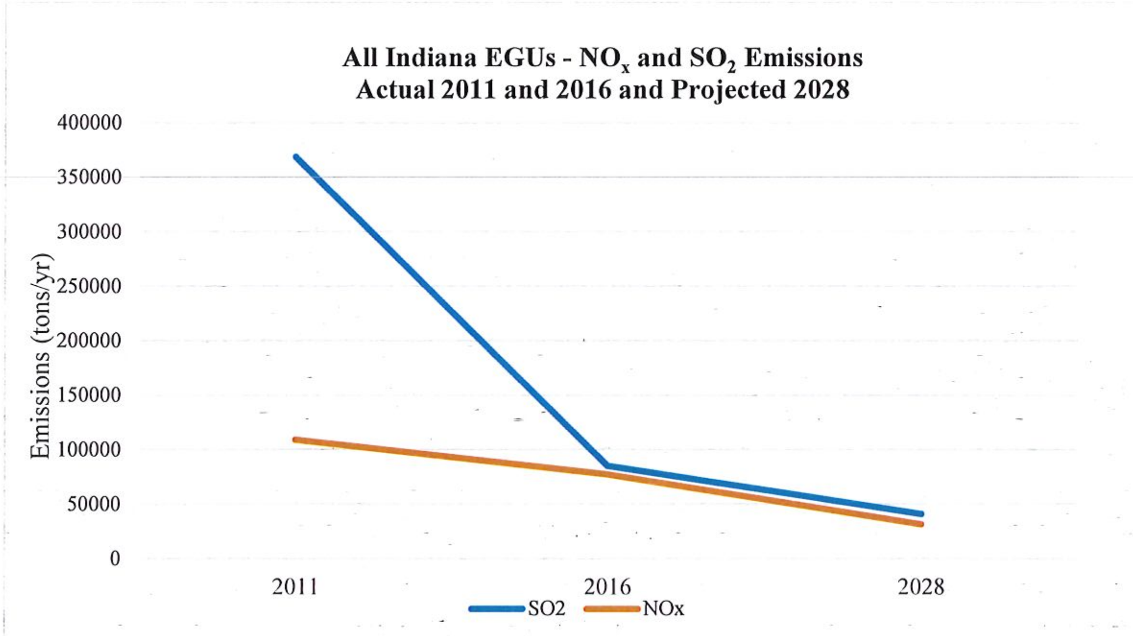
Graph 3-3 Indiana EGU Emissions Comparison: 2011 and 2016 and ERTAC Projected 2028



Future year projections are based on the latest LADCO ERTAC modeling analysis. LADCO replaced EPA's Integrated Planning Model (IPM) EGU inventories in the EPA 2011 and 2016 modeling platforms with inventories derived from the ERTAC EGU model (Mid-Atlantic Regional Air Management Association-MARAMA, 2012). The ERTAC EGU model for growth was developed around activity pattern matching algorithms designed to provide hourly EGU emissions data for air quality planning. The original goal of the model was to create low-cost software that air quality planning agencies could use for developing EGU emission projections. States needed a transparent model that did not produce dramatic changes to the emission forecasts with small changes in inputs. A key feature of the model includes data transparency; all of the inputs to the model are publicly available. The open source software includes documentation and a diverse user community to support new users of the software.

The ERTAC EGU model imports base-year Continuous Emissions Monitoring (CEM) data from EPA and sorts the data from the peak to the lowest generation hour. It applies hour specific growth rates that include peak and off peak rates. The model then balances the system for all units and hours that exceed physical or regulatory limits. ERTAC EGU applies future year controls to the emission estimates and tests for reserve electricity generating capacity, generates quality assurance reports, and converts the outputs to Sparse Matrix Operator Kernel Emissions (SMOKE)-ready modeling files.

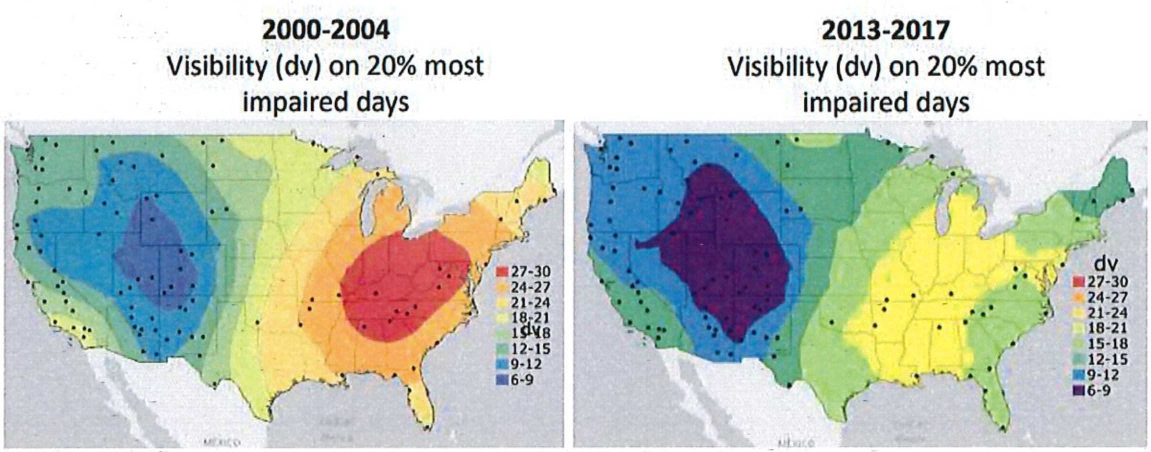
ERTAC EGU generates hourly future year emission estimates. The model does not shutdown or mothball existing units because economic algorithms suggest they are not economically viable. Additionally, alternate control scenarios are easy to simulate with the model. Significant effort has been put into the model to prevent simulations from spawning new coal plants to meet forecasted power demand. As an alternative, the model now allows portability of generation to different fuel types like renewables and NG. Differences between the IPM and ERTAC EGU emission forecasts arise from alternative forecast algorithms and from the data used to inform the model predictions.

The IPM forecasts used for the EPA "2016fh" modeling platform were based on comments from states and stakeholders received through April 2019. LADCO replaced the IPM EGU forecasts in its modeling with ERTAC EGU version 16.1. The ERTAC EGU 16.1 forecasts used CEM data from 2016 and state-reported changes to EGUs received through September 2020. The LADCO-modified ERTAC EGU 16.1 emissions used for this modeling application represent the best available information on EGU forecasts for the Midwest and Eastern United States available through September 2020.

3.3 Visibility Impacts on Class I Areas

The Interagency Monitoring of Protected Visual Environments (IMPROVE) monitored visibility values for the period of 2014 through 2018 are below the base-year 2011 - future year 2028 modeled visibility results in most instances and are nearly equal to the modeled visibility results for base-year 2016 - future year 2028, which accounts for the lower emissions base in 2016. This indicates that visibility improvements already realized are well ahead of the glidepaths of all Class I areas, especially those in the eastern half of the country that Indiana may impact. This improvement is very evident in Figure 3-5 as monitoring visibility in deciviews has improved greatly over the past decade or more.

Figure 3-2 Comparison of Visibility on 20% Most Impaired Days 2000-2017



3.4 Planned Retirements and Shutdowns for Coal fired EGUs at Indiana Power Plants

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 3-5 shows the expected unit retirements by 2028 for many of the EGUs in Indiana.

Table 3-5 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 2022 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.
Jefferson	77	1	Indiana-Kentucky Electric Corporation Clifty Creek	None announced.
Pike	125	2	Indianapolis Power and Light - 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 Indiana 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. In addition, the source confirmed the expected retirements. Finally, AES-Petersburg is now operating under a federal Consent Decree agreement with the United States and State of Indiana (Civil Action No. 3:20-cv-202-RYL-MPB, found at www.epa.gov/sites/default/files/2020-09/documents/indianapolispowerlight-cd.pdf) and will be subject to NO_x and SO_2 limitations for 2025 and 2026 as follows: operate the coal-fired Units 1 through 4 at the Petersburg Station so the Units combined do not emit SO_2 in excess of an annual tonnage limitation of 10,100 tons per year and operate the coal-fired Units 1 through 4 at the Petersburg Station so the Units combined do not emit NO_x in excess of an annual tonnage limitation of 8,500 tons per year.
Posey	129	10	SIGECO - AB Brown	Units 1 & 2 are set to retire in 2023 per the 2019-2020 IRP and the dates was verified with the source.

Spencer	147	20	Indiana Michigan Power Agency dba AEP - Rockport	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 (www.govinfo.gov/content/pkg/FR-2019-06-07/pdf/2019-11948.pdf), 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. SO2 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 SO2 emission rate on the combined stack beginning with the 30th SO2 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 NOx emission rate on the combined stack beginning with the 30th NOx 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.

In addition, Indiana's coal-fired boilers will continue to dwindle in number after 2028. Based on long-range projections and IRPs, several utilities are planning on further retirements of boilers beyond 2028. Duke Gibson and Rockport are planning on retiring boilers at their facilities during the third implementation period of the Regional Haze Program. The specific units projected to retire at these facilities are shown in the following table.

Table 3-6 Indiana EGUs and Expected Unit Retirements beyond 2028 as used in the ERTAC Model

ORIS	Unit ID	Facility	State	ERTAC Region	Fuel/Unit Type Bin	Generation capacity (MW)	2016 BY Annual SO2 (tons)	2016 BY Annual NOx (tons)	2028 FY Annual SO2 (tons)	2028 FY Annual NOx (tons)	Retirement Date
990	GT4	IPL - Harding Street S	IN	RFCW	simplecycleg	86	0	53	1	132	1/1/44
990	GT5	IPL - Harding Street S	IN	RFCW	simplecycleg	88	0	39	1	77	1/1/30
990	GT6	IPL - Harding Street S	IN	RFCW	simplecycleg	199	1	28	3	129	1/1/30
6113	1	Gibson	IN	RFCW	coal	753	1,807	1,887	1,990	2,204	1/1/38
6113	2	Gibson	IN	RFCW	coal	720	2,340	2,953	2,619	2,092	1/1/38
6113	3	Gibson	IN	RFCW	coal	677	2,114	3,019	2,296	1,988	1/1/34
6113	5	Gibson	IN	RFCW	coal	728	5,495	3,273	6,095	2,337	1/1/34
6166	MB1	Rockport	IN	RFCW	coal	1,394	11,401	6,043	4,912	4,334	12/30/28

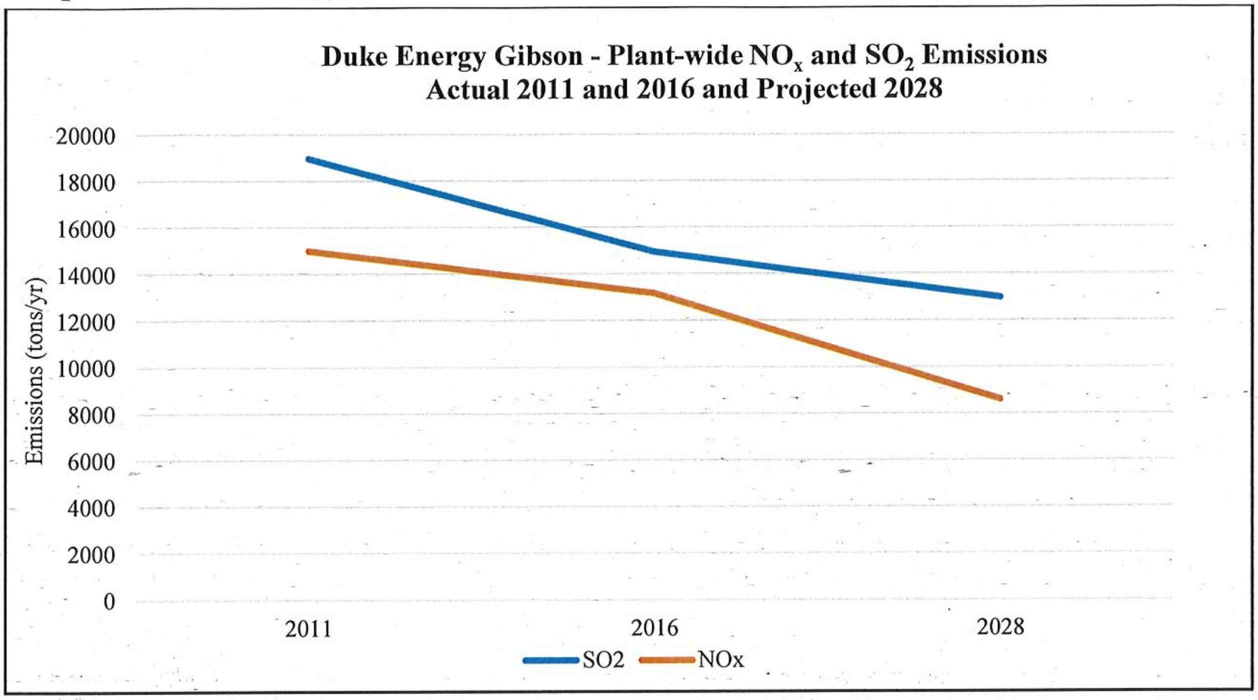
To pursue additional emission reductions through the use of new emission control equipment or emission limitations is not desired as a cost-effective method and will only drive utility rates even higher. As will be shown below, the emission reductions and modeling results show that visibility impairment from Indiana EGUs in total and particularly from Duke Gibson and AEP Rockport are decreasing as total light extinction at most all Class I areas is decreasing.

4.0 DUKE ENERGY, INC - GIBSON GENERATING STATION

Duke Energy, INC - Gibson Generating Station is located 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 dry bottom, pulverized coal-fired boilers. Controls for these units include wet limestone fluidized-gas desulfurization units controlling SO_2 emissions with control efficiencies above 93% (based on source calculations) and selective catalytic reduction systems for NO_x emissions with control efficiencies above 81% (based on source calculations).

Gibson's EGUs 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. Graph 4-1 shows the actual emissions changes that have occurred and changes in emissions projected by 2028.

Graph 4-1 Duke Energy - Gibson's SO_2 and NO_x Emission Trends



Duke Energy's IRP from 2019 was updated to reflect the advancement of retirements for several of their existing coal fired EGUs. Gibson is projected to accelerate retirements of Units 1-6; however, Unit 4 is the only unit expected to retire before 2028. These retirements are part of Duke Energy's overall plan to move to a more diversified clean energy portfolio. The retirement dates for Gibson's Unit 4 were confirmed with the source in November 2020.

The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. 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 power generation capacity with retirements of other boilers. For Gibson's future emission 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 Table 4-1.

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

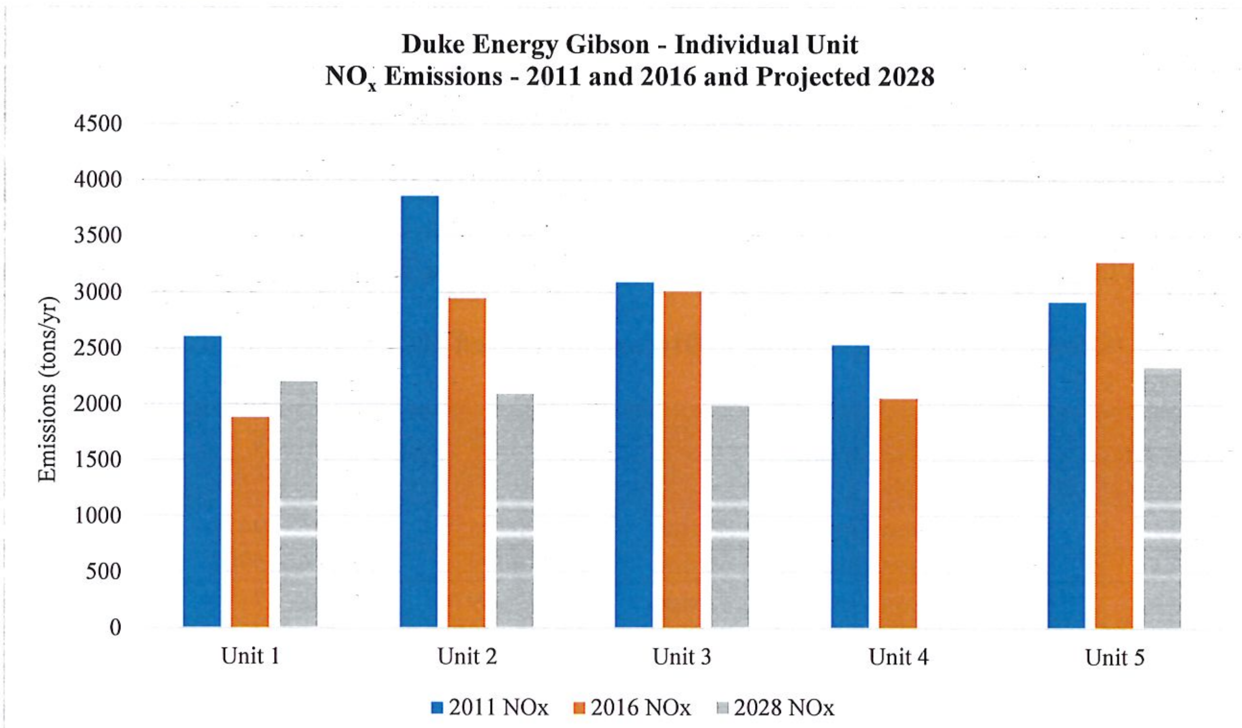
ORIS-ID	Unit ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028-ERTAC	Percentage Change in Utilization
6113	1	Gibson Generating Station	0.470088650	0.5175329430	10.09%
6113	2	Gibson Generating Station	0.634009223	0.7096633900	11.93%
6113	3	Gibson Generating Station	0.615733974	0.6688487450	8.63%
6113	4	Gibson Generating Station	0.548344335	Retired	-100.00%
6113	5	Gibson Generating Station	0.572596578	0.6350943340	10.91%

These 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. 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 emission 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 emission 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 as a result of the retirement of Unit 4 in order to meet anticipated electricity demands based on less generation capacity.

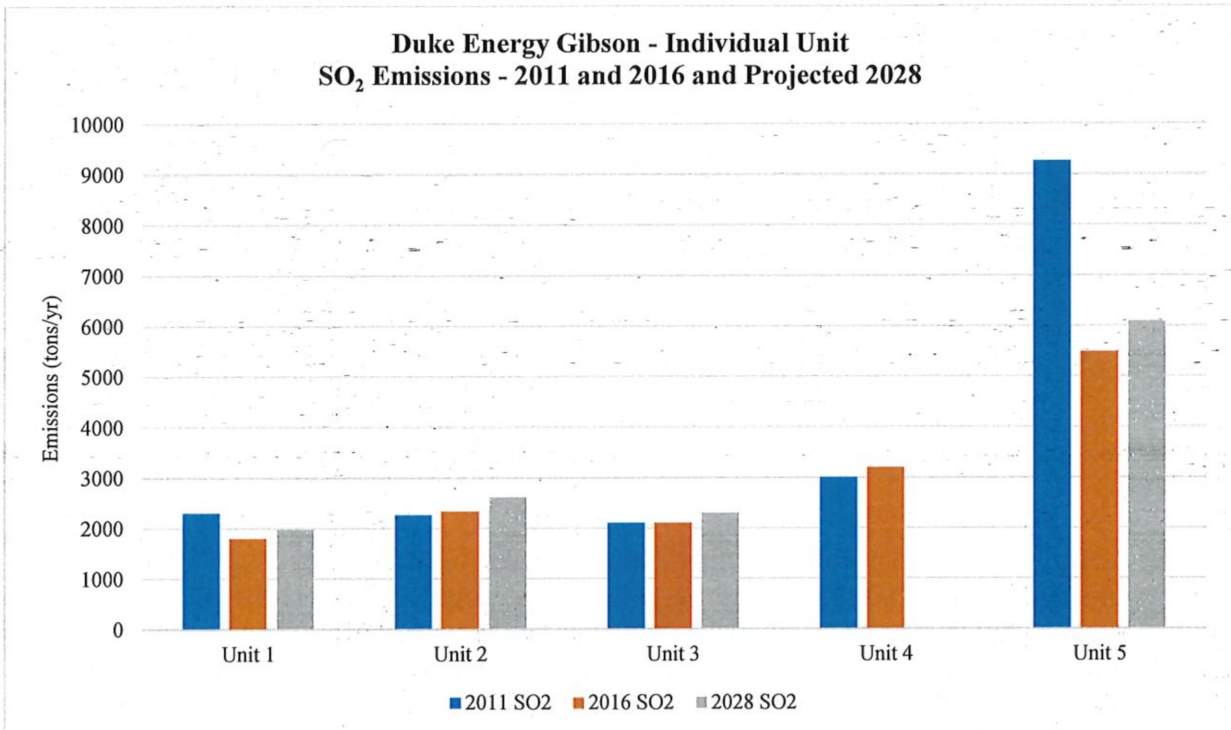
Graph 4-2 demonstrates the unit-by-unit comparison of NO_x emissions at the Duke - Gibson power plant. Note the slight increase in emissions at each of the four remaining units, this demonstrates the increase in utilization based on Unit 4's retirement to meet anticipated power demand. As with SO_2, overall NO_x emissions at Gibson are projected to decrease by 35% from 2016 to 2028.

Graph 4-2 Unit Comparison of 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 Gibson's SO_2 Emissions – Actual 2011 and 2016, Projected 2028

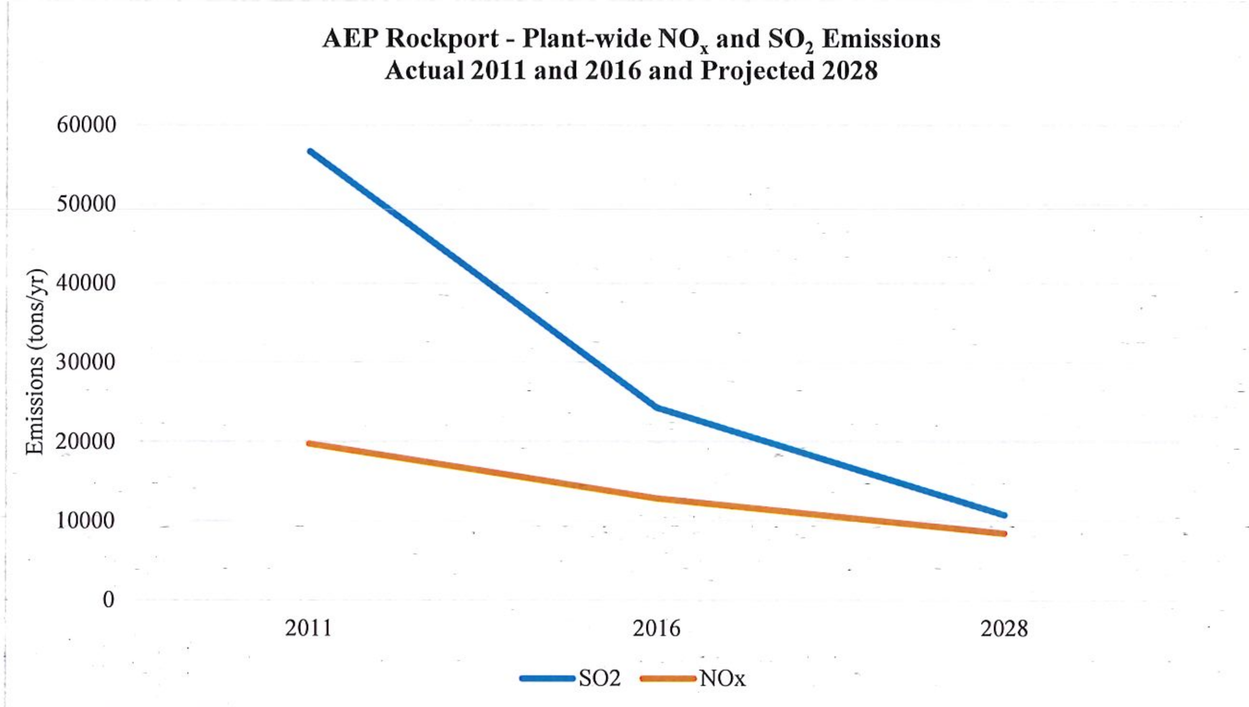


5.0 INDIANA MICHIGAN POWER COMPANY DBA AMERICAN ELECTRIC POWER - ROCKPORT GENERATING STATION

Indiana Michigan Power Company, dba American Electric Power (AEP) - Rockport Generating Station is located in Spencer County, in the southern portion of Indiana. It is a stationary electric utility generating station with a maximum generating capacity of 2,774 megawatts among two pulverized coal opposed wall fired dry bottom boilers (Units MB1 and MB2). Controls for these units include FGD units with SO_2 control efficiencies nearly 50% based on the latest 5-year average; low NO_x burner (dry bottom only) and air selective catalytic reduction systems/DSI for NO_x with control efficiencies above 57% based on the latest 5-year average.

Rockport NO_x emissions are estimated to be reduced by over 4,400 tons by 2028 or by 34% from 2016 emission levels. SO_2 emissions are undergoing greater reductions with over 13,500 tons reduced or 56% of the 2016 SO_2 emission levels by 2028 as demonstrated in Graph 5-1 on the next page.

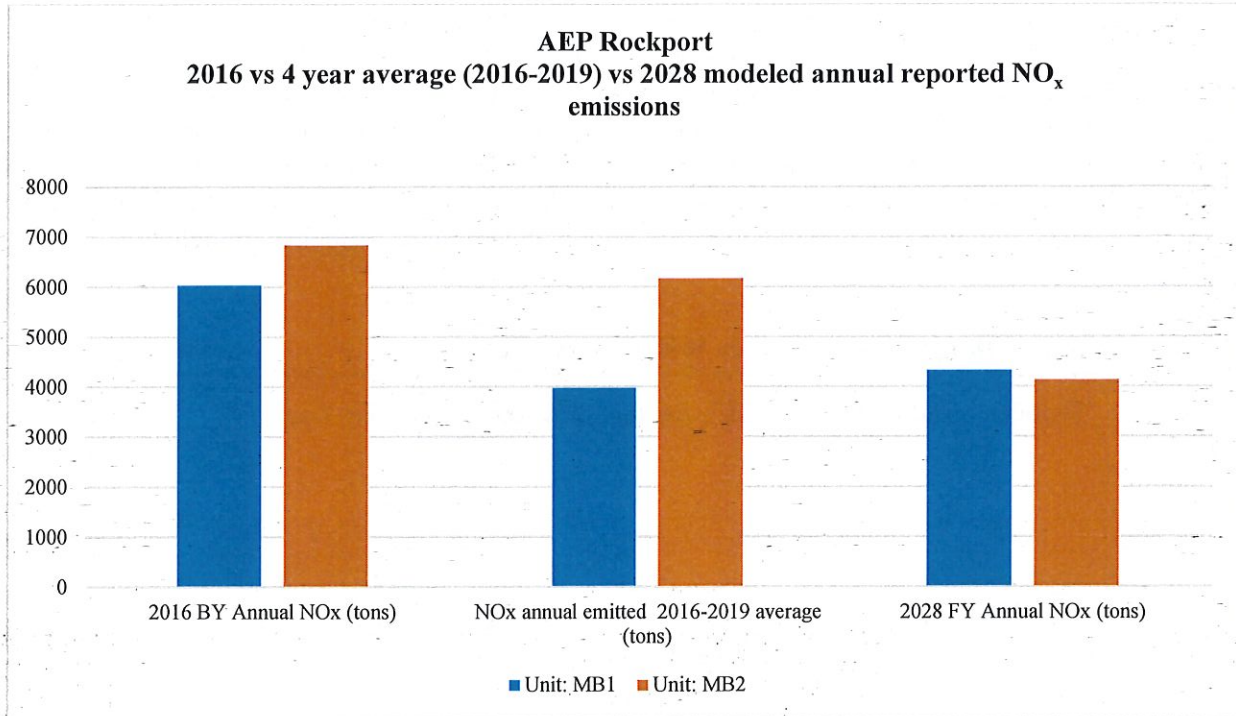
Graph 5-1 AEP Rockport's NO_x and SO_2 Emission Trends



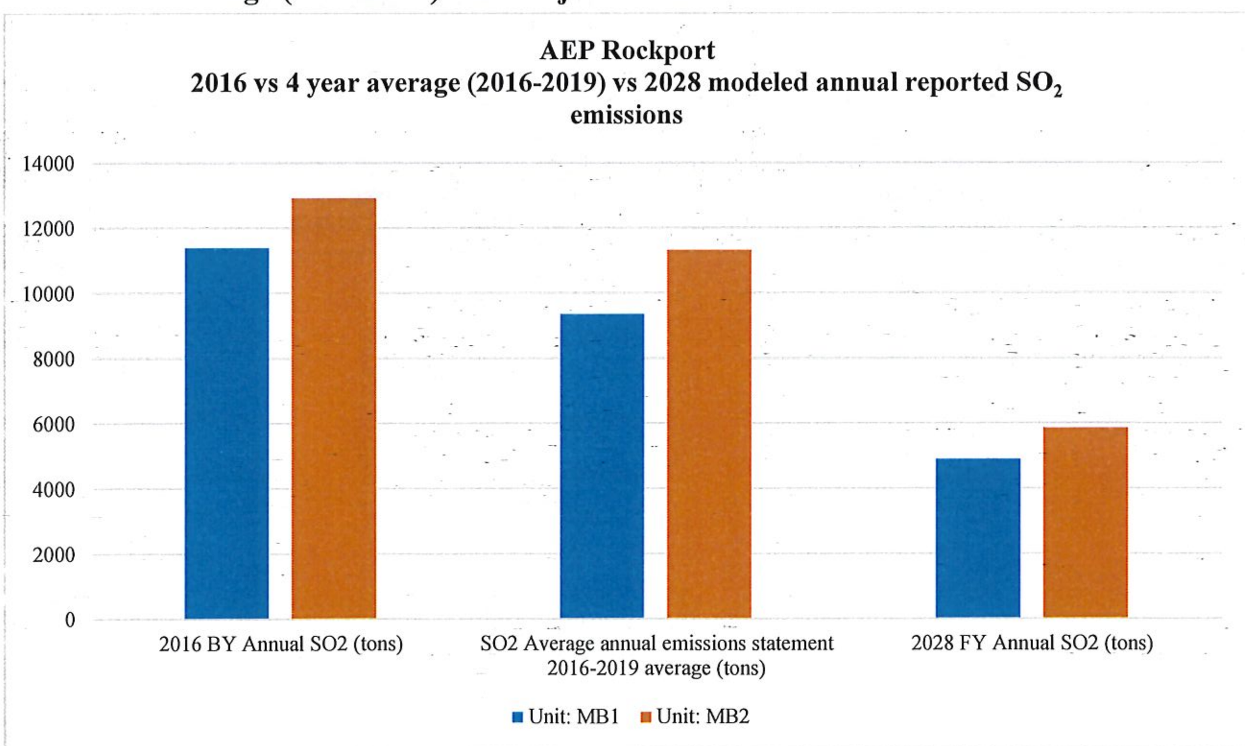
Rockport is required under a jointly modified consent decree signed on July 17, 2019, to install and continuously operate FGD systems, retire, refuel, or re-power Unit MB1 by December 31, 2025. This same requirement applies to Unit MB2 but by December 31, 2028. Rockport is also required to install advanced DSI by the same dates as listed above and operate a 30-day rolling average of 0.15 lb/MMBtu SO_2. Emissions are also required to be capped plant-wide in the agreement at 10,000 tons on an annual basis in between 2021 and 2028. Beginning in 2029 that plant wide total cap is lowered to 5,000 tons per year. In addition, Rockport was required to install and continuously operate a SCR on Unit MB1 by December 31, 2018, and Unit MB2 by June 1, 2020. AEP-Rockport met this requirement. This SCR shall maintain a 30-day rolling average NO_x emissions of 0.09 lb/MMBtu not later than the 13th calendar day of 2021. Both units at Rockport are included in the modeling for 2028.

Comparison of NO_x and SO_2 emissions by unit are shown below in Graphs 5-2 and 5-3 on the following page. The analysis demonstrates the continued downward trend of emissions from 2016 to projected emissions for 2028 with NO_x and SO_2 emissions decreases at both Units MB1 and MB2.

Graph 5-2 Unit Comparison of AEP Rockport's NO_x Emissions - Actual 2016 and 4-year Average (2016-2019) and Projected 2028



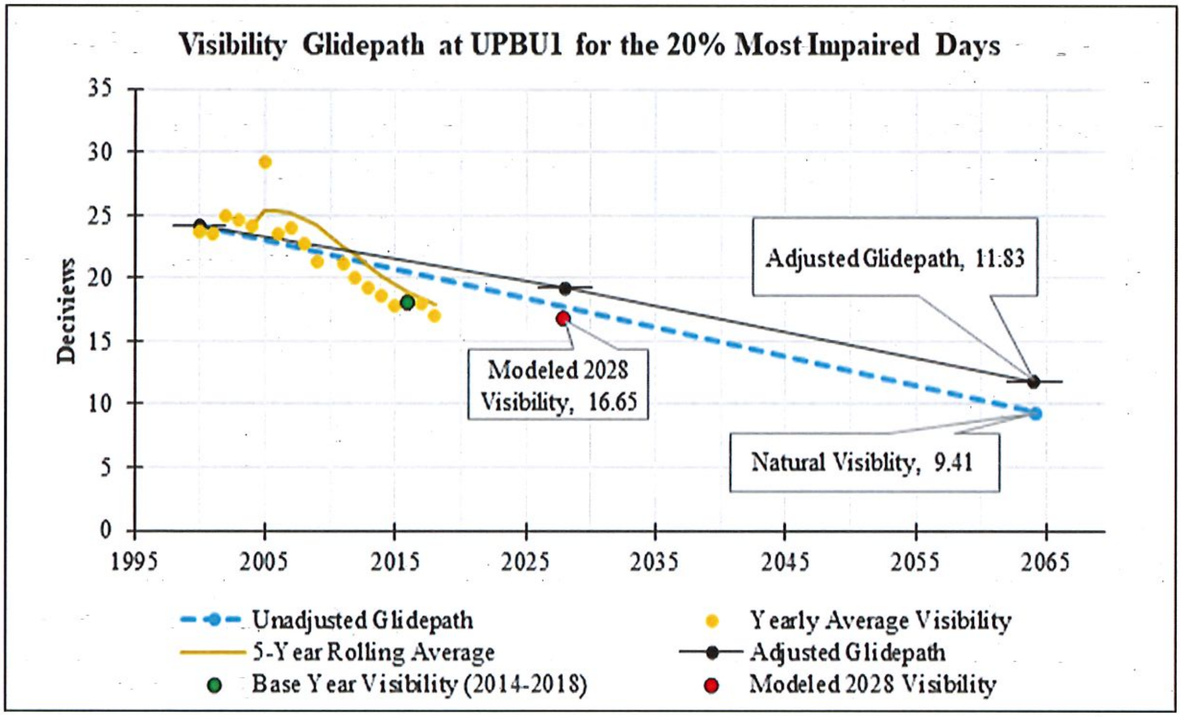
Graph 5-3 Unit Comparison of AEP Rockport's SO_2 Emissions – Actual 2016 and 4-year Average (2016-2019) and Projected 2028



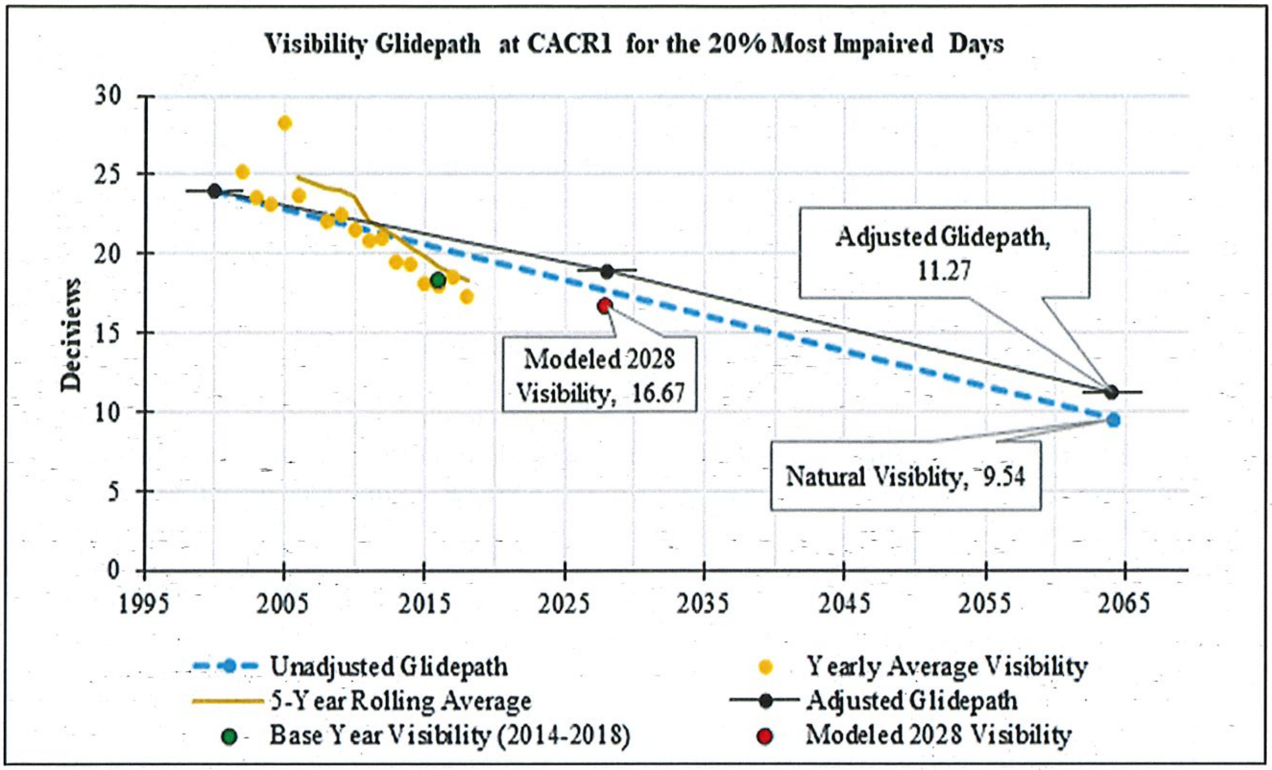
6.0 LADCO JUNE 2021 MODELING RESULTS

Indiana relied on LADCO to conduct photochemical modeling to determine visibility impacts, based on base-year 2016 emissions. Indiana included the Caney Creek Wilderness Area in its analysis as this is Arkansas' other Class I area within the state. The resulting glidepaths, shown below, include the IMPROVE monitoring data to determine visibility impacts on the 20% most anthropogenically impaired days. As can be seen, the IMPROVE monitoring data from 2014-2018 showed tremendous visibility progress at both Class I areas with visibility on the 20% most anthropogenically impaired days well below the glidepath and nearly equal to modeled 2028 visibility.

Graph 6-1 Glidepath for Upper Buffalo Wilderness Area



Graph 6-2 Glidepath for Caney Creek Wilderness Area



Results for both Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, are lower than the modeled visibility impacts at both Arkansas Class I areas for 2028, based on the 2011 emissions and nearly equal the modeled results from the base-year 2016 future year 2028 modeling. Table 6-1 shows the marked improvement of visibility at Class I areas from both the monitored data from 2000 through 2018 and the modeling data from base-year 2011 to base-year 2016 with projected emissions to 2028. Undoubtedly, more current monitored visibility data will show even further visibility improvement.

Table 6-1 Comparison of Monitored and Modeled Visibility for Arkansas Class I Areas

Site	2000-2004 Monitored Baseline (dv)	2009-2013 Monitored Baseline (dv)	2014-2018 Monitored Baseline (dv)	2011 base - 2028 Modeled Results (dv)	2016 base - 2028 Modeled Results (dv)
Upper Buffalo	24.2	20.5	18.0	18.8	16.7
Caney Creek	24.0	21.1	18.3	19.5	16.7

The significance of the 2014-2018 monitoring period is the marking of the end of the first implementation period of the Regional Haze Rule with much-improved visibility progress at all Class I areas. This visibility improvement emphasizes the emission reductions that have occurred in Indiana and throughout the country. Emission reductions from 2011 to 2016 reduced the visibility impacts from previous visibility modeling analyses, thus showing continued improvement in visibility at Class I areas over time. This fact is confirmed by the decrease in monitored visibility impairment at both Upper Buffalo and Caney Creek over the first implementation period. The emission reductions have realized monitored visibility benefits, and the reasonable progress goals are well ahead of future projections of visibility at the Class I areas for 2028. The steady decline of visibility impacts at the Class I areas from anthropogenic emissions over the past decade or more is significant and indicate that Indiana, as well as all other states, are taking the necessary steps to remain ahead of schedule in attaining natural visibility conditions at all Class I areas by 2064.

7.0 LADCO SOURCE APPORTIONMENT MODELING

LADCO conducted source apportionment modeling, completed in June of 2021, in which several Indiana emission sectors including all EGUs in Indiana and both of the identified Indiana EGU sources, Duke Energy - Gibson Generating Station and AEP - Rockport Generating Station tagged individually, were evaluated to determine their modeled visibility impacts. The visibility modeling results are shown below in Table 7-1 for both Class I areas in Arkansas, each Class I area's modeled 2028 total light extinction value based on 2016 emissions, Indiana EGUs overall visibility contribution to the total light extinction at each of the Class I areas, and the percentage of Indiana's EGUs visibility impact.

Table 7-1 All Indiana EGUs Visibility Impacts for Arkansas' Class I Areas

Class I Area	2016-2028 Total Light Extinction (Mm^{-1})	Indiana EGU Contribution to 2016-2028 Total Light Extinction (Mm^{-1})	Indiana EGU Contribution to 2016-2028 Total Light Extinction (%)
Upper Buffalo	54.4	0.715	1.3%
Caney Creek	54.4	0.43	0.8%

As mentioned, LADCO's source apportionment modeling looked at the individual impacts from Rockport and Gibson. In Table 7-2, modeled results show Rockport contributes below 0.4% to total light extinction at Upper Buffalo Wilderness Area and at 0.21% at Caney Creek. A more detailed look at the precursor pollutants showed Rockport's contribution to total sulfate visibility impacts were below 1% at Upper Buffalo Class I area and below 0.5% at Caney Creek. Rockport's contribution to total nitrate visibility impacts were less than 0.2% at both Class I areas. Indiana believes a better representation of visibility impairments on the 20% most anthropogenically impaired days is to consider the total light extinction and compare with the source's combined emissions impact on visibility. Rockport's future year visibility contribution as a percent of total emissions is projected to be higher as a result of the number of coal unit retirements statewide between 2016 and 2028. In terms of total mass contribution from Rockport, emissions are lower in 2028 versus the base year. As stated previously, overall visibility modeling demonstrates RPGs are being met and the RPGs are well below the uniform rate of progress for all Class I areas of concern.

Table 7-2 Rockport Visibility Impacts for Selected VISTAS Class I Areas

Class I Area	Rockport	Total Nitrate	Rockport Nitrate	Rockport	Total Sulfate	Rockport Sulfate	Total Class I Light	Rockport

	Nitrate Impact (Mm^{-1})	Impact (Mm^{-1})	Impact (%)	Sulfate Impact (Mm^{-1})	Impact (Mm^{-1})	Impact (%)	Extinction (Mm^{-1})	Total Impact (%)
UPBU	0.02	11.2	0.17%	0.19	19.9	0.96%	54.4	0.39%
CACR	0.01	8.31	0.17%	0.1	21.89	0.46%	54.4	0.21%

LADCO modeling shows that Duke Gibson contributes 0.22% to total light extinction at Upper Buffalo and 0.16% to total light extinction at Caney Creek Class I areas. While Duke Gibson's contribution to total sulfate visibility impacts were approximately 0.5% at Upper Buffalo and 0.35% at Caney Creek, its contribution to total nitrate impact was less than 0.2% at both Class I areas. Indiana considers a better representation of visibility impairments on the 20% most anthropogenically impaired days is to compare the total light extinction at the Class I areas with the source's combined NO_x and SO_2 emissions and its impact on total light extinction. Gibson's future year visibility contribution as a percent of total emissions is projected to be higher as a result of the number of coal unit retirements statewide between 2016 and 2028. In terms of total mass contribution from Gibson, emissions are lower in 2028 versus the base year.

Table 7-3 Gibson Visibility Impacts for Selected VISTAS Class I Areas

Class I Area	Gibson Nitrate Impact (Mm^{-1})	Total Nitrate Impact (Mm^{-1})	Gibson Nitrate Impact (%)	Gibson Sulfate Impact (Mm^{-1})	Total Sulfate Impact (Mm^{-1})	Gibson Sulfate Impact (%)	Total Class I Light Extinction (Mm^{-1})	Gibson Total Impact (%)
UPBU	0.01	11.20	0.15	0.11	19.93	0.53	54.4	0.22
CACR	0.01	8.31	0.12	0.08	21.89	0.35	54.4	0.16

In summary, the source apportionment modeling conducted by LADCO confirms the overall visibility improvement realized by both Class I areas in Arkansas as with all other Class I areas in the eastern half of the country. Contributions from Rockport and Gibson are small percentages of the overall visibility impairment, which based on current monitoring and modeling results, is decreasing each year and remains well below the uniform rate of progress. Further retirements of boilers and anticipated emission reductions throughout the country will continue to drive the visibility impairment lower at Arkansas' Class I areas and will realize continued improved visibility.

8.0 FEDERAL AND STATE REGULATIONS DISCUSSION

The primary Federal and state regulations governing the interstate transport of NO_X and SO_2 emissions from EGUs are described below.

8.1 Cross State Air Pollution Rule

EPA finalized the Cross State Air Pollution Rule (CSAPR) to reduce the interstate transport of fine PM and ozone on July 6, 2011, with publication in the Federal Register on August 8, 2011. The final rule replaces EPA's 2005 Clean Air Interstate Rule (CAIR) that was vacated by a December 2008 court decision that kept CAIR in place temporarily while directing EPA to issue a replacement rule. CSAPR requires 27 states, including Indiana, in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle ($PM_{2.5}$) pollution in other states.

CSAPR includes a process for determining each upwind state's responsibility to protect downwind air quality. Each time the National Ambient Air Quality Standard (NAAQS) is changed, U.S. EPA will apply this process and determine if interstate pollution transport contributes to exceedances of the new standard and whether new emission reductions should be required from upwind states. The rule defines what portion of an upwind state's emissions "significantly contribute" to ozone or $PM_{2.5}$ pollution in nonattainment or maintenance areas in downwind states. This definition considers the magnitude of a state's contribution, the air quality benefits of reductions, and the cost of controlling pollution from various sources. Once these obligations are determined, the rule requires states to eliminate the portion of their emissions defined as their "significant contribution" by setting a pollution limit (or budget) for each covered state.

The rule allows air quality-assured allowance trading among covered sources, utilizing an allowance market infrastructure based on existing, successful allowance trading programs. CSAPR allows sources to trade emission allowances with other sources within the same program (for example, Transport Rule Ozone Season NO_x Trading Program) in the same or different states, while firmly constraining any emissions shifting that may occur by requiring a strict emission ceiling (state assurance level) in each state (the budget plus variability limit). It includes assurance provisions that ensure each state will make the emission reductions necessary to meet the "good neighbor" provision of the Clean Air Act.

CSAPR requires significant reductions in NO_x and SO_2 emissions that react in the atmosphere to form $PM_{2.5}$ and ground-level ozone and are transported long distances. The first phase of compliance began January 1, 2012, for annual NO_x and SO_2 reductions and May 1, 2012, for ozone season NO_x reductions. The second phase of SO_2 reductions began January 1, 2014. Indiana is designated as a Group 1 state in CSPAR with additional SO_2 reductions in 2014.

The state of Indiana developed a state implementation plan to administer the three trading programs under CSAPR and allocate allowances for affected EGUs that started in 2021. The CSAPR Programs rulemaking revised Article 24 of the Indiana Administrative Code (IAC) to incorporate CSAPR requirements and repealed the remaining portions of CAIR. The final rule, 326 IAC 24, was adopted on November 24, 2017, and SIP approved and published in the Federal Register on December 17, 2018.

8.2 Revised Cross-State Air Pollution Rule Update

On October 15, 2020, EPA proposed the Revised Cross-State Air Pollution Rule Update in order to fully address 21 states' outstanding interstate pollution transport obligations for the 2008 ozone NAAQS. Starting in the 2021 ozone season, the proposed rule would require additional emission reductions of NO_x from power plants in 12 states. The proposed rulemaking responds to a September 2019 ruling by the United States Court of Appeals for the D.C. Circuit, Wisconsin v. EPA, which remanded the 2016 CSAPR Update to EPA for failing to fully eliminate significant contribution to nonattainment and interference with maintenance of the 2008 ozone NAAQS from upwind states by downwind areas' attainment dates.

Indiana is one of the 12 linked states required to participate in a new CSAPR NO_x Ozone Season Group 3 Trading Program that largely replicates the existing CSAPR NO_x Ozone Season Group 2 Trading Program with additional budget stringency for affected states. Indiana's projected 2021 emissions were found to contribute at or above a threshold of 1% of the NAAQS (0.75 ppb) to the identified nonattainment and/or maintenance problems in downwind states. EPA proposes to issue new or amended Federal Implementation Plans (FIPs) to revise state emission budgets to reflect additional emission reductions from EGUs beginning with the 2021 ozone season. In order to respect attainment deadlines as directed by the court in Wisconsin v. EPA, EPA must revise the existing CSAPR NO_x ozone season program as quickly as possible to enable improvements in downwind ozone by the 2021 ozone season, which corresponds with the 2021 Serious area attainment date under the 2008 ozone NAAQS. This proposed action's FIPs would require power plants in the 12 linked states to participate in a new CSAPR NO_x Ozone Season Group 3 Trading Program that largely replicates the existing CSAPR NO_x Ozone Season Group 2 Trading Program, with the main differences being the geography and budget stringency. Aside from the removal of the 12 covered states from the current CSAPR NO_x Ozone Season Group 2 Trading Program, this proposal leaves unchanged the budget stringency and geography of the existing CSAPR NO_x Ozone Season Group 1 and Group 2 Trading Programs.

EPA also proposes to adjust these 12 states' emission budgets for each ozone season thereafter to incentivize ongoing operation of identified emission controls to address significant contribution, until such time that air quality projections demonstrate resolution of the downwind nonattainment and/or maintenance problems for the 2008 ozone NAAQS. As such, the proposal includes adjusting emission budgets for each state for each ozone season for 2021 through 2024. After the 2024 ozone season, no further adjustments would be required under this proposed rulemaking. EPA proposes to authorize a one-time conversion of allowances banked in 2017-2020 under the CSAPR NO_x Ozone Season Group 2 Trading Program into a limited number of allowances that can be used for compliance in the CSAPR NO_x Ozone Season Group 3 Trading Program. This approach gives due credit for the emission reductions represented by banked allowances, while also securing the additional reductions required in this proposed rulemaking. EPA solicited comments on the proposed rule and allowed 45 days for comment following publication.

9.0 SUMMARY OF INDIANA'S EGU ANALYSIS

Indiana surmises that its EGU sector was evaluated in great detail for the first implementation period of the Regional Haze Rule. Based on diverse industry-wide emission control measures mandated by strict regulations and far less reliance on coal over the past decade as more alternative power generation becomes available; 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 with overall EGU NO_x emission decreases projected from 2011 to 2028 to be over 70%, and a nearly 90% decrease in SO_2 emissions. Additional retirements of EGUs are expected in addition to those listed herein.

Results for all Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, are nearly equal and in some cases, lower than the modeled results from the base-year 2011 and base-year 2016 modeling. This emphasizes the emission reductions that have occurred in Indiana and throughout the country have realized monitored visibility benefits and the reasonable progress goals are well ahead of future projections of visibility at the Class I areas for 2028. PSAT results have shown that the two utilities identified by CENSARA have 1% or less visibility impacts on the CENSARA Class I areas located within 300 kilometers of the two utilities.

The steady decline of visibility impacts at the Class I areas from anthropogenic emissions over the past decade or more is significant. This indicates that Indiana, as well as all other states, are taking the necessary steps to remain ahead of schedule in attaining natural visibility conditions at all Class I areas by 2064.

The CSAPR Update proposes revised state emission budgets that reflect additional emission reductions from EGUs beginning with the 2021 ozone season to address projected 2021 emissions found to contribute at or above a threshold of 1% of the NAAQS (0.75 ppb) to the identified nonattainment and/or maintenance problems in downwind states. The proposed budget for 2021 NO_x Ozone Season was 23,303. The new budget is 12,500 with a 21% variability limit and EPA's projected emissions are 15,856.

As can be seen, emission reductions, monitoring data and modeling results clearly demonstrates improved visibility, especially in the eastern half of the county. Monitoring data indicated stark reductions in impaired visibility values, which are well ahead of the uniform rate of progress for the Class I area identified in the CENSARA request. The most current source apportionment modeling conducted by LADCO indicates Indiana's overall visibility impacts are declining. Anticipated further retirements of EGUs in the state will only continue to lower emissions and the state's visibility impacts on surrounding Class I areas. EPA's "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, dated August 2019 states the "key flexibility of the regional haze program is that a state is not required to evaluate all sources of emissions in each implementation period". IDEM is intently evaluating other emission sectors for this second implementation period to determine their visibility impacts on Class I areas. IDEM will conduct a review of all its emission sources, with focus on the EGU sector, for its January 31, 2025, progress report: pursuant to 40 CFR 51.308 (g). IDEM will evaluate EGUs for the third implementation period of the RH Rule, as necessary, to be submitted in 2028. As a result, IDEM is not requiring 4-factor analyses from its EGUs nor will it conduct a 4-factor analysis on this emission sector for this second implementation period.

This page intentionally left blank.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.
100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • www.idem.IN.gov

Eric J. Holcomb
Governor

Brian C. Rockensuess
Commissioner

December 22, 2021

Darcy A. Bybee
Director, Office of Air Quality
Missouri Department of Natural Resources
Air Pollution Control Program
P.O. Box 176 Jefferson City, MO 65102

Re: Response to Notification for Consultation; Missouri Regional Haze State Implementation Plan for Planning Period II

Dear Mrs. Darcy A. Bybee:

On September 11, 2020, Indiana Department of Environmental Management (IDEM) received a request from the Missouri Department of Natural Resources' Air Pollution Control Program to consider whether performing a four-factor analysis is appropriate for each of these sources in accordance with 40 CFR 51.308(f)(2)(i) and, if so, whether any control measures for nitrogen oxides and sulfur dioxide are necessary to make reasonable progress towards natural visibility at Missouri's Mingo National Wildlife Refuge Area during the Regional Haze (RH) State Implementation Plan (SIP) second planning period.

Missouri is a member of the Central States Air Resources Agencies (CENSARA), which conducted a screening analysis to identify specific sources in Missouri and other states that warrant further analysis and evaluation for potential emission controls. The CENSARA modeling results showed visibility impacts from two of Indiana's electric generating unit sources: Duke Energy - Gibson Generating Station and AEP - Rockport Generating Station were reasonably anticipated to impact visibility conditions at the Mingo Class I area.

The Lake Michigan Air Directors Consortium (LADCO) regional planning organization conducted emissions analyses and photochemical modeling in support of its member states to assist with the development of their Regional Haze RH SIPs. Final source apportionment modeling results from LADCO were not available to IDEM in order to formulate an adequate response to the Missouri request until June of 2021.

The results of LADCO's modeling exercise, as well as emissions evaluations for the sources identified by Missouri are detailed in Indiana's response to Missouri's request within the attached document. Indiana's response emphasizes that LADCO's modeling results and the emissions analyses do in fact support Indiana's position that the state is meeting its RH obligations to the surrounding states with Class I areas and no further analysis is necessary for the sources identified by Missouri.

This response consists of one (1) hard copy of the requested information and electronic versions of the response to the Missouri request in PDF format sent to the Missouri Department of Natural Resources, Air Pollution Control Program. Thank you for initiating consultation on this important matter. If you have any questions or need additional information, please contact Jean Boling, Environmental Engineer, Air Quality Planning Section, Office of Air Quality, at (317) 232-8228 or jboling@idem.IN.gov.

Sincerely,

Matt Stuckey
Assistant Commissioner
Office of Air Quality

MS/sd/md/sb/jb
Enclosures

1. Missouri Request letter for RH Reasonable Progress Analysis for Indiana Sources Impacting Missouri Class I Areas
2. State of Indiana's Response to Missouri Request for RH SIP for the Second Implementation Period Consultation, Electric Generating Units Nitrogen Oxides and Sulfur Dioxide Reasonable Progress Emissions Reduction and Visibility Analysis

cc: Emily Wilbur, Missouri Department of Natural Resources, Air Pollution Control Program
Zac Adelman, Lake Michigan Air Directors Consortium (w/ enclosures)
Matt Stuckey, IDEM-OAQ (no enclosures)
Scott Deloney, IDEM-OAQ (no enclosures)
Mark Derf, IDEM-OAQ (w/ enclosures)
Susan Bem, IDEM-OAQ (w/ enclosures)
Jean Boling, IDEM-OAQ (w/ enclosures)
File Copy

STATE OF INDIANA'S RESPONSE

TO THE

STATE OF MISSOURI

FOR

REGIONAL HAZE STATE IMPLEMENTATION PLAN
FOR THE
SECOND IMPLEMENTATION PERIOD CONSULTATION

Electric Generating Units
Nitrogen Oxides and Sulfur Dioxide
Reasonable Progress Emissions Reduction and Visibility Analysis

Prepared by:
The Indiana Department of Environmental Management
December 2021

This page intentionally left blank.

TABLE OF CONTENTS

FIGURES

TABLES

GRAPHS

ACRONYMS/ABBREVIATIONS LIST

AoI	Area of Influence
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
CAA	Clean Air Act
CAMD	Clean Air Markets Division
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
EGU	Electric Generating Units
EPA	United States Environmental Protection Agency
ERTAC	Eastern Regional Technical Advisory Committee
ETS	Emission Tracking System
FGD	Flue Gas Desulfurization
FLMs	Federal Land Managers
IDEM	Indiana Department of Environmental Management
IMPROVE	Interagency Monitoring of Protected Visual Environments
IPM	Integrated Planning Model
IRP	Integrated Resource Plan
LADCO	Lake Michigan Air Directors Consortium
lb/MMscf	Pound Per Million Standard Cubic Foot
lb/MMBtu	Pound Per Million British Thermal Units
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NEEDS	National Electric Energy Demand System
NG	Natural Gas
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
MARAMA	Mid-Atlantic Regional Air Management Association
MMBtu	Million British Thermal Unit
MMBtu/hr	Million British Thermal Unit Per Hour
PSAT	Particulate Matter Source Apportionment Technology
RH	Regional Haze
RPGs	Reasonable Progress Goals
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SMOKE	Sparse Matrix Operator Kernel Emissions
SO_2	Sulfur Dioxide
tons/yr	Tons Per Year
VISTAS	Visibility Improvement State and Tribal Association of the Southeast

This page intentionally left blank.

1.0 BACKGROUND

The Indiana Department of Environmental Management (IDEM) received a request from the Missouri Department of Natural Resources' Air Pollution Control Program (Air Program) to consider whether performing a four-factor analysis is appropriate for each of these sources in accordance with 40 CFR 51.308(f)(2)(i) and, if so, whether any control measures for nitrogen oxides (NO_x) and sulfur dioxide (SO_2) are necessary to make reasonable progress towards natural visibility at Missouri's Mingo National Wildlife Refuge Area during the Regional Haze (RH) State Implementation Plan (SIP) second planning period.

Missouri is a member of the Central States Air Resources Agencies (CENSARA), which conducted a screening analysis to identify specific sources in Missouri and other states that warrant further analysis and evaluation for potential emission controls. The CENSARA modeling results showed visibility impacts from two of Indiana's EGU sources: Duke Energy - Gibson Generating Station and AEP - Rockport Generating Station were reasonably anticipated to impact visibility conditions at the Mingo Class I area.

2.0 INTRODUCTION

The Environmental Protection Agency (EPA) acknowledged in its "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," dated August 20, 2019 (EPA RH SIP Guidance) that "A key flexibility of the RH program is that a state is not required to evaluate all sources of emissions in each implementation period." Twenty sources met IDEM's source selection criteria for the RH SIP four-factor analysis. Eleven of the sources are power generating stations with coal-fired electric generating units (EGUs). Instead of conducting a four-factor analysis for the eleven EGU sources for the RH SIP, IDEM chose to perform a reasonable progress analysis that consisted of a quantitative analysis of state-wide NO_x and SO_2 emission reductions from Indiana's EGU fleet for 2009-2019; photochemical modeling using 2016 NO_x and SO_2 base-year modeled emissions for all existing Indiana EGUs in 2016 to project 2028 emissions; and source apportionment modeling to assess visibility impacts from all EGUs in Indiana. However, a four-factor analysis will be conducted for the other nine non-EGUs that met the selection criteria.

Indiana's rationale for this approach is based on the guidance that an analysis of control measures is not required for every source in each implementation period. The RH Rule sets up an iterative planning process and anticipates that a state may not need to analyze control measures for all its sources in a given SIP revision. Specifically, section 51.308(f)(2)(i) of the RH Rule requires a SIP to include a description of the criteria the state used to determine the sources or groups of sources it evaluated for potential controls. Accordingly, it is reasonable and permissible for a state to distribute its own analytical work for the sources that are not selected for an analysis of control measures for purposes of the second implementation period and it may be appropriate for a state to consider whether measures for such sources are necessary to make reasonable progress in later implementation periods as stated in the EPA RH SIP Guidance, Section 3 on page 9.

The EPA RH SIP Guidance also states that a state has the flexibility to use any reasonable method for quantifying the impacts of its own emissions on out-of-state Class I areas, and it may use any reasonable assessment for this determination according to Section 2 on page 8 in the EPA RH SIP Guidance. The RH Rule does not explicitly list factors that a state must or may not consider when selecting the sources for which it will determine what control measures are necessary to make reasonable progress. A state opting to select a set of its sources to analyze must reasonably choose factors and apply them in a reasonable way given the statutory requirement to make reasonable progress towards natural visibility.

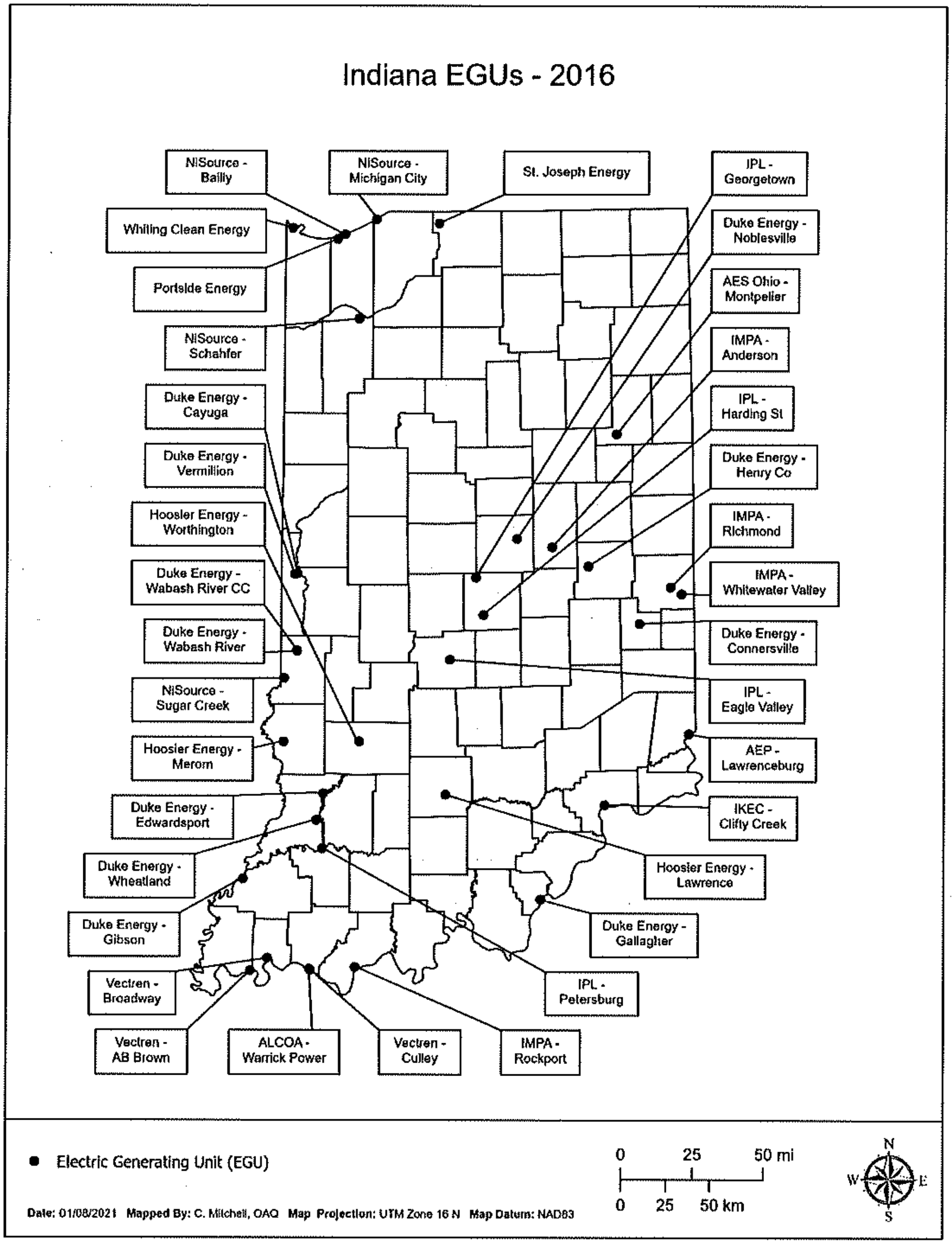
Indiana used the Q/d analysis to develop a source ranking list of the facilities in Indiana with the highest facility-wide NO_x and SO_2 emissions. The Q/d analysis is a simple surrogate metric used for quantifying and considering visibility impacts for the purpose of selecting sources to analyze for visibility impact at Class I Areas. Q/d equals the sum of the source's annual NO_x and SO_2 emissions in tons, Q, divided by the distance in kilometers (km) between the source and nearest Class I area, d. Visibility Impact = Q (NO_x Emissions + SO_2 Emissions)/d (Distance)

The Q/d threshold value of five was used as the cutoff for Indiana's source selections. The threshold of five was chosen to include a reasonable number of representative sources in the state for the four-factor analysis and for consistency among the Lake Michigan Air Director Consortium (LADCO) states. Therefore, sources with Q/d values above five, with the exception of the power generating stations, were chosen for evaluation. Indiana's EGU sources were evaluated in the RH SIP for the first implementation period under the 2005 BART Guidelines. Indiana's EGU fleet has multiple retirements and shutdowns and new add-on controls state-wide that the State can take credit for when evaluating EGUs for reasonable progress for the second implementation period RH SIP. Thus, Indiana decided that conducting four-factor analyses for the EGUs would expend needless resources and provide less value for the second implementation period than it would for the next implementation period since the owners/operators of the EGU sources in Indiana are still in the process of making decisions related to more retirements and shutdowns and new add-on control modifications.

3.0 INDIANA'S ELECTRIC GENERATING UNITS

Figure 3-1 below shows a map of the existing power generating stations located in Indiana in 2016. All the electric generating units at these facilities are included in the LADCO Eastern Regional Technical Advisory Committee (ERTAC) 2016 modeling.

Figure 3-1 Map of Indiana's Power Generating Stations in 2016

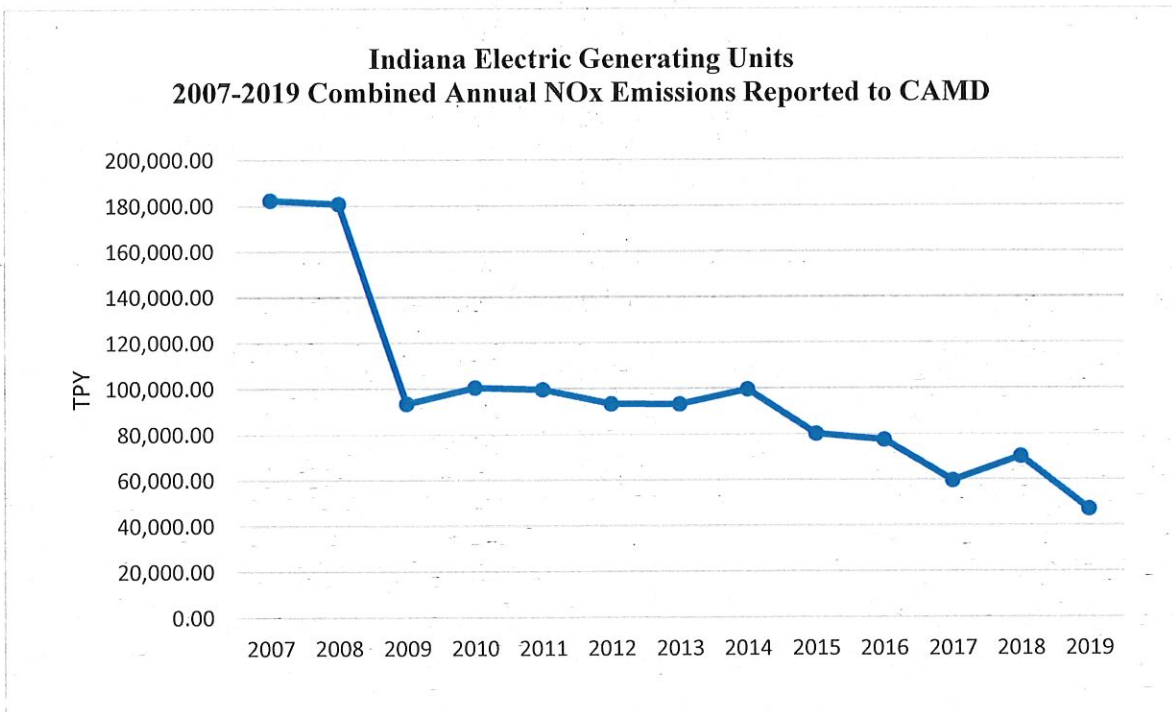


3.1 Indiana's EGUs 2007-2019 NOx Emission Trends

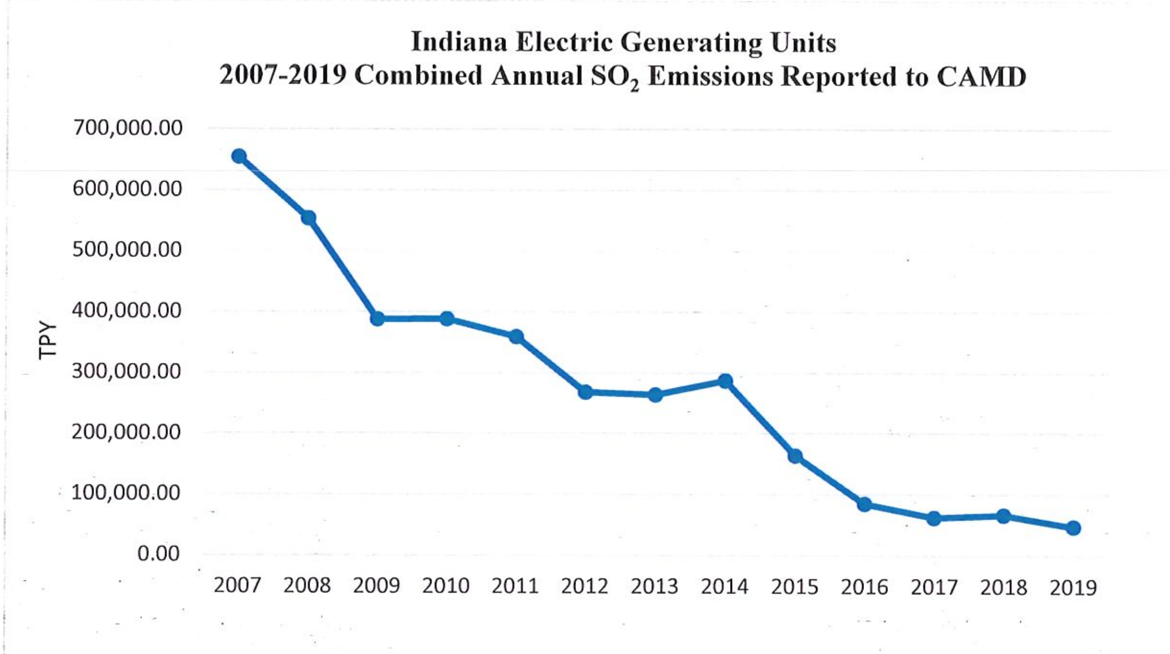
The combined annual NO_x and SO_2 emissions for all EGUs throughout Indiana decreased substantially from 2007 to 2019. Graph 3-1 below and Graph 3-2 on the next page demonstrate a downward trend in both NO_x and SO_2 state-wide annual emissions for Indiana EGUs during the 13-year evaluation period. The combined annual NO_x emissions for all EGUs throughout Indiana decreased by 50%, 46,360 tons, for 2019 compared to 2011 and 39%, 30,350 tons, for 2019 compared for 2016. A more dramatic downward trend is illustrated for state-wide annual SO_2 emissions for Indiana EGUs from 2007 to 2019 as shown by the line graph in Graph 3-2. The combined annual SO_2 emissions for all EGUs throughout Indiana were drastically reduced by 81%, 210,180 tons, for 2019 compared to 2011 and 38%, 29,490 tons, for 2019 compared for 2016. State-wide NO_x and SO_2 annual emissions data for Indiana's EGUs combined from 2007 to 2019 are listed in Table 1, respectively, under the "Combined 2007-19 NO_x Emissions" tab and Table 3 under the "Combined 2007-19 SO_2 Emissions" tab in Appendix A. The actual emissions data were taken from the Clean Air Markets Division (CAMD) database.

The combined annual NO_x and SO_2 emission reductions for all EGUs throughout Indiana are a direct result of shutdowns, fuel conversions from coal to natural gas (NG) and pollution control device upgrades and new add-ons that occurred during the 11-year evaluation period. Consent decree agreements with EPA, new Federal regulations designed to reduce NO_x and SO_2 (and mercury) emissions from power plants that were implemented after 2009 and revised National Ambient Air Quality Standards have also aided in lowering state-wide emissions from all EGUs throughout Indiana from 2007 to 2019.

Graph 3-1 Indiana EGUs 2007-2019 Combined Annual NO_x Emissions Reported to CAMD



Graph 3-2 Indiana EGUs 2007-2019 Combined Annual SO_2 Emissions Reported to CAMD



3.1.1 EGU Retirements and Shutdowns

The following coal fired EGUs were shut down during the 13-year evaluation period. A total of 34 coal fired EGUs have been retired and shutdown due to consent decree agreements and new Federal and state regulations implemented during the evaluation period.

Table 3-1 Indiana EGUs Retirements and Shutdowns between 2007 and 2019

Facility Name	Unit Identification	Year
Bailly Generating Station	10, 7, and 8	2018
FB Culley Generating Station	1	2007
Cayuga Generating Station	4	2009
Dean H Mitchell	4, 5, and 6	2010
Edwardsport Generating Station	7-1, 7-2, and 8-1	2010
Frank E Ratts Generating Station	1SG1	2016
	2SG1	2015
Harding Street Generating Station	9 and 10	2011
Eagle Valley Generating Station	1 and 2	2011
	4, 5, 6, and 7	2015
R Gallagher Generating Station	1 and 3	2012
State Line Generating Station	3 and 4	2012
Tanners Creek Generating Station	U1, U2, U3, and U4	2015
Wabash River Generating Station	2, 3, 4, and 5	2015
State Line Generating Station	6	2016

3.1.2 EGU Fuel Switch Conversions

Three EGUs at the Harding Generating Station (Units 50, 60, and 70) were converted from coal to natural gas fuels in 2015 and 2016. As a result, annual NO_x emissions decreased by 76% for Unit 50 (62 tons), 72% for Unit and 60 (52 tons), and 50%, for Unit 70 (382 tons) for 2019 compared to 2016. Annual SO_2 emissions from Units 50, 60, and 70 decreased by 74, 70, and 99%, respectively for 2019 compared to 2016 with reductions in tons of SO_2 emissions equal to nearly 1 ton for Units 50 and 60 and 269 tons for Unit 70. The complete results of the fuel switches were not realized until 2017. Table 2 under the EGUs 2007-2019 NO_x Emissions Tab and Table 4 under the EGUs 2007-2019 SO_2 Emissions Tab in Appendix A lists the actual NO_x and SO_2 emissions for all Indiana EGUs for 2007-2019 reported to CAMD.

Table 3-2 Indiana EGUs Fuel Conversions between 2009 and 2019

Facility Name	Unit Identification	Year
Harding Street Generating Station	50 and 60	2015
Harding Street Generating Station	70	2016

3.1.3 EGU Pollution Control Devices Upgrade and Add-on Modifications

Table 3-3 summarizes the pollution control devices upgrade and new add-on modifications to Indiana's coal fired EGUs in order to meet consent decree agreement requirements and new Federal and state regulations implemented during the 11-year evaluation period. A more detailed list of the coal fired EGU pollution control devices, control efficiencies and retirements and shutdowns is attached in Appendix B. A source-specific evaluation of the three EGU sources VISTAS identified for reasonable progress analysis is provided in Sections 4, 5, and 6.

Table 3-3 Indiana EGUs Pollution Control Devices Upgrade and New Add-on Modifications between 2009 and 2019

Facility Name	Unit Id	PM	SO_2	NO_x	SO_3/ $H2SO_4$	Hg
AB Brown Generating Station	1 & 2				Sorbent Injection	Mercury re-emission chemical injection (2015), Calcium Bromide (2016)
Alcoa Power Plant	4				Reagent Injection	
Cayuga Generating Station	1 & 2			SCR	SO_3 Mitigation (2015)	
Clifty Creek Generating Station	1, 2, 3, 4, 5, & 6	FGD installed in 2013 (co-benefit of PM removal)	FGD became operational on all six units in 2013		Dry Sorbent Injection installed on units 1 through 5 in 2013	FGD installed in 2013 (co-benefit of Hg removal) with ability to provide chemical additives on as needed basis
FB Culley Generating Station	3				Sorbent Injection	Mercury re-emission chemical injection (2015)
Gibson Generating Station	1, 2,3, & 5				SO_3 Mitigation Systems	Mercury re-emission chemical injection system (2015), Calcium Bromide (2015)
	4					Calcium Bromide (2015)
Merom Generating Station	1SG1 & 2SG1		Redesigned FGDs		SO_3 Mitigation Systems	ACI (2015)
Petersburg Generating Station	1	Upgrade ESP	Upgrade Bypass Scrubber and DSI		Reagent Injection	ACI
	2	Baghouse (2015)	Upgrade Bypass Scrubber and DSI		Reagent Injection	ACI
	3	Baghouse (2016)/ Cold-side ESP	Wet FGD upgraded in 2006		Reagent Injection	ACI
	4	Upgrade ESP	Wet FGD upgraded in 2011		Reagent Injection	ACI
R Gallagher Generating Station	2 & 4		DSI (2010)			
R M Schahfer	14		FGD (2013)	Reagent Injection System		ACI (2014)
	15		FGD (2014)	Reagent Injection System		ACI (2014)
	17		Wet FGD (2010)			
	18		Wet FGD (2009)			
Rockport Generating Station	MBI & MB2		DSI - 2015 Enhanced DSI 2020	MB1 SCR - 2017 MB2 SCR - 2020		ACI

3.2 Indiana's EGUs Future Year NO_x and SO_2 Emissions

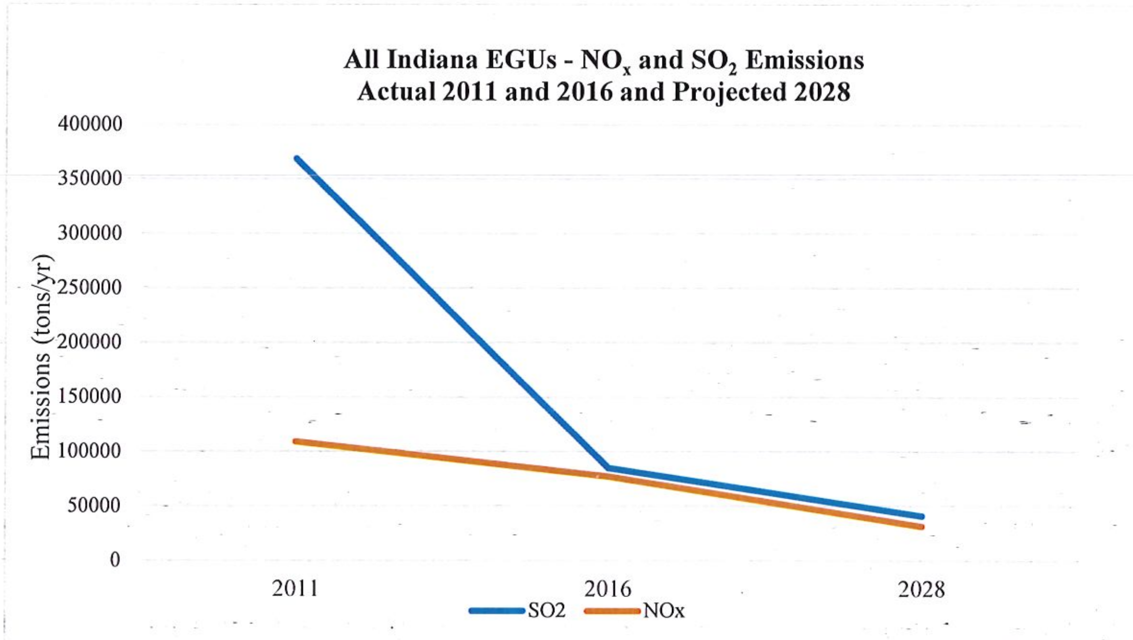
In regard to the photochemical modeling, Table 3-4 summarizes the NO_x and SO_2 emissions for EGUs throughout Indiana for modeled base-years 2011 and 2016 and projected emissions for 2028. The modeled emissions data was provided by ERTAC. The 2011 and 2016 base-year emissions are taken from the CAMD actual emisisons data which is the basis of the ERTAC base runs. The net effect from the photochemical modeling evaluation shows dramatic decreases in NO_x and SO_2 emissions state-wide, not only actual emissions decreases from 2011 to 2016 but additional projected emissions decreases that are substantial for 2028.

Table 3-4 Indiana EGUs Emissions for Base-years 2011 and 2016 and ERTAC Projected 2028

All Indiana EGUs	2011 Modeled Emissions (tons)	2016 Modeled Emissions (tons)	Projected 2028 Emissions (tons)
NO_x	109,507.4	77,777.3	32,015.6
SO_2	369,325.3	85,328.9	41,374.4

Modeled NO_x emissions were reduced by 29% and SO_2 emissions dropped dramatically with reductions equating to 77% from 2011 to 2016. As shown in Graph 3-3 on page 14, projected NO_x and SO_2 emissions for Indiana EGUs in 2028 decrease even more with NO_x emissions dropping an additional 59% from 2016 to 2028 and SO_2 emissions reduced by 52%. In total, from 2011 to 2028, Indiana's EGU NO_x and SO_2 emissions are projected to decrease by 71% for NO_x and 89% for SO_2. Graph 3-3 shows the significant downward trend for both NO_x and SO_2 emissions.

Graph 3-3 Indiana EGU Emissions Comparison: 2011 and 2016 and ERTAC Projected 2028



Future year projections are based on the latest LADCO ERTAC modeling analysis. LADCO replaced EPA's Integrated Planning Model (IPM) EGU inventories in the EPA 2011 and 2016 modeling platforms with inventories derived from the ERTAC EGU model (Mid-Atlantic Regional Air Management Association-MARAMA, 2012). The ERTAC EGU model for growth was developed around activity pattern matching algorithms designed to provide hourly EGU emissions data for air quality planning. The original goal of the model was to create low-cost software that air quality planning agencies could use for developing EGU emission projections. States needed a transparent model that did not produce dramatic changes to the emission forecasts with small changes in inputs. A key feature of the model includes data transparency; all of the inputs to the model are publicly available. The open source software includes documentation and a diverse user community to support new users of the software.

The ERTAC EGU model imports base-year Continuous Emissions Monitoring (CEM) data from EPA and sorts the data from the peak to the lowest generation hour. It applies hour specific growth rates that include peak and off peak rates. The model then balances the system for all units and hours that exceed physical or regulatory limits. ERTAC EGU applies future year controls to the emission estimates and tests for reserve electricity generating capacity, generates quality assurance reports, and converts the outputs to Sparse Matrix Operator Kernel Emissions (SMOKE)-ready modeling files.

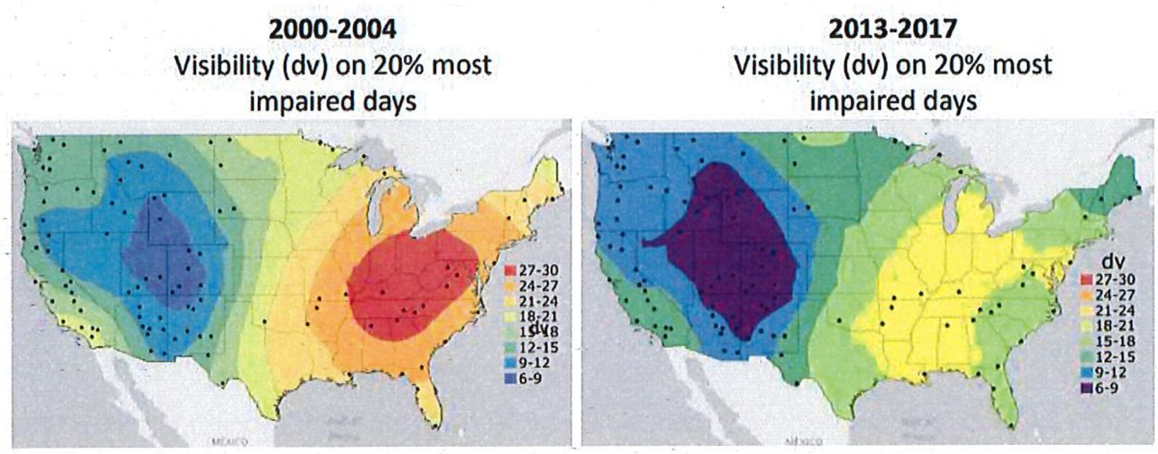
ERTAC EGU generates hourly future year emission estimates. The model does not shutdown or mothball existing units because economic algorithms suggest they are not economically viable. Additionally, alternate control scenarios are easy to simulate with the model. Significant effort has been put into the model to prevent simulations from spawning new coal plants to meet forecasted power demand. As an alternative, the model now allows portability of generation to different fuel types like renewables and NG. Differences between the IPM and ERTAC EGU emission forecasts arise from alternative forecast algorithms and from the data used to inform the model predictions.

The IPM forecasts used for the EPA "2016fh" modeling platform were based on comments from states and stakeholders received through April 2019. LADCO replaced the IPM EGU forecasts in its modeling with ERTAC EGU version 16.1. The ERTAC EGU 16.1 forecasts used CEM data from 2016 and state-reported changes to EGUs received through September 2020. The LADCO-modified ERTAC EGU 16.1 emissions used for this modeling application represent the best available information on EGU forecasts for the Midwest and Eastern United States available through September 2020.

3.3 Visibility Impacts on Class I Areas

The Interagency Monitoring of Protected Visual Environments (IMPROVE) monitored visibility values for the period of 2014 through 2018 are below the base-year 2011 - future year 2028 modeled visibility results in most instances and are nearly equal to the modeled visibility results for base-year 2016 - future year 2028, which accounts for the lower emissions base in 2016. This indicates that visibility improvements already realized are well ahead of the glidepaths of all Class I areas, especially those in the eastern half of the country that Indiana may impact. This improvement is very evident in Figure 3-5 as monitoring visibility in deciviews has improved greatly over the past decade or more.

Figure 3-2 Comparison of Visibility on 20% Most Impaired Days 2000-2017



3.4 Planned Retirements and Shutdowns for Coal fired EGUs at Indiana Power Plants

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 3-5 shows the expected unit retirements by 2028 for many of the EGUs in Indiana.

Table 3-5 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 2022 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.
Jefferson	77	1	Indiana-Kentucky Electric Corporation Clifty Creek	None announced.
Pike	125	2	Indianapolis Power and Light - 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 Indiana 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. In addition, the source confirmed the expected retirements. Finally, AES-Petersburg is now operating under a federal Consent Decree agreement with the United States and State of Indiana (Civil Action No. 3:20-cv-202-RYL-MPB, found at www.epa.gov/sites/default/files/2020-09/documents/indianapolispowerlight-cd.pdf) and will be subject to NO_x and SO_2 limitations for 2025 and 2026 as follows: operate the coal-fired Units 1 through 4 at the Petersburg Station so the Units combined do not emit SO_2 in excess of an annual tonnage limitation of 10,100 tons per year and operate the coal-fired Units 1 through 4 at the Petersburg Station so the Units combined do not emit NO_x in excess of an annual tonnage limitation of 8,500 tons per year.
Posey	129	10	SIGECO - AB Brown	Units 1 & 2 are set to retire in 2023 per the 2019-2020 IRP and the dates was verified with the source.

Spencer	147	20	Indiana Michigan Power Agency dba AEP - Rockport	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 (www.govinfo.gov/content/pkg/FR-2019-06-07/pdf/2019-11948.pdf), 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. SO2 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 SO2 emission rate on the combined stack beginning with the 30th SO2 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 NOx emission rate on the combined stack beginning with the 30th NOx 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.

In addition, Indiana's coal-fired boilers will continue to dwindle in number after 2028. Based on long-range projections and IRPs, several utilities are planning on further retirements of boilers beyond 2028. Duke Gibson and Rockport are planning on retiring boilers at their facilities during the third implementation period of the Regional Haze Program. The specific units projected to retire at these facilities are shown in the following table.

Table 3-6 Indiana EGUs and Expected Unit Retirements beyond 2028 as used in the ERTAC Model

ORIS	Unit ID	Facility	State	ERTAC Region	Fuel/Unit Type Bin	Generation capacity (MW)	2016 BY Annual SO2 (tons)	2016 BY Annual NOx (tons)	2028 FY Annual SO2 (tons)	2028 FY Annual NOx (tons)	Retirement Date
990	GT4	IPL - Harding Street	IN	RFCW	simplecycleg	86	0	53	1	132	1/1/44
990	GT5	IPL - Harding Street	IN	RFCW	simplecycleg	88	0	39	1	77	1/1/30
990	GT6	IPL - Harding Street	IN	RFCW	simplecycleg	199	1	28	3	129	1/1/30
6113	1	Gibson	IN	RFCW	coal	753	1,807	1,887	1,990	2,204	1/1/38
6113	2	Gibson	IN	RFCW	coal	720	2,340	2,953	2,619	2,092	1/1/38
6113	3	Gibson	IN	RFCW	coal	677	2,114	3,019	2,296	1,988	1/1/34
6113	5	Gibson	IN	RFCW	coal	728	5,495	3,273	6,095	2,337	1/1/34
6166	MB1	Rockport	IN	RFCW	coal	1,394	11,401	6,043	4,912	4,334	12/30/28

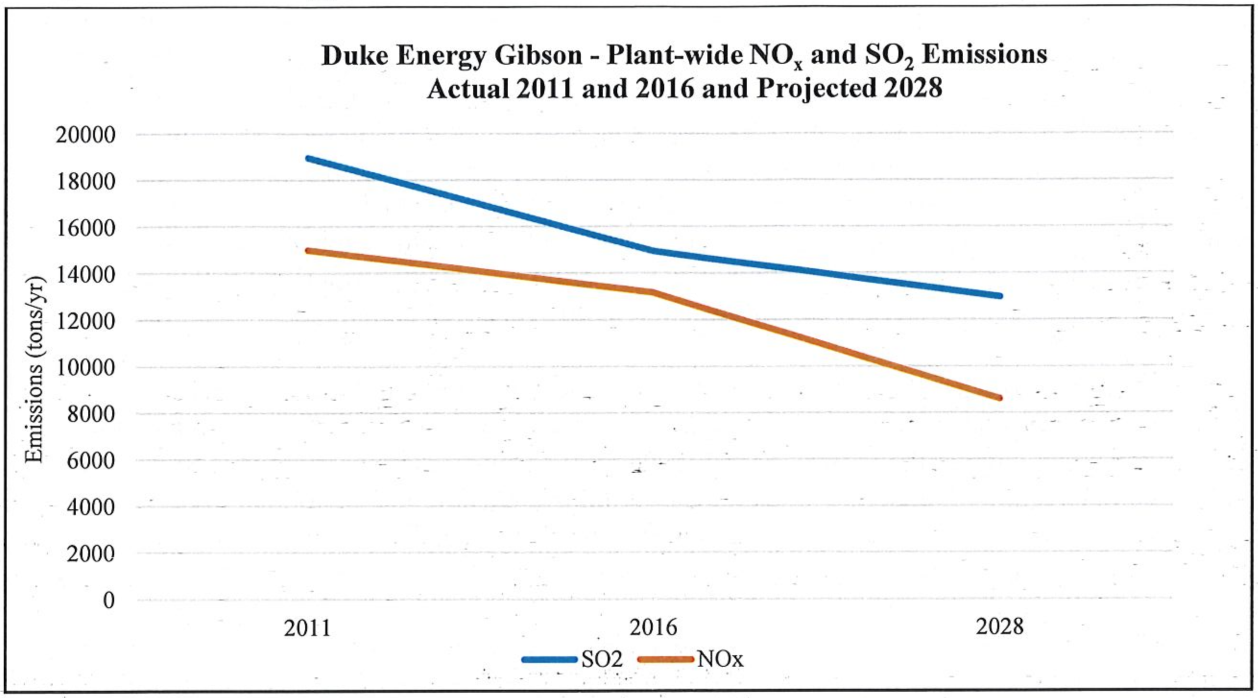
To pursue additional emission reductions through the use of new emission control equipment or emission limitations is not desired as a cost-effective method and will only drive utility rates even higher. As will be shown below, the emission reductions and modeling results show that visibility impairment from Indiana EGUs in total and particularly from Duke Gibson and AEP Rockport are decreasing as total light extinction at most all Class I areas is decreasing.

4.0 DUKE ENERGY, INC - GIBSON GENERATING STATION

Duke Energy, INC - Gibson Generating Station is located 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 dry bottom, pulverized coal-fired boilers. Controls for these units include wet limestone fluidized-gas desulfurization units controlling SO_2 emissions with control efficiencies above 93% (based on source calculations) and selective catalytic reduction systems for NO_x emissions with control efficiencies above 81% (based on source calculations).

Gibson's EGUs 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. Graph 4-1 shows the actual emissions changes that have occurred and changes in emissions projected by 2028.

Graph 4-1 Duke Energy - Gibson's SO_2 and NO_x Emission Trends



Duke Energy's IRP from 2019 was updated to reflect the advancement of retirements for several of their existing coal fired EGUs. Gibson is projected to accelerate retirements of Units 1-6; however, Unit 4 is the only unit expected to retire before 2028. These retirements are part of Duke Energy's overall plan to move to a more diversified clean energy portfolio. The retirement dates for Gibson's Unit 4 were confirmed with the source in November 2020.

The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. 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 power generation capacity with retirements of other boilers. For Gibson's future emission 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 Table 4-1.

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

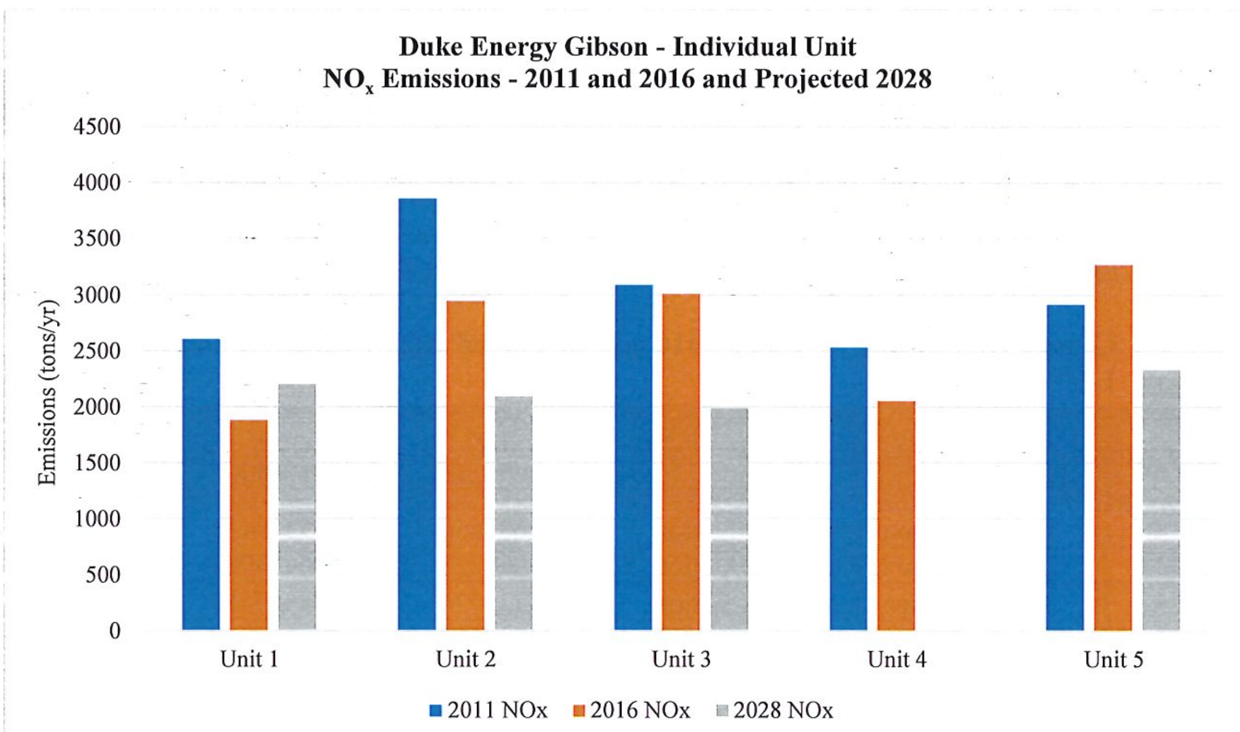
ORIS-ID	Unit ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028-ERTAC	Percentage Change in Utilization
6113	1	Gibson Generating Station	0.470088650	0.5175329430	10.09%
6113	2	Gibson Generating Station	0.634009223	0.7096633900	11.93%
6113	3	Gibson Generating Station	0.615733974	0.6688487450	8.63%
6113	4	Gibson Generating Station	0.548344335	Retired	-100.00%
6113	5	Gibson Generating Station	0.572596578	0.6350943340	10.91%

These 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. 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 emission 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 emission 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 as a result of the retirement of Unit 4 in order to meet anticipated electricity demands based on less generation capacity.

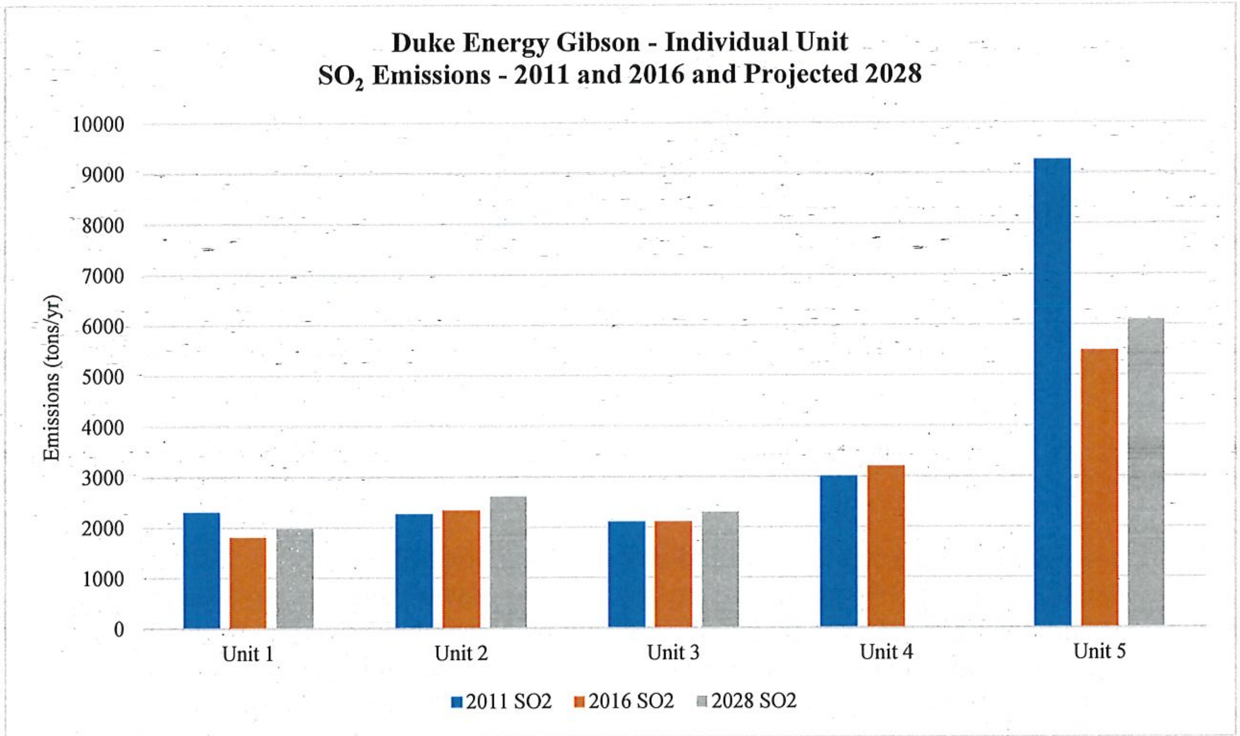
Graph 4-2 demonstrates the unit-by-unit comparison of NO_x emissions at the Duke - Gibson power plant. Note the slight increase in emissions at each of the four remaining units, this demonstrates the increase in utilization based on Unit 4's retirement to meet anticipated power demand. As with SO_2, overall NO_x emissions at Gibson are projected to decrease by 35% from 2016 to 2028.

Graph 4-2 Unit Comparison of 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 Gibson's SO_2 Emissions – Actual 2011 and 2016, Projected 2028

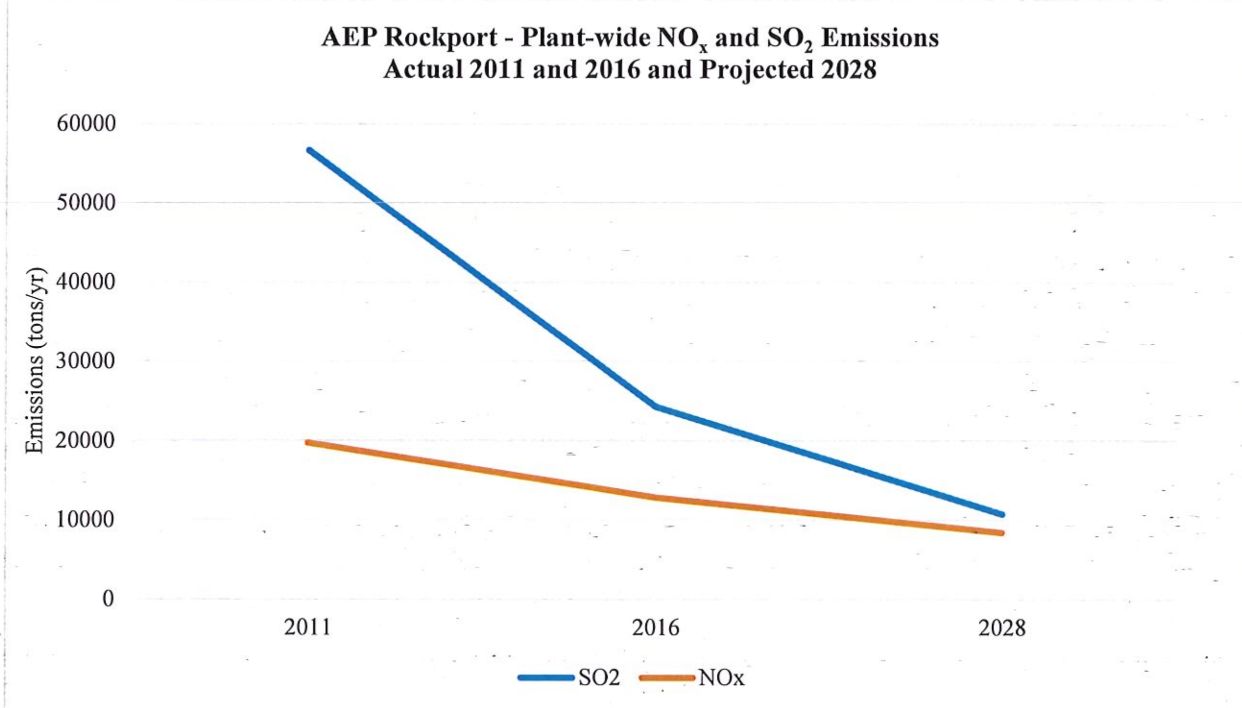


5.0 INDIANA MICHIGAN POWER COMPANY DBA AMERICAN ELECTRIC POWER - ROCKPORT GENERATING STATION

Indiana Michigan Power Company, dba American Electric Power (AEP) - Rockport Generating Station is located in Spencer County, in the southern portion of Indiana. It is a stationary electric utility generating station with a maximum generating capacity of 2,774 megawatts among two pulverized coal opposed wall fired dry bottom boilers (Units MB1 and MB2). Controls for these units include FGD units with SO_2 control efficiencies nearly 50% based on the latest 5-year average; low NO_x burner (dry bottom only) and air selective catalytic reduction systems/DSI for NO_x with control efficiencies above 57% based on the latest 5-year average.

Rockport NO_x emissions are estimated to be reduced by over 4,400 tons by 2028 or by 34% from 2016 emission levels. SO_2 emissions are undergoing greater reductions with over 13,500 tons reduced or 56% of the 2016 SO_2 emission levels by 2028 as demonstrated in Graph 5-1 on the next page.

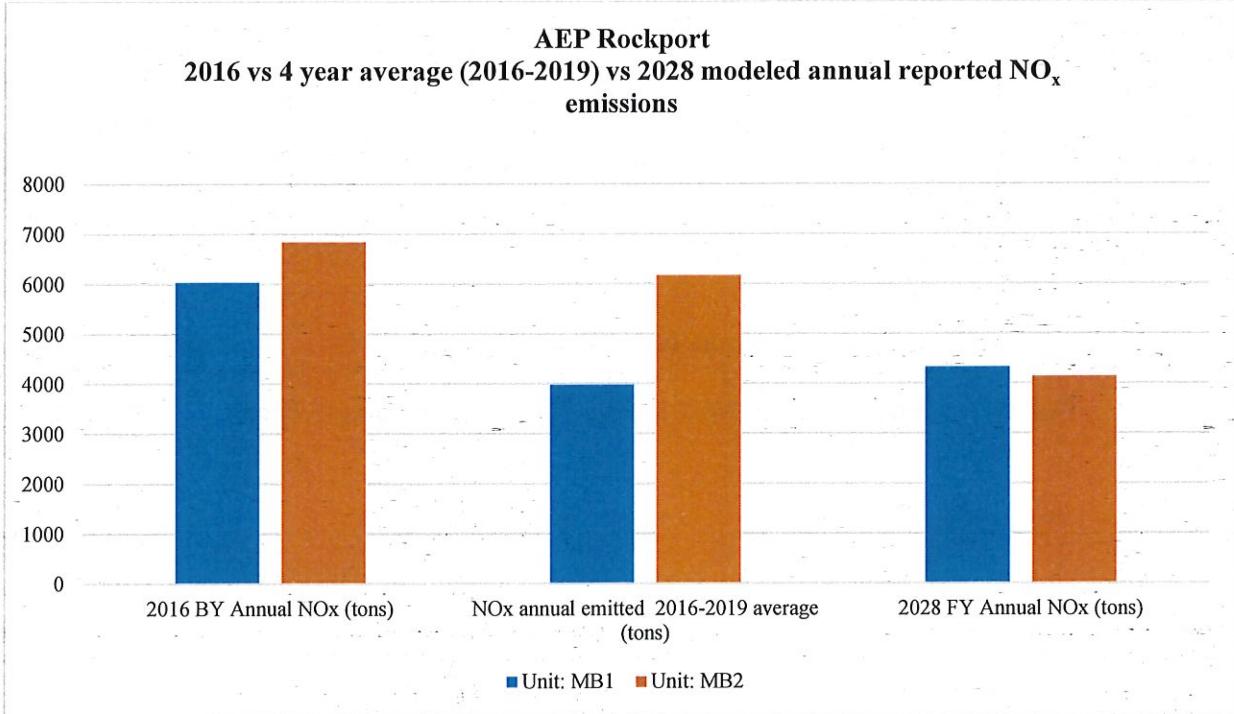
Graph 5-1 AEP Rockport's NO_x and SO_2 Emission Trends



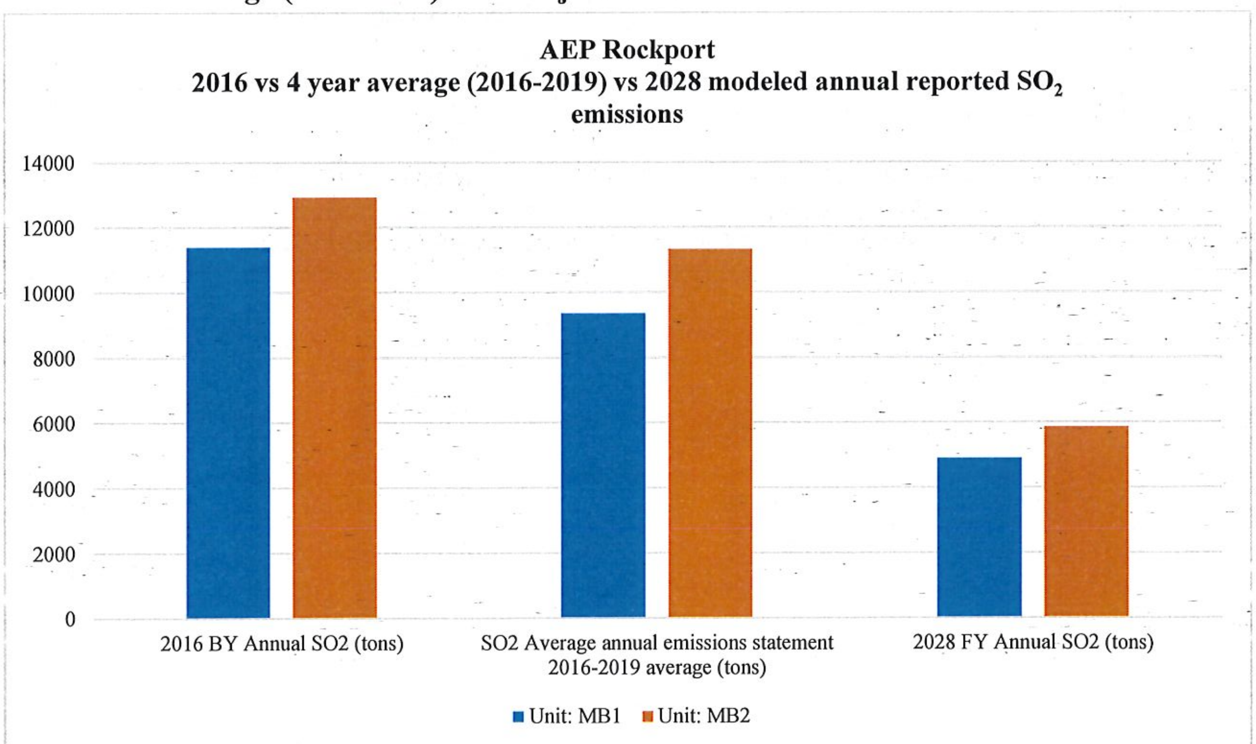
Rockport is required under a jointly modified consent decree signed on July 17, 2019, to install and continuously operate FGD systems, retire, refuel, or re-power Unit MB1 by December 31, 2025. This same requirement applies to Unit MB2 but by December 31, 2028. Rockport is also required to install advanced DSI by the same dates as listed above and operate a 30-day rolling average of 0.15 lb/MMBtu SO_2. Emissions are also required to be capped plant-wide in the agreement at 10,000 tons on an annual basis in between 2021 and 2028. Beginning in 2029 that plant wide total cap is lowered to 5,000 tons per year. In addition, Rockport was required to install and continuously operate a SCR on Unit MB1 by December 31, 2018, and Unit MB2 by June 1, 2020. AEP-Rockport met this requirement. This SCR shall maintain a 30-day rolling average NO_x emissions of 0.09 lb/MMBtu not later than the 13th calendar day of 2021. Both units at Rockport are included in the modeling for 2028.

Comparison of NO_x and SO_2 emissions by unit are shown below in Graphs 5-2 and 5-3 on the following page. The analysis demonstrates the continued downward trend of emissions from 2016 to projected emissions for 2028 with NO_x and SO_2 emissions decreases at both Units MB1 and MB2.

Graph 5-2 Unit Comparison of AEP Rockport's NO_x Emissions - Actual 2016 and 4-year Average (2016-2019) and Projected 2028



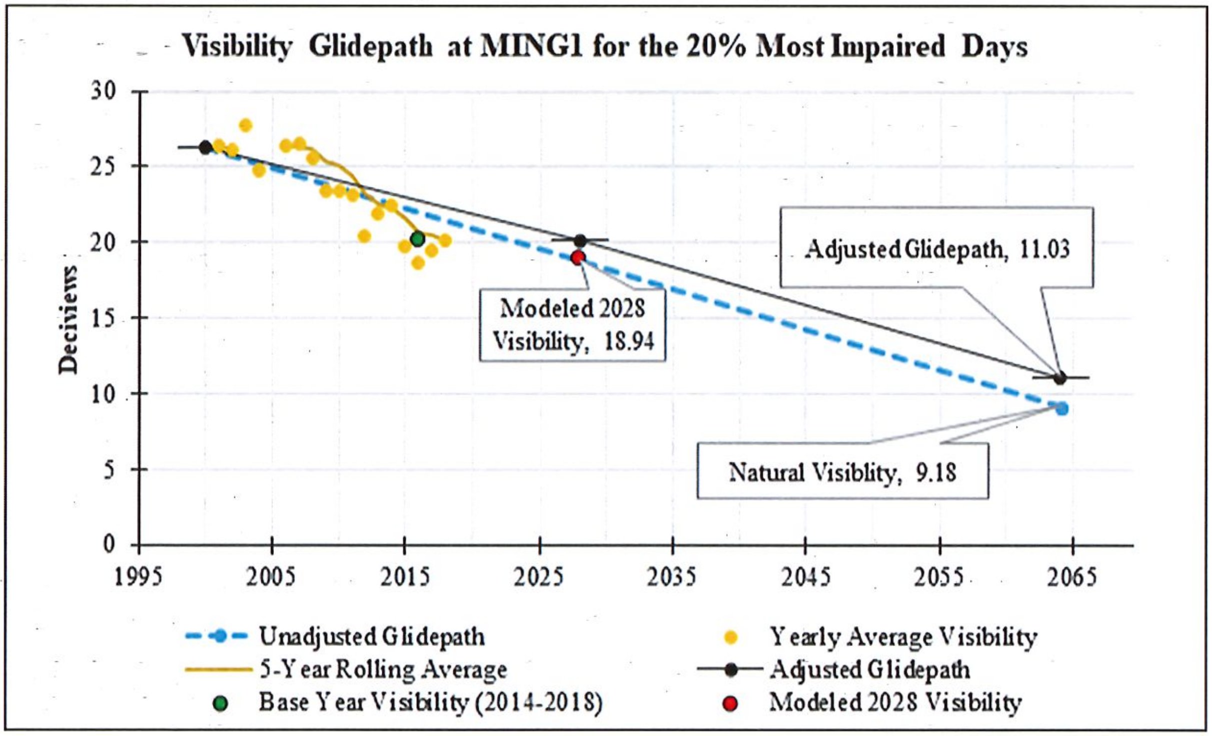
Graph 5-3 Unit Comparison of AEP Rockport's SO_2 Emissions – Actual 2016 and 4-year Average (2016-2019) and Projected 2028



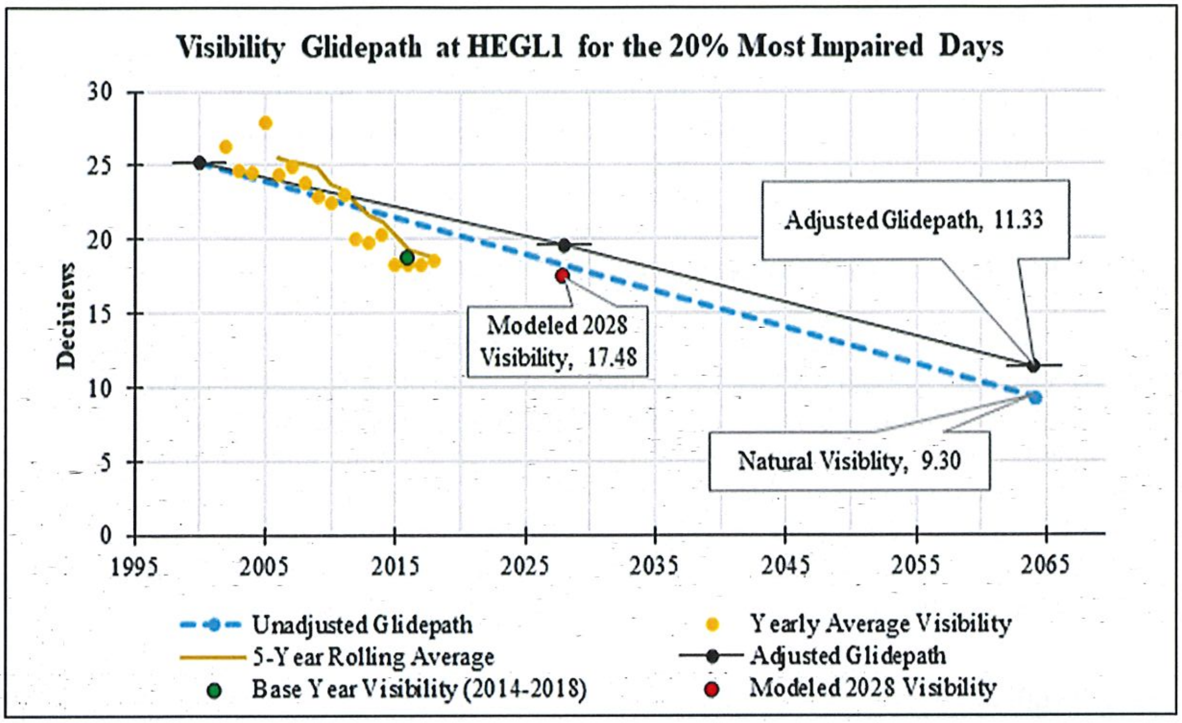
6.0 LADCO JUNE 2021 MODELING RESULTS

Indiana relied on the LADCO to conducted photochemical modeling to determine visibility impacts, based on base-year 2016 emissions. Indiana included the Hercules Glades Wilderness Area in its analysis as this is Missouri's other Class I area within the state. The resulting glidepaths, shown below, include the IMPROVE monitoring data to determine visibility impacts on the 20% most anthropogenically impaired days. As can be seen, the IMPROVE monitoring data from 2014-2018 showed tremendous visibility progress at both Class I areas with visibility on the 20% most anthropogenically impaired days well below the glidepath and nearly equal to modeled 2028 visibility.

Graph 6-1 Glidepath for Mingo National Wildlife Refuge Area



Graph 6-2 Glidepath for Hercules-Glades Wilderness Area



Results for both Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, are lower than the modeled visibility impacts at both Missouri Class I areas for 2028, based on the 2011 emissions and nearly equal the modeled results from the base-year 2016 future year 2028 modeling. Table 6-1 shows the marked improvement of visibility at Class I areas from both the monitored data from 2000 through 2018 and the modeling data from base-year 2011 to base-year 2016 with projected emissions to 2028. Undoubtedly, more current monitored visibility data will show even further visibility improvement.

Table 6-1 Comparison of Monitored and Modeled Visibility for Missouri Class I Areas

Site	2000-2004 Monitored Baseline (dv)	2009-2013 Monitored Baseline (dv)	2014-2018 Monitored Baseline (dv)	2011 base - 2028 Modeled Results (dv)	2016 base - 2028 Modeled Results (dv)
Mingo	26.3	22.5	20.1	20.4	18.9
Hercules-Glades	25.2	21.6	18.8	19.7	17.5

The significance of the 2014-2018 monitoring period is the marking of the end of the first implementation period of the Regional Haze Rule with much-improved visibility progress at all Class I areas. This visibility improvement emphasizes the emission reductions that have occurred in Indiana and throughout the country. Emission reductions from 2011 to 2016 reduced the visibility impacts from previous visibility modeling analyses, thus showing continued improvement in visibility at Class I areas over time. This fact is confirmed by the decrease in monitored visibility impairment at both Mingo and Hercules Glades over the first implementation period. The emission reductions have realized monitored visibility benefits, and the reasonable progress goals are well ahead of future projections of visibility at the Class I areas for 2028. The steady decline of visibility impacts at the Class I areas from anthropogenic emissions over the past decade or more is significant and indicate that Indiana, as well as all other states, are taking the necessary steps to remain ahead of schedule in attaining natural visibility conditions at all Class I areas by 2064.

7.0 LADCO SOURCE APPORTIONMENT MODELING

LADCO conducted source apportionment modeling, completed in June of 2021, in which several Indiana emission sectors including all EGUs in Indiana and both of the identified Indiana EGU sources, Duke Energy - Gibson Generating Station and AEP - Rockport Generating Station tagged individually, were evaluated to determine their modeled visibility impacts. The visibility modeling results are shown below in Table 7-1 for both Class I areas in Missouri, each Class I area's modeled 2028 total light extinction value based on 2016 emissions, Indiana EGUs overall visibility contribution to the total light extinction at each of the Class I areas, and the percentage of Indiana's EGUs visibility impact.

Table 7-1 All Indiana EGUs Visibility Impacts for Missouri's Class I Areas

Class I Area	2016-2028 Total Light Extinction (Mm^{-1})	Indiana EGU Contribution to 2016-2028 Total Light Extinction (Mm^{-1})	Indiana EGU Contribution to 2016 2028 Total Light Extinction (%)
Mingo	69.67	1.602	2.3%
Hercules-Glades	59.43	0.813	1.4%

As mentioned, LADCO's source apportionment modeling looked at the individual impacts from Rockport and Gibson. In Table 7-2, modeled results show Rockport contributed 0.52% to total light extinction at Mingo National Wildlife Refuge while Rockport's contribution to total light extinction at Hercules Glades Wilderness Area was 0.37%. A more detailed look at the precursor pollutants showed Rockport's contribution to total sulfate visibility impacts were approximately 1% at both Class I areas in Missouri and Rockport's contribution to total nitrate visibility impacts were less than 0.5% at both Class I areas. Indiana believes a better representation of visibility impairments on the 20% most anthropogenically impaired days is to consider the total light extinction and compare with the source's combined emissions impact on visibility. Rockport's future year visibility contribution as a percent of total emissions is projected to be higher as a result of the number of coal unit retirements statewide between 2016 and 2028. In terms of total mass contribution from Rockport, emissions are lower in 2028 versus the base year. As stated previously, overall visibility modeling demonstrates RPG are being met and are well below the uniform rate of progress for all Class I areas of concern.

Table 7-2 Rockport Visibility Impacts for Missouri's Class I Areas

Class I Area	Rockport Nitrate Impact (Mm^{-1})	Total Nitrate Impact (Mm^{-1})	Rockport Nitrate Impact (%)	Rockport Sulfate Impact (Mm^{-1})	Total Sulfate Impact (Mm^{-1})	Rockport Sulfate Impact (%)	Total Class I Light Extinction (Mm^{-1})	Rockport Total Impact (%)
MING	0.09	19.36	0.45%	0.28	24.08	1.14%	69.67	0.52%
HEGL	0.02	14.87	0.14%	0.20	20.37	0.96%	59.43	0.37%

LADCO modeling shows that Duke Gibson contributed 0.53% to total light extinction at Mingo National Wildlife Refuge while Gibson's contribution to total light extinction at Hercules Glades Wilderness Area was 0.25%. While Duke Gibson's contribution to total sulfate visibility impacts at Mingo were just above 1% and 0.623% at Hercules Glades, its contribution to total nitrate impact was 0.61 at Mingo and 0.13% at Hercules Glades. Indiana considers a better representation of visibility impairments on the 20% most anthropogenically impaired days is to compare the total light extinction at the Class I areas with the source's combined NO_x and SO_2 emissions and its impact on total light extinction. Gibson's future year visibility contribution as a percent of total emissions is projected to be higher as a result of the number of coal unit retirements statewide between 2016 and 2028. In terms of total mass contribution from Gibson, emissions are lower in 2028 versus the base year.

Table 7-3 Gibson Visibility Impacts for Selected VISTAS Class I Areas

Class I Area	Gibson Nitrate Impact (Mm^{-1})	Total Nitrate Impact (Mm^{-1})	Gibson Nitrate Impact (%)	Gibson Sulfate Impact (Mm^{-1})	Total Sulfate Impact (Mm^{-1})	Gibson Sulfate Impact (%)	Total Class I Light Extinction (Mm^{-1})	Gibson Total Impact (%)
MING	0.12	19.36	0.61%	0.25	24.08	1.03%	69.67	0.53%
HEGL	0.02	14.87	0.13%	0.13	20.37	0.62%	59.43	0.25%

In summary, the source apportionment modeling conducted by LADCO confirms the overall visibility improvement realized by both Class I areas in Missouri as with all other Class I areas in the eastern half of the country. Contributions from Rockport and Gibson are small percentages of the overall visibility impairment, which based on current monitoring and modeling results, is decreasing each year and remains well below the uniform rate of progress. Further retirements of boilers and anticipated emission reductions throughout the country will continue to drive the visibility impairment lower at Missouri's Class I areas and will realize continued improved visibility.

8.0 FEDERAL AND STATE REGULATIONS DISCUSSION

The primary Federal and state regulations governing the interstate transport of NO_x and SO_2 emissions from EGUs are described below.

8.1 Cross State Air Pollution Rule

EPA finalized the Cross State Air Pollution Rule (CSAPR) to reduce the interstate transport of fine PM and ozone on July 6, 2011, with publication in the Federal Register on August 8, 2011. The final rule replaces EPA's 2005 Clean Air Interstate Rule (CAIR) that was vacated by a December 2008 court decision that kept CAIR in place temporarily while directing EPA to issue a replacement rule. CSAPR requires 27 states, including Indiana, in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle ($PM_{2.5}$) pollution in other states.

CSAPR includes a process for determining each upwind state's responsibility to protect downwind air quality. Each time the National Ambient Air Quality Standard (NAAQS) is changed, U.S. EPA will apply this process and determine if interstate pollution transport contributes to exceedances of the new standard and whether new emission reductions should be required from upwind states. The rule defines what portion of an upwind state's emissions "significantly contribute" to ozone or $PM_{2.5}$ pollution in nonattainment or maintenance areas in downwind states. This definition considers the magnitude of a state's contribution, the air quality benefits of reductions, and the cost of controlling pollution from various sources. Once these obligations are determined, the rule requires states to eliminate the portion of their emissions defined as their "significant contribution" by setting a pollution limit (or budget) for each covered state.

The rule allows air quality-assured allowance trading among covered sources, utilizing an allowance market infrastructure based on existing, successful allowance trading programs. CSAPR allows sources to trade emission allowances with other sources within the same program (for example, Transport Rule Ozone Season NO_x Trading Program) in the same or different states, while firmly constraining any emissions shifting that may occur by requiring a strict emission ceiling (state assurance level) in each state (the budget plus variability limit). It includes assurance provisions that ensure each state will make the emission reductions necessary to meet the "good neighbor" provision of the Clean Air Act.

CSAPR requires significant reductions in NO_x and SO_2 emissions that react in the atmosphere to form $PM_{2.5}$ and ground-level ozone and are transported long distances. The first phase of compliance began January 1, 2012, for annual NO_x and SO_2 reductions and May 1, 2012, for ozone season NO_x reductions. The second phase of SO_2 reductions began January 1, 2014. Indiana is designated as a Group 1 state in CSPAR with additional SO_2 reductions in 2014.

The state of Indiana developed a state implementation plan to administer the three trading programs under CSAPR and allocate allowances for affected EGUs that started in 2021.

The CSAPR Programs rulemaking revised Article 24 of the Indiana Administrative Code (IAC) to incorporate CSAPR requirements and repealed the remaining portions of CAIR. The final rule, 326 IAC 24, was adopted on November 24, 2017, and SIP approved and published in the Federal Register on December 17, 2018.

8.2 Revised Cross-State Air Pollution Rule Update

On October 15, 2020, EPA proposed the Revised Cross-State Air Pollution Rule Update in order to fully address 21 states' outstanding interstate pollution transport obligations for the 2008 ozone NAAQS. Starting in the 2021 ozone season, the proposed rule would require additional emission reductions of NO_x from power plants in 12 states. The proposed rulemaking responds to a September 2019 ruling by the United States Court of Appeals for the D.C. Circuit, Wisconsin v. EPA, which remanded the 2016 CSAPR Update to EPA for failing to fully eliminate significant contribution to nonattainment and interference with maintenance of the 2008 ozone NAAQS from upwind states by downwind areas' attainment dates.

Indiana is one of the 12 linked states required to participate in a new CSAPR NO_x Ozone Season Group 3 Trading Program that largely replicates the existing CSAPR NO_x Ozone Season Group 2 Trading Program with additional budget stringency for affected states. Indiana's projected 2021 emissions were found to contribute at or above a threshold of 1% of the NAAQS (0.75 ppb) to the identified nonattainment and/or maintenance problems in downwind states. EPA proposes to issue new or amended Federal Implementation Plans (FIPs) to revise state emission budgets to reflect additional emission reductions from EGUs beginning with the 2021 ozone season. In order to respect attainment deadlines as directed by the court in Wisconsin v. EPA, EPA must revise the existing CSAPR NO_x ozone season program as quickly as possible to enable improvements in downwind ozone by the 2021 ozone season, which corresponds with the 2021 Serious area attainment date under the 2008 ozone NAAQS. This proposed action's FIPs would require power plants in the 12 linked states to participate in a new CSAPR NO_x Ozone Season Group 3 Trading Program that largely replicates the existing CSAPR NO_x Ozone Season Group 2 Trading Program, with the main differences being the geography and budget stringency. Aside from the removal of the 12 covered states from the current CSAPR NO_x Ozone Season Group 2 Trading Program, this proposal leaves unchanged the budget stringency and geography of the existing CSAPR NO_x Ozone Season Group 1 and Group 2 Trading Programs.

EPA also proposes to adjust these 12 states' emission budgets for each ozone season thereafter to incentivize ongoing operation of identified emission controls to address significant contribution, until such time that air quality projections demonstrate resolution of the downwind nonattainment and/or maintenance problems for the 2008 ozone NAAQS. As such, the proposal includes adjusting emission budgets for each state for each ozone season for 2021 through 2024. After the 2024 ozone season, no further adjustments would be required under this proposed rulemaking. EPA proposes to authorize a one-time conversion of allowances banked in 2017-2020 under the CSAPR NO_x Ozone Season Group 2 Trading Program into a limited number of allowances that can be used for compliance in the CSAPR NO_x Ozone Season Group 3 Trading Program. This approach gives due credit for the emission reductions represented by banked allowances, while also securing the additional reductions required in this proposed rulemaking. EPA solicited comments on the proposed rule and allowed 45 days for comment following publication.

9.0 SUMMARY OF INDIANA'S EGU ANALYSIS

Indiana surmises that its EGU sector was evaluated in great detail for the first implementation period of the Regional Haze Rule. Based on diverse industry-wide emission control measures mandated by strict regulations and far less reliance on coal over the past decade as more alternative power generation becomes available; 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 with overall EGU NO_x emission decreases projected from 2011 to 2028 to be over 70%, and a nearly 90% decrease in SO_2 emissions. Additional retirements of EGUs are expected in addition to those listed herein.

Results for all Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, are nearly equal and in some cases, lower than the modeled results from the base-year 2011 and base-year 2016 modeling. This emphasizes the emission reductions that have occurred in Indiana and throughout the country have realized monitored visibility benefits and the reasonable progress goals are well ahead of future projections of visibility at the Class I areas for 2028. PSAT results have shown that the two utilities identified by CENSARA have 1% or less visibility impacts on the CENSARA Class I areas located within 300 kilometers of the two utilities.

The steady decline of visibility impacts at the Class I areas from anthropogenic emissions over the past decade or more is significant. This indicates that Indiana, as well as all other states, are taking the necessary steps to remain ahead of schedule in attaining natural visibility conditions at all Class I areas by 2064.

The CSAPR Update proposes revised state emission budgets that reflect additional emission reductions from EGUs beginning with the 2021 ozone season to address projected 2021 emissions found to contribute at or above a threshold of 1% of the NAAQS (0.75 ppb) to the identified nonattainment and/or maintenance problems in downwind states. The proposed budget for 2021 NO_x Ozone Season was 23,303. The new budget is 12,500 with a 21% variability limit and EPA's projected emissions are 15,856.

As can be seen, emission reductions, monitoring data and modeling results clearly demonstrates improved visibility, especially in the eastern half of the county. Monitoring data indicated stark reductions in impaired visibility values, which are well ahead of the uniform rate of progress for the Class I area identified in the CENSARA request. The most current source apportionment modeling conducted by LADCO indicates Indiana's overall visibility impacts are declining. Anticipated further retirements of EGUs in the state will only continue to lower emissions and the state's visibility impacts on surrounding Class I areas. EPA's "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, dated August 2019 states the "key flexibility of the regional haze program is that a state is not required to evaluate all sources of emissions in each implementation period". IDEM is intently evaluating other emission sectors for this second implementation period to determine their visibility impacts on Class I areas. IDEM will conduct a review of all its emission sources, with focus on the EGU sector, for its January 31, 2025, progress report: pursuant to 40 CFR 51.308 (g). IDEM will evaluate EGUs for the third implementation period of the RH Rule, as necessary, to be submitted in 2028. As a result, IDEM is not requiring 4-factor analyses from its EGUs nor will it conduct a 4-factor analysis on this emission sector for this second implementation period.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.
100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • www.idem.IN.gov

Eric J. Holcomb
Governor

Brian C. Rockensuess
Commissioner

December 22, 2021

Paul Miller
Lead Manager
Mid-Atlantic/Northeast Visibility Union Regional Planning Organization
89 South Street, Suite 602
Boston, MA 02111

Re: Response to the Mid-Atlantic/Northeast Visibility Union Consultation ASKs for the Regional Haze State Implementation Plan Second Implementation Period

Dear Mr. Paul Miller:

October 16, 2017, the Indiana Department of Environmental Management (IDEM) received a request from the Mid-Atlantic/Northeast Visibility Union (MANE-VU) regional planning organization to facilitate reasonable progress in protecting visibility at its region's Class I areas. MANE-VU identified Indiana emissions as significantly contributing to Class I areas in the MANE-VU region. In addition, MAN-VU submitted a comment letter on November 5, 2021 to Indiana's draft Regional Haze State Implementation Plan (RH SIP) for the second implementation period, which was received during the draft RH SIP public notice period.

The comment letter iterated that Indiana had failed to address the MANE-VU Asks from several years ago. Supporting information and hyperlinks supplied by MANE-VU in its letter also referenced information and data analysis conducted in 2016 and 2017 by MANE-VU and its member states. Based on these analyses from four years ago, MANE-VU developed its Asks of all upwind states (including Indiana) that were found to contribute, at that time, to visibility impairment at MANE-VU Class I areas. These determinations were based on 2015 actual emissions for EGUs and 2011 emissions for all other sources. These Asks included:

1) EGUs greater than 25 MW with installed controls, ensure that controls are run year round
2) For emission sources having a 3.0- Mm-1impact or greater at MANE-VU Class I area, perform a four-factor analysis
3) Adopt an ultra-low sulfur fuel oil standard
4) For EGUs and other large sources, pursue enforceable mechanisms to lock in lower emission rates
5) Encourage and promote energy efficiency and clean technologies

Indiana has relied on more current emissions, data analysis and modeling to determine visibility impacts from its sources on Class I areas and is providing responses to MANE-VU's five Asks. It should be noted that section-specific comments MANE-VU made on Indiana's draft RH SIP that will be addressed by Indiana in its responses to public comments document that will be included in the final RH SIP submittal.

The Lake Michigan Air Directors Consortium (LADCO) regional planning organization conducted emissions analyses and photochemical modeling in support of its member states to assist with the development of their Regional Haze RH SIPs. Final source apportionment modeling results from LADCO were not available to IDEM in order to formulate an adequate response to the MANE-VU request until June of 2021.

The results of LADCO's modeling exercise as well as emissions evaluations for MANE-VU's five Asks are detailed in Indiana's response to the MANE-VU planning organization's request within the attached document. Indiana's response emphasizes that LADCO's modeling results and the emissions analyses do in fact support Indiana's position that the state is meeting its RH obligations to the surrounding states with Class I areas and no further analysis is necessary for the issues listed in MANE-VU's five Asks.

This response consists of one (1) hard copy of the requested information and electronic versions of the response to the MANE-VU planning organization's request in PDF format sent to the MANE-VU planning organization and member states. Thank you for initiating consultation on this important matter. If you have any questions or need additional information, please contact Jean Boling, Environmental Engineer, Air Quality Planning Section, Office of Air Quality, at (317) 232-8228 or jboling@idem.IN.gov.

Sincerely,

Matt Stuckey
Assistant Commissioner
Office of Air Quality

MS/sd/md/sb/jb
Enclosures

1. MANE-VU ASKs for the RH SIP Second Implementation Period
2. State of Indiana's Response to the MANE-VU Organizations' Request for RH Second Implementation Period Consultation, Electric Generating Units Nitrogen Oxides and Sulfur Dioxide Reasonable Progress Emissions Reduction and Visibility Analysis

cc: Sharon Davis, New Jersey Department of Environmental Protection
David Healy, New Hampshire Department of Environmental Services
Zac Adelman, Lake Michigan Air Directors Consortium (w/ enclosures)
Matt Stuckey, IDEM-OAQ (no enclosures)
Scott Deloney, IDEM-OAQ (no enclosures)
Mark Derf, IDEM-OAQ (w/ enclosures)
Susan Bem, IDEM-OAQ (w/ enclosures)
Jean Boling, IDEM-OAQ (w/ enclosures)
File Copy

STATE OF INDIANA'S RESPONSE

TO THE

MID-ATLANTIC/NORTHEAST VISIBILITY UNION PLANNING ORGANIZATION'S REQUEST

FOR

REGIONAL HAZE STATE IMPLEMENTATION PLAN FOR THE SECOND IMPLEMENTATION PERIOD CONSULTATION

Electric Generating Units
Nitrogen Oxides and Sulfur Dioxide
Reasonable Progress Emissions Reduction and Visibility Analysis

Prepared by:
The Indiana Department of Environmental Management
December 2021

This page intentionally left blank.

TABLE OF CONTENTS

TABLES

GRAPHS

ACRONYMS/ABBREVIATIONS LIST

CAA	Clean Air Act
EGU	Electric Generating Units
EPA	United States Environmental Protection Agency
ERTAC	Eastern Regional Technical Advisory Committee
IDEM	Indiana Department of Environmental Management
IMPROVE	Interagency Monitoring of Protected Visual Environments
LADCO	Lake Michigan Air Directors Consortium
NG	Natural Gas
NO_x	Nitrogen Oxides
MANE-VU	Mid Atlantic- Northeast Visibility Union
MARAMA	Mid-Atlantic Regional Air Management Association
RH	Regional Haze
RPGs	Reasonable Progress Goals
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
tons/yr	Tons Per Year
URP	Uniform Rate of Progress

1.0 BACKGROUND

The Indiana Department of Environmental Management (IDEM) received a request from the Mid-Atlantic/Northeast Visibility Union (MANE-VU) to facilitate reasonable progress in protecting visibility at its Class I areas. MANE-VU identified Indiana emissions as significantly contributing to Class I areas in the MANE-VU region. This process was initiated by MANE-VU with a request for consultation dated October 16, 2017. Following Indiana's consultations with MANE-VU which took place in 2017 and early 2018 over a series of conference call and webinars, MANE-VU submitted five specific Asks to Indiana at that time. Meanwhile, the United States Environmental Protection Agency (EPA) issued a final rule updating the Regional Haze (RH) program (82 Federal Register (FR) 3078), including revising portions of the visibility protection rule promulgated in 1980 (45 FR 80084) and the RH Rule promulgated in 1999 (82 FR 3078) in January of 2017. The revised rule governs states' obligations and EPA's review of periodic SIPs developed for the second and subsequent implementation periods. Part of the revision was extending the due date for the second implementation period RH State Implementation Plans (SIPs), from July 31, 2018, to July 31, 2021. This extension of time allowed for more current emissions and modeling information to be generated in order to make more informed and appropriate decisions on visibility contributions and responsible actions to take to address regional haze. U.S. EPA released supporting documentation for the second implementation period. "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" dated August 2019 supported key principles of program implementation such as complying with visibility requirements, reducing state planning burdens and leveraging emission reductions achieved through the Clean Air Act and other programs to further improve visibility in Class I areas. MANE-VU did not re-engage its consultation with Indiana after the revised Regional Haze rule and revised guidance were finalized.

MANE-VU submitted a comment letter on November 5, 2021, to Indiana's draft Regional Haze State Implementation Plan (RH SIP) for the second implementation period, which was received during the draft RH SIP public notice period. The comment letter iterated that Indiana had failed to address the MANE-VU Asks from several years ago. Supporting information and hyperlinks supplied by MANE-VU in its letter also referenced information and data analysis conducted by MANE-VU and its member states in 2016 and 2017. MANE-VU conducted analyses referenced in its "Statement of the Mid-Atlantic/Northeast Visibility Union (MANE-VU) States Concerning a Course of Action in Contributing States Located Upwind of MANE-VU Toward Assuring Reasonable Progress for the Second Regional Haze Implementation Period (2018-2028), dated August 25, 2017. Based on these analyses from four years ago, MANE-VU developed its Asks of all upwind states (including Indiana) that were found to contribute, at that time, to visibility impairment at MANE-VU Class I areas. These determinations were based on 2015 actual emissions for EGUs and 2011 emissions for all other sources. These Asks included:

1) EGUs greater than 25 MW with installed controls, ensure that controls are run year round
2) For emission sources having a 3.0- Mm^{-1} impact or greater at MANE-VU Class I area, perform a four-factor analysis
3) Adopt an ultra-low sulfur fuel oil standard
4) For EGUs and other large sources, pursue enforceable mechanisms to lock in lower emission rates

5) Encourage and promote energy efficiency and clean technologies

Indiana has relied on more current emissions, data analysis and modeling to determine visibility impacts from its sources on Class I areas and is providing responses to MANE-VU's five Asks. In addition, MANE-VU made section-specific comments on Indiana's draft RH SIP that will be addressed by Indiana in its responses to public comments document that will be included in the final RH SIP submittal.

2.0 MANE-VU'S ASK #1 - EGUS GREATER THAN 25 MW WITH INSTALLED CONTROLS, ENSURE THAT CONTROLS ARE RUN YEAR ROUND

MANE-VU's first Ask focused on Indiana's EGUs with power generation at or greater than 25 megawatts; the request is these facilities should be required to run their installed emission controls all year round, not just during ozone season. MANE-VU believes IDEM's approach of deferring analysis of the EGU sector to later implementation periods is inconsistent with MANE-VU's Inter-RPO Ask.

Indiana Response: IDEM enforces all permit conditions for the power plant facilities and all other permitted emission sources throughout the state for which the state has authority. Appendix F of the RH SIP submittal details the emission control units on Indiana's EGUs and control efficiencies. Indiana has determined that these EGUs are well-controlled and continue to reduce emissions to lessen their visibility impacts on surrounding Class I areas.

Several federal measures such as the Mercury and Air Toxics Standard (MATS) and the Cross State Air Pollution Rule (CSAPR) have specifically targeted NO_x and SO_2 emission reductions from EGUs that will continue to reduce emissions in the future.

3.0 MANE-VU'S ASK #2 - PERFORM A FOUR-FACTOR ANALYSIS FOR EMISSION SOURCES HAVING A 3.0 MM^{-1} IMPACT OR GREATER AT MANE-VU CLASS I AREAS

MANE-VU had identified one Indiana power plant in its screening analysis to determine possible contribution to visibility impairment at one or more of MANE-VU's Class I areas. MANE-VU requests a four-factor analysis be performed for Michigan Power Company, dba American Electric Power (AEP) - Rockport Generating Station.

Indiana Response: Due to flexibility afforded to states in EPA's "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" document, dated August 20, 2019, Indiana decided the EGU source category would not be chosen to have four-factor analyses conducted for the second implementation period; however, these sources were not exempt from being evaluated. These sources were evaluated using other factors that are reasonable to consider. Since the EGU sector contributed to a significant portion of the progress made over the last implementation period due to the Mercury and Air Toxics Standard (MATS) and the Cross State Air Pollution Rule (CSAPR) that specifically targeted NO_x and SO_2 emission reductions from this source category, a reasonable progress analysis for these units was conducted in lieu of four-factor analyses. Indiana's reasonable progress analysis for these units consists of a quantitative analysis of statewide NO_x and SO_2 emission reductions from Indiana's EGU fleet for 2007-2019; photochemical modeling using 2016 NO_x and SO_2 base-year modeled emissions for all existing Indiana EGUs in 2016 to projected 2028 emissions; and source apportionment modeling to assess visibility impacts by tagging all EGUs in Indiana.

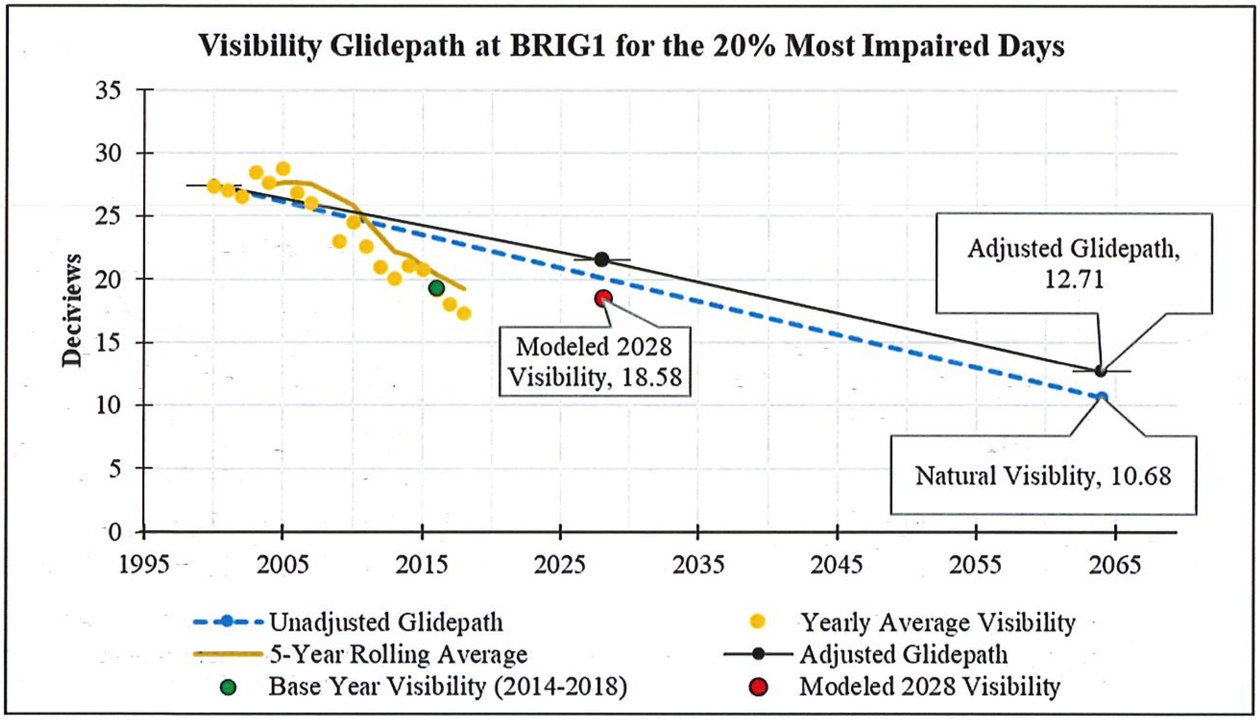
Indiana believes that conducting four-factor analyses for the EGUs in the next implementation period would result in a better use of resources due to the fact that numerous modifications have been made to Indiana's EGU fleet in the form of upgrades to existing emissions control equipment and the installation of new add-on control devices to comply with MATS and CSAPR. In addition, numerous units have retired or are scheduled for shutdown over the course of the next implementation period. As such, Indiana believes that conducting four-factor analyses for the EGUs in the next implementation period would result in a better use of resources.

In order to address the modeled visibility impacts, Indiana wishes to review the MANE-VU request. As previously mentioned in this document, MANE-VU has supplied their Asks relying on outdated emissions and modeling information. MANE-VU conducted CALPUFF dispersion modeling for its contribution analysis in 2017. The MANE-VU screening results showed visibility impacts from only one Indiana source: AEP - Rockport Generating Station with visibility impairment measured in light extinction above 3.0 inverse megameters (Mm^{-1}) at one or more of its Class I areas. While this type of screening helps to narrow the focus on potential source contributions, IDEM does not feel it represents current and realistic visibility contributions from individual sources or states. In addition, review of the MANE-VU Ask shows the screening results were not updated from its initial Ask dated August 25, 2017, therefore emission reductions and updates in regional haze guidance and modeling techniques have not been taken into account.

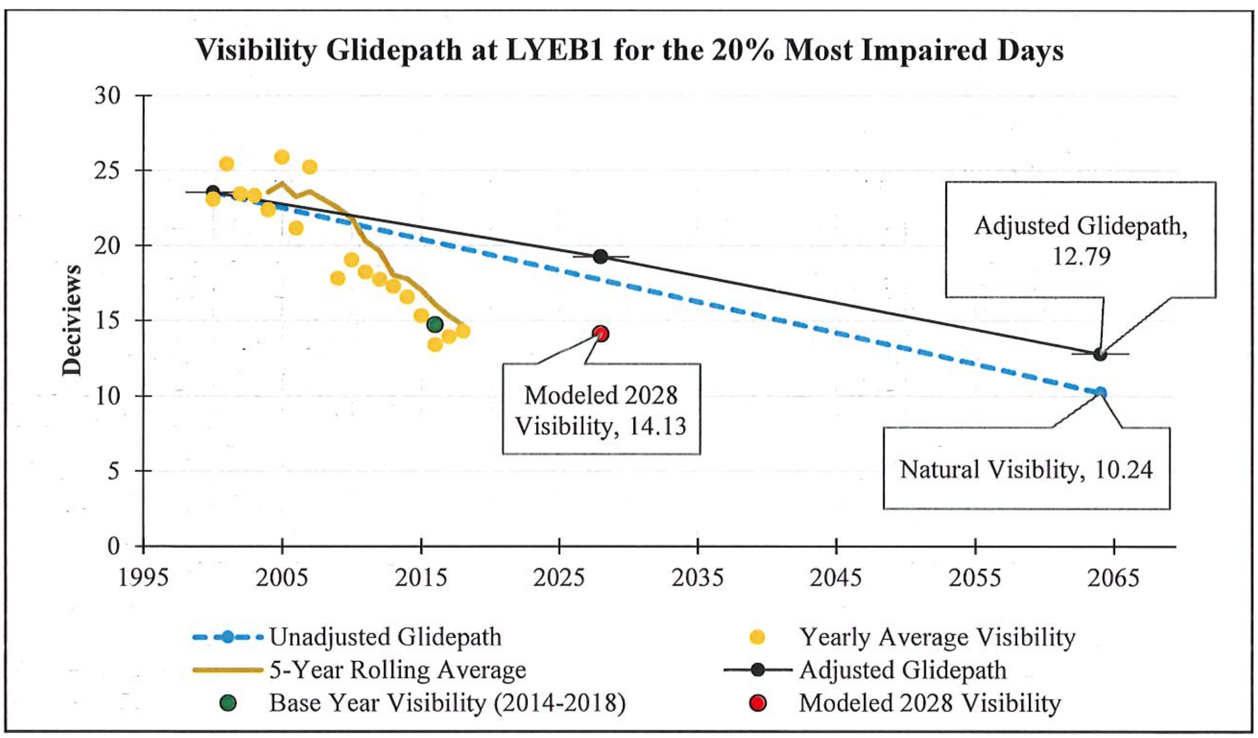
IDEM has worked with LADCO to conduct current photochemical modeling to determine up-to-date visibility impacts. This work has shown marked improvement in both emissions reductions from not only Rockport but all Indiana EGUs as well as visibility impact improvements from Indiana emission sources. As MANE-VU identified Rockport as a possible contributor to visibility impairment at one or more of MANE-VU's Class I areas, IDEM will address overall visibility assessment at the MANE-VU Class I areas and Rockport's modeled visibility impacts.

LADCO conducted photochemical modeling to determine visibility impacts, based on base-year 2016 emissions. The resulting glidepaths, shown below in Graphs 3-1 and 3-2, include the IMPROVE monitoring data to determine visibility impacts on the 20% most anthropogenically impaired days at the two nearest MANE-VU Class I areas, Brigantine Wilderness Area in New Jersey and Lye Brook Wilderness Area in Vermont. As can be seen, the IMPROVE monitoring data from 2014-2018 showed tremendous visibility progress with visibility on the 20% most anthropogenically impaired days well below the glidepath and nearly equal to modeled 2028 visibility.

Graph 3-1 URP Glidepath for Brigantine Wilderness Area



Graph 3-2 URP Glidepath for Lye Brook Wilderness Area



Visibility modeling results for the MANE-VU Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, are near the modeled visibility impacts at each of the MANE-VU Class I areas for 2028, based on the 2011 emissions and within 0.75 deciviews to the modeled results from the base-year 2016 future year 2028 modeling. Table 3-1 shows the marked improvement of visibility at Class I areas from both the monitored data from 2000 through 2018 and the modeling data from base-year 2011 to base-year 2016 with projected emissions to 2028.

Table 3-1 Comparison of Monitored and Modeled Visibility for MANE-VU Class I Areas

Site	2000-2004 Monitored Baseline (dv)	2009-2013 Monitored Baseline (dv)	2014-2018 Monitored Baseline (dv)	2011 base - 2028 Modeled Results (dv)	2016 base - 2028 Modeled Results (dv)
Brigantine	27.43	22.25	19.31	18.97	18.58
Lye Brook	23.57	18.06	14.73	15.02	14.13
Great Gulf/ Presidential Range-Dry River	21.88	15.40	13.07	12.95	12.37
Acadia	22.01	16.84	14.54	14.98	13.95
Moosehorn/Roosevelt Campobello	20.65	15.80	13.32	14.26	12.84

The significance of the 2014-2018 monitoring period marks the end of the first implementation period of the Regional Haze Program with much-improved visibility progress at all Class I areas. This visibility improvement emphasizes the emission reductions that have occurred in Indiana and throughout the country. The emission reductions have realized monitored visibility benefits, and the reasonable progress goals are well ahead of future projections of visibility at the Class I areas for 2028. It is worth noting that Indiana's modeled visibility impacts, based on 2011 emissions was higher, thus showing emission reductions from 2011 to 2016 reduced the visibility impacts. This fact is confirmed in the decrease in monitored visibility impairment over this period of time. The steady decline of visibility impacts at the Class I areas from anthropogenic emissions over the past decade or more is significant and indicates that Indiana, as well as all other states, are taking the necessary steps to remain ahead of schedule in attaining natural visibility conditions at all Class I areas by 2064.

LADCO conducted updated source apportionment photochemical modeling with 2016 emissions projected to 2028 in which several Indiana source categories and two Indiana EGU sources were tagged to determine their individual modeled visibility impacts. The details of this modeling effort are found in Indiana's Regional Haze SIP and LADCO "Modeling and Analysis for Demonstrating Reasonable Progress for the RH Rule 2018-2028 Planning Period" Technical Support Document, dated June 17, 2021. The visibility impact results for the MANE-VU Class I areas are shown below in Table 3-2. The results are based on Indiana's modeled 2028 total light extinction value based on 2016 emissions and include Indiana's EGUs and all other anthropogenic sources' overall visibility contributions and the total light extinction at each of the MANE-VU Class I areas. Comparing the modeled results show the visibility impacts from all Indiana EGUs and all other Indiana sources cumulatively are very low, well below the 3.0 Mm^{-1} threshold MANE-VU had established for requesting four-factor analyses.

Table 3-2 Indiana's Modeled Visibility Impacts on MANE-VU Class I Areas

Class I Area	All Indiana EGUs Contribution to 2016-2028 Total Light Extinction (Mm^{-1})	All Indiana Sources Contribution to 2016-2028 Total Light Extinction (Mm^{-1})	MANE-VU Class I Area 2016-2028 Total Light Extinction (Mm^{-1})
Brigantine	0.48	1.62	69.40
Lye Brook	0.4	1.0	42.86
Great Gulf/Presidential Range/Dry River	0.23	0.51	36.40
Acadia	0.14	0.36	41.90
Moosehorn/Roosevelt Campobello	0.1	0.22	37.33

As mentioned, LADCO's source apportionment modeling looked at the individual visibility impacts from Rockport. Additional expected emission reductions before 2028 will reduce the monitored visibility impacts even further. In Table 3-3, Rockport's contribution to total sulfate visibility impacts was 0.62% at Lye Brook Wilderness Areas, all other sulfate visibility contributions were modeled at 0.3% or less. Rockport's contribution to total nitrate visibility impacts were approximately 0.1% or less at all MANE-VU Class I areas. Overall modeled visibility impact results show Rockport contributes well below 0.3% to total light extinction at all MANE-VU Class I areas. Indiana believes an appropriate representation of visibility impairments on the 20% most anthropogenically impaired days is to consider the total light extinction and compare with the source's combined emissions impact on visibility. As stated previously, overall visibility modeling demonstrates reasonable progress goals are being met and the reasonable progress goals are well below the uniform rate of progress for all MANE-VU Class I areas of concern.

Table 3-3 Rockport's Modeled Visibility Impacts on MANE-VU Class I Areas

Class I Area	Rockport Nitrate Impact (Mm^{-1})	Total Nitrate Impact (Mm^{-1})	Rockport Nitrate Impact (%)	Rockport Sulfate Impact (Mm^{-1})	Total Sulfate Impact (Mm^{-1})	Rockport Sulfate Impact (%)	Total Class I Light Extinction (Mm^{-1})	Rockport Total Impact (%)
BRIG	0.006	18.71	0.03%	0.07	21.03	0.3%	69.40	0.1%
LYBR	0.01	9.15	0.11%	0.09	14.55	0.62%	42.86	0.22%
GRGU/ PRRA	0.002	3.0	0.1%	0.04	14.07	0.3%	36.40	0.1%
ACAD	0.003	5.41	0.06%	0.026	13.79	0.2%	41.90	0.05%
MOOS/ ROCA	0.002	3.81	0.05%	0.02	13.13	0.1%	37.33	0.25%

In summary, the source apportionment modeling conducted by LADCO confirms the overall visibility improvement realized by all MANE-VU Class I areas. Contributions from Rockport are small percentages of the overall visibility impairment and well below MANE-VU's threshold of 3.0 Mm^{-1} for requesting four-factor analyses. In fact, visibility impacts from all Indiana emission sources, based on current monitoring and modeling results, are very low and decreasing each year. Further retirements of boilers and anticipated emission reductions in Indiana and throughout the country will continue to drive the visibility impairment lower at the MANE-VU Class I areas and will realize continued improved visibility.

4.0 MANE-VU ASK #3 - ADOPT AN ULTRA-LOW SULFUR FUEL OIL STANDARD

MANE-VU requests Indiana adopt ultra-low sulfur fuel oil standards as part of its long-term strategy or demonstrate why it would not be feasible.

Indiana Response: Indiana has incorporated ultra-low sulfur fuel oil emission limits into its state implementation plan in order to comply with the 1-hour SO_2 National Ambient Air Quality Standard (NAAQS); several sources located in 1-hour SO_2 nonattainment areas were required to switch to ultra-low sulfur fuel oil. This along with other state and federal emission reduction measures, helped to achieve compliance with the 1-hour SO_2 standard in several of the state's modeled attainment demonstrations. As a result, Indiana has addressed all its monitored 1-hour SO_2 nonattainment areas and brought each of these areas into attainment. Indiana does not believe adopting additional ultra-low sulfur fuel oil standards offers the amount of emission reductions that would make appreciable visibility improvements at Class I areas, especially those located in the MANE-VU region. Furthermore, Indiana does not have existing regulatory authority to require ultra-low sulfur fuel oil state-wide. A national control strategy calling for ultra-low sulfur fuel oil would be more equitable to provide consistent and meaningful emissions reductions that are more appropriate to address regional haze issues throughout the country.

5.0 MANE-VU ASK #4 - PURSUE ENFORCEABLE MECHANISMS TO LOCK IN LOWER EMISSION RATES FOR EGUS AND OTHER LARGE SOURCES

MANE-VU notes that although IDEM has documented EGU emissions reductions in the draft RH SIP, MANE-VU requests IDEM directly address Ask #4 to pursue enforceable regulatory mechanisms to ensure lower emissions rates.

Indiana Response: The RH Rule was designed to be implemented with respect to reasonable visibility progress to natural conditions by the year 2064 with several implementation periods to measure and assess reasonable progress towards the natural visibility conditions. The uniform rate of progress (URP) for each Class I area, especially in the eastern half of the country, shows the visibility progress made during the last implementation period represents another positive step towards attaining natural conditions at all Class I areas by 2064, if not much sooner.

IDEM stands by its assertion that emissions reductions due to federal and state regulations, fuel conversion switches, control upgrades and add-on modifications and retirements have led to tremendous visibility impairment improvements and further reductions are anticipated. To incorporate new emission limits into Indiana's SIP, a new rule must be developed and adopted. The state's rulemaking process takes three to four years to complete. As such, there was not sufficient time to complete a new rulemaking. Furthermore, the cost of resources and time required to evaluate selected sources for unit-specific emission controls and emission limits compared to the visibility benefits realized to address transport emissions at this time was not warranted.

Indiana has determined existing emission controls are adequate to address regional haze for sources throughout the state based on the tremendous visibility progress made to date along with current "on-the-books" regulatory measures expected to continue improvement into the future. IDEM maintains that it makes no sense to evaluate EGUs at this time when the outcome of compliance with other CAA regulations, such as the Revised CSAPR Update Rule and new wastewater regulations for coal ash, are not fully in place. Implementation of the Revised CSAPR Update Rule will reduce EGU NO_x Ozone Season budgets, which will cause the EGUs to restrict emissions even further. More stringent federal wastewater guidelines are also causing EGUs to move away from coal or shut down. These regulations require power plants to clean coal ash and toxic heavy metals such as mercury, arsenic, and selenium from plant wastewater before it is dumped into streams and rivers.

6.0 MANE-VU ASK #5 - ENCOURAGE AND PROMOTE ENERGY EFFICIENCY AND CLEAN TECHNOLOGIES

MANU-VU asks IDEM consider and report measures and programs under consideration or currently operating in Indiana that reduce emissions by encouraging energy efficiency and promote cleaner energy technologies.

Indiana Response: Clean energy technology, including wind farms, solar, bioenergy and other clean forms of energy resources, are available for power plants to actively pursue. However, there is no legal authority for IDEM to require these types of operational changes to any facility's method of energy production. IDEM and other Indiana state agencies work closely with all utilities in the state and have found that overall plans for most if not all power plants are to move to a more diversified clean energy portfolio in the near future.