for reasonable costs. However, IDEM concluded in its draft SIP that no additional controls are needed because the visibility benefit would be insufficient to justify controls and because the Class I areas impacted by Indiana facilities are meeting their uniform rate of progress (URP). According to the draft SIP:

"SO_2 and NO_x emissions reductions from Indiana's highest emitting sources contributing to visibility impairment at Class I areas outside the state has had a significant impact on Indiana's ability to meet the first implementation period reasonable progress goals. As such, Indiana had concluded that the reasonable progress analysis for Indiana's EGU selected sources and four-factor analysis conducted for the remaining non-EGU selected sources do not provide adequate evidence for the state to require additional control measures considering the significant progress already made towards achieving the national visibility goal. Indiana has determined that none of the controls identified in the four-factor analyses were cost effective for the small amount of emission reductions that would be realized. Indiana has demonstrated that visibility improvements for this second implementation period for regional haze is well ahead of reasonable progress goals. The following evaluation of Indiana's point source SO_2 and NO_x emissions demonstrate that additional control measures are not necessary to make reasonable progress in the second implementation period."

This conclusion is contrary to the intent of the Regional Haze Rule. A recent memo issued by the EPA on July 8, 2021, titled "Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period", addresses these issues. Although this is a recent memo, it does not add any new requirements beyond those already included in the Regional Haze Rule and the August 2019 guidance on regional haze rule implementation. Regarding the URP, the memo states:

"The 2017 RHR preamble and the August 2019 Guidance clearly state that it is not appropriate to use the URP in this way, i.e., as a "safe harbor." The URP is a planning metric used to gauge the amount of progress made thus far and the amount left to make. It is not based on consideration of the four statutory factors and, therefore, cannot answer the question of whether the amount of progress made in any particular implementation period is "reasonable progress." This concept was explained in the RHR preamble."

While the August 2019 RHR guidance does allow states to consider visibility when determining their long term strategy, the guidance did not intend for visibility improvement to be used as a fifth factor to reject controls that would otherwise be determined to be reasonable. The Regional Haze Rule does not include visibility improvement as one of the four-factors specified for used in determining reasonable progress. According to EPA's recent clarification memo:

"It is important that, where applicable, each state considers the magnitude of modeled visibility impacts or benefits in the context of its own contribution to visibility impairment. That is, whether a particular visibility impact or change is "meaningful" should be assessed in the context of the individual state's contribution to visibility impairment, rather than total impairment at a Class I area. As stated in the RHR preamble:

Regional haze is visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. At any given Class I area, hundreds or even thousands of individual sources may contribute to regional haze. Thus, it would not be appropriate for a state to reject a control measure (or measures) because its effect on the RPG is subjectively assessed as not "meaningful."

EPA recognizes the significant improvements in visibility that have already occurred in most Class I areas but notes that additional progress is needed to achieve the national goal set by Congress. Evaluation of control measures for relatively smaller sources (with commensurate smaller visibility benefits from each individual source) will be needed to continue making reasonable progress towards the national goal. This is true for the second planning period, as many of the largest individual visibility impairing sources have either already been controlled (under the RHR or other CAA or state programs) or have retired. To this end, EPA is reiterating that visibility thresholds used for BART and other analyses in the first planning period (e.g., 0.5

deciviews) are, in most cases, not appropriate thresholds for selecting sources or evaluating the impact of controls for reasonable progress in the second planning period."

Thus, reasonable progress is defined by applying the four-factors to determine which controls are reasonable. Those controls found to be reasonable should be included as part of the state's long term strategy.

3.3 Cement Facilities

3.3.1 Summary of NPS Recommendations and Requests for Cement Plants

The Air Resources Division reviewed the four-factor analyses for the emissions units located at two cement plants, Lehigh Cement Company's Mitchell plant and Lone Star Industries Greencastle cement plant. We provide the following recommendations and requests for the cement plants:

- An analysis is not necessary for Lehigh Cement Company's Mitchell plant:

  We agree with IDEM's conclusion that a four-factor analysis is not needed for the Lehigh Cement Company's Mitchell plant, as the facility is replacing its three existing kilns with a new kiln that will be equipped with dry sorbent injection and selective non-catalytic reduction (SNCR) systems to control SO_2 and NO_x emissions. The kiln will meet new source performance standards for SO_2 and NO_x emissions.
- We request that IDEM require SNCR for the Lone Star Industries Greencastle cement plant as it is clearly cost-effective:
- We also reviewed the four-factor analysis provided for the Lone Star Industries Greencastle cement plant. We disagree with the use of a 15-year expected lifetime for the facility, as there is no federally enforceable requirement for the facility to shut down in that time. We also disagree with the use of a 7% interest rate for the reasons discussed earlier. Nonetheless, the estimated cost for adding SNCR is clearly cost effective at \$873/ton of NO_x removed and should be required as part of the state's long-term strategy. The analysis for dry sorbent injection only summarized the costs; we request that IDEM provide a detailed cost analysis so that we may complete our review.

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