Appendix D

Indiana RH SIP for the Second Implementation Period
EGUs Reasonable Progress Analysis

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INDIANA'S

REGIONAL HAZE

STATE IMPLEMENTATION PLAN

FOR THE

SECOND IMPLEMENTATION PERIOD

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

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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
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

1.0 BACKGROUND

The Regional Haze (RH) Rule requires each state to develop a long-term strategy that includes the control measures necessary to make reasonable progress at each Class I area outside the state "that may be affected by emissions from the state." The Clean Air Act (CAA) and RH Rule provides for states to determine what emission control measures for its own sources, groups of sources, and/or source categories are necessary to make reasonable progress in Class I areas. 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."

Eighteen 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 consist of a quantitative analysis of state-wide nitrogen oxides ($NO_{x)}$ and sulfur dioxide ($SO_{2)}$ 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 seven non-EGUs that met the selection criteria.

Indiana's rational 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.

2.0 INTRODUCTION

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.

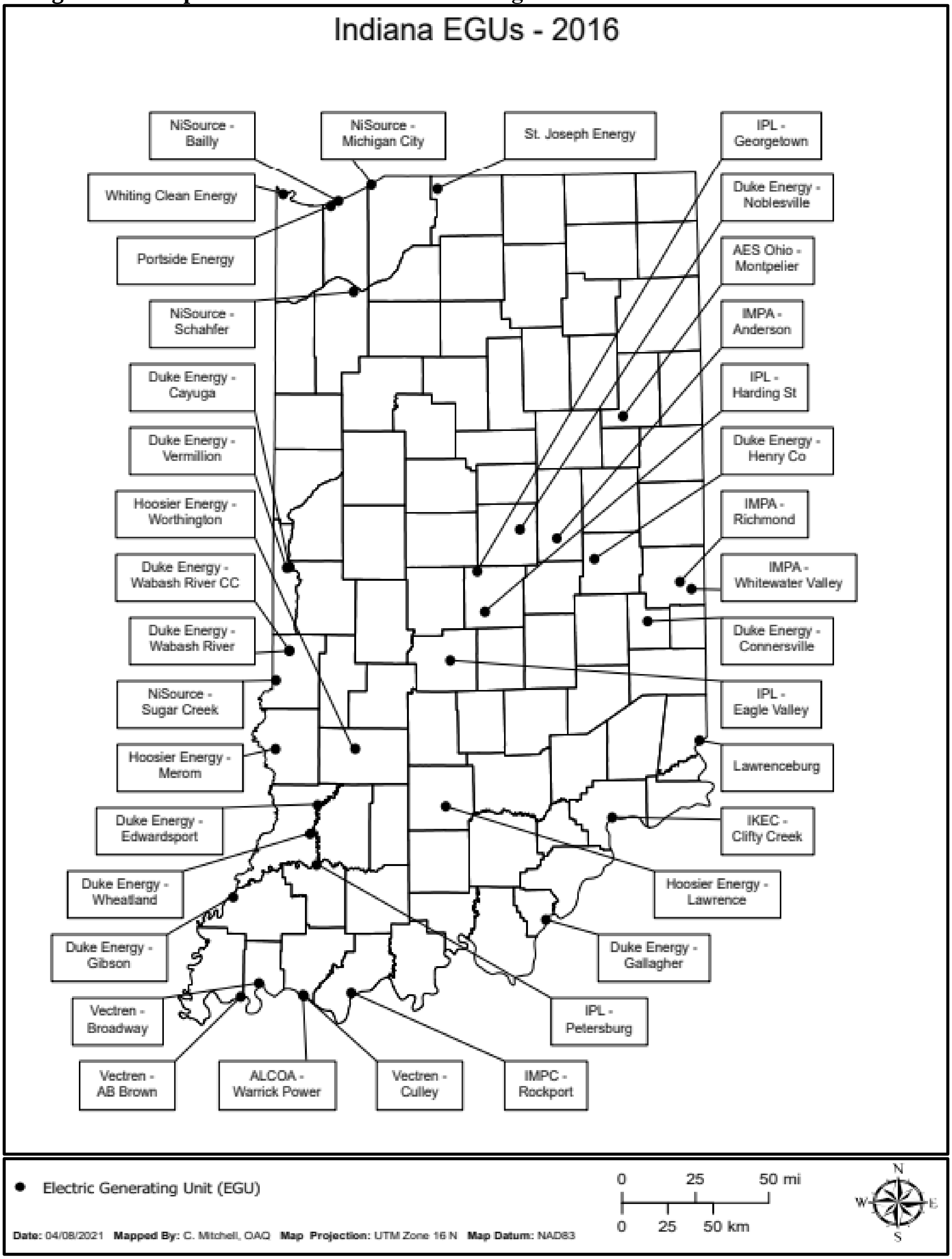
Indiana used the Q/d analysis to develop a source ranking list of the facilities in Indiana with the highest facility-wide NO_x and SO_2 emissions. The Q/d analysis is a simple surrogate metric used for quantifying and considering visibility impacts for the purpose of selecting sources to analyze for 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 on the next page 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

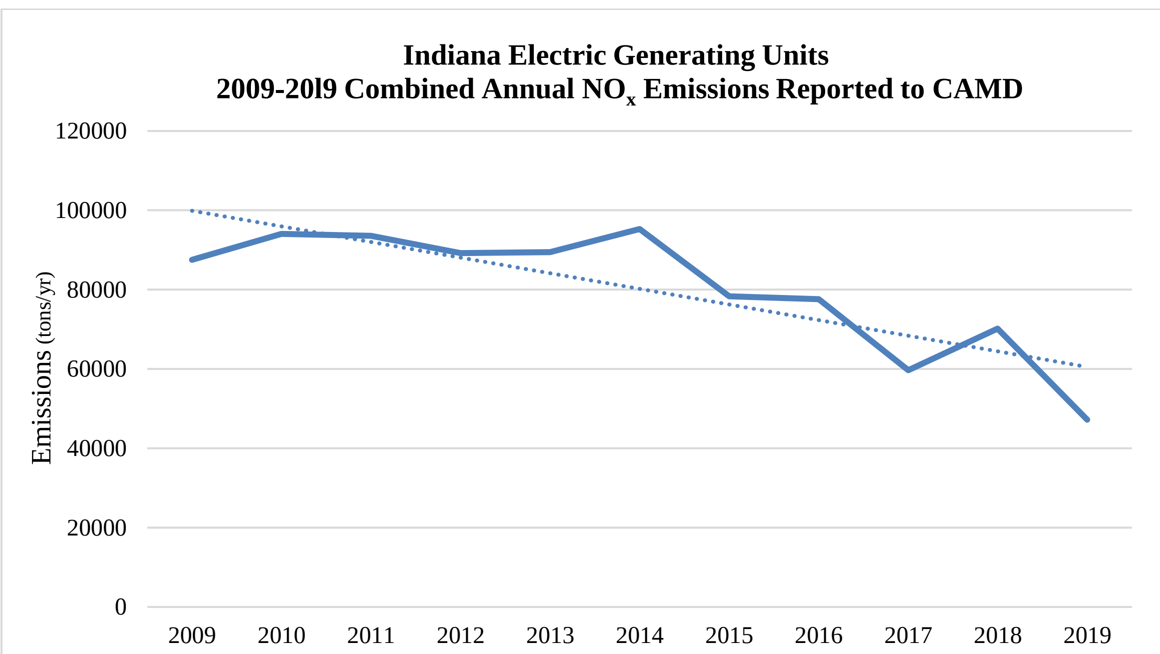


3.1 Indiana EGUs 2009-2019 NO_x Emissions Trends

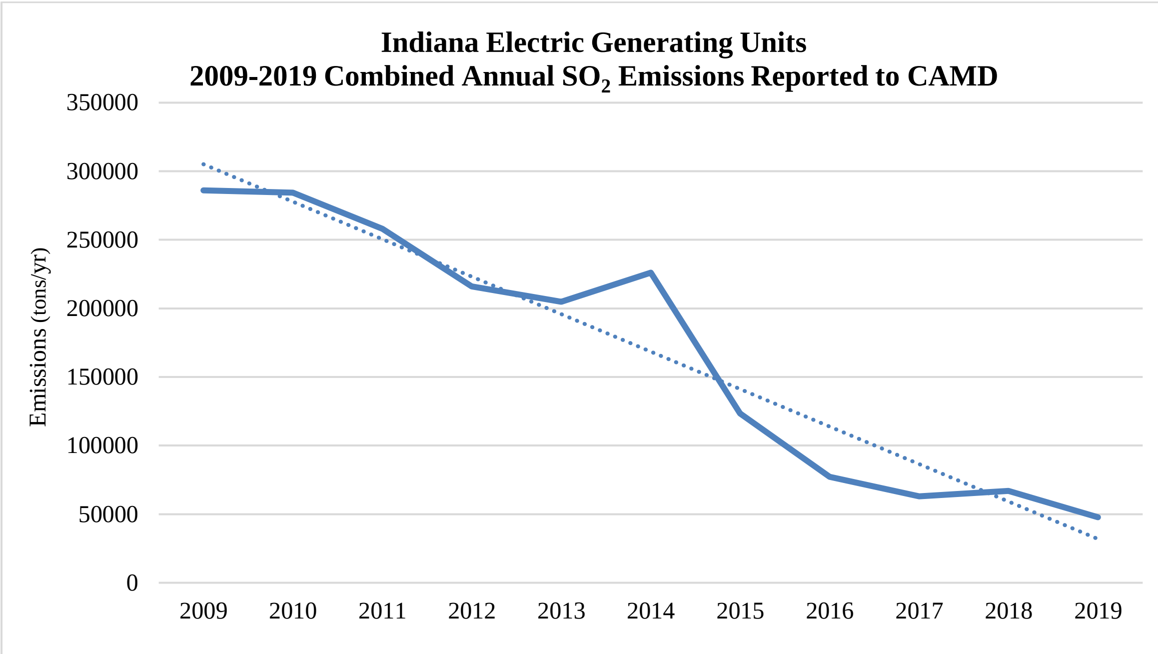
The combined annual NO_x and SO_2 emissions for all EGUs throughout Indiana decreased substantially from 2009 to 2019. Graph 3-1 below and Graph 3-2 on the next page demonstrate a downward trend in both NO_x and SO_2 state-wide annual emissions for Indiana EGUs during the 11-year evaluation period. The 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 2009 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 2009 to 2019 are listed in Table 1, respectively, under the "Combined 2009-19 NO_x Emissions" tab and Table 3 under the "Combined 2009-19 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 2009 to 2019.

Graph 3-1 Indiana EGUs 2009-2019 Combined Annual NO_x Emissions Reported to CAMD



Graph 3-2 Indiana EGUs 2009-2019 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 11-year evaluation period, as listed in Table 3-1. A total of 29 coal fired EGU boilers 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 2009 and 2019

Facility Name	Unit Identification	Year
Bailly Generating Station	10, 7, and 8	2018
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
	6	2016

3.1.2 EGU Fuel Switch Conversions

Three EGUs at the Harding Generating Station were converted from coal to natural gas fuels. Units 50 and 60 were converted in 2015 and Unit 70 in 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 2009-2019 NO_x Emissions Tab and Table 4 under the EGUs 2009-2019 SO_2 Emissions Tab in Appendix A lists the actual NO_x and SO_2 emissions for all Indiana EGUs for 2009 - 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 on the following page 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.

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)
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)
Michigan City Generating Station	12	Baghouse	FGD			ACI (2015)
Petersburg Generating Station	1	Upgrade ESP	Upgrade FGD and DSI		Reagent Injection	ACI
	2	Baghouse (2015)	Upgrade FGD 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 Plant	MB1 & MB2		DSI - 2015 Enhanced DSI - 2020	MB1 SCR - 2017 MB2 SCR - 2020		ACI
Whitewater Valley	1 & 2			SNCR/ DSI (2015)	Shared ACI (2015)	

3.2 Indiana EGUs Future Year NO_x and SO_2 Emissions

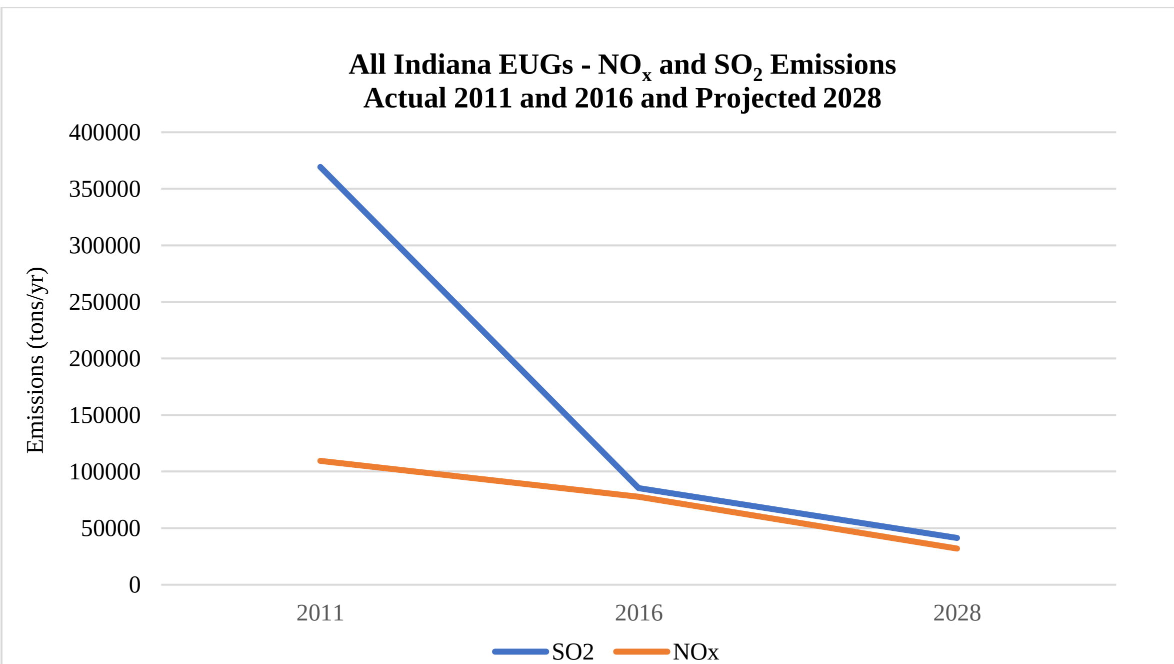
In regard to the photochemical modeling, Table 3-4 summarizes the NO_x and SO_2 emissions for EGUs throughout Indiana for modeled base-years 2011 and 2016 and projected emissions for 2028. The modeled emissions data was provided by ERTAC. The 2011 and 2016 base-year emissions are taken from the CAMD 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 EGU 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, 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 emissions projections. States needed a transparent model that did not produce dramatic changes to the emissions 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 emissions 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.

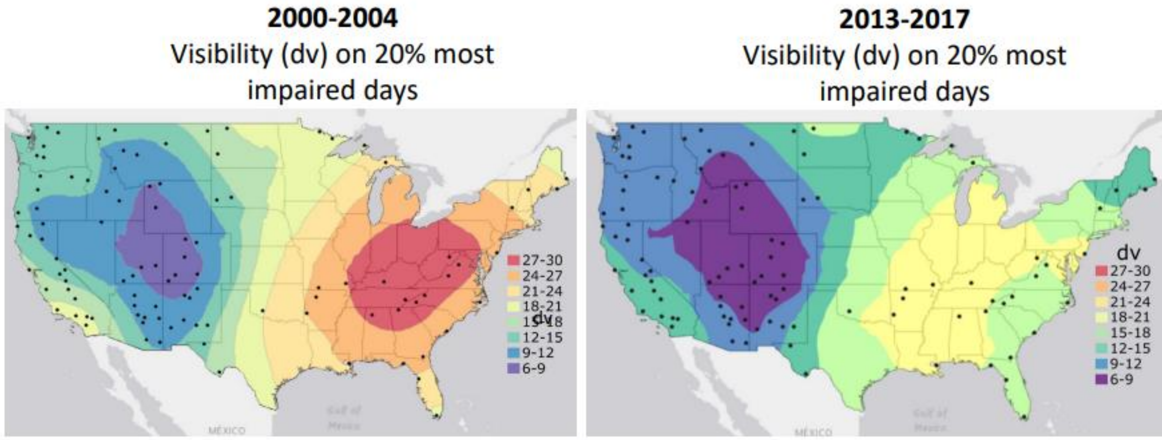
ERTAC EGU generates hourly future year emissions estimates. The model does not shutdown or mothball existing units because economics algorithms suggest they are not economically viable. Additionally, alternate control scenarios are easy to simulate with the model. Significant effort has been put into 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 emissions 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 on the following page as monitored visibility, measured in deciviews, has improved greatly over the past decade or more.

Figure 3-5 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 on the next page 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 June 2021 retirement.
Gibson	51	13	Duke Energy Indiana, LLC – Gibson	Unit 4 per the 2019 Duke IRP and verified with source by 2026.
Jasper	73	8	NIPSCO - R M Schahfer	Units 14, 15, 17 & 18 per the 2018 IRP and was added to the October 2020 NEEDS update from CAMD, verified with source for 2023 for units 17 and 18. Source stated that units 14 and 15 are accelerating retirement now by the end of 2021.
Jefferson	77	1	Indiana-Kentucky Electric Corporation Clifty Creek	None announced.
Pike	125	2	AES Indiana - Petersburg	AES Indiana Petersburg will retire units 1 and 2 before 2028. A determination was made to retire those units in the modeling in 2021 and 2023, respectively. This decision was made based on AES Indianan determining in their 2019 Integrated Resource Plan (IRP) that retiring those units was the "preferred low-cost option", in addition these units were identified in U.S. EPA's 2020 NEEDS update from CAMD as retiring. Finally, the source confirmed the expected retirements.
Posey	129	10	SIGECO - AB Brown	Units 1 & 2 are set to retire in 2023 per the 2019-2020 IRP and the dates were verified with the source.
Spencer	147	20	AEP Indiana Michigan Power Company dba American Electric Power - Rockport Plant	Rockport Plant, which is owned by AEP Indiana Michigan Power Company,, AEP Generating Company, and a group of unaffiliated financial investors is operated by AEP Indiana Michigan Power Company. Under the terms of the Fifth Modification of the AEP System Eastern Fleet NSR Consent Decree signed on July 17, 2019, Rockport Plant must install and operate Enhanced Dry Sorbent Injection Systems by June 1, 2020 on Unit 2 and by December 31, 2020 on Unit 1. 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; and are planning on retiring boilers at their facilities during the third implementation period of the Regional Haze. The following units are projected to retire in the next planning period for Regional Haze.

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	simple cycle g	86	0	53	1	132	1/1/44
990	GT5	IPL - Harding Street S	IN	RFCW	simple cycle g	88	0	39	1	77	1/1/30
990	GT6	IPL - Harding Street S	IN	RFCW	simple cycle g	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	12/31/28

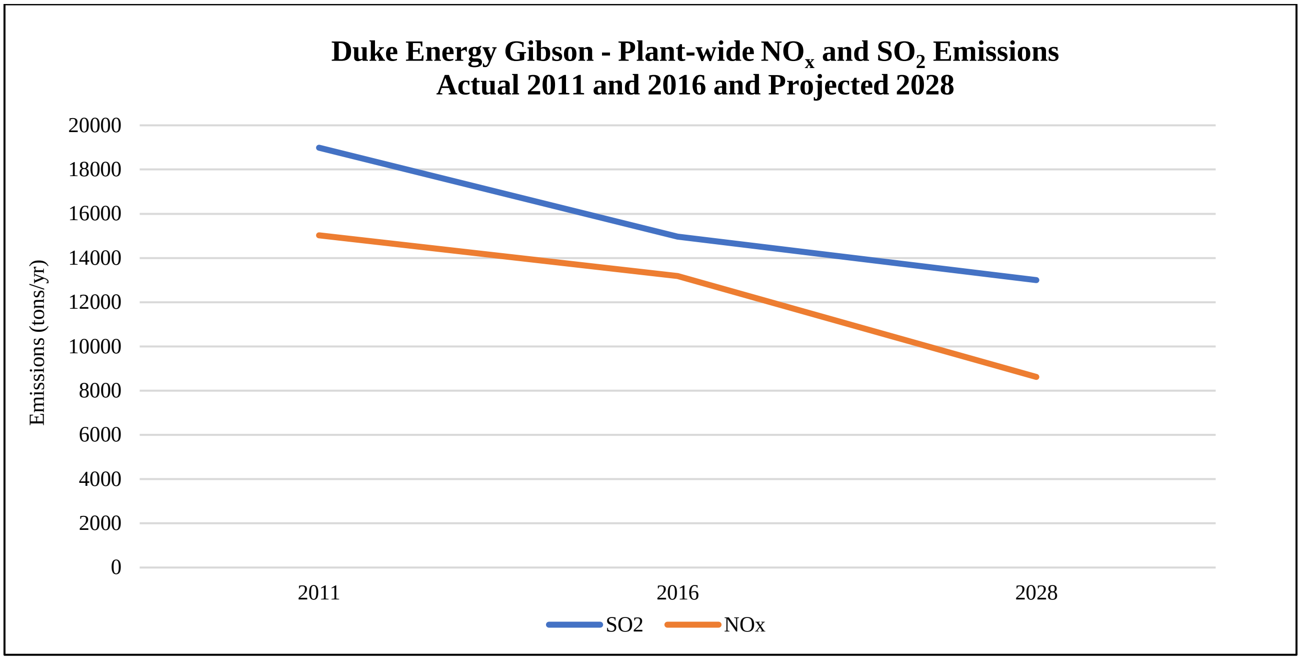
To pursue additional emissions reductions through the use of new emission control equipment or emissions limitations is not desired as a cost-effective method and will only drive utility rates even higher. As will be shown below, the emissions reductions and modeling results demonstrate that visibility impairment from Indiana EGUs in total 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 (Gibson) 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 (SCR) 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 on the following page shows the actual emissions changes that have occurred and changes in emissions projected by 2028.

Graph 4-1 Duke Energy Gibson - SO_2 and NO_x Emissions Trends



Duke Energy's IRP from 2019 was updated to reflect the advancement of several of their existing coal fired EGUs. Gibson is projected to accelerate retirements of Units 1, 2, 3, and 5; 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 was 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 coal-fired power generation capacity with retirements of other boilers. For Gibson's future emissions projections, Units 1, 2, 3, and 5 will be utilized more to meet the electricity demands without Unit 4. Gibson's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 4-1.

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

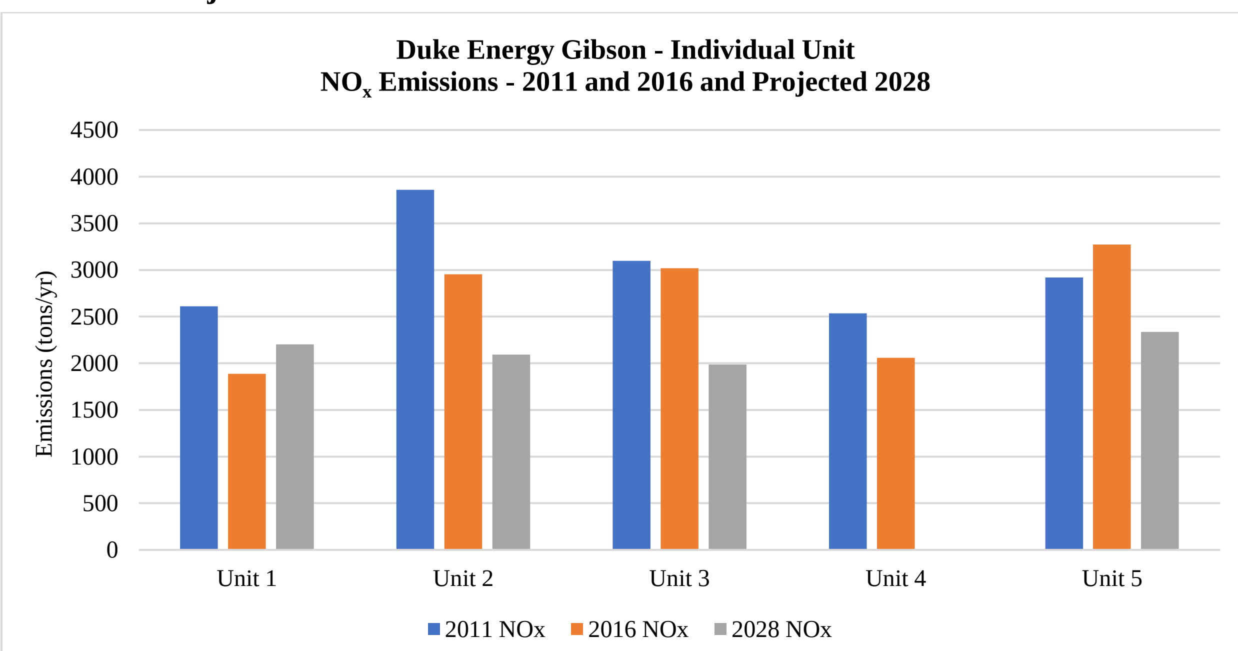
ORIS-ID	Unit ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028-ERTAC	Percentage Change in Utilization
6113	1	Gibson Generating Station	0.4701	0.5175	10.09%
6113	2	Gibson Generating Station	0.6340	0.7097	11.93%
6113	3	Gibson Generating Station	0.6157	0.6688	8.63%
6113	4	Gibson Generating Station	0.5483	Retired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

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 emissions projections, the ERTAC tool will dispatch generation to the coal unit fuel type according to the hourly hierarchy order up to the maximum ERTAC annual utilization fraction for that fuel/unit type bin. In the case of coal, no unit will run above 90% utilization rate in the emission model.

In the case of Gibson and the retirement of Unit 4, before the demand for additional power results in a need to make up electric generation within ERTAC's emissions model, the demand is met by other coal units at the facility based on the growth rates for coal. Gibson's future year utilization rates among Units 1, 2, 3 and 5 vary from the 2016 base-year to the 2028 projection year as a result of the retirement of Unit 4 in order to meet anticipated electricity demands based on less coal-fired power generation capacity.

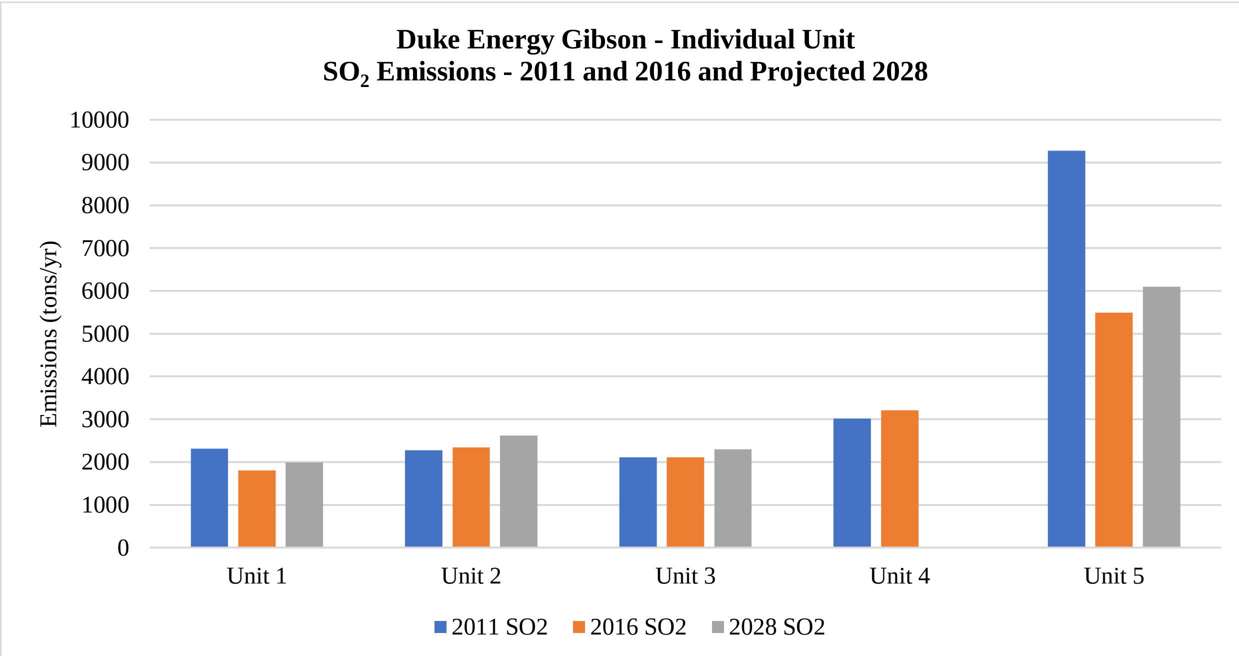
Graph 4-2 shows the unit-by-unit comparison of NO_x emissions at the Duke - Gibson power plant. Note the slight increase in emissions at each of the four remaining units, this demonstrates the increase in utilization based on Unit 4's retirement to meet anticipated power demand. As with SO_2, overall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

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



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

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

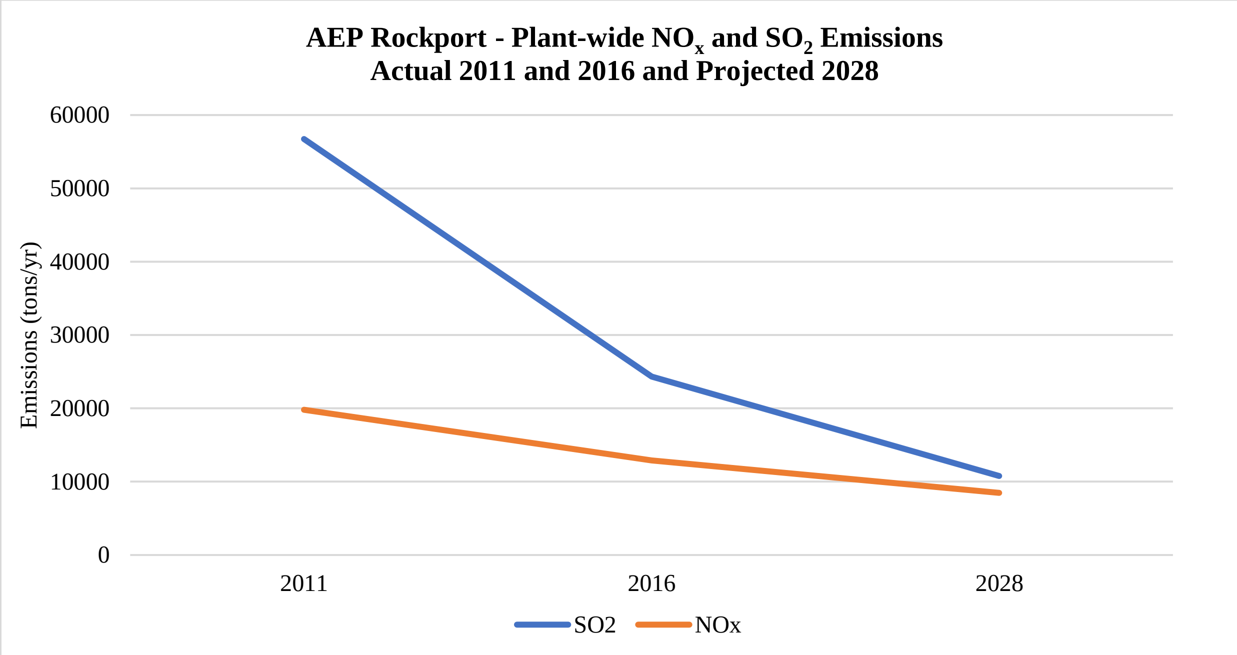


5.0 INDIANA MICHIGAN POWER COMPANY DBA AMERICAN ELECTRIC POWER - ROCKPORT PLANT

Indiana Michigan Power Company, dba American Electronic Power (AEP) - Rockport Plant (Rockport) is located in Spencer County, in the southern portion of Indiana. It is a stationary electric utility generating plant with a maximum generating capacity of 2,774 gross megawatts with two identical pulverized coal opposed wall fired dry bottom wall fired steam generators identified as Units 1 and 2 with Boilers MB1 and MB2, respectively. SO_2 controls for these units include DSI operated since 2015 with a control efficiency of nearly 50% from installation until upgraded to enhanced DSI in 2020. The enhanced DSI is intended to increase the removal efficiency to in excess of 75% to allow compliance with the Consent Decree requirements that went into effect in 2020. NO_x control is supplied by existing low-NO_x burner/Overfire Air Systems (LNB/OFA) along with SCRs installed on Unit 1 in 2017 and Unit 2 in 2020. Over the past 5 years, NO_x control has been observed at or above the 57% level at the stack.

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 following page.

Graph 5-1 AEP Rockport - NO_x and SO_2 Emissions Trends



Rockport is required under the Fifth Modification of the AEP Eastern Fleet NSR Consent Decree, entered on July 17, 2019, to install and continuously operate dry sorbent injection systems on Units 1 and 2 by 2015, and enhanced dry sorbent injection systems on Unit 2 by June 1, 2020 and December 31, 2020 on Unit 1 and Rockport is meeting these requirements currently. Starting with the 30th stack operating day, as defined in the Fifth Modification, Units 1 and 2 are required to meet a 30-day rolling average of 0.15 lb/MMBtu SO_2. SO_2 emissions are also required to be capped plant-wide in the Fifth Modification at 10,000 tons on an annual basis in between 2021 and 2028. Beginning in 2029 that plant wide total cap is lowered to 5,000 tons per year, concurrently with the retirement of Unit 1 (MB1) by no later than December 31, 2028. In addition, Rockport was required to install and continuously operate a SCR on Unit 1 (MB1) by December 31, 2017 and Unit 2 (MB2) by June 1, 2020; Rockport Plant met these requirements. The SCRs shall maintain a 30-day rolling average NO_x emissions on the common stack of 0.09 lb/MMBtu beginning with the 30th stack operating day in 2021, as defined in the Fifth Modification. Both units at Rockport are included in the modeling for 2028.

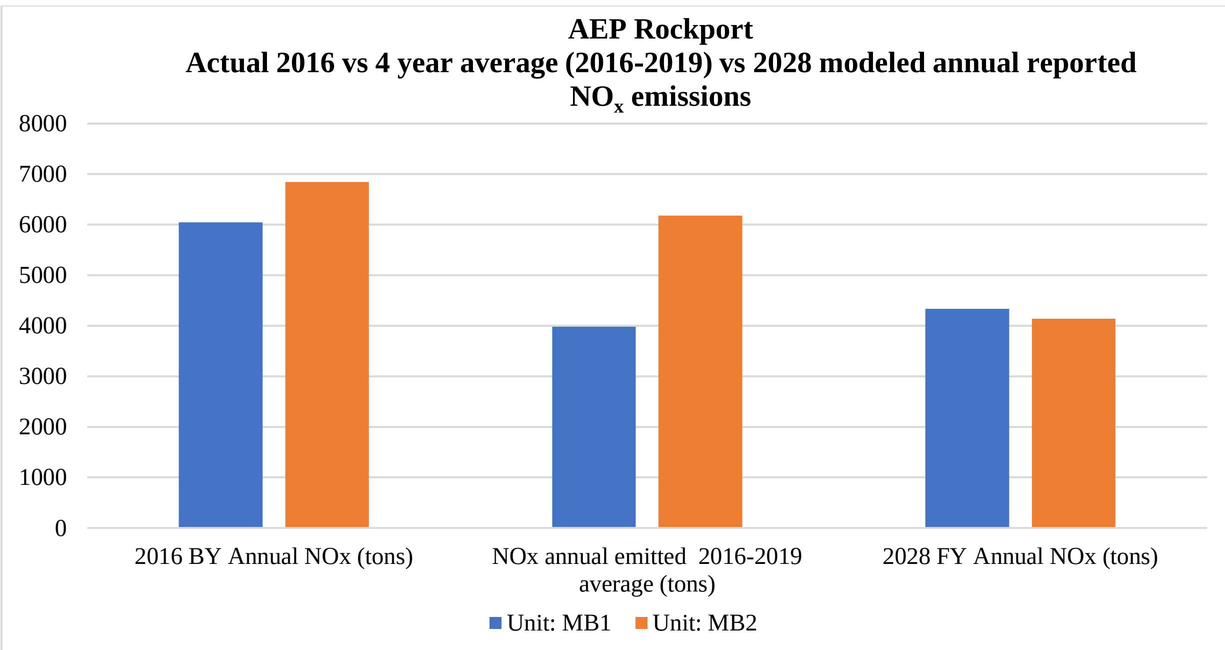
The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. In graph 5-1 above, emissions are depicted for 2011, 2016 and 2028 and do not reflect emission reductions that occur between 2016 and 2028 because the modeling analysis only evaluated 2016 and 2028, respectively. In addition, modeled emission for SO_2 in 2028 are above the 10,000 tons per year cap for SO_2 per the consent decree as a result of the rates used in the model to estimate the 2028 emission. In addition, NO_x emissions used in the ERTAC model run version 16.1 are slightly higher than the 0.09 lb./MMBtu rate required by the consent decree. This results in a 2028 projection that is slightly higher than the agreement allows and will be adjusted downward in the next version of ERTAC projections. The result of these overestimates of emissions will be a more conservative analysis in 2028. Rockport's ERTAC future emission projections for Units MB1 and MB2 increase slightly from 2016 to 2028 due to shifts in demand across the power grid as other coal-fired units retire in the modeling analysis. Rockport's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 5-1 below.

Table 5-1 Rockport Plant's 2016 and Projected 2028 Utilization Rates for Units MB1 and MB2

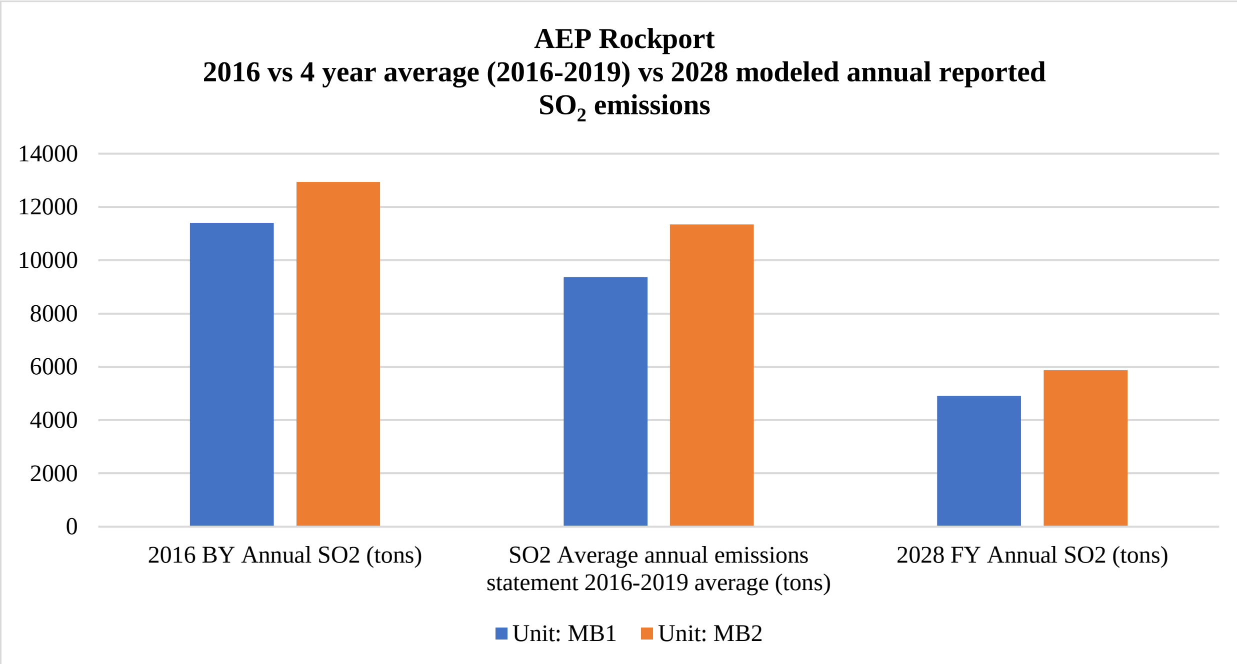
ORIS-ID	Steam Generator ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028-ERTAC	Percentage Change in Utilization
6166	MB1	Rockport Plant	0.4619	0.4895	5.6%
6166	MB2	Rockport Plant	0.5534	0.5956	7.1%

Comparison of NO_x and SO_2 emissions by unit are shown below in Graphs 5-2 and 5-3. 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



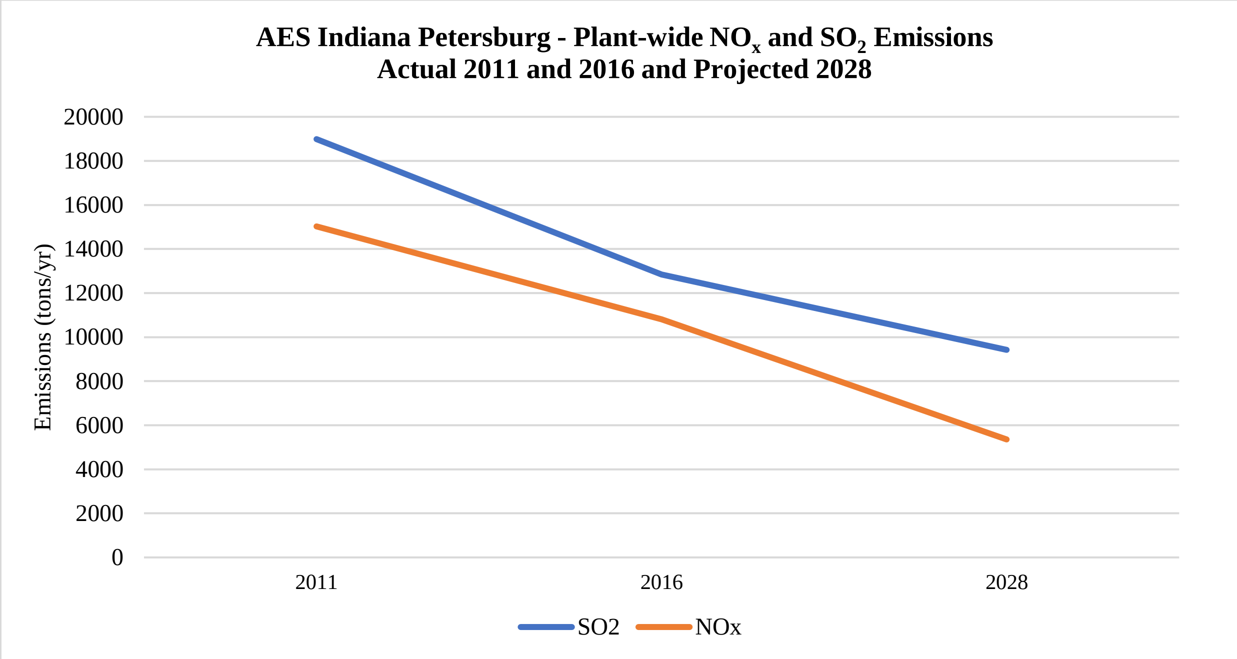
6.0 AES INDIANA - PETERSBURG GENERATING STATION

AES Indiana (AES) Petersburg Generating Station (Petersburg) is located in Pike County, in the southwestern portion of Indiana. It is a stationary electric utility generating station with a maximum generating capacity of 1,824 megawatts among four coal/No. 2 fuel oil fired boilers. Controls for these units include FGD scrubbers with SO_2 control efficiencies above 94% based on source estimates; LNB technology with ACI technology on Unit 1, ACI technology with SCR system and LNB technology on Unit 2, ACI and SCR on Unit 3 and ACI and LNB as control for NO_x with control efficiencies on Units 3 and 4 above 70% based on source estimates.

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

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

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



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

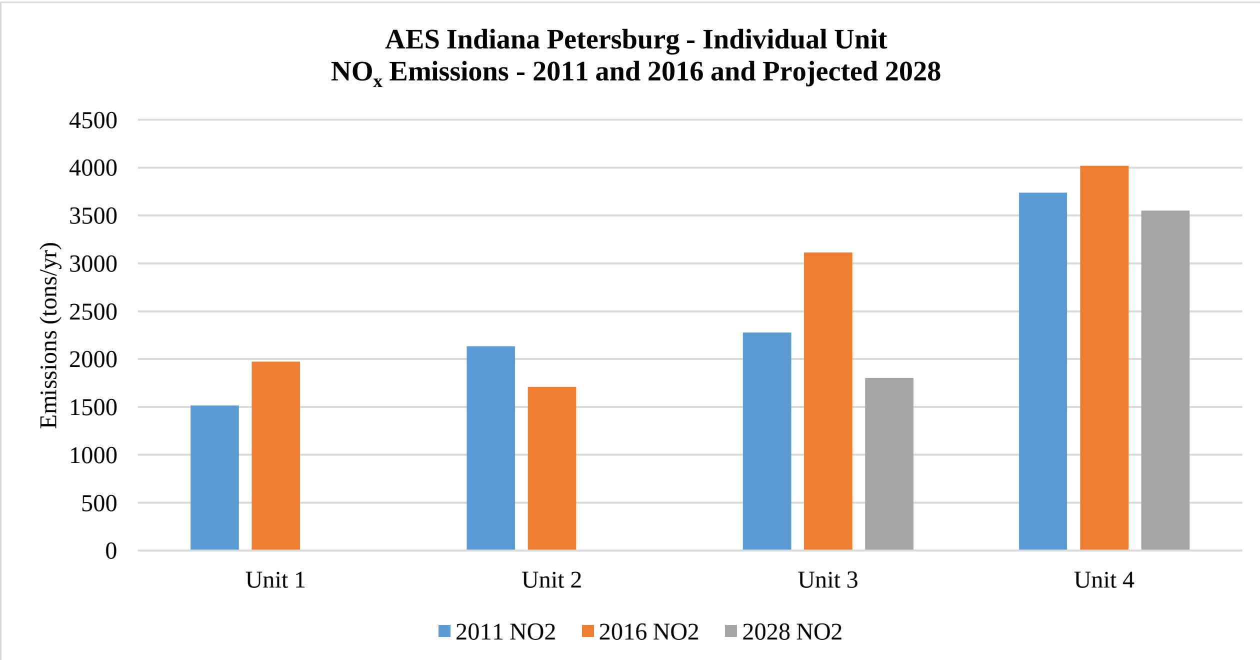
The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. The overall emissions from each facility will be reduced because of the unit shutdowns but individual unit emissions may be slightly higher than their 2016 emissions due to power demand and limited coal-fired power generation capacity with retirements of other boilers. For Petersburg's future emissions projections, Units 3 and 4 are anticipated to be utilized more to meet the electricity demands for the area with the retirement of Units 1 and 2. Petersburg's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 6-1.

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

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

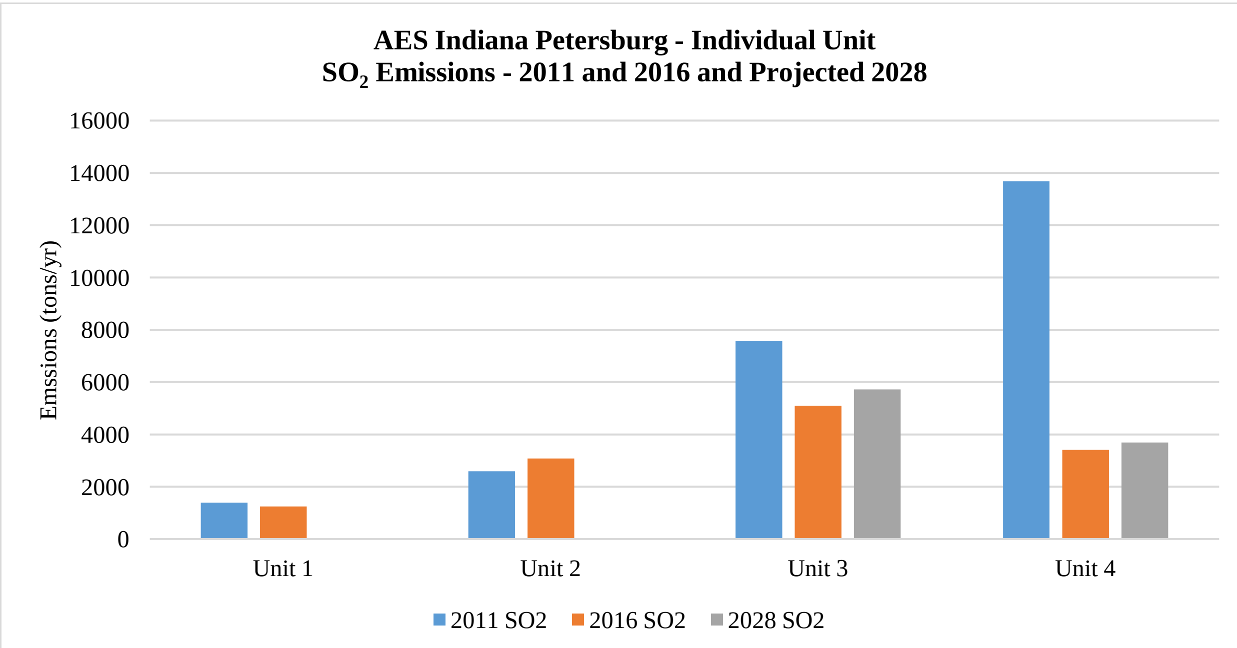
Graph 6-2 shows the unit-by-unit comparison of NO_x emissions at the Petersburg power plant. There are significant projected decreases in NO_x emissions with the retirement of Units 1 and 2 and modest NO_x emission reduction from Units 3 and 4 as observed from actual CAMD data for 2011 and 2016 and ERTAC's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

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



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

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

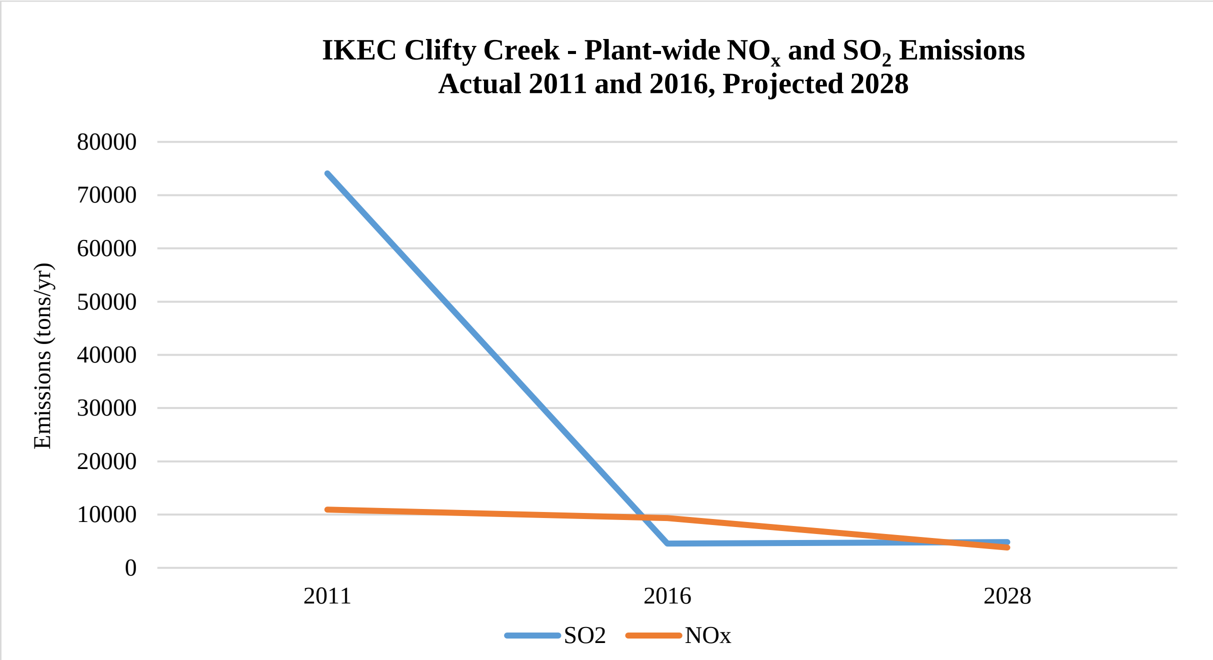


7.0 INDIANA-KENTUCKY ELECTRIC CORPORATION - THE OHIO VALLEY ELECTRCAL CORPORATION - CLIFTY CREEK STATION

The Indiana Kentucky Electric Corporation (IKEC) and the Ohio Valley Electrical Corporation's Clifty Creek Station (Clifty Creek) is a 1,300 megawatts (MW) coal-fired power station located in Madison, Jefferson County. The Clifty Creek Station operates six wet-bottom pulverized coal-fired boilers, with each of its six generating units rated at 217.26 MW, for a total capacity of 1,303.56 MW. Controls for NO_x and SO_2 are as follows: Fluidized-Gas Desulfurization System and Overfire Air on all six units and Selective Catalytic Reduction on Units 1 through 5.

Clifty Creek 2028 EGU NO_x emissions are projected to be reduced by 59% or 5,534 tons from 2016 emission levels and SO_2 emissions are expected to increase slightly, by 6% or 286 tons from 2016 to 2028. The ERTAC model projects small increases in utilization at the facility for all six units.

Graph 7-1 IKEC Clifty Creek NO_x and SO_2 Emissions Trends



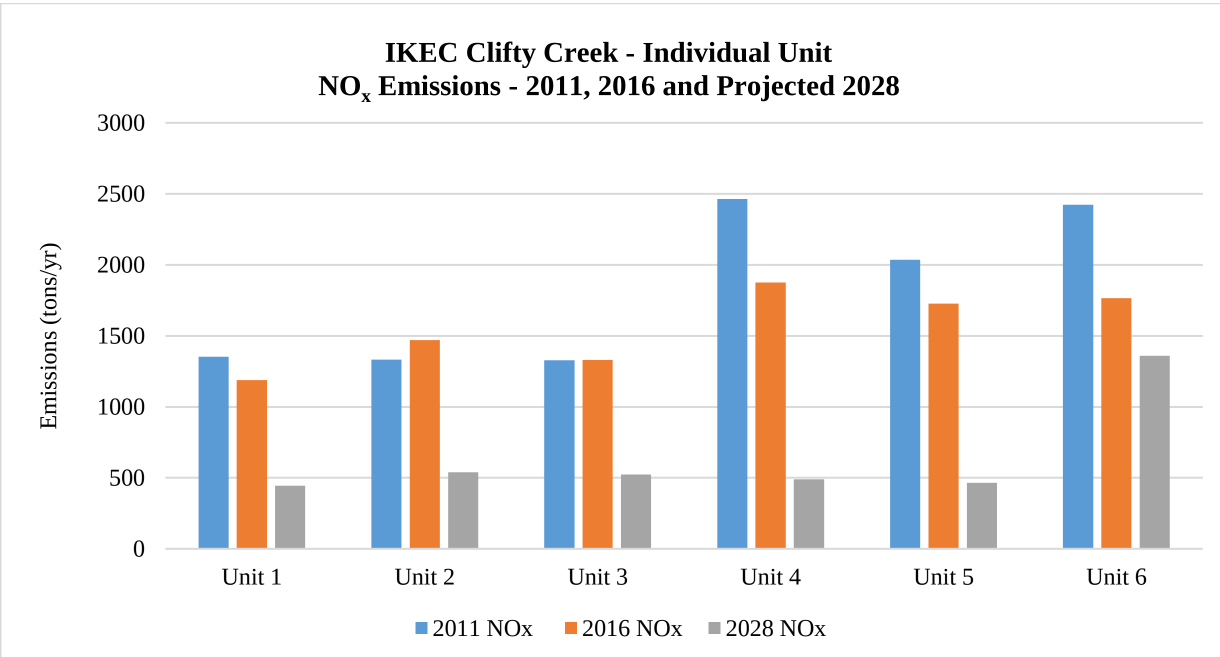
The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. The overall emissions from each facility will be reduced because of the unit shutdowns but individual unit emissions may be slightly higher than their 2016 emissions due to power demand and limited coal-fired power generation capacity with retirements of other boilers. For Clifty Creek's future emissions projections, Units 1- 6 is anticipated to be utilized more to meet the electricity demands for the area. Clifty Creek's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 7-1.

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

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

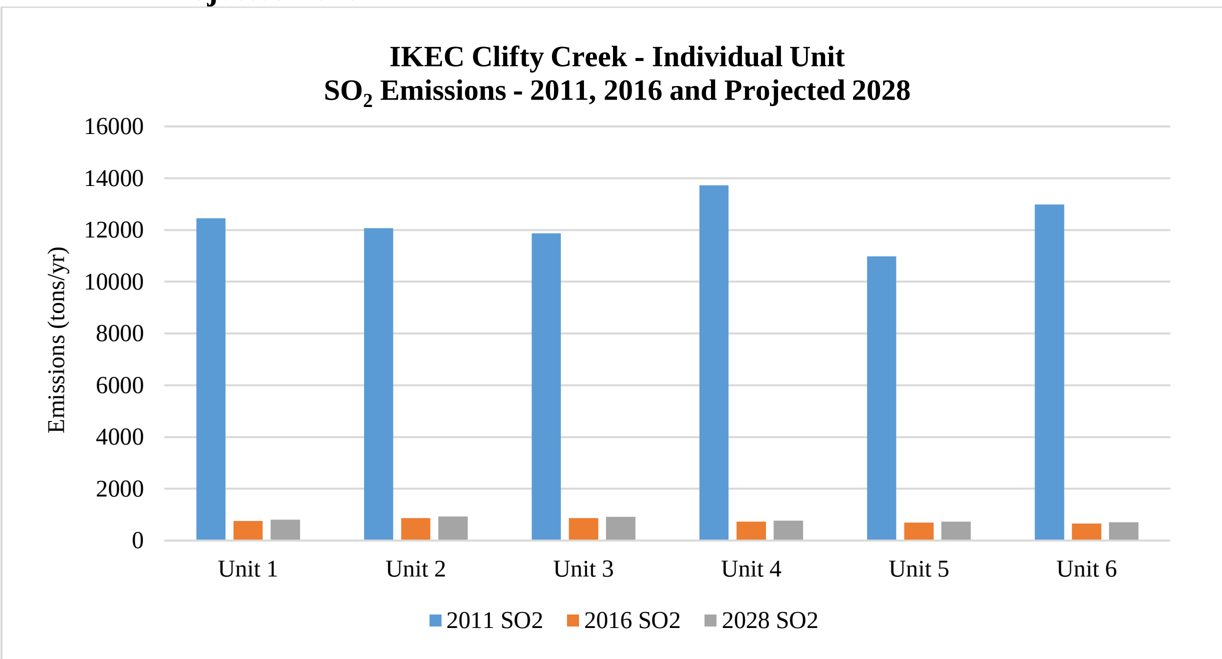
Graph 7-2 below shows the unit-by-unit comparison of NO_x emissions at the Clifty Creek power plant. There is a significant projected decrease in NO_x emissions at each of the six units from actual CAMD data for 2011 and 2016 to projected 2028 emissions by ERTAC.

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



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

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

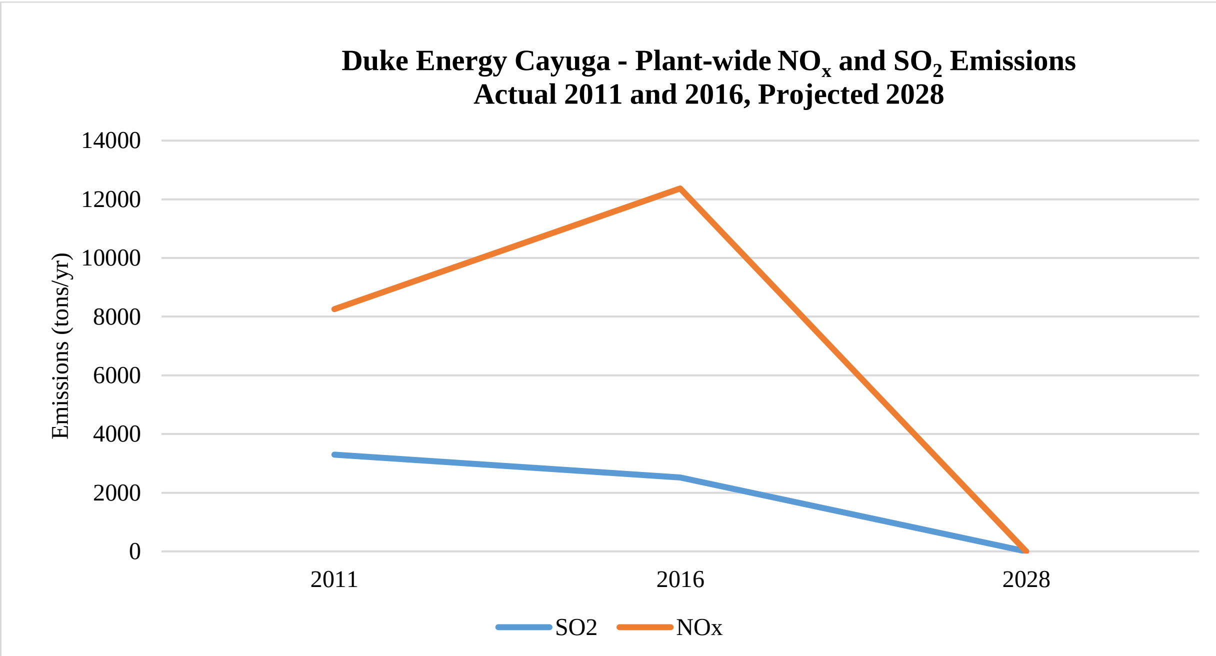


8.0 DUKE ENERGY INDIANA, LLC - CAYUGA GENERATING STATION

Duke Energy Indiana, LLC - Cayuga Generating Station (Cayuga) is a three-unit generating facility built between 1970 and 1993 with a total generation capacity of 1,104 MW located in Vermillion County Indiana. Units 1 and 2 are dry bottom, pulverized coal-fired boilers that have been equipped with flue FGD scrubbers to reduce the station's sulfur dioxide emissions by approximately 95%. Both units also have a LNB and SCR to control NO_x emissions. Units 1 and 2 are expected to retire according to Duke's 2019 IRP resulting in 1108 MW of coal-fired retired power generation by 2028. Unit 4 is a natural gas and no. 2 fuel oil-fired combustion turbine and does not have a retirement date as of the last IRP review.

Cayuga's 2028 EGU NO_x emissions are projected to be reduced by 100% or 12,369 tons from 2016 emission levels and SO_2 emissions are expected to be reduced by 100% or 2,520 tons from 2016 to 2028.

Graph 8-1 Duke Energy Cayuga NO_x and SO_2 Emissions Trends



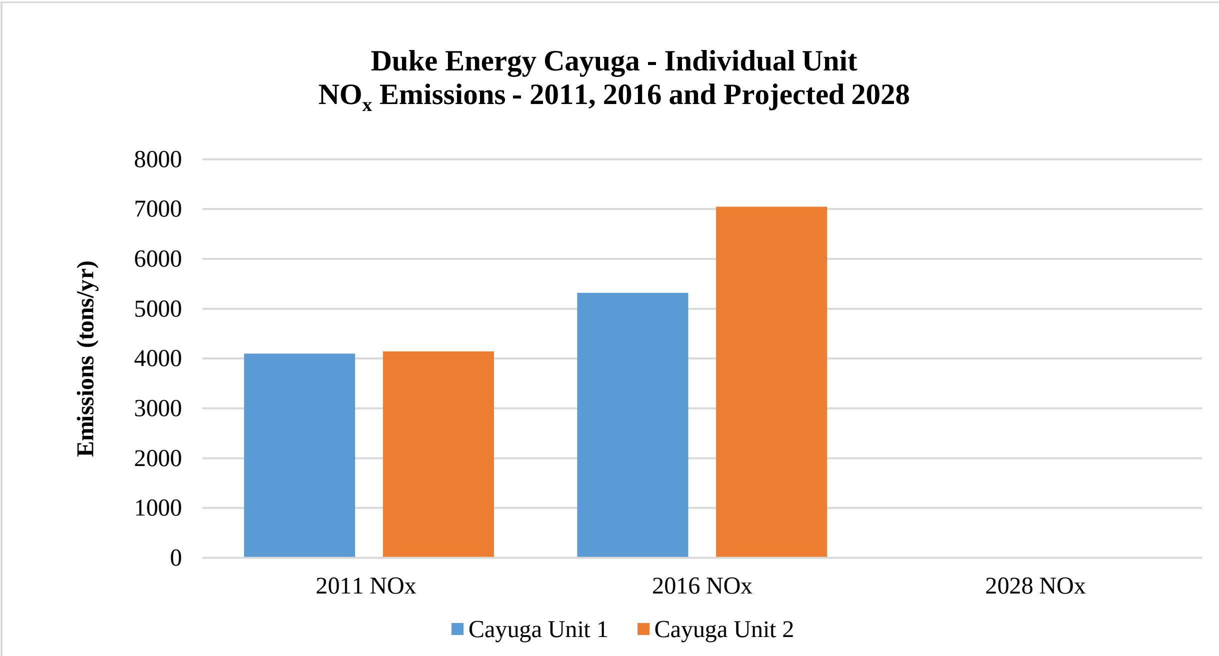
The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. The overall emissions from each facility will be reduced because of the unit shutdowns but individual unit emissions may be slightly higher than their 2016 emissions due to power demand and limited power generation capacity with retirements of other boilers. For Cayuga's future emissions projections, Unit 4 may be utilized more to meet the electricity demands without Units 1 and 2. Cayuga's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 8-1.

Table 8-1 Cayuga Power Generating Station's 2016 and Projected 2028 Utilization Rates for Units 1, 2 and 4

ORIS-ID	Unit ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028-ERTAC	Percentage Change in Utilization
1001	1	Cayuga Generating Station	0.5365	Retired	-100.0%
1001	2	Cayuga Generating Station	0.8109	Retired	-100.0%
1001	4	Cayuga Generating Station	0.0005	0.0017	68.6%

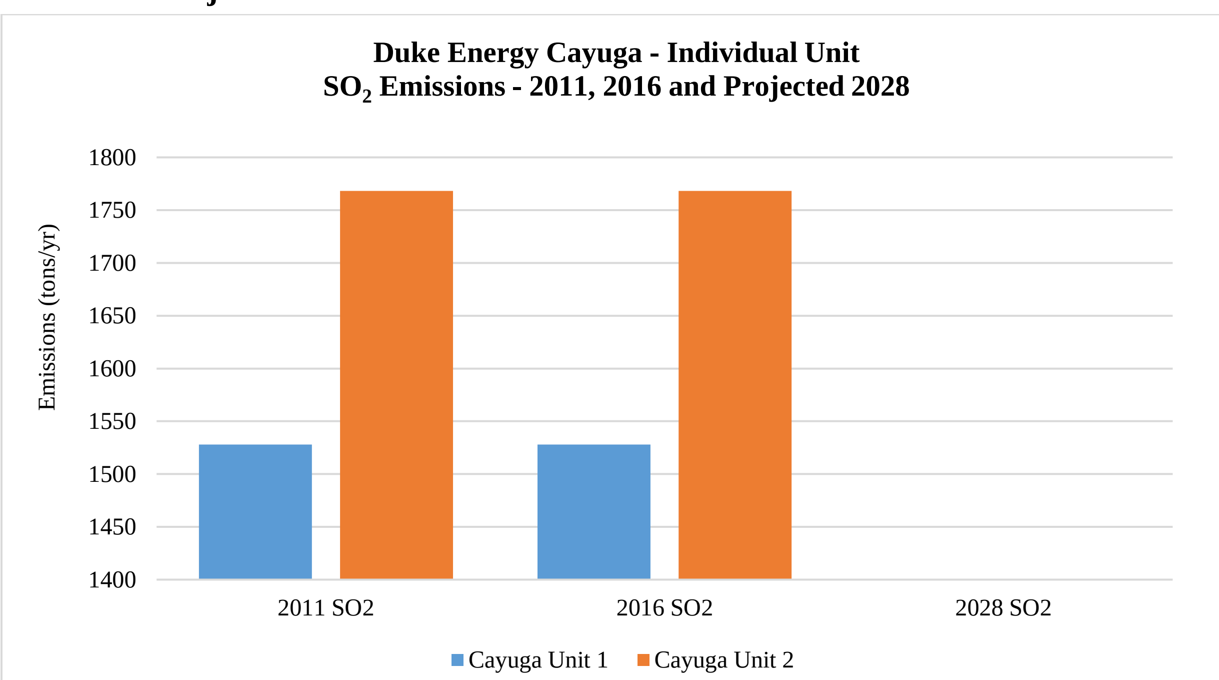
Graph 8-2 on the next page shows the unit-by-unit comparison of NO_x emissions at the Cayuga power plant. With the retirements of both Units 1 and 2, NO_x emissions at both units decrease from actual CAMD data for 2011 and 2016 to ERTAC's projected 2028 emissions of zero. Unit 4 is not included in the chart because its base year and future year utilization is very low with total NO_x emissions less than 1 ton per year.

Graph 8-2 Unit Comparison of Duke Energy Cayuga NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 8-3 shows the unit-by-unit comparison of SO_2 emissions at the Cayuga power plant. With the retirements of both Units 1 and 2, SO_2 emissions at both units decrease from actual CAMD data for 2011 and 2016 to ERTAC's projected 2028 emissions of zero. Unit 4 is not included in the chart because its base year and future year utilization is very low with total SO_2 emissions less than 1 ton per year.

Graph 8-3 Unit Comparison of Duke Energy Cayuga SO_2 Emissions - Actual 2011 and 2016, Projected 2028

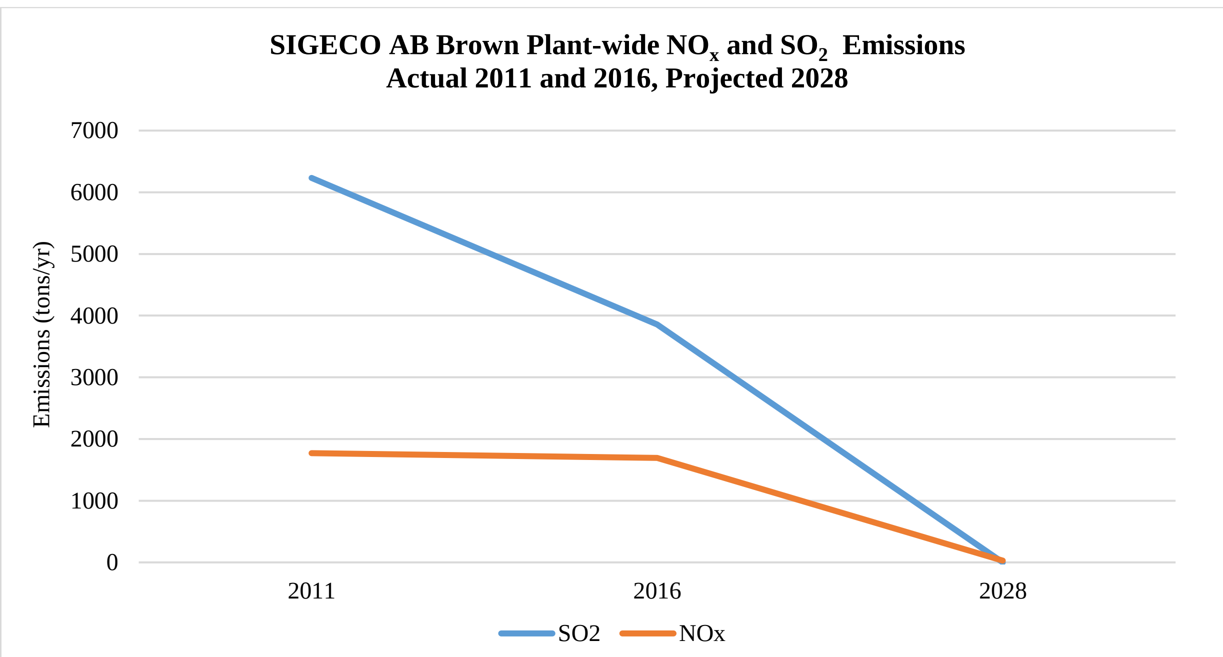


9.0 SOUTHERN INDIANA GAS AND ELECTRIC COMPANY - AB BROWN GENERATING STATION

Southern Indiana Gas and Electric Company (SIGECO) AB Brown Generating Station (AB Brown) is a four-unit, 700-MW power generating facility located near Mount Vernon, Posey County, Indiana. The two dry bottom, pulverized coal-fired boilers (Units 1 and 2) have a name-plate capacity of 265.2 MW, commissioned from 1979 to 1986. Unit 1 controls include dual alkali FGD system for control of SO_2, with low-NO_x combustion (low-excess air and LNB and SCR system for control of NO_x. Unit 2 controls include a dual alkali FGD system for control of SO_2, with low-NO_x combustion (low-excess air and LNB and SCR system for control of NO_x. Units 1 and 2 are set to retire in 2023 per the 2019-2020 IRP and will remove 530 MW of coal fired generation off the power grid. There are also two simple-cycle, natural gas-fired combustion turbines (Units ABB3 and ABB4) that have 88.2 MW of nameplate capacity each.

AB Brown's 2028 EGU NO_x emissions are projected to be reduced by 98% or 1,665 tons from 2016 emission levels and SO_2 emissions are expected to be reduced by 100% or 3,854 tons from 2016 to 2028.

Graph 9-1 SIGECO AB Brown NO_x and SO_2 Emissions Trends



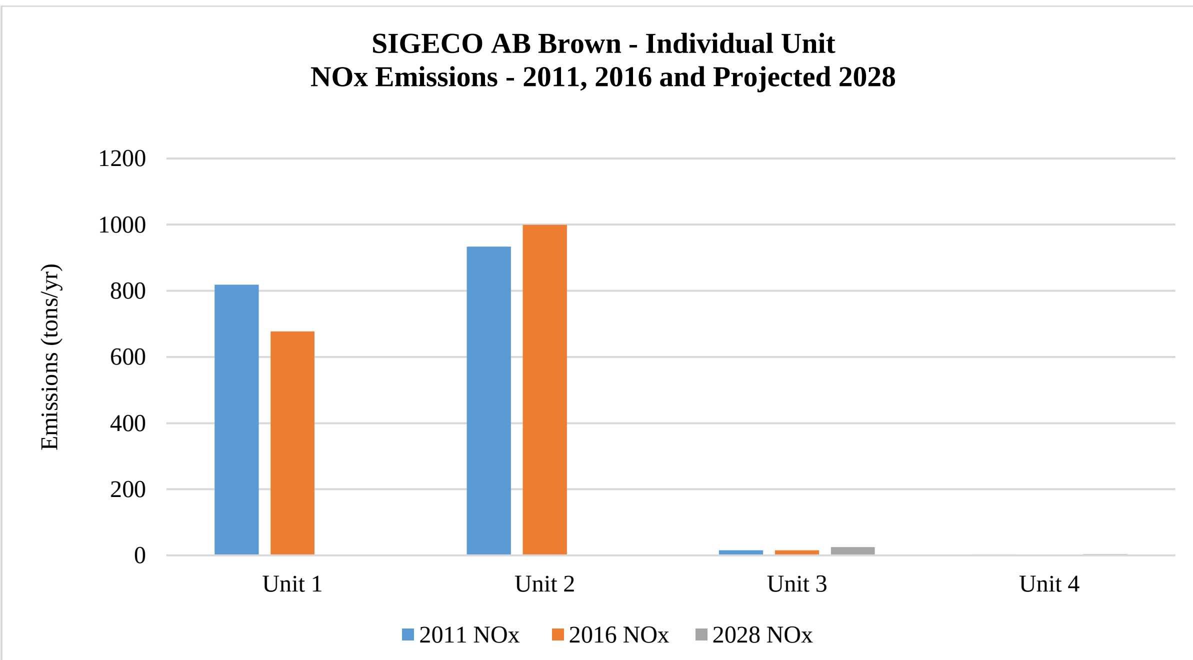
The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. The overall emissions from each facility will be reduced because of the unit shutdowns but individual unit emissions may be slightly higher than their 2016 emissions due to power demand and limited power generation capacity with retirements of other boilers. For AB Brown's future emissions projections, Units 1 and 2 megawatts are being replaced by renewables and NG-fired combustion turbines. The renewables filing was recently submitted. Units 3 and 4 will be utilized more to meet the electricity demands without Unit 1 and 2. AB Brown's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 9-1 on the following page.

Table 9-1 AB Brown Generation 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
6137	1	AB Brown Generating Station	0.2997	Retired	-100.0%
6137	2	AB Brown Generating Station	0.3819	Retired	-100.0%
6137	3	AB Brown Generating Station	0.0150	0.0249	39.7%
6137	4	AB Brown Generating Station	0.0145	0.0236	38.8%

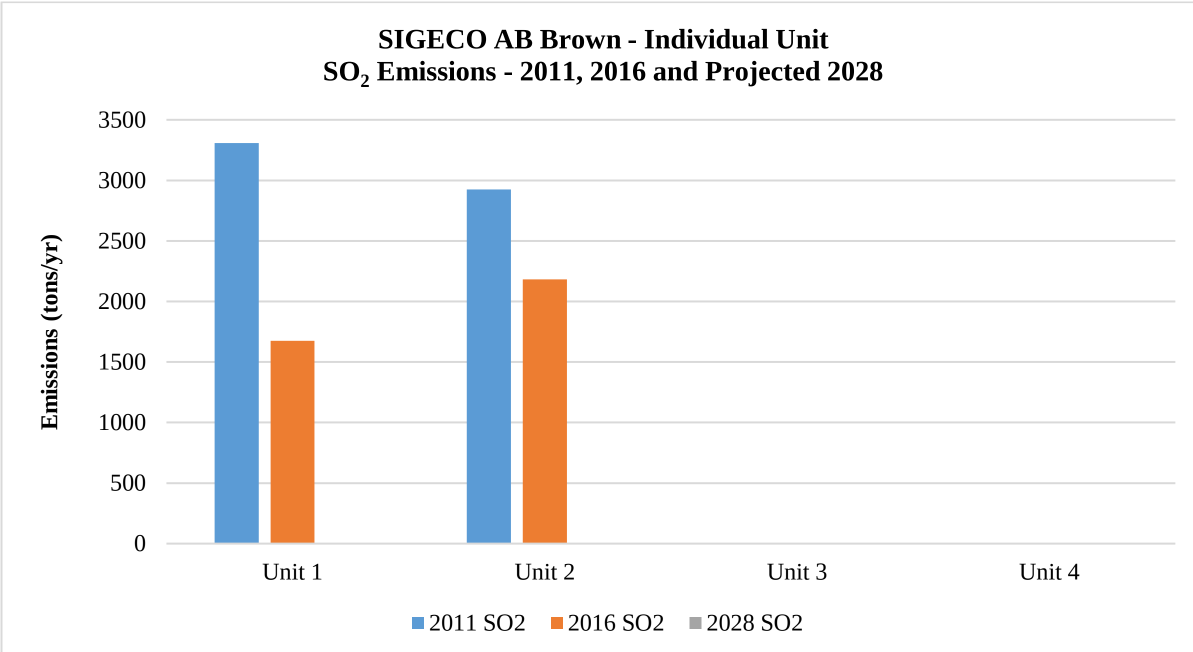
Graph 9-2 shows the unit-by-unit comparison of NO_x emissions at the AB Brown power plant. With the retirements of both Units 1 and 2, NO_x emissions at both units decrease from actual CAMD data for 2011 and 2016 to projected 2028 emissions by ERTAC of zero. Units ABB3 and ABB4's base year and future year utilization are low so projected NOx emissions for 2028 will be very low.

Graph 9-2 Unit Comparison of SIGECO AB Brown NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 9-3 on the next page shows the unit-by-unit comparison of SO_2 emissions at the AB Brown power plant. With the retirements of both Units 1 and 2, SO_2 emissions at both units decrease from actual CAMD data for 2011 and 2016 to projected emissions by ERTAC in 2028 of zero. The natural gas-fired combustion turbines, Units ABB3 and ABB4's base year and future year utilization are low so projected SO_2 emissions for 2028 will be very low.

Graph 9-3 Unit Comparison of SIGECO AB Brown SO_2 Emissions - Actual 2011 and 2016, Projected 2028

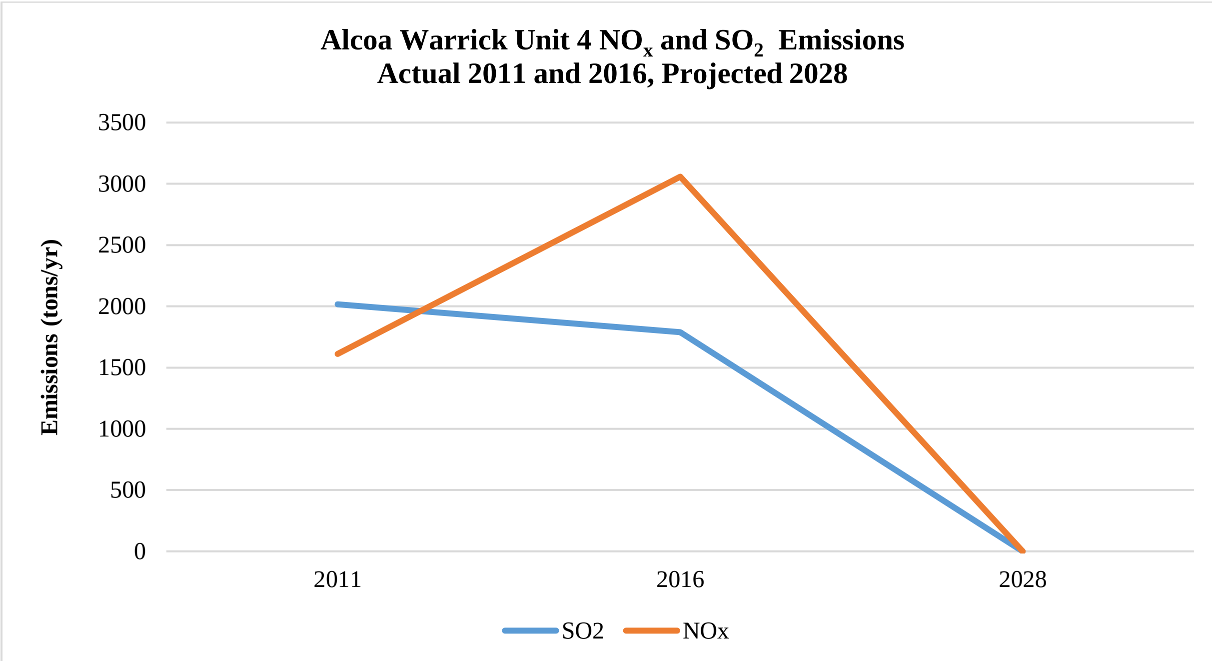


10.0 ALCOA POWER GENERATING, INC - WARRICK POWER PLANT

Alcoa Power Generating Inc - Warrick Power Plant (Alcoa) owns three of the four generating stations at the Warrick facility, located near Newburgh, Warrick County, Indiana. These units were placed into service in the early 1960s. The largest unit, known as Unit 4, is a dry bottom, pulverized coal-fired boiler with capacity of 323-MWe jointly owned by Alcoa and Vectren and is characterized as an EGU. Emission controls include LNB and a SCR system for NO_x and a wet FGD scrubber for SO_2 controls.

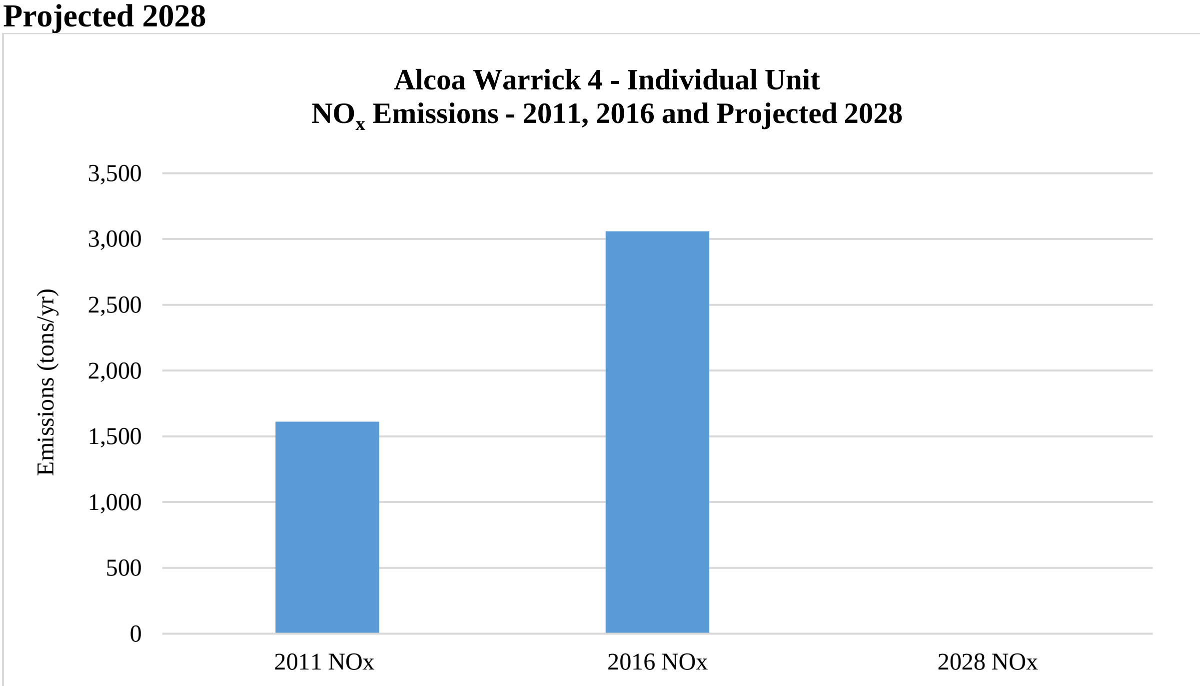
According to the 2019-2020 Vectren IRP, both companies will exit their agreement to purchase power in 2023 from Alcoa Unit 4. Therefore, this unit was not modeled as an EGU and was not included in the ERTAC future year emissions projections and was not modeled by LADCO. After modeling was concluded,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

Graph 10-1 Alcoa Warrick Unit 4 NO_x and SO_2 Emissions Trends



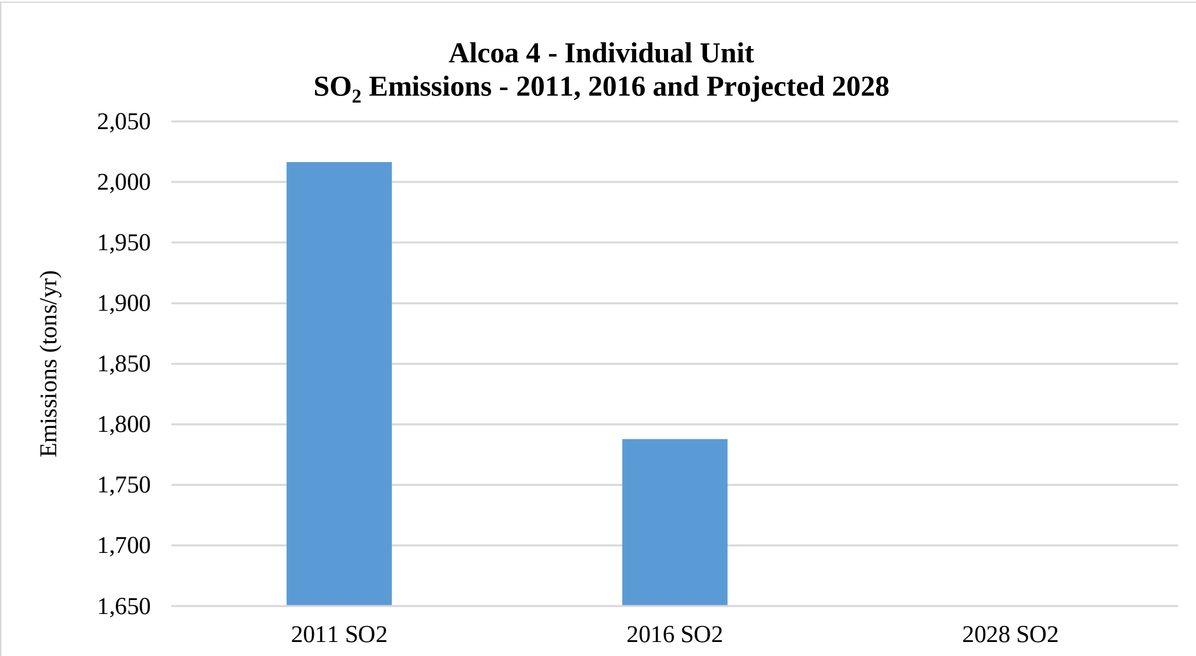
Graph 10-2 shows the unit-by-unit comparison of NO_x emissions at the Alcoa power plant. With the originally presumed retirement of Unit 4, NO_x emissions were modeled to decrease from actual CAMD reported emissions for 2011 and 2016 to projected 2028 emissions by ERTAC of zero but in fact NO_x emissions should be close to the 2016 reported levels.

Graph 10-2 Unit Comparison of Alcoa Warrick NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 10-3 shows the unit-by-unit comparison of SO_2 emissions at the Alcoa power plant. With the originally presumed retirement of Unit 4, SO_2 emissions were modeled to decrease from actual CAMD reported emissions for 2011 and 2016 to projected 2028 emissions by ERTAC of zero but in fact SO_2 emissions should be close to the 2016 reported levels.

Graph 10-3 Unit Comparison of Alcoa SO_2 Emissions - Actual 2011 and 2016, Projected 2028

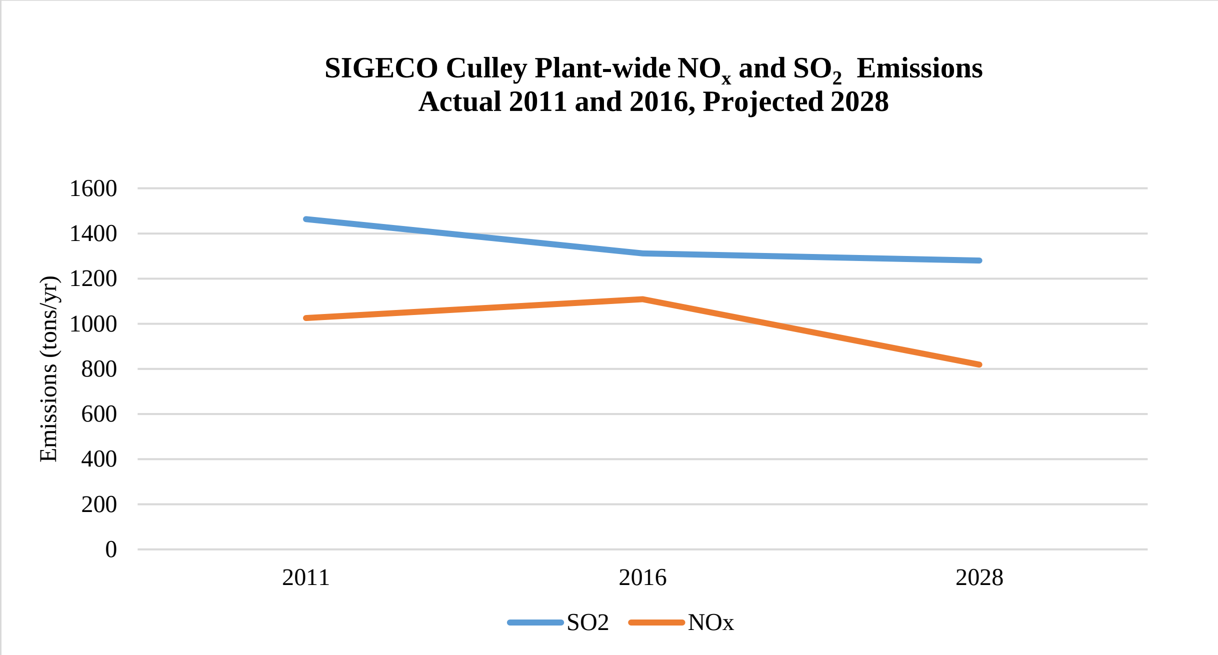


11.0 SOUTHERN INDIANA GAS AND ELECTRIC COMPANY - F.B. CULLEY GENERATING STATION

Southern Indiana Gas and Electric Company (SIGECO) F. B. Culley Generating Station (Culley) is a coal-fired power plant located southeast of Newburgh in Warrick County, Indiana. Culley has two coal/natural gas fired boilers, Unit 2 has a generation capacity of 90 MW and Unit 3 has a generation capacity of 270 MW. It is expected that Unit 2 will retire in 2023 and remove 90 MW of coal fired power generation from the grid. This information was obtained from the Vectren 2019-2020 IRP. Emission controls include LNB for NO_x control and FGD system for SO_2 controls on Unit 2. Unit 3 has LNB and SCR for NO_x reduction and shares the FGD system for SO_2 controls with Unit 2.

Culley's 2028 EGU NO_x emissions are projected to be reduced by 26% or 290 tons from 2016 emission levels and SO_2 emissions are expected to be reduced by 2% or 31 tons from 2016 to 2028. While overall emissions at the facility are down between 2016 and 2028, Unit 3 may have increased utilization and be required to operate more in order to meet the demand for additional power generation as a result of the retirement of Unit 2.

Graph 11-1 SIGECO Culley NO_x and SO_2 Emissions Trends



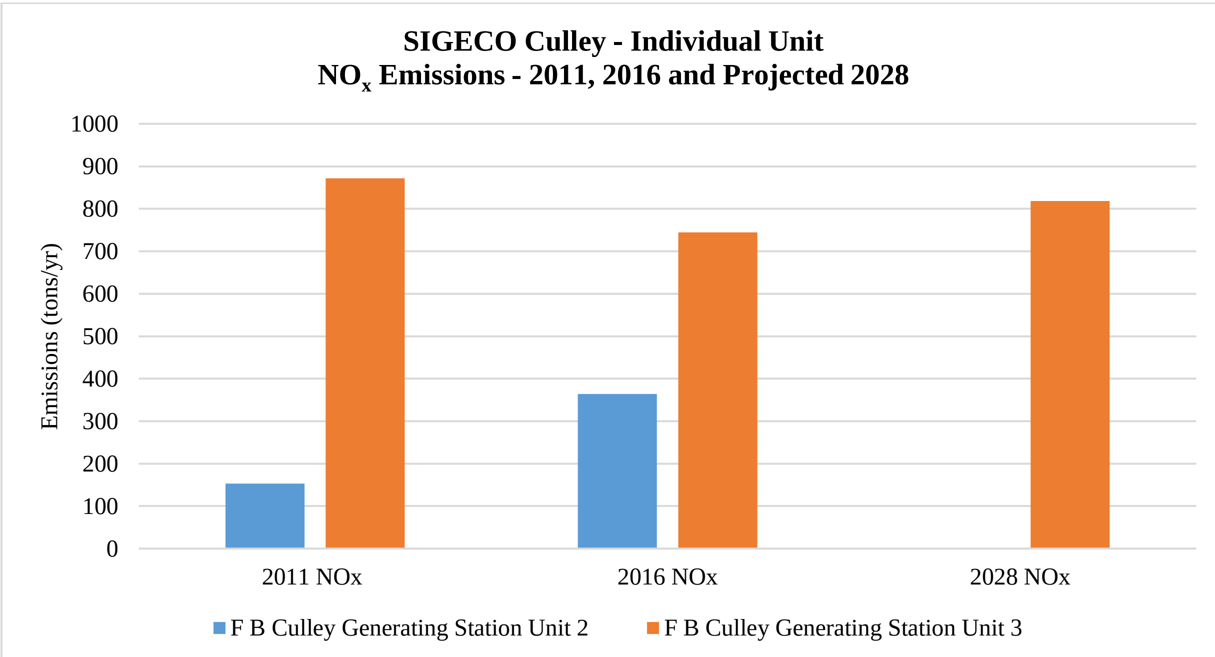
The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. The overall emissions from each facility will be reduced because of the unit shutdowns but individual unit emissions may be slightly higher than their 2016 emissions due to power demand and limited power generation capacity with retirements of other boilers. For Culley's future emissions projections, Unit 2 coal-fired power generation is being replaced with renewables and NG-fired combustion turbines. The renewables filing was recently submitted with the Indiana Utility Regulatory Commission. Meanwhile, Unit 3 may be utilized more to meet the electricity demands with the retirement of Unit 2. Culley's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 11-1.

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

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

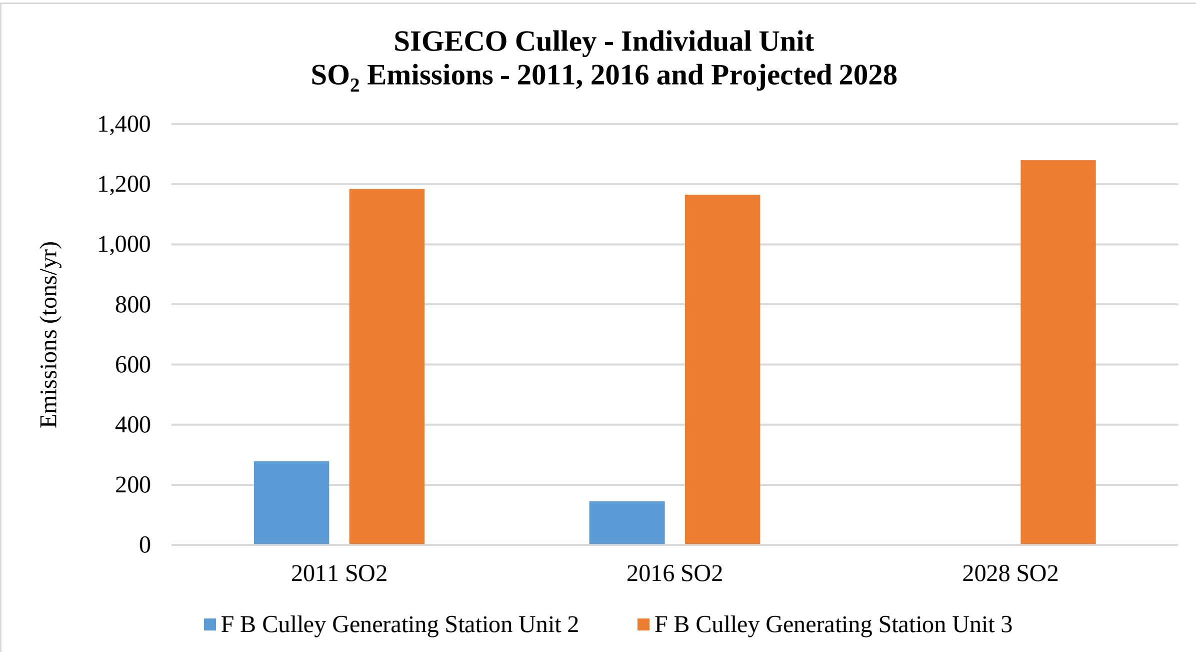
Graph 11-2 shows the unit-by-unit comparison of NO_x emissions at the Culley power plant. Note the slight increase in projected emissions at Unit 3. This demonstrates the slight increase in utilization based on projected increased electricity demand in the area due to the retirement of Unit 2. The overall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

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



Graph 11-3 shows the unit-by-unit comparison of SO_2 emissions at the Culley power plant. Note the slight increase in projected emissions at Unit 3. This demonstrates the slight increase in utilization based on projected electricity demand in the area due to the retirement of Unit 2. The overall SO_2 emissions decrease at Culley from 2016 to 2028 is projected to be 2%.

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

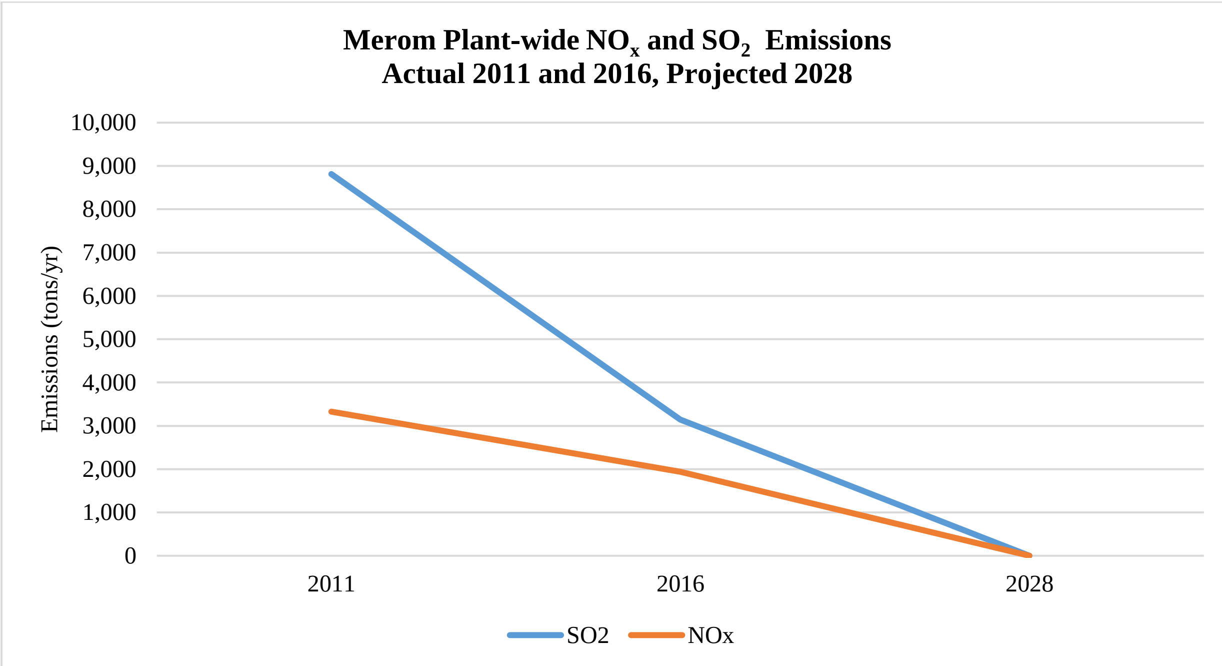


12.0 HOOSIER ENERGY REC INC - MEROM GENERATING STATION

Hoosier Energy REC Inc - Merom Generating Station (Merom) is a two-unit, 1080 MW rated coal-fired power plant located near Merom, Indiana in Sullivan County, Indiana. The two pulverized coal-fired dry bottom boilers (Units 1SG1 and 2SG1) are owned by Hoosier Energy REC Inc, a Touchstone Energy cooperative. Emission controls for both units include FGD, Wet Scrubber System and SCR. The plant has been in operation since 1982 and is expected to retire both units in 2023 according to the following; December 2020 NEEDsv620 update from CAMD, also the IPMv5.15 CSAPR update has the unit retired by 2024, as well as the Hoosier Energy 20-year plan and the retirements were included in the Merom November 2020 IRP.

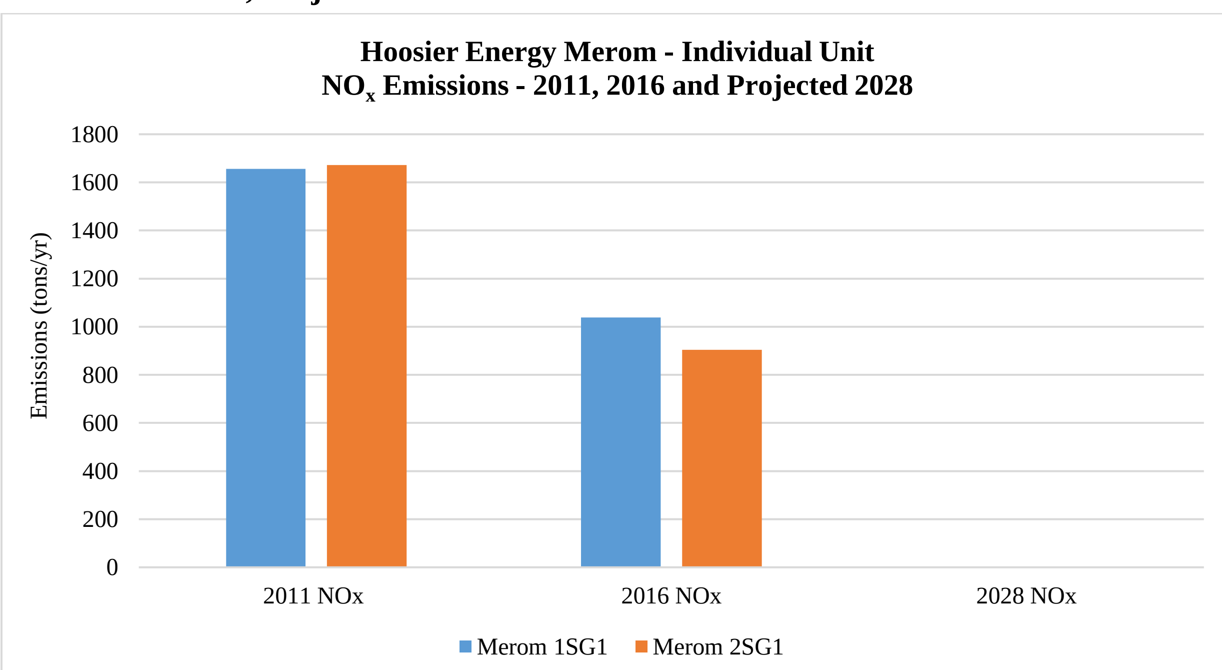
Merom's 2028 EGU NO_x emissions are projected to be reduced by 1,942 tons from 2016 emission levels and SO_2 emissions are expected to be reduced by 3,143 tons from 2016 to 2028.

Graph 12-1 Hoosier Energy Merom NO_x and SO_2 Emissions Trends



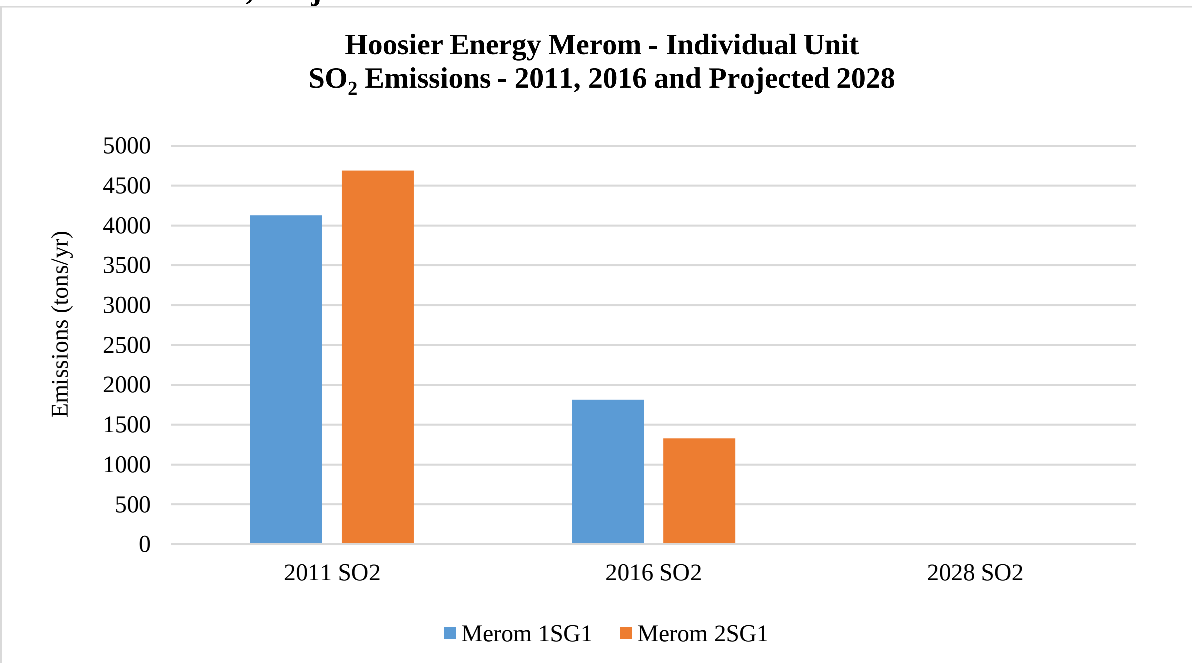
Graph 12-2 shows the unit-by-unit comparison of NO_x emissions at the Merom power plant. With the retirements of both Units 1SG1 and 2SG1, NO_x emissions at both units decrease from actual CAMD data for 2011 and 2016 to ERTAC's projected 2028 emissions of zero.

Graph 12-2 Unit Comparison of Hoosier Energy Merom NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 12-3 shows the unit-by-unit comparison of SO_2 emissions at the Merom power plant. With the retirements of both Units 1SG1 and 2SG1, SO_2 emissions at both units decrease from actual CAMD data for 2011 and 2016 to ERTAC's projected 2028 emissions of zero.

Graph 12-3 Unit Comparison of Hoosier Energy Merom SO_2 Emissions - Actual 2011 and 2016, Projected 2028

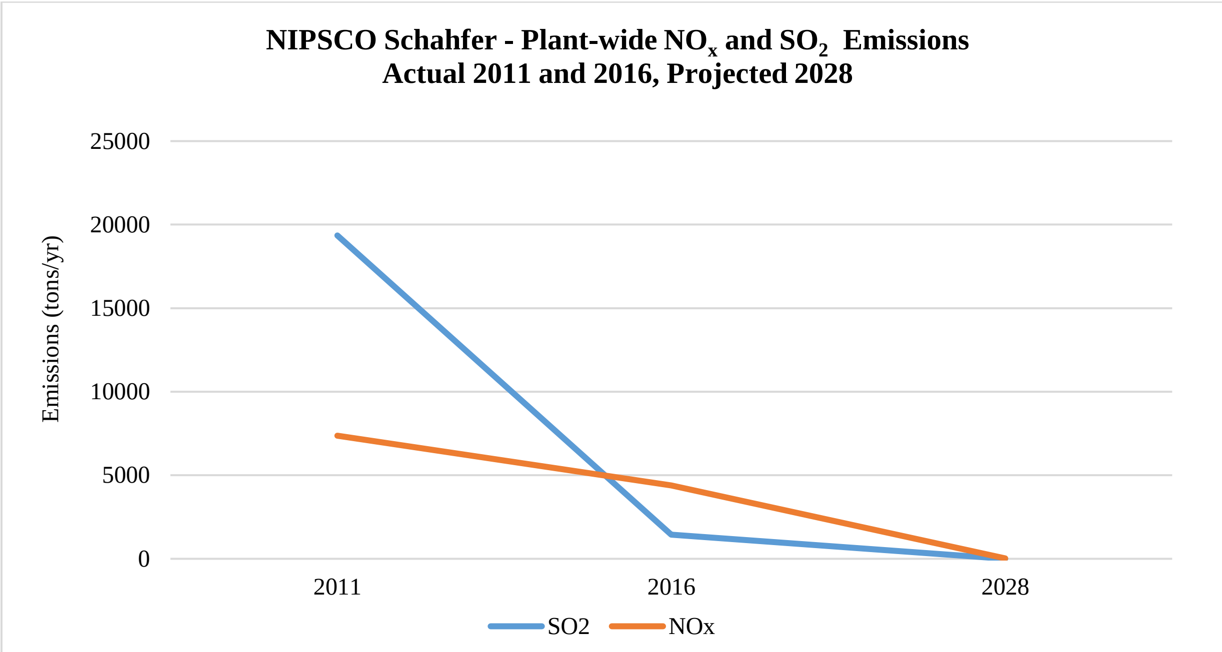


13.0 NORTHERN INDIANA PUBLIC SERVICE COMPANY, LLC - R.M. SCHAHFER GENERATING STATION

The Northern Indiana Public Service Company, LLC (NIPSCO) R.M. Schahfer Generating Station (Schahfer) is located near Wheatfield in Jasper County, Indiana. There are four dry bottom pulverized coal-fired boilers (Units 14, 15, 17 and 18) and two natural gas-fired combustion turbines (Units 16A and 16B). Emission controls for Unit 14 include selective SCR system, a reagent injection system, a flue gas desulfurization system, Unit 15 has selective non-catalytic reduction (SNCR) system, a reagent injection system, a flue gas desulfurization system for emission controls. Unit 17 and 18 each rely on LNB and limestone-based flue gas desulfurization system for emission controls. Retirement of 1700 MW in coal-fired power generation from Units 14, 15, 17 & 18 are expected based on the 2018 IRP with all four units retired in 2023 in the modeling analysis. Recent updates indicate that units 14 and 15 will retire now by the end of 2021. These retirements are included in the CAMD December 2020 NEEDsv620 update. Units 16A and 16B have water injection as needed for NO_x control and are projected to remain in operation.

R.M. Schahfer's 2028 EGU NO_x emissions are projected to be reduced by 4,373 tons from 2016 emission levels and SO_2 emissions are expected to be reduced by 1,440 tons from 2016 to 2028. This will result in a 99% reduction in emission from the facility if the two simple cycle units remain.

Graph 13-1 NIPSCO Schahfer NO_x and SO_2 Emissions Trends



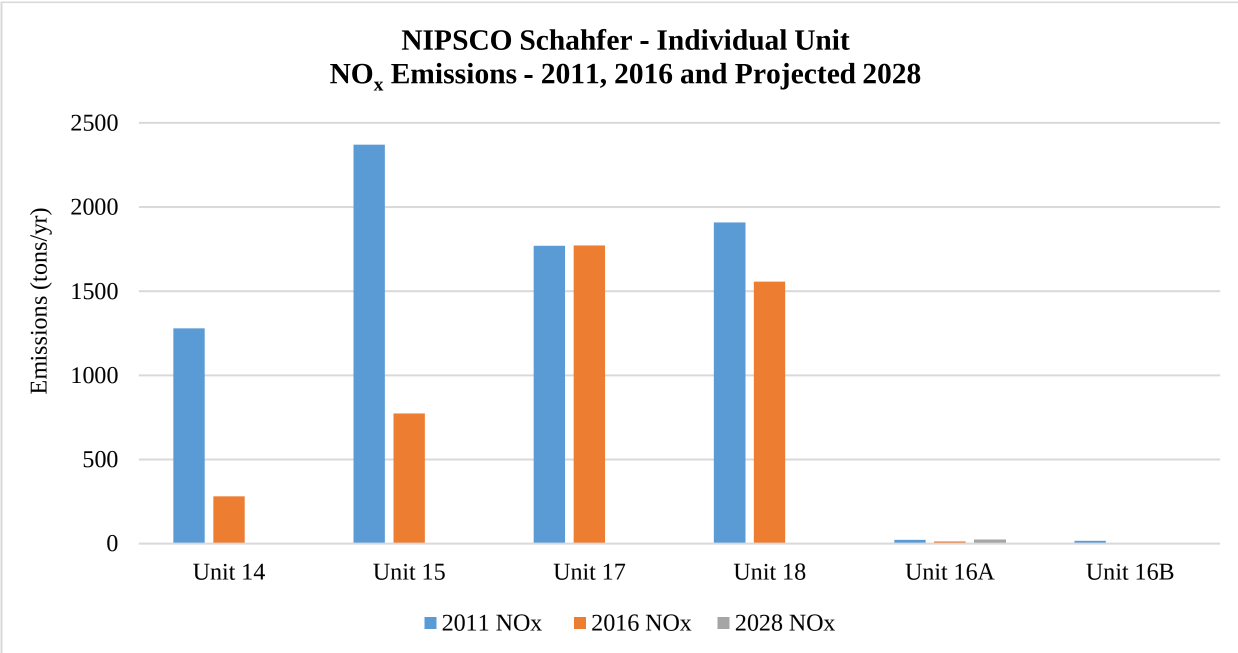
The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. The overall emissions from each facility will be reduced because of the unit shutdowns but individual unit emissions may be slightly higher than their 2016 emissions due to power demand and limited coal-fired power generation capacity with retirements of other boilers. For Schahfer's future emissions projections, the natural gas-fired combustion turbines, Units 16A and 16B, may be utilized more to meet the electricity demands without Units 14, 15, 17 and 18. Schahfer's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 13-1.

Table 13-1 Schahfer Generating Station's 2016 and Projected 2028 Utilization Rates for Units 14, 15, 17, 18, 16A and 16B

ORIS-ID	Unit ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028-ERTAC	Percentage Change in Utilization
6085	14	Schahfer Generating Station	0.1405	Retired	-100.0%
6085	15	Schahfer Generating Station	0.2864	Retired	-100.0%
6085	17	Schahfer Generating Station	0.5187	Retired	-100.0%
6085	18	Schahfer Generating Station	0.4539	Retired	-100.0%
6085	16A	Schahfer Generating Station	0.0077	0.0132	42.1%
6085	16B	Schahfer Generating Station	Not reported	0.0004	100.0%

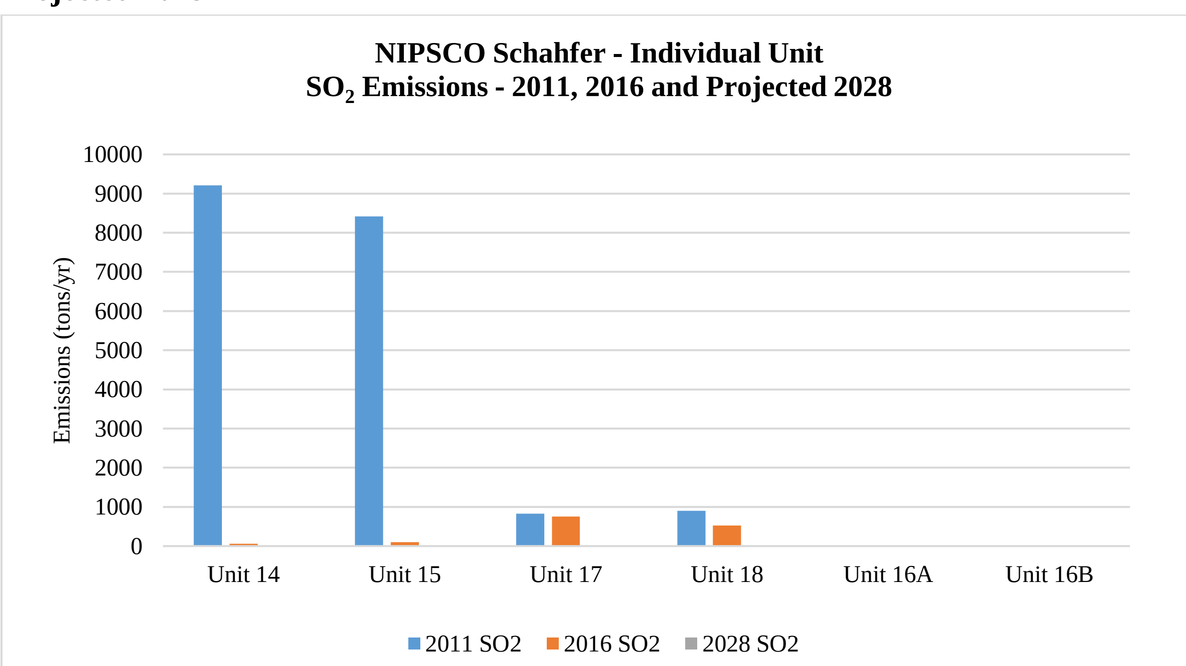
Graph 13-2 on the following page shows the unit-by-unit comparison of NO_x emissions at the Schahfer power plant. With the retirements of Units 14, 15, 17 and 18, NO_x emissions at all these units decrease from actual CAMD data for 2011 and 2016 to ERTAC's projected emissions in 2028 of zero. The natural gas-fired combustion turbines, Units 16A and 16B's base year and future year utilization are low so projected NO_x emissions for 2028 will be very low.

Graph 13-2 Unit Comparison of NIPSCO Schahfer NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 13-3 below shows the unit-by-unit comparison of SO_2 emissions at the Schahfer power plant. With the retirements of Units 14, 15, 17 and 18, SO_2 emissions at all these units decrease from actual CAMD data for 2011 and 2016 to ERTAC's projected emissions in 2028 of zero. The natural gas-fired combustion turbines, Units 16A and 16B's base year and future year utilization are low so projected SO_2 emissions for 2028 will be very low.

Graph 13-3 Unit Comparison of NIPSCO Schahfer SO_2 Emissions - Actual 2011 and 2016, Projected 2028

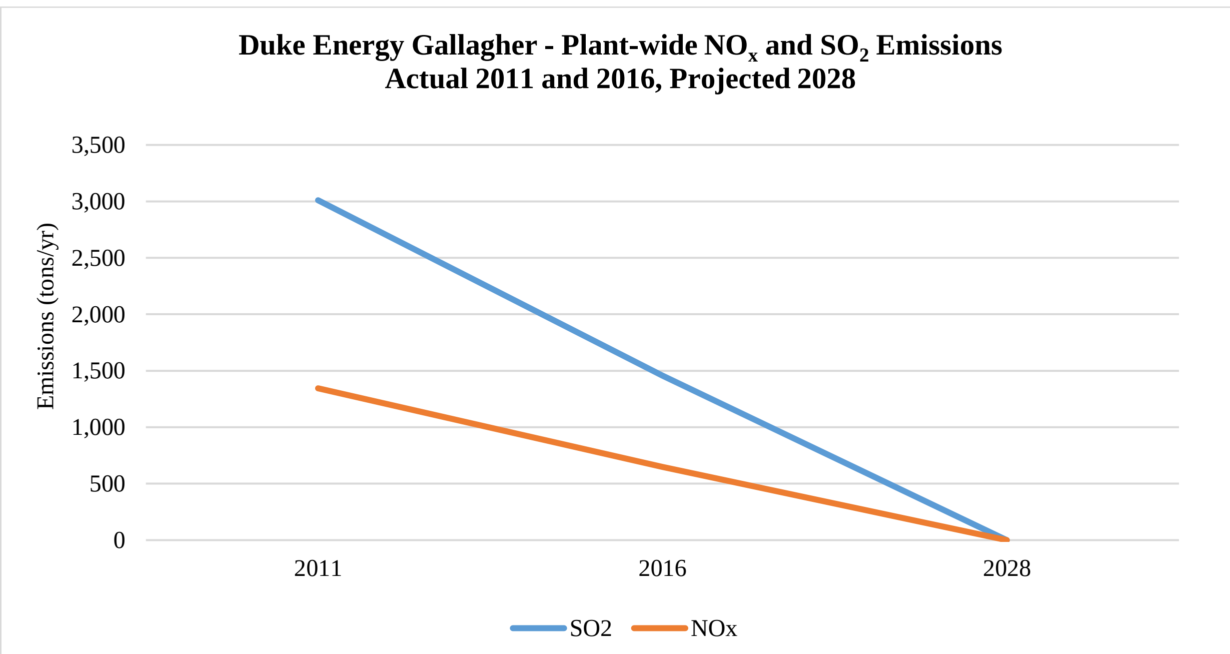


14.0 DUKE ENERGY INDIANA, LLC - GALLAGHER GENERATING STATION

The Duke Energy Indiana, LLC - Gallagher Generating Station (Gallagher) is currently a two-unit coal-fired generating facility located in Floyd County, Indiana. There were initially four units which were dry bottom, pulverized coal-fired boilers. Unit 2 began operating in 1958; Unit 1 in 1959; Unit 3 in 1960 and Unit 4 in 1961. In early 2012, Units 1 and 3 with a combined power generation capacity of 280 megawatts were retired. Units 2 and 4 control SO_2 emissions by a DSI system and have LNB for NO_x controls. Both Units 2 and 4 will be retired per the 2019 IRP for Duke in 2022. The units were also retired in the NEEDsv620 per CAMD's December 2020 update.

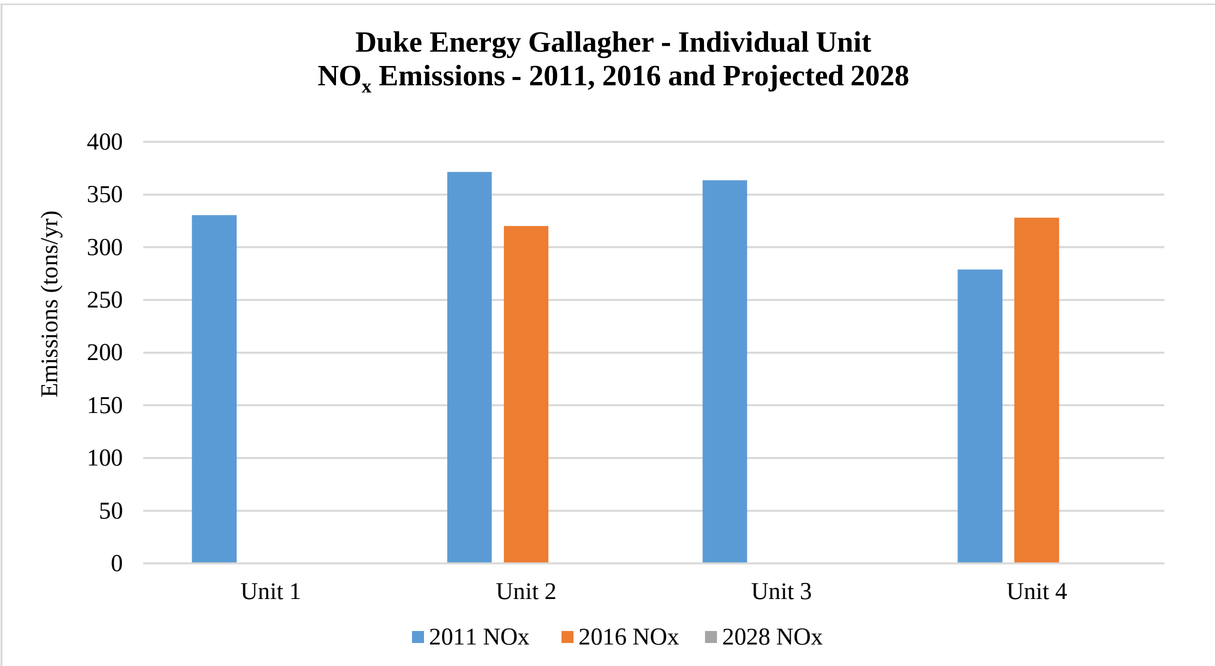
Gallagher's 2028 EGU NO_x emissions are projected to be reduced by 648 tons from 2016 emission levels and SO_2 emissions are expected to be reduced by 1,457 tons from 2016 to 2028 as a result of the final two units retirements. In 2016, emissions at Unit 4 increased as a result of the retirement of Units 1 and 3. This is a result of the need to make up for a portion of the lost coal-fired power generation overall at the facility.

Graph 14-1 Duke Energy Gallagher NO_x and SO_2 Emissions Trends



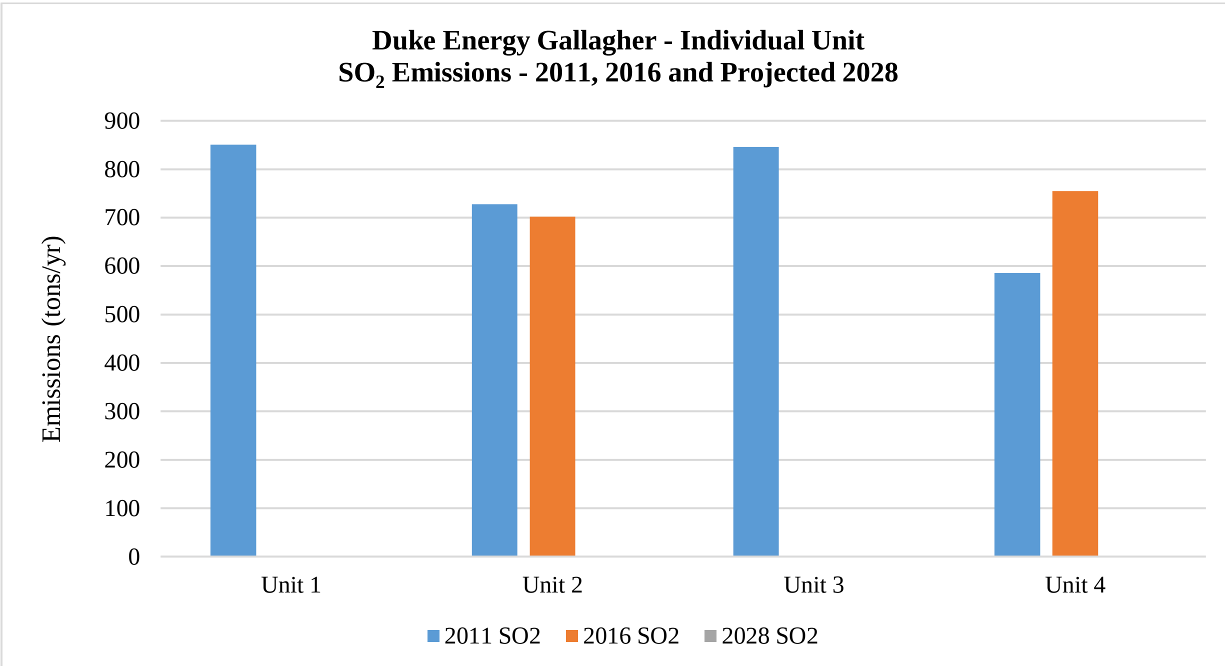
Graph 14-2 shows the unit-by-unit comparison of NO_x emissions at the Gallagher power plant. With the retirements of both Units 2 and 4, NO_x emissions at both units decrease from actual CAMD data for 2011 and 2016 to projected emissions by ERTAC in 2028 of zero. As can be seen, the retirements of Units 1 and 3 are reflected in no NO_x emissions from those units in 2016.

Graph 14-2 Unit Comparison of Duke Energy Gallagher NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 14-3 shows the unit-by-unit comparison of SO_2 emissions at the Gallagher power plant. With the retirements of both Units 2 and 4, SO_2 emissions at both units decrease from actual CAMD data for 2011 and 2016 to projected emissions by ERTAC in 2028 of zero. As can be seen, the retirements of Units 1 and 3 are reflected in no SO_2 emissions from those units in 2016.

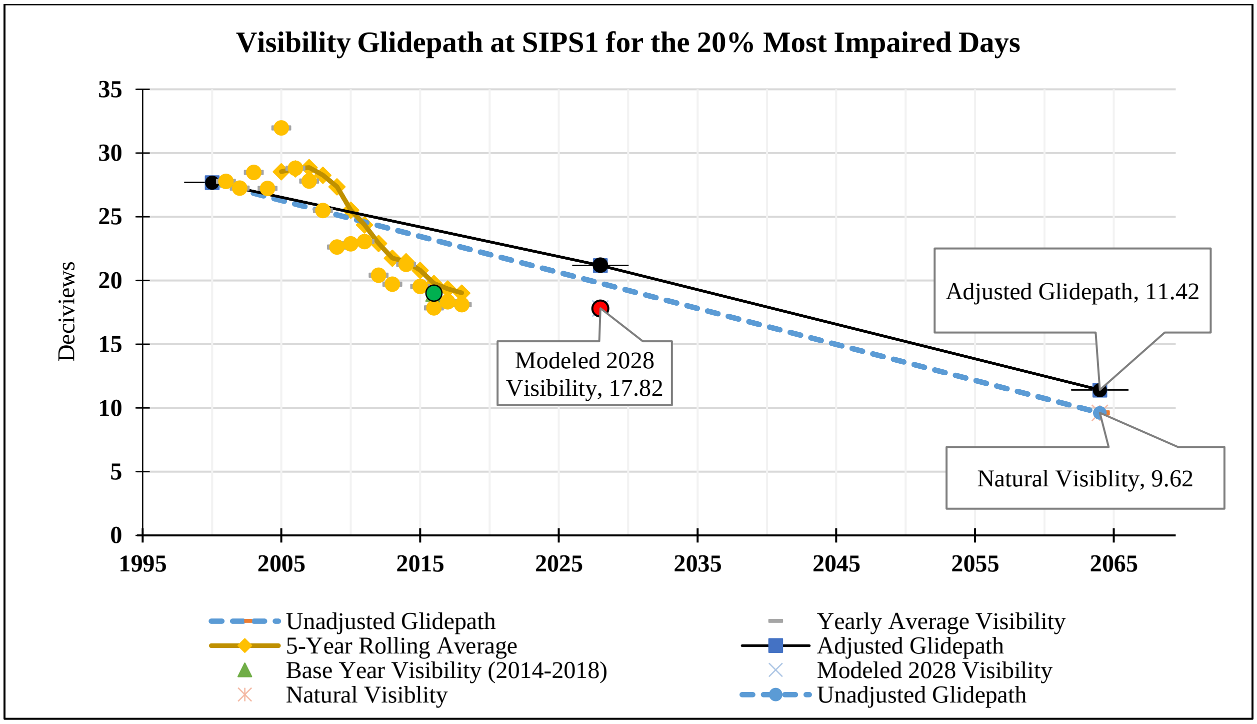
Graph 14-3 Unit Comparison of Duke Energy Gallagher SO_2 Emissions - Actual 2011 and 2016, Projected 2028



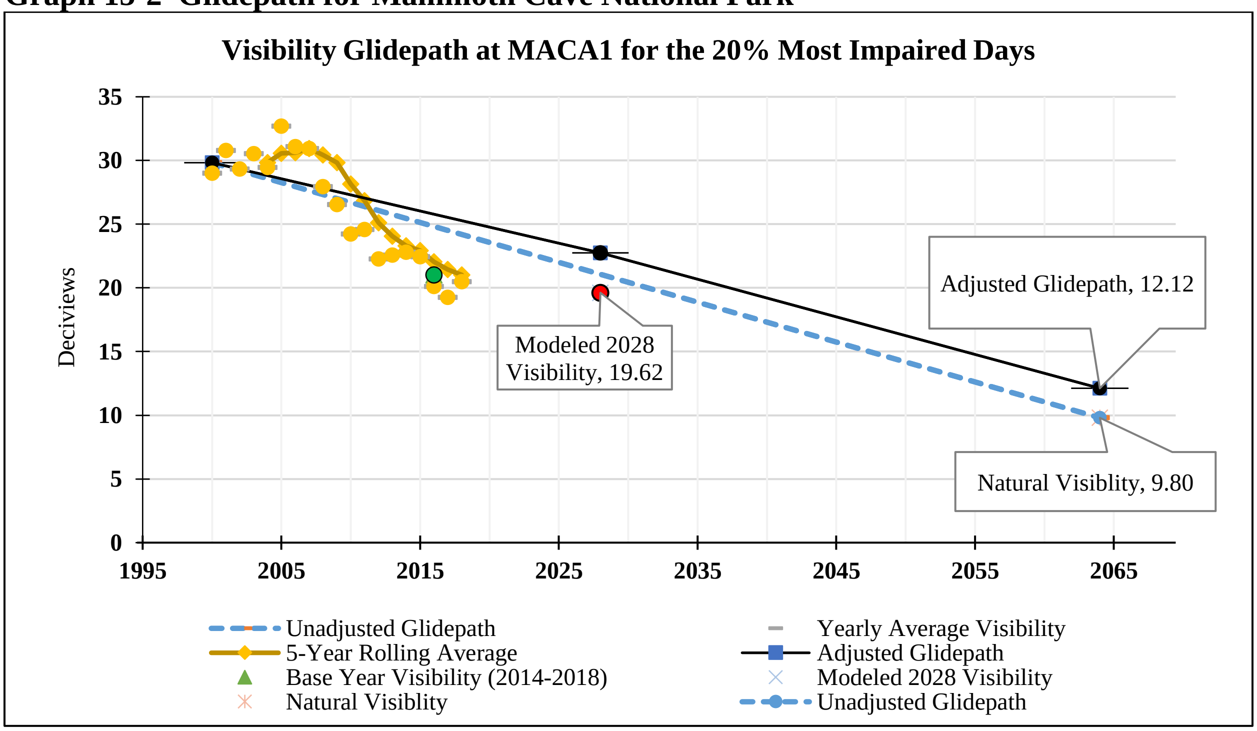
15.0 LADCO JANUARY 2021 MODELING RESULTS

LADCO conducted photochemical modeling to determine visibility impacts, based on base-year 2016 emissions. 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 with visibility on the 20% most anthropogenically impaired days well below the glidepath and nearly equal to modeled 2028 visibility.

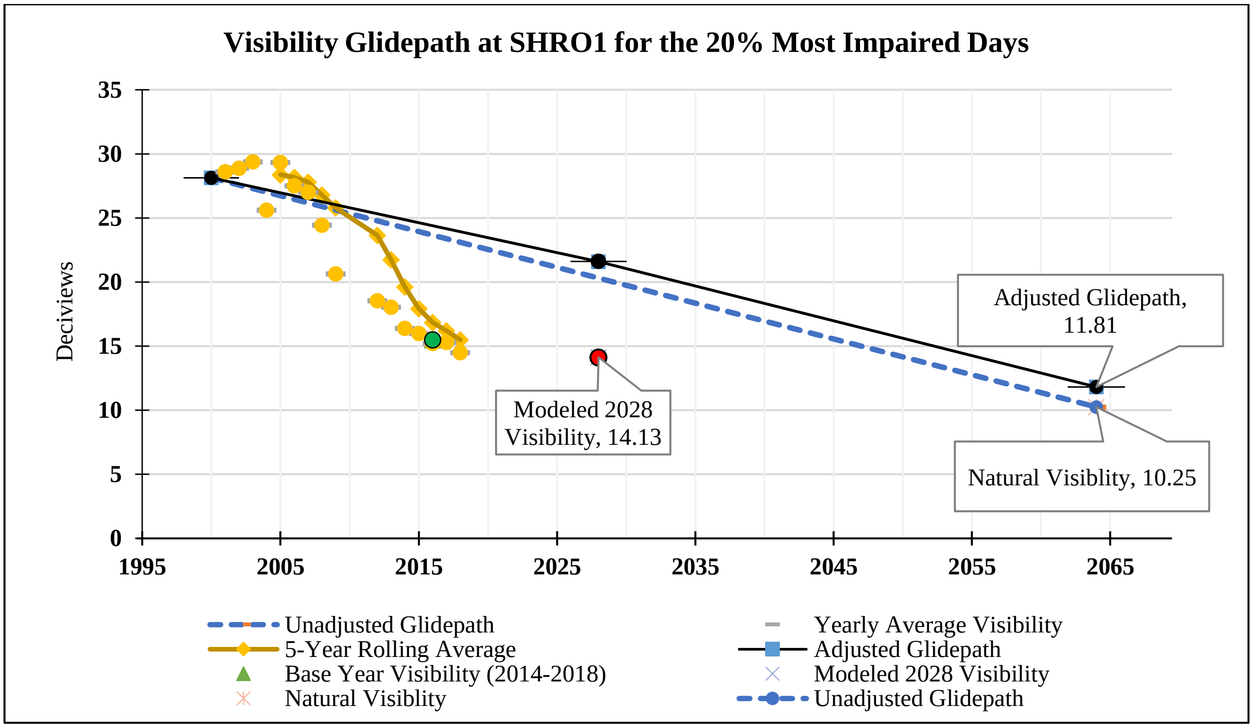
Graph 15-1 Glidepath for Sipsey Wilderness Area



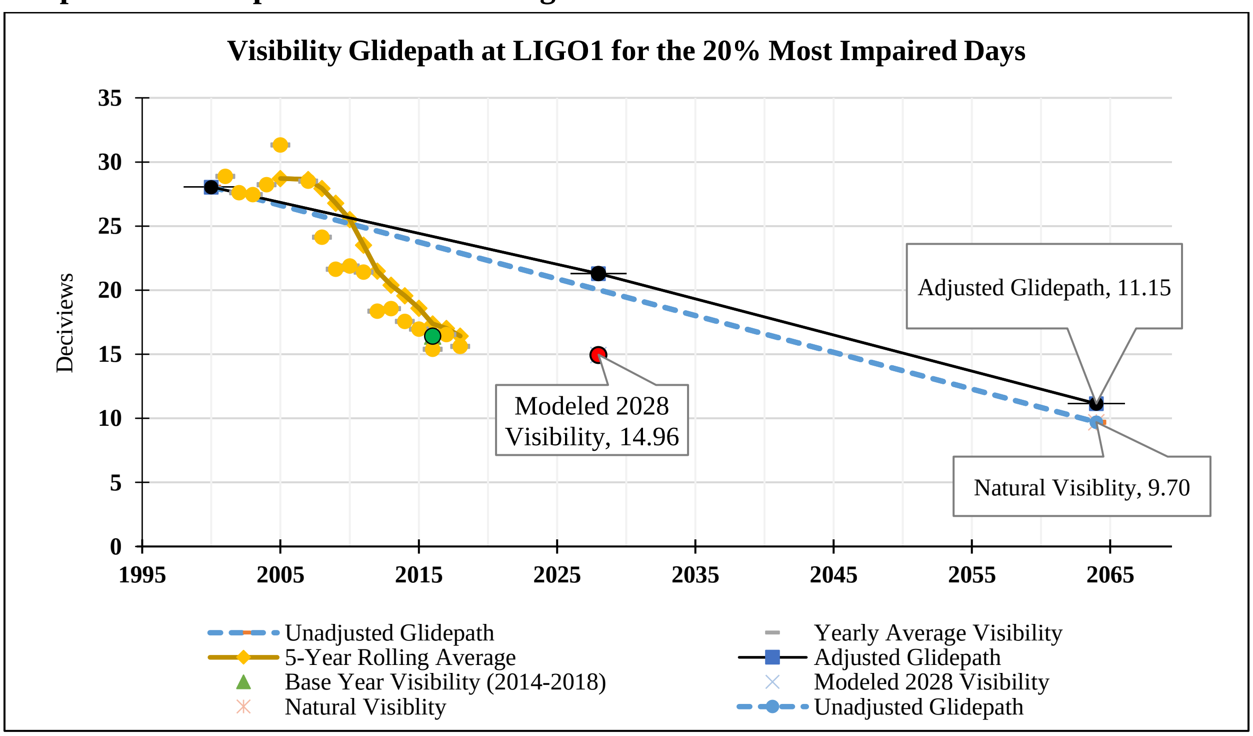
Graph 15-2 Glidepath for Mammoth Cave National Park



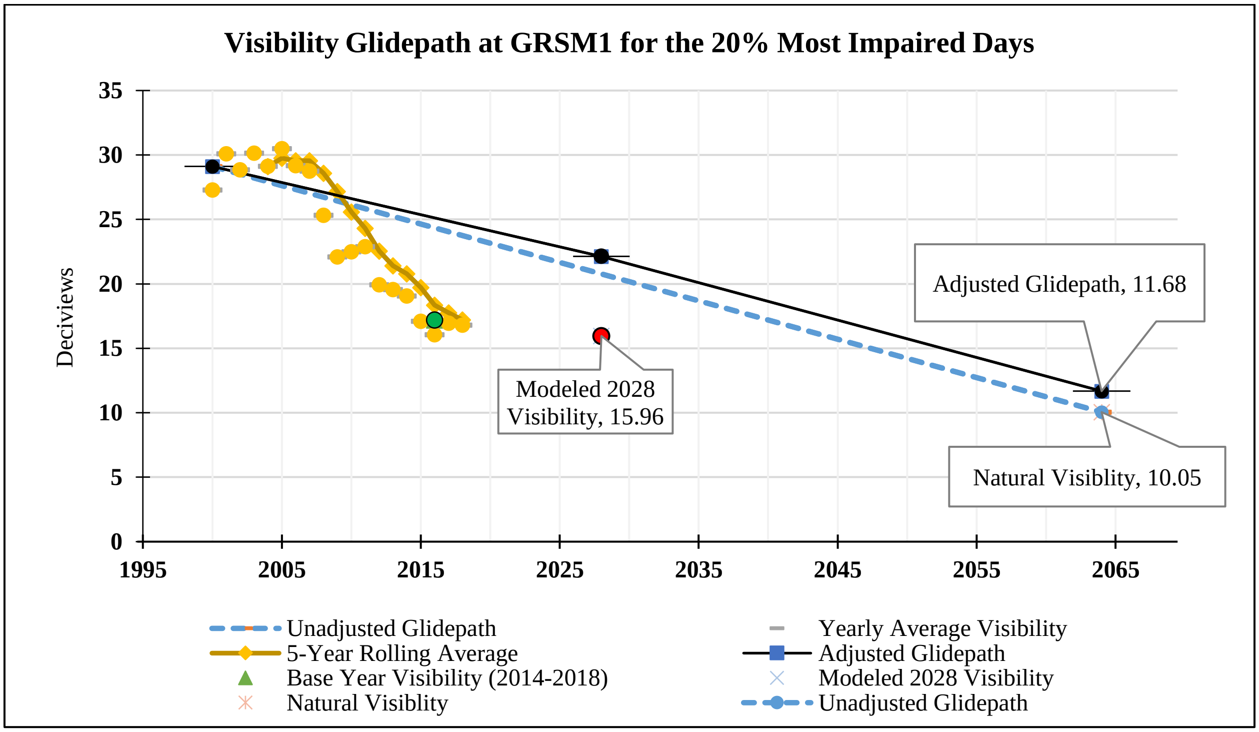
Graph 15-3 Glidepath for Shining Rock Wilderness Area



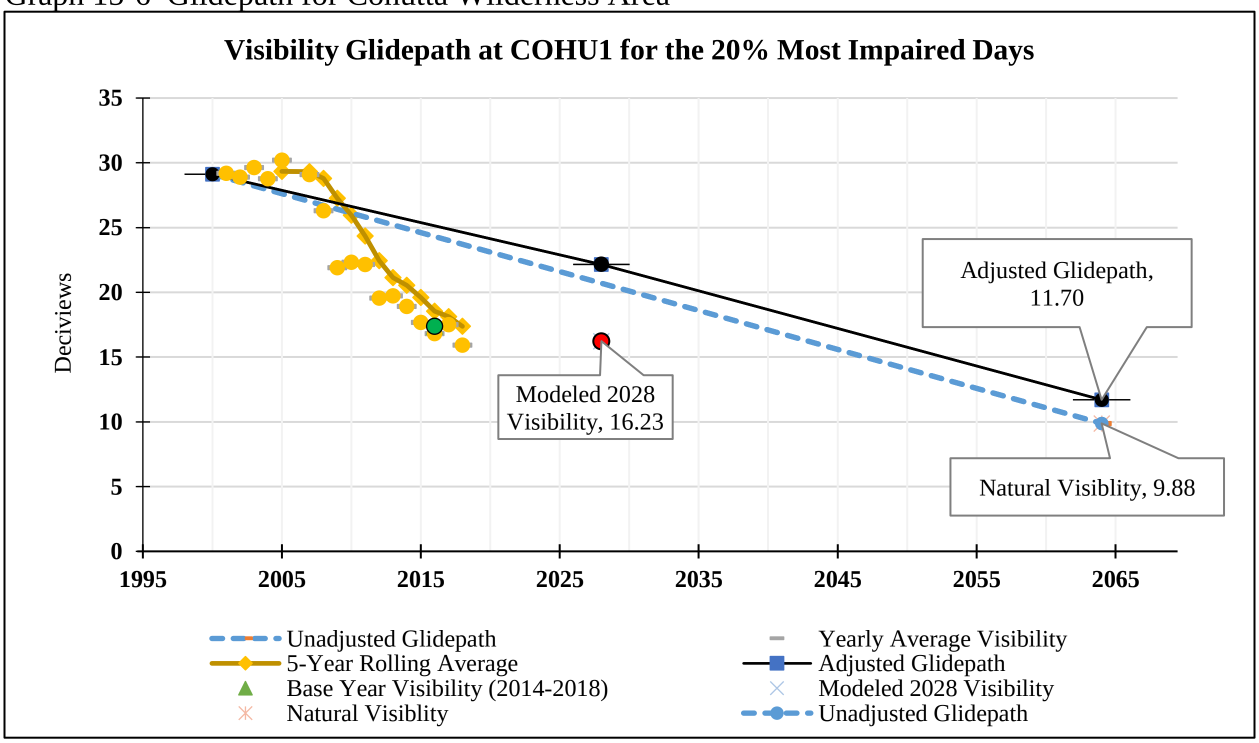
Graph 15-4 Glidepath for Linville Gorge Wilderness Area



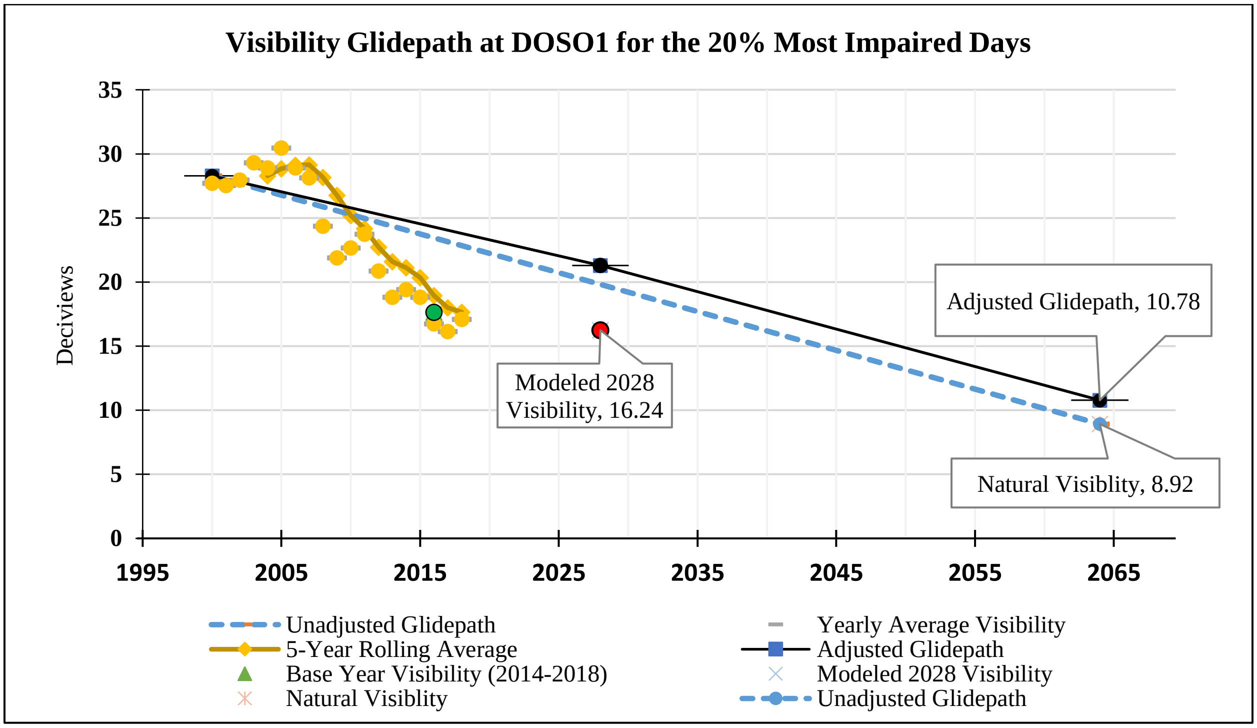
Graph 15-5 Glidepath for Great Smokey Mountains National Park/Joyce Kilmer-Slickrock Wilderness Area



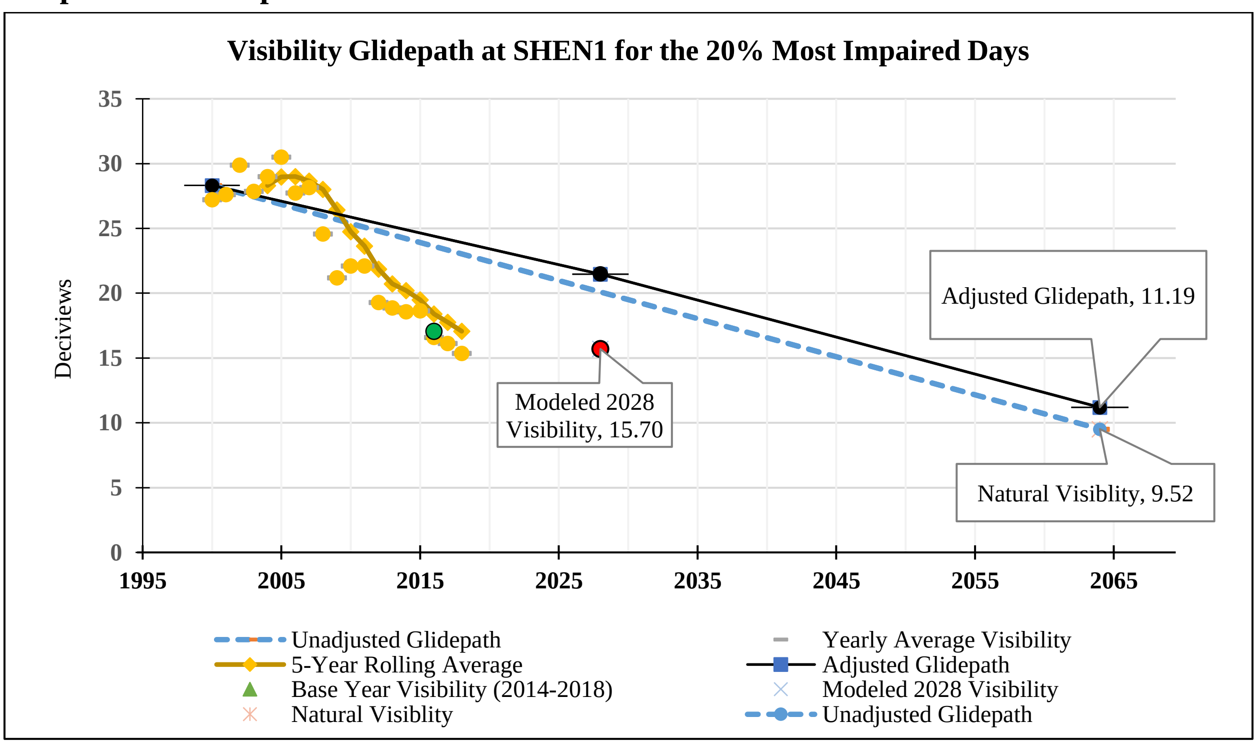
Graph 15-6 Glidepath for Cohutta Wilderness Area



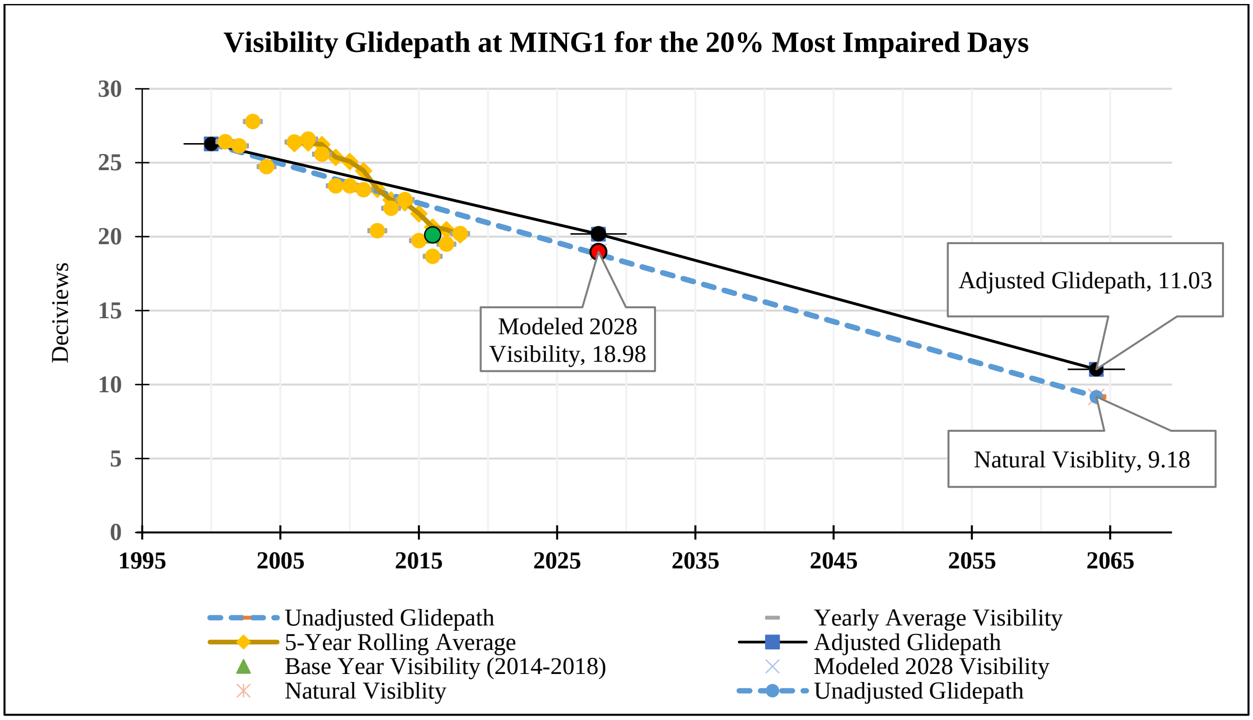
Graph 15-7 Glidepath for Dolly Sods/Otter Creek Wilderness Areas



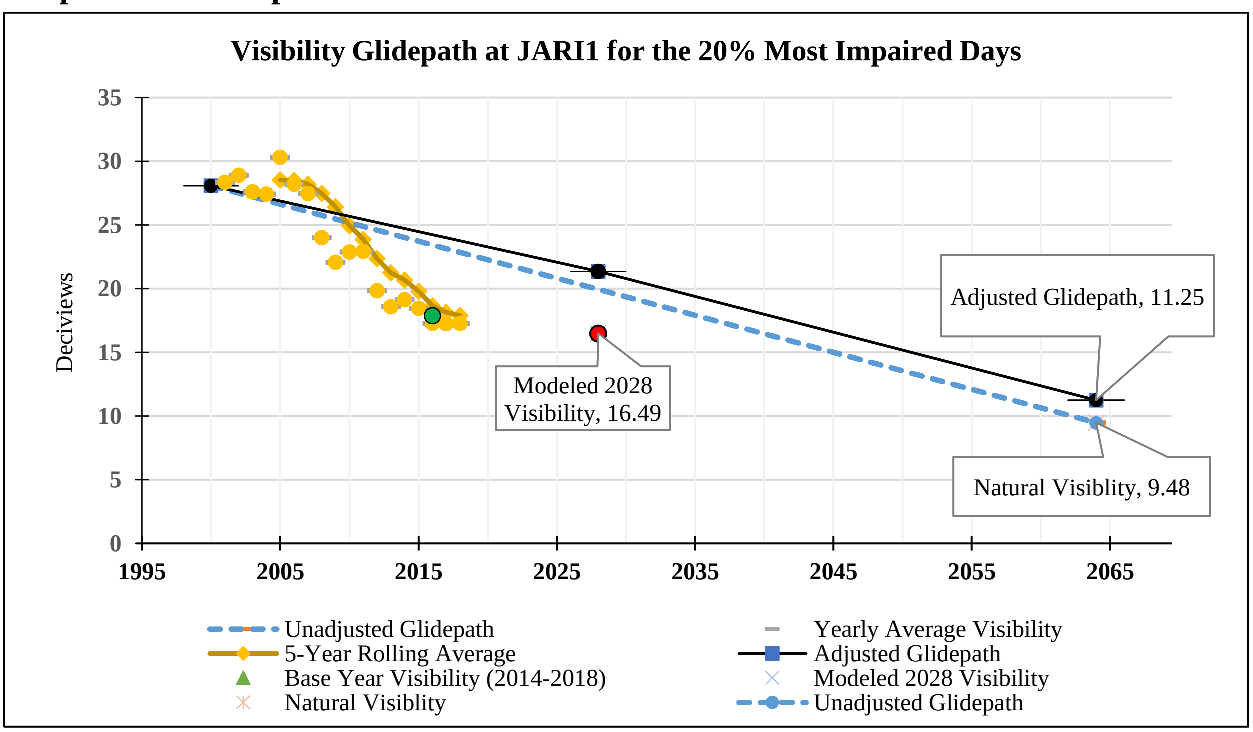
Graph 15-8 Glidepath for Shenandoah Wilderness Areas



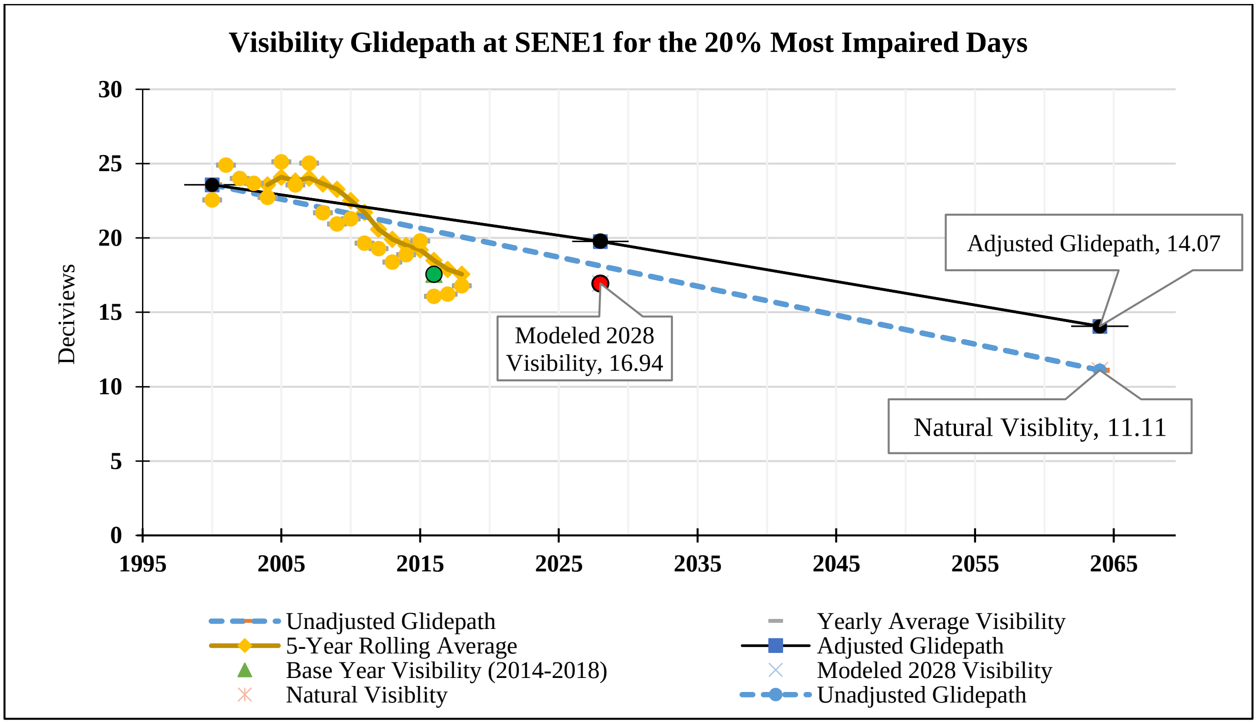
Graph 15-9 Glidepath for Mingo Wilderness Areas



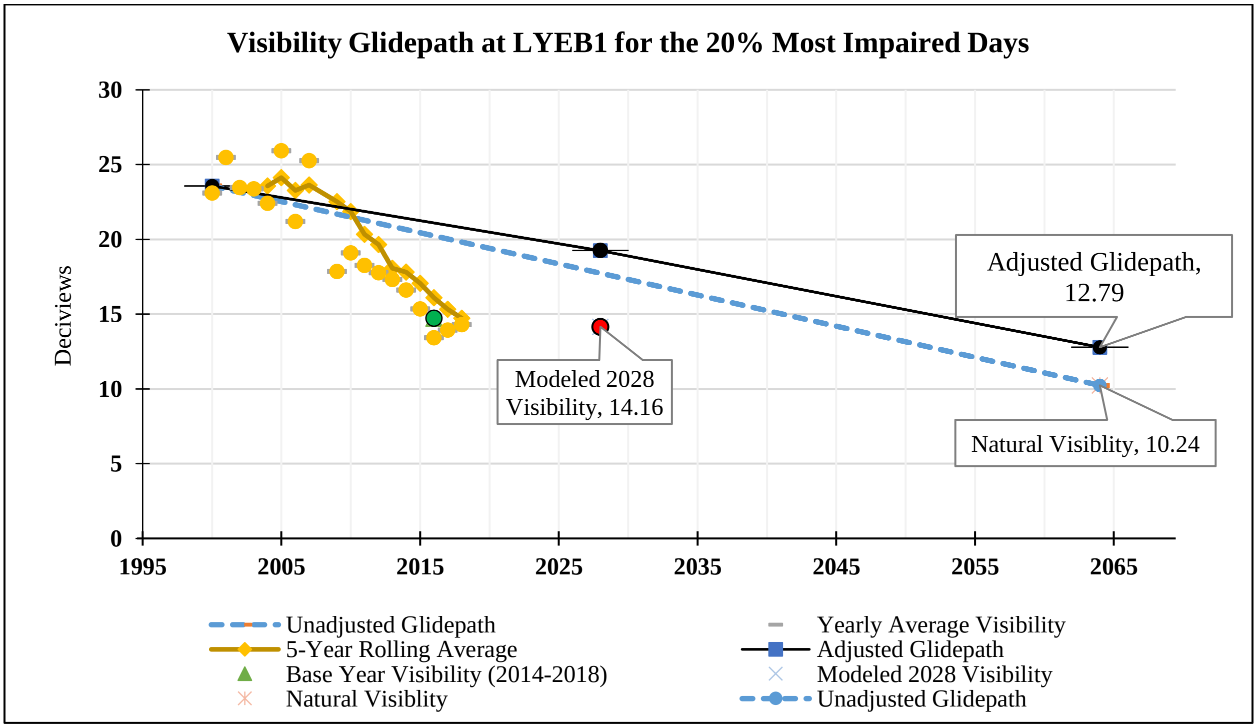
Graph 15-10 Glidepath for James River Wilderness Areas



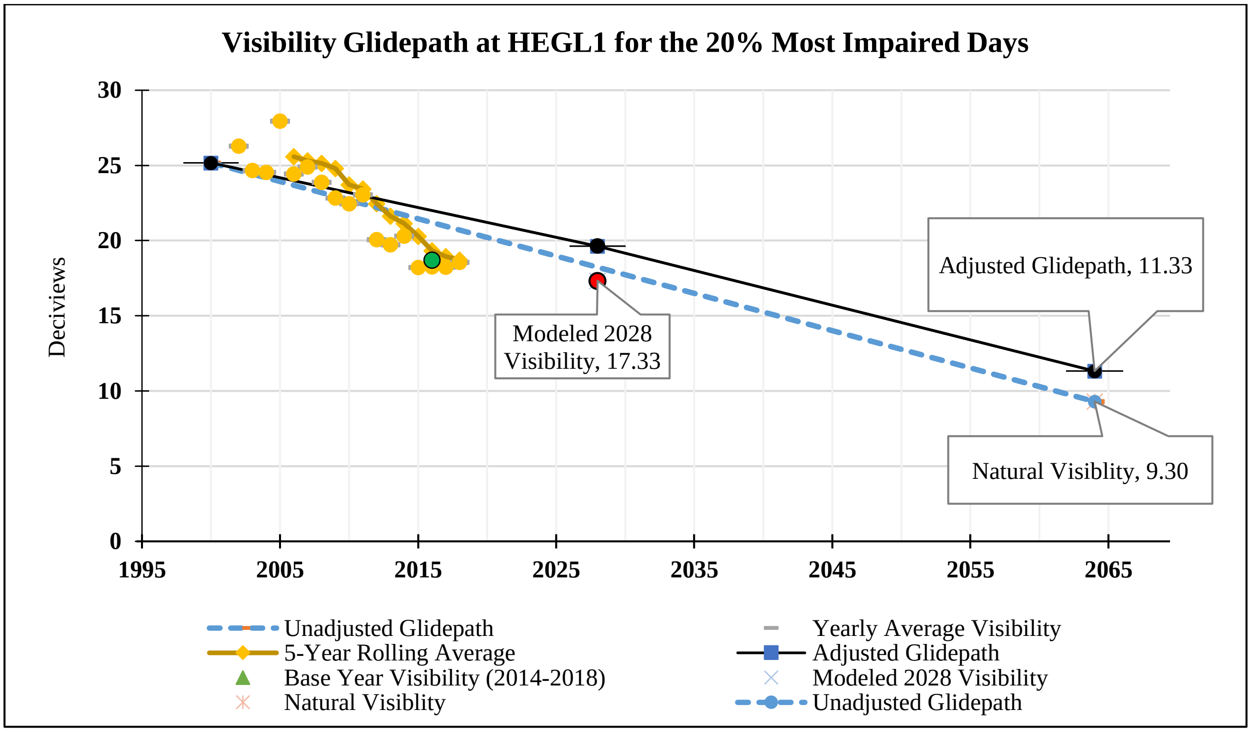
Graph 15-11 Glidepath for Seney Wilderness Areas



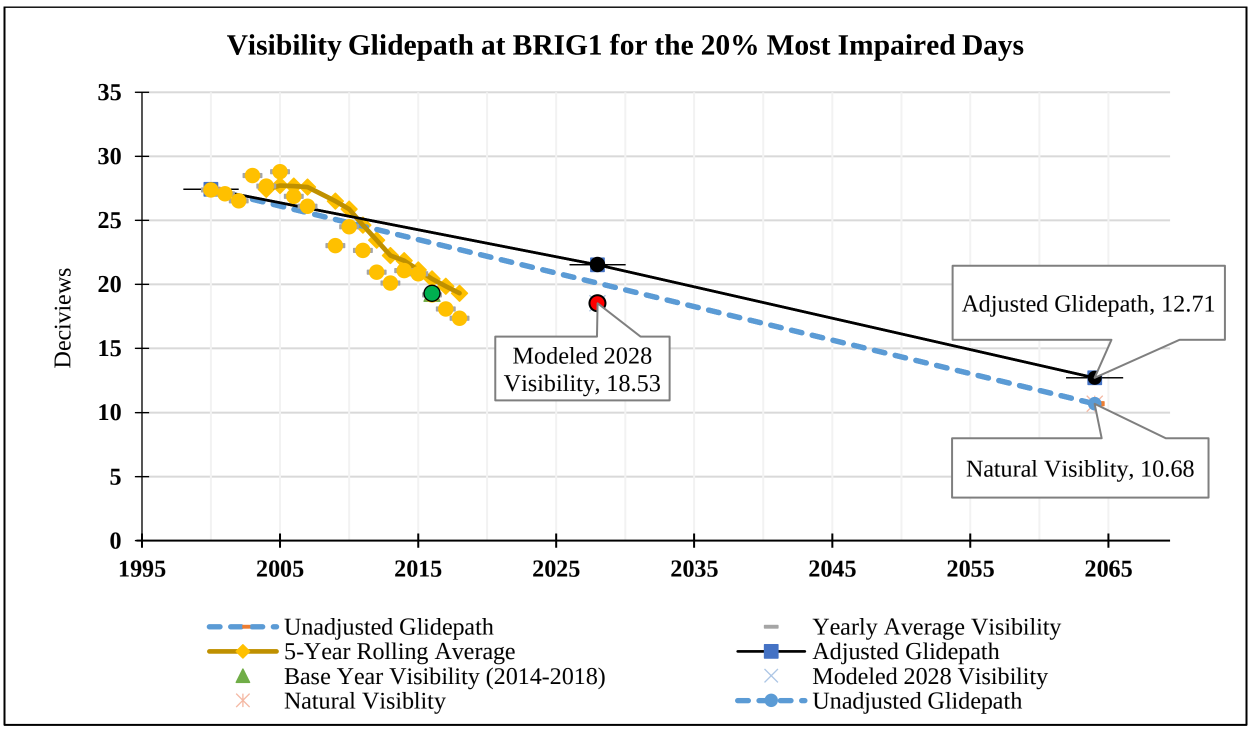
Graph 15-12 Glidepath for Lye Brook Wilderness Areas



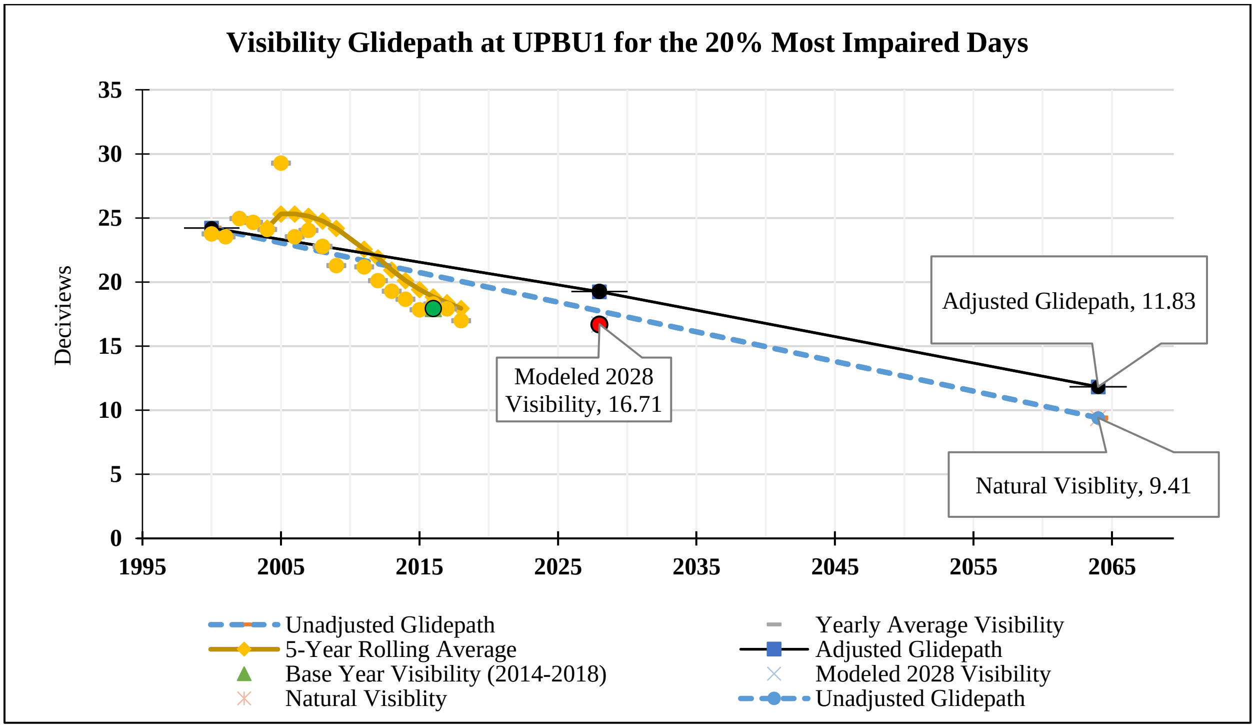
Graph 15-13 Glidepath for Hercules Glades Wilderness Areas



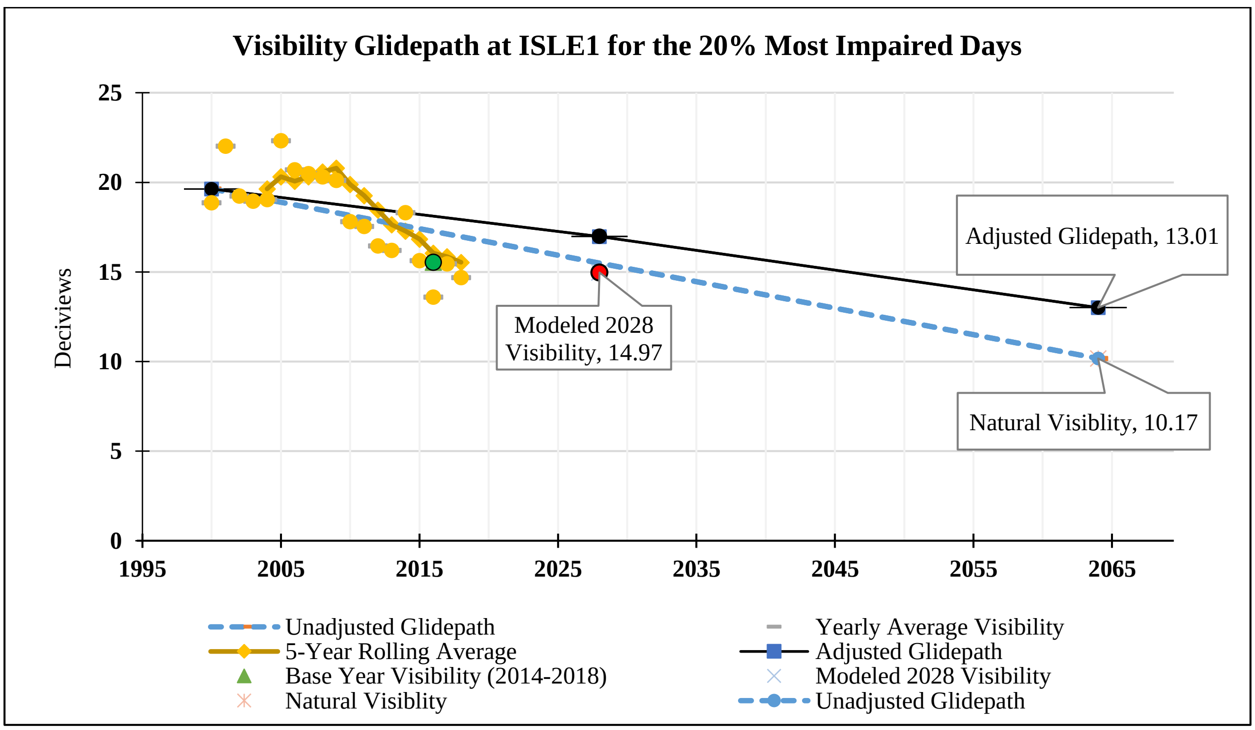
Graph 15-14 Glidepath for Brigantine Wilderness Areas



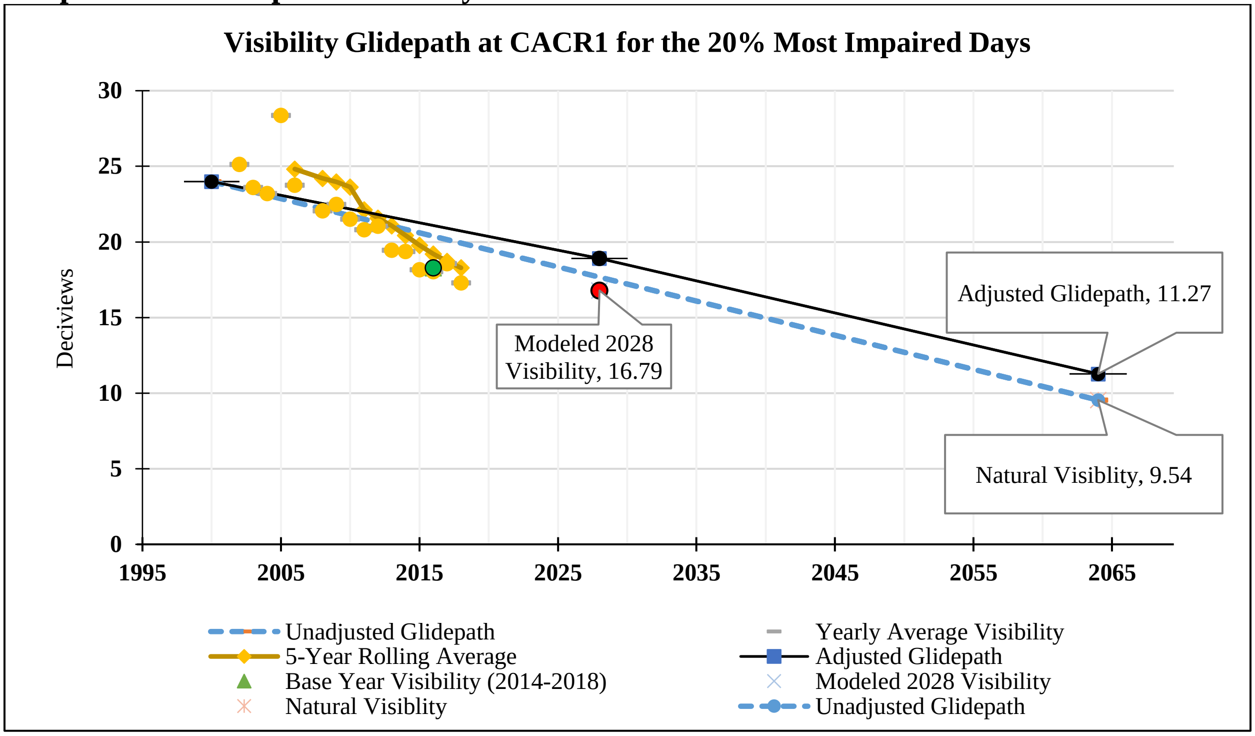
Graph 15-15 Glidepath for Upper Buffalo Wilderness Areas



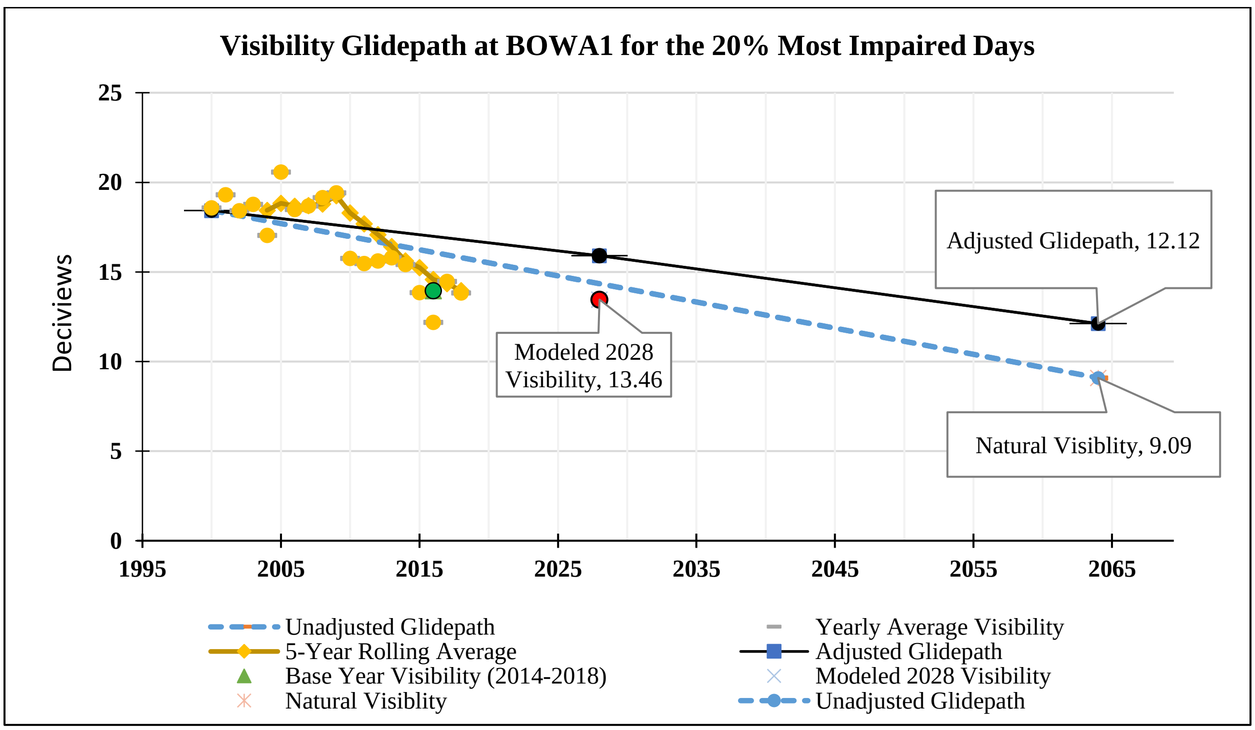
Graph 15-16 Glidepath for Isle Royale Wilderness Areas



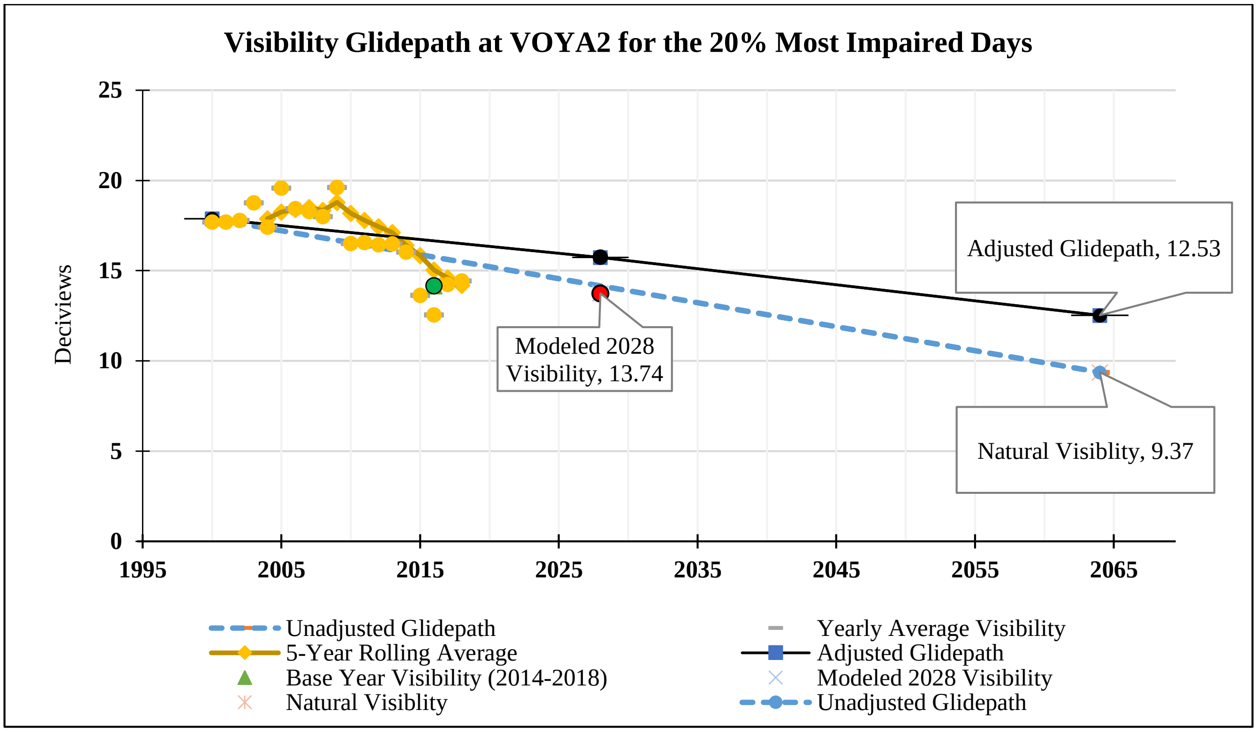
Graph 15-17 Glidepath for Caney Creek Wilderness Areas



Graph 15-18 Glidepath for Boundary Waters Wilderness Areas



Graph 15-19 Glidepath for Voyageurs Wilderness Areas



Results for all 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 each Class I area for 2028, based on the 2011 emissions and nearly equal the modeled results from the base-year 2016 future year 2028 modeling. Table 15-1 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 15-1 Comparison of Monitored and Modeled Visibility for 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)
Sipsey	27.69	21.75	19.03	17.90	17.82
Mammoth Cave	29.83	24.04	21.02	20.24	19.62
Cohutta	29.12	21.13	17.37	15.81	16.23
Shining Rock	28.37 [a]	16.85 [b]	15.49	N/A	14.13
Great Smokey Mountains	29.11	21.40	17.21	16.08	15.96
Linville Gorge	28.05	20.39	16.42	15.34	14.96
Dolly Sods	28.29	21.61	17.65	16.71	16.24
Shenandoah	28.32	20.72	17.07	15.85	15.70
Mingo	26.28	22.49	20.13	20.37	18.98
James River Face	28.08	21.27	17.89	16.93	16.49
Seney	23.58	19.92	17.57	17.34	16.94
Lye Brook	23.57	18.06	14.73	15.02	14.16
Hercules-Glades	25.17	21.63	18.72	19.71	17.33
Brigantine	27.43	22.25	19.31	18.97	18.53
Upper Buffalo	24.21	20.47	17.95	18.78	16.71
Isle Royale	19.63	17.63	15.54	15.48	14.97
Swanquarter	23.79	19.7	16.3	16.1	15.39
Great Gulf	21.88	15.4	13.07	12.95	12.43
Caney Creek	23.99	21.07	18.29	19.5	16.79
Boundary Waters	18.43	16.42	13.96	14.43	13.46
Voyageurs	17.88	5.71	14.18	5.33	13.74

[a] Baseline (2001-2005)

[b] Baseline (2012-2016)

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. 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.

16.0 LADCO SOURCE APPORTIONMENT MODELING

LADCO is in the process of conducting source apportionment modeling in which several Indiana emission sectors, among those were the EGU sources, will be tagged to determine their individual modeled visibility impacts. This modeling is expected to be completed in the summer of 2021 and will be submitted to EPA as a supplement to Indiana RH SIP submittal. It is anticipated to show that emission sector and individual source impacts will be very low.

Visibility impairment is decreasing each year and the reasonable rate of progress remains well below the uniform rate of progress. Further retirements of boilers and anticipated emission reductions throughout the country will continue to drive the monitored visibility impairment lower at the Class I areas and will realize continued improved visibility.

17.0 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.

17.1 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) 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.

17.2 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 emissions 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.

18.0 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. These visibility impacts have been shown through monitoring and modeling to continue to decrease and continued emissions reductions will help improve visibility impacts even more in the future. The steady decline of visibility impacts at the Class I areas from anthropogenic emissions from all emission sources 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 budgets 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 each of the Class I areas. 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.

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Appendix A

EGUs 2009-2019 Annual NOx and SO2 and Ozone Season NOx Emissions

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Table 1 Indiana Electric Generating Units 2009-2019 Combined Annual NO_x Emissions Reported to CAMD

Facility Name	Sum of 2009 NOx Emissions (tons)	Sum of 2010 NOx Emissions (tons)	Sum of 2011 NOx Emissions (tons)	Sum of 2012 NOx Emissions (tons)	Sum of 2013 NOx Emissions (tons)	Sum of 2014 NOx Emissions (tons)	Sum of 2015 NOx Emissions (tons)	Sum of 2016 NOx Emissions (tons)	Sum of 2017 NOx Emissions (tons)	Sum of 2018 NOx Emissions (tons)	Sum of 2019 NOx Emissions (tons)
A B Brown	1,720.87	1,698.26	1,770.65	2,121.18	1,805.42	2,866.52	2,138.64	1,694.03	1,605.36	2,128.10	2,423.51
Alcoa	1,576.24	1,229.97	1,612.13	2,191.54	2,825.22	3,166.50	3,319.33	3,058.25	1,929.52	3,028.05	3,136.39
Anderson	2.85	1.19	6.20	7.73	2.90	5.08	5.68	5.11	4.91	5.03	4.06
Bailly	2,460.02	2,754.48	1,974.42	1,515.89	1,924.06	1,726.26	1,072.33	1,345.24	1,168.45	196.24	
Broadway Avenue	21.10	22.19	20.88	20.30	5.88	8.09	15.39	13.04	6.62	12.39	
Cayuga	6,865.64	8,332.59	8,251.84	7,577.46	9,703.48	8,692.14	10,508.14	12,369.60	7,061.30	8,977.11	4,408.47
Clifty Creek	8,018.79	9,118.70	10,938.03	13,816.45	11,841.97	9,131.97	6,755.57	9,355.41	5,762.23	6,139.48	5,375.41
Connersville		0.68	0.45	1.04	4.12	2.40	2.01	3.78	2.02		
Vermillion	15.07	18.72	13.85	17.20	17.21	6.27	26.94	31.87	15.88	54.96	23.59
Eagle Valley										62.16	114.95
Edwardsport				90.41	618.32	698.81	841.22	761.49	838.12	867.35	769.19
F B Culley	1,021.42	1,480.93	1,024.58	1,384.20	1,504.08	1,344.02	870.31	1,108.45	1,339.94	1,529.03	1,002.93
Georgetown	3.01	10.04	11.43	21.53	16.93	4.33	18.91	32.03	24.55	38.45	20.43
Gibson	9,568.63	12,018.45	15,024.29	12,642.03	11,397.43	14,292.16	10,833.95	13,190.14	11,385.15	10,255.59	8,120.68
Harding Street	2,720.68	2,653.01	2,669.32	3,109.46	4,305.63	4,428.70	2,480.62	1,036.15	443.62	551.41	491.67
Henry County	18.25	27.37	19.59	35.25	33.79	25.60	68.61	69.32	109.30	133.72	108.16
Lawrence County	9.57	20.81	18.89	34.89	10.80	13.82	9.03	18.26	20.13	70.82	20.37
Lawrenceburg	36.83	72.90	163.20	252.30	158.03	264.31	344.91	356.21	323.55	266.44	282.78
Merom	4,220.48	4,016.01	3,326.97	2,246.63	2,041.66	2,043.72	1,619.77	1,942.71	1,565.28	1,835.37	1,475.63
Michigan City	1,095.73	1,160.50	1,431.89	1,169.68	1,115.54	1,241.07	793.94	815.40	621.44	989.63	534.13
Montpelier	18.79	47.83	48.31	82.40	63.84	69.51	129.54	142.10	96.94	103.41	122.45
Noblesville	9.73	24.67	28.26	54.89	37.79	31.04	60.13	66.34	32.19	62.21	59.89
Petersburg	9,657.99	11,205.60	9,666.50	9,292.74	10,907.03	13,047.80	12,426.78	10,813.20	8,372.80	8,225.45	6,946.48
R Gallagher	1,657.03	2,243.46	650.40	503.16	1,200.02	1,656.70	940.39	648.55	392.99	534.88	84.11
R M Schahfer	10,565.83	9,615.14	7,366.68	5,940.22	6,746.45	7,115.90	5,172.32	4,396.57	4,924.92	6,089.67	4,985.70
Richmond	0.42	2.34	4.32	3.00	2.18	1.70	4.66	2.67	5.98	10.96	2.03
Rockport	19,762.18	20,545.31	19,808.98	21,643.68	17,200.82	19,725.95	13,921.69	12,888.08	11,261.07	8,740.75	6,093.39
St. Joseph										96.78	115.62
Sugar Creek	46.47	90.02	87.59	100.59	88.60	82.18	90.40	110.41	121.20	98.38	114.93
Wabash River	5,974.52	5,101.00	7,097.85	3,127.63	3,691.42	3,351.77	3,541.08	941.87	14.04	414.45	19.03
Wheatland	17.56	53.36	50.23	81.57	81.38	43.79	53.11	92.89	67.31	0.04	133.69
Whitewater Valley	369.33	358.73	375.89	52.95	39.76	92.02	101.91	124.43	89.56	8,680.25	101.92
Whiting	79.98	102.12	108.28	104.05	100.96	100.51	98.74	110.95	84.70	5.08	99.06
Worthington	5.13	9.91	7.91	7.93	2.02	3.50	18.24	24.48	22.90	0.08	28.26
Grand Total	**87,540.13**	**94,036.26**	**93,579.82**	**89,249.97**	**89,494.74**	**95,284.10**	**78,284.28**	**77,569.00**	**59,713.95**	**70,203.71**	**47,218.89**

Table 2 Electric Generating Units 2009-2019 Annual NO_x Emissions

Facility Name	Facility ID (ORISPL)	Unit ID	2009 NO_x Emissions (tons)	2010 NO_x Emissions (tons)	2011 NO_x Emissions (tons)	2012 NO_x Emissions (tons)	2013 NO_x Emissions (tons)	2014 NO_x Emissions (tons)	2015 NO_x Emissions (tons)	2016 NO_x Emissions (tons)	2017 NO_x Emissions (tons)	2018 NO_x Emissions (tons)	2019 NO_x Emissions (tons)
A B Brown	6137	1	742.42	786.12	818.63	1,068.93	1,034.75	1,498.79	1,215.67	677.20	775.80	1,033.01	1,127.255
A B Brown	6137	2	965.69	886.45	934.03	1,033.55	760.46	1,359.05	911.06	999.34	816.47	1,078.54	1,286.802
A B Brown	6137	3	11.36	23.49	15.42	16.09	6.94	6.85	8.42	15.18	10.41	12.20	7.022
A B Brown	6137	4	1.40	2.20	2.57	2.62	3.27	1.84	3.50	2.31	2.69	4.36	2.433
Alcoa	6705	4	1,576.24	1,229.97	1,612.13	2,191.54	2,825.22	3,166.50	3,319.33	3,058.25	1,929.52	3,028.05	3,136.393
Anderson	7336	ACT1	0.86	0.40	2.16	2.09	0.93	1.58	2.40	1.61	2.19	1.46	1.599
Anderson	7336	ACT2	0.93	0.45	2.41	3.33	1.21	1.78	2.20	1.58	1.74	1.36	1.208
Anderson	7336	ACT3	1.07	0.34	1.62	2.31	0.76	1.72	1.09	1.92	0.97	2.21	1.257
Bailly	995	10	0.71	2.21	2.67	5.28	1.94	1.47	0.87	2.72	0.12	0.43	
Bailly	995	7	996.42	1,168.82	682.71	582.28	686.04	639.72	539.78	611.21	532.93	192.20	
Bailly	995	8	1,462.90	1,583.45	1,289.04	928.33	1,236.09	1,085.07	531.68	731.32	635.40	3.61	
Broadway Avenue	1011	1	4.57	3.99	7.25	6.77	0.83						
Broadway Avenue	1011	2	16.54	18.21	13.64	13.53	5.05	8.09	15.39	13.04	6.62	12.39	
Cayuga	1001	1	3,455.76	4,357.48	4,101.84	3,968.23	4,385.94	4,301.51	6,772.08	5,322.10	4,201.38	4,696.93	2,833.955
Cayuga	1001	2	3,405.09	3,971.56	4,146.25	3,599.51	5,307.43	4,383.10	3,732.27	7,047.34	2,859.77	4,280.02	1,568.531
Cayuga	1001	4	4.80	3.55	3.75	9.71	10.11	7.52	3.79	0.16	0.15	0.16	5.986
Clifty Creek	983	1	687.00	861.18	1,352.55	2,497.28	1,468.86	1,229.58	992.19	1,187.75	796.31	753.15	721.955
Clifty Creek	983	2	715.54	918.21	1,333.36	2,197.47	2,558.19	1,412.70	753.63	1,469.80	803.88	630.05	834.954
Clifty Creek	983	3	551.62	877.45	1,328.74	2,854.21	1,312.76	708.50	933.40	1,329.46	517.98	730.45	749.757
Clifty Creek	983	4	2,004.78	2,135.02	2,463.46	2,035.44	1,558.97	1,934.85	1,197.14	1,875.96	1,306.60	1,246.99	1,110.026
Clifty Creek	983	5	1,954.91	2,151.24	2,036.72	2,134.11	2,540.12	2,079.31	1,568.01	1,727.53	1,269.82	1,344.55	1,053.835
Clifty Creek	983	6	2,104.96	2,175.58	2,423.19	2,097.93	2,403.07	1,767.03	1,311.20	1,764.91	1,067.64	1,434.29	904.880
Connersville	1002	1A		0.12	0.10	0.20	0.97	0.63	0.52	0.60	0.47		
Connersville	1002	1B		0.10	0.11	0.28	0.97	0.63	0.52	0.60	0.47		
Connersville	1002	2A		0.17	0.11	0.27	1.09	0.57	0.49	1.30	0.54		
Connersville	1002	2B		0.29	0.13	0.29	1.09	0.57	0.49	1.29	0.53		
Edwardsport	1004	CTG1				46.26	275.13	370.01	392.75	416.80	450.92	416.76	360.945
Edwardsport	1004	CTG2				44.15	343.19	328.80	448.47	344.69	387.20	450.59	408.243
F B Culley	1012	2	237.50	299.39	152.91	290.57	306.05	372.88	92.54	364.11	215.84	296.78	147.072
F B Culley	1012	3	783.92	1,181.54	871.67	1,093.62	1,198.03	971.14	777.77	744.33	1,124.10	1,232.25	855.855
Georgetown	7759	GT1	0.28	1.88	2.51	3.48	3.04	1.07	2.83	6.65	5.82	10.06	3.055
Georgetown	7759	GT2	1.32	3.34	3.35	6.97	5.58	0.96	7.09	10.38	6.66	9.44	5.366
Georgetown	7759	GT3	1.07	2.70	3.03	5.69	4.43	0.82	5.70	8.05	5.85	7.94	5.858
Georgetown	7759	GT4	0.34	2.12	2.55	5.39	3.89	1.49	3.29	6.95	6.23	11.02	6.151
Gibson	6113	1	1,345.31	2,229.33	2,609.48	2,060.03	2,518.36	2,176.04	1,832.78	1,886.51	2,509.26	2,550.51	2,009.752
Gibson	6113	2	2,229.23	2,896.14	3,860.77	3,281.85	1,909.07	2,711.55	2,216.44	2,953.11	1,604.65	1,817.65	1,593.314

Gibson	6113	3	2,904.03	3,420.35	3,096.44	3,039.54	3,076.62	2,810.48	2,051.12	3,018.74	2,207.66	2,060.30	1,458.264
Gibson	6113	4	1,287.98	1,768.24	2,536.51	2,133.73	2,016.17	1,690.28	1,647.53	2,059.01	2,282.92	1,720.36	1,625.667
Gibson	6113	5	1,802.08	1,704.39	2,921.10	2,126.89	1,877.22	4,903.81	3,086.09	3,272.77	2,780.66	2,106.78	1,433.679
Henry County	7763	1	6.50	9.75	5.34	11.81	11.51	8.77	23.84	19.36	36.63	43.73	32.805
Henry County	7763	2	5.82	9.04	7.67	11.84	11.29	8.43	25.80	26.53	41.01	44.51	37.209
Henry County	7763	3	5.94	8.58	6.58	11.61	10.99	8.40	18.97	23.42	31.66	45.48	38.149
Lawrence County	7948	1	1.37	3.63	2.92	5.55	2.13	2.68	2.41	3.38	2.66	10.71	3.195
Lawrence County	7948	2	1.79	3.79	3.18	6.05	2.52	2.88	1.58	2.57	2.68	10.99	3.431
Lawrence County	7948	3	1.43	4.01	3.14	6.24	1.99	2.31	1.56	2.78	2.55	10.21	3.181
Lawrence County	7948	4	1.29	3.02	3.67	5.11	1.51	2.12	1.42	2.75	2.72	10.87	3.439
Lawrence County	7948	5	1.41	2.79	3.70	5.92	1.35	1.88	1.00	2.50	4.20	12.92	3.274
Lawrence County	7948	6	2.27	3.57	2.29	6.01	1.31	1.94	1.06	4.29	5.32	15.13	3.849
Eagle Valley	991	GT1										35.45	58.511
Eagle Valley	991	GT2										26.71	56.443
Harding Street	990	50	727.85	892.13	739.03	811.48	823.78	861.49	449.47	81.85	24.11	17.22	19.515
Harding Street	990	60	761.68	689.93	700.01	759.64	812.33	832.54	349.88	71.66	23.69	16.60	19.850
Harding Street	990	70	1,226.58	1,023.47	1,177.39	1,494.60	2,610.09	2,693.45	1,573.75	762.77	306.20	372.56	380.690
Harding Street	990	GT4	1.22	21.52	21.66	15.47	23.85	18.23	38.77	53.36	32.94	62.95	21.570
Harding Street	990	GT5	2.14	18.78	21.50	18.69	25.08	13.33	32.31	38.74	18.20	54.28	27.330
Harding Street	990	GT6	1.21	7.18	9.74	9.58	10.49	9.67	36.45	27.77	38.50	27.82	22.714
Petersburg	994	1	1,629.89	1,619.92	1,516.46	1,743.59	1,868.41	1,992.14	2,339.65	1,972.73	1,717.34	1,920.10	1,774.875
Petersburg	994	2	1,159.16	2,795.17	2,133.30	1,555.15	1,412.60	3,054.00	3,082.19	1,708.25	1,209.87	853.32	1,255.824
Petersburg	994	3	2,262.91	2,010.73	2,276.89	1,833.03	3,583.40	3,149.01	2,657.10	3,112.89	1,694.72	1,111.18	1,108.311
Petersburg	994	4	4,606.04	4,779.78	3,739.85	4,160.98	4,042.62	4,852.65	4,347.84	4,019.33	3,750.88	4,340.85	2,807.465
Lawrenceburg	55502	1	10.09	16.93	41.76	65.22	35.91	72.17	91.28	87.09	101.33	65.01	75.416
Lawrenceburg	55502	2	9.22	16.22	41.27	64.54	39.51	73.64	90.51	77.36	74.95	63.60	76.722
Lawrenceburg	55502	3	10.04	20.70	40.39	64.52	38.41	55.04	77.63	100.13	76.17	68.47	65.883
Lawrenceburg	55502	4	7.49	19.06	39.78	58.02	44.21	63.46	85.49	91.63	71.11	69.36	64.758
Merom	6213	1SG1	1,938.89	2,177.29	1,655.44	1,296.94	959.47	1,131.43	729.71	1,038.35	727.98	1,004.34	825.428
Merom	6213	2SG1	2,281.59	1,838.73	1,671.54	949.68	1,082.20	912.29	890.06	904.37	837.29	831.03	650.202
Michigan City	997	12	1,095.73	1,160.50	1,431.89	1,169.68	1,115.54	1,241.07	793.94	815.40	621.44	989.63	534.129
Montpelier	55229	G1CT1	2.34	5.96	5.94	9.87	7.98	8.61	14.58	15.87	11.86	12.54	12.805
Montpelier	55229	G1CT2	2.75	7.23	5.72	10.23	7.47	8.42	16.98	8.24	10.50	11.52	12.889
Montpelier	55229	G2CT1	2.48	6.07	5.57	9.97	9.50	10.30	18.48	17.54	12.17	13.67	15.229
Montpelier	55229	G2CT2	1.96	5.49	6.02	10.34	8.04	9.01	14.57	24.37	8.21	13.46	17.338
Montpelier	55229	G3CT1	2.48	5.93	6.62	9.96	7.58	8.02	17.03	15.34	13.57	13.49	18.777
Montpelier	55229	G3CT2	2.02	5.09	5.99	10.34	6.67	6.73	14.95	22.55	12.01	12.50	15.942
Montpelier	55229	G4CT1	2.46	6.29	6.14	10.65	8.66	9.35	19.64	16.13	13.93	12.88	15.070
Montpelier	55229	G4CT2	2.30	5.77	6.30	11.04	7.95	9.06	13.33	22.06	14.69	13.37	14.396
Noblesville	1007	CT3	2.94	9.28	6.82	17.80	10.56	9.19	18.24	23.98	9.71	17.95	21.026
Noblesville	1007	CT4	3.01	7.87	8.70	17.58	13.76	10.80	18.88	19.48	9.88	22.16	23.718

Noblesville	1007	CT5	3.77	7.52	12.74	19.51	13.48	11.05	23.02	22.88	12.60	22.10	15.149
R Gallagher	1008	2	990.84	1,194.91	371.58	336.73	727.40	859.55	512.47	320.34	213.27	318.16	43.426
R Gallagher	1008	4	666.19	1,048.55	278.82	166.43	472.62	797.15	427.93	328.20	179.72	216.73	40.681
R M Schahfer	6085	14	3,335.95	1,835.47	1,278.56	782.37	910.81	939.14	332.77	280.59	383.95	760.16	676.452
R M Schahfer	6085	15	2,167.61	3,093.71	2,370.01	2,086.38	1,755.61	1,593.96	1,420.81	773.97	649.40	1,668.57	1,227.710
R M Schahfer	6085	16A	5.94	15.97	23.26	48.94	12.21	13.06	32.87	13.57	19.34	13.87	5.493
R M Schahfer	6085	16B	5.13	15.83	16.53	28.55	10.41	11.99	29.98		6.54	23.78	8.979
R M Schahfer	6085	17	2,755.16	2,051.18	1,770.10	1,147.59	1,590.29	2,374.42	1,372.36	1,771.32	1,455.30	2,040.66	1,447.146
R M Schahfer	6085	18	2,296.04	2,602.97	1,908.23	1,846.41	2,467.12	2,183.33	1,983.53	1,557.12	2,410.38	1,582.64	1,619.915
Richmond	7335	RCT1	0.23	1.19	1.92	1.05	1.00	0.85	2.34	1.35	3.09	5.64	0.964
Richmond	7335	RCT2	0.20	1.15	2.40	1.96	1.18	0.85	2.32	1.32	2.89	5.33	1.063
Rockport	6166	MB1	10,906.12	10,804.46	7,520.93	11,016.47	10,351.58	10,363.51	6,534.63	6,043.04	4,631.03	3,801.73	2,479.243
Rockport	6166	MB2	8,856.06	9,740.85	12,288.05	10,627.21	6,849.24	9,362.44	7,387.05	6,845.04	6,630.04	4,939.02	3,614.150
St. Joseph	57794	CTG01A										49.87	57.836
St. Joseph	57794	CTG01B										46.91	57.779
Sugar Creek	55364	CT11	24.10	43.93	42.65	49.07	44.57	40.47	44.33	54.65	61.36	50.40	57.826
Sugar Creek	55364	CT12	22.37	46.09	44.94	51.52	44.03	41.70	46.07	55.76	59.84	47.98	57.105
Vermillion	55111	1	1.55	2.26	1.70	2.36	4.22	1.04	3.94	4.13	2.57	8.21	3.591
Vermillion	55111	2	2.43	1.73	1.11	1.96	1.95	0.60	3.58	4.80	1.28	7.01	3.229
Vermillion	55111	3	1.85	3.02	1.68	2.15	3.25	1.44	3.22	2.74	1.91	6.58	3.790
Vermillion	55111	4	1.93	2.67	2.15	2.11	1.59	0.72	3.99	4.20	1.81	5.58	1.746
Vermillion	55111	5	2.23	1.99	1.83	2.18	1.96	0.68	2.25	5.66	2.93	7.41	2.680
Vermillion	55111	6	1.88	2.33	1.84	2.08	1.89	0.53	3.76	4.25	2.26	8.76	3.619
Vermillion	55111	7	1.28	2.18	1.40	2.38	1.31	0.65	3.73	3.03	2.14	6.51	2.806
Vermillion	55111	8	1.92	2.54	2.14	1.98	1.04	0.62	2.47	3.08	0.98	4.91	2.127
Wabash River	1010	1	306.72	307.37	363.96	254.22	431.51	385.74	374.95	163.09	14.04	414.45	19.028
Wabash River	1010	2	379.62		645.33	372.01	349.58	302.52	87.86				
Wabash River	1010	3	310.10		723.61	309.71	403.85	320.72	292.08				
Wabash River	1010	4	1,033.02	1,194.43	1,006.58	364.77	360.51	431.77	305.05				
Wabash River	1010	5	276.92		382.03	79.34	169.55	260.04	15.26				
Wabash River	1010	6	3,668.13	3,599.20	3,976.33	1,747.59	1,976.43	1,650.99	2,465.89	778.79			
Wheatland	55224	EU-01	5.55	17.66	15.57	25.88	27.24	12.83	17.28	31.27	19.19	0.01	46.544
Wheatland	55224	EU-02	4.19	14.26	13.33	10.28	22.37	10.52	15.37	32.31	19.06	0.01	34.893
Wheatland	55224	EU-03	4.34	9.98	11.13	19.97	16.90	8.93	2.91	2.30	15.00	0.00	29.274
Wheatland	55224	EU-04	3.47	11.46	10.20	25.44	14.87	11.52	17.54	27.01	14.06	0.02	22.979
Whitewater Valley	1040	1	80.56	136.54	137.84	17.60	13.21	26.96	32.83	38.86	27.87	2,357.42	30.854
Whitewater Valley	1040	2	288.77	222.18	238.05	35.35	26.55	65.06	69.08	85.57	61.69	6,322.83	71.064
Whiting	55259	CT1	31.53	54.42	59.17	50.04	65.39	45.05	55.05	58.32	43.54	2.11	49.222
Whiting	55259	CT2	48.45	47.70	49.11	54.01	35.58	55.46	43.69	52.63	41.15	2.97	49.840
Worthington	55148	1	1.53	3.05	2.41	2.31	0.85	0.67	5.11	7.39	7.26	0.02	7.871
Worthington	55148	2	0.93	2.12	1.75	1.96	0.26	0.48	4.10	6.60	5.65	0.02	6.690

Worthington	55148	3	1.07	1.98	2.04	1.87	0.27	1.21	4.04	4.63	3.53	0.01	6.280
Worthington	55148	4	1.61	2.76	1.71	1.79	0.63	1.15	4.98	5.86	6.47	0.02	7.419

Table 3 Indiana Electric Generating Units 2009-2019 Combined Annual SO_2 Emissions Reported to CAMD

Facility Name	2009 SO_2 Emissions (tons)	2010 SO_2 Emissions (tons)	2011 SO_2 Emissions (tons)	2012 SO_2 Emissions (tons)	2013 SO_2 Emissions (tons)	2014 SO_2 Emissions (tons)	2015 SO_2 Emissions (tons)	2016 SO_2 Emissions (tons)	2017 SO_2 Emissions (tons)	2018 SO_2 Emissions (tons)	2019 SO_2 Emissions (tons)
A B Brown	5,778.04	5,293.07	6,232.74	7,091.27	6,816.20	8,080.13	6,942.24	3,854.78	3,114.11	3,528.03	3,957.47
Alcoa	1,465.49	2,256.43	2,016.45	2,283.43	2,124.55	1,894.14	967.84	1,787.86	1,505.30	1,233.63	648.34
Anderson	0.61	0.02	0.08	0.08	0.03	0.49	0.05	0.05	0.05	0.05	0.73
Bailly	4,903.40	9,161.98	2,560.47	1,813.47	2,474.40	1,116.76	514.78	807.76	545.09	53.17	
Broadway Avenue	0.05	0.06	0.06	0.05	0.02	0.02	0.05	0.03	0.02	0.03	
Cayuga	2,423.16	2,015.43	3,296.42	3,222.11	4,627.80	3,448.00	1,832.02	2,520.61	1,914.18	2,656.16	1,802.05
Clifty Creek	54,475.97	68,931.99	74,085.74	52,838.93	19,562.58	3,731.23	4,444.25	4,560.86	4,860.01	5,126.57	4,191.13
Connersville		0.00	0.00	0.00	1.72	1.00	0.84	1.58	0.84		
Vermillion				26.50	102.45	41.97	60.78	58.81	184.55	57.50	55.05
Eagle Valley	2,050.91	1,899.92	1,463.36	2,115.99	1,947.81	1,895.90	1,513.48	1,310.81	1,858.28	1,895.61	1,050.22
Edwardsport	0.09	0.29	0.34	0.62	0.45	0.11	0.49	0.82	0.59	0.89	0.45
F B Culley	20,942.05	21,873.97	18,986.61	22,446.78	20,669.13	22,055.39	16,098.04	14,962.74	13,648.03	16,212.90	9,666.32
Georgetown	0.13	0.19	0.14	0.26	0.24	0.18	0.48	0.49	0.75	0.93	0.78
Gibson	0.07	0.15	0.13	0.23	0.08	0.10	0.06	0.12	0.13	0.46	0.13
Harding Street										5.65	10.32
Henry County	23,598.13	21,666.26	18,994.22	21,541.70	27,973.87	29,855.15	14,929.73	274.74	4.30	4.66	3.59
Lawrence County	40,129.08	29,845.57	25,231.76	15,463.08	33,755.88	66,251.85	27,637.44	12,837.51	7,966.88	6,569.81	6,586.00
Lawrenceburg	1.25	3.45	8.84	14.27	5.84	7.39	14.77	16.71	15.90	15.75	17.37
Merom	14,629.40	11,939.74	8,813.17	4,377.45	2,815.85	3,315.62	2,578.82	3,143.81	2,638.09	3,802.72	2,897.89
Michigan City	9,429.90	9,730.22	13,353.54	11,584.24	10,428.80	15,990.64	10,148.07	1,901.03	601.35	996.98	485.25
Montpelier	0.11	0.32	0.29	0.50	0.25	0.27	0.31	0.64	5.32	0.97	1.65
Noblesville	0.33	0.57	0.86	1.94	1.17	0.79	2.44	2.46	1.37	3.32	3.21
Petersburg	14,618.84	13,124.52	1,313.77	922.43	2,495.26	3,524.45	2,174.69	1,457.35	857.93	1,148.95	170.25
R Gallagher	32,437.34	27,064.70	19,352.12	14,899.50	16,413.55	8,412.40	1,688.96	1,440.94	1,570.44	1,467.10	1,167.59
R M Schahfer	0.00	0.26	0.03	0.02	0.02	0.34	0.13	0.03	0.03	0.06	0.13
Richmond	54,795.88	54,242.21	56,732.96	54,389.96	51,636.00	54,978.64	29,889.06	24,341.10	20,783.62	21,240.87	14,341.44
Rockport										7.92	11.34
St. Joseph	1.64	3.53	5.01	6.66	5.36	4.83	7.17	8.29	7.74	6.51	7.84
Sugar Creek	0.18	0.35	0.28	0.37	0.29	0.08	0.45	0.58	0.24	0.94	0.40
Wabash River	6,147.02	5,320.66	7,000.47	3,230.24	3,778.14	3,352.39	3,680.71	1,019.93	0.17	0.30	0.27
Wheatland	0.08	0.25	0.24	0.41	0.36	0.19	0.25	0.47	0.32	0.81	0.49
Whitewater Valley	3,919.40	4,806.06	5,240.53	573.09	536.87	1,157.83	1,391.91	1,726.64	837.00	880.41	694.44
Whiting	5.30	7.25	7.27	7.09	6.88	6.72	7.03	7.74	5.90	6.83	7.31
Worthington	0.04	0.08	0.06	0.06	0.01	0.02	0.12	0.17	0.15	0.43	0.20
Grand Total	291,753.86	289,189.47	264,697.96	218,852.73	208,181.83	229,125.04	126,527.44	78,047.44	62,928.64	66,926.92	47,779.63

Table 4 Electric Generating Units 2009-2019 SO_2 Emissions

Facility Name	Facility ID (ORISPL)	Unit ID	2009 SO_2 Emissions (tons)	2010 SO_2 Emissions (tons)	2011 SO_2 Emissions (tons)	2012 SO_2 Emissions (tons)	2013 SO_2 Emissions (tons)	2014 SO_2 Emissions (tons)	2015 SO_2 Emissions (tons)	2016 SO_2 Emissions (tons)	2017 SO_2 Emissions (tons)	2018 SO_2 Emissions (tons)	2019 SO_2 Emissions (tons)
A B Brown	6137	1	3,161.17	2,964.40	3,308.16	4,289.92	4,456.90	4,967.28	4,461.98	1,673.55	1,867.05	1,948.00	2,060.76
A B Brown	6137	2	2,616.79	2,328.52	2,924.37	2,801.20	2,358.79	3,112.31	2,480.13	2,181.13	1,246.91	1,578.88	1,896.61
A B Brown	6137	3	0.04	0.09	0.15	0.08	0.44	0.50	0.04	0.04	0.09	1.06	0.04
A B Brown	6137	4	0.03	0.06	0.06	0.08	0.08	0.05	0.10	0.05	0.06	0.09	0.05
Alcoa	6705	4	1,465.49	2,256.43	2,016.45	2,283.43	2,124.55	1,894.14	967.84	1,787.86	1,505.30	1,233.63	648.34
Anderson	7336	ACT1	0.14	0.00	0.02	0.01	0.01	0.13	0.01	0.01	0.01	0.01	0.19
Anderson	7336	ACT2	0.16	0.00	0.01	0.02	0.01	0.15	0.02	0.01	0.01	0.01	0.13
Anderson	7336	ACT3	0.32	0.01	0.05	0.05	0.02	0.21	0.03	0.04	0.03	0.04	0.41
Bailly	995	10	0.00	0.01	0.01	0.02	0.01	0.00	0.00	0.01		0.00	
Bailly	995	7	2,741.10	6,202.01	878.00	558.34	776.92	389.72	227.83	311.31	192.24	52.48	
Bailly	995	8	2,162.30	2,959.96	1,682.46	1,255.11	1,697.47	727.03	286.95	496.44	352.85	0.70	
Broadway Avenue	1011	1	0.01	0.01	0.02	0.01	0.00						
Broadway Avenue	1011	2	0.04	0.05	0.04	0.04	0.01	0.02	0.05	0.03	0.02	0.03	
Cayuga	1001	1	962.91	958.57	1,528.11	1,779.24	2,355.49	1,902.06	1,350.60	1,052.48	1,226.16	1,511.78	1,251.43
Cayuga	1001	2	1,459.74	1,056.83	1,768.27	1,442.74	2,272.20	1,545.88	481.38	1,468.13	688.03	1,144.37	550.57
Cayuga	1001	4	0.51	0.03	0.04	0.14	0.11	0.06	0.04	0.00	0.00	0.00	0.06
Clifty Creek	983	1	9,572.52	9,749.85	12,446.65	9,205.07	1,710.26	529.76	935.11	751.93	848.71	925.82	670.04
Clifty Creek	983	2	9,875.14	10,062.09	12,073.84	7,348.09	4,923.14	543.41	732.10	863.83	841.41	842.47	782.21
Clifty Creek	983	3	7,293.52	10,817.62	11,870.70	9,840.13	1,606.79	299.95	792.02	863.90	619.78	966.41	756.60
Clifty Creek	983	4	9,468.49	12,962.76	13,731.73	8,566.74	1,883.98	860.72	629.68	728.94	1,015.03	854.09	768.28
Clifty Creek	983	5	9,379.60	12,998.39	10,975.78	8,935.71	4,368.94	860.63	780.79	693.89	988.74	885.46	719.15
Clifty Creek	983	6	8,886.71	12,341.28	12,987.03	8,943.19	5,069.47	636.77	574.55	658.37	546.34	652.32	494.85
Connersville	1002	1A					0.40	0.26	0.22	0.25	0.20		
Connersville	1002	1B					0.40	0.26	0.22	0.25	0.20		
Connersville	1002	2A			0.00	0.00	0.46	0.24	0.20	0.54	0.23		
Connersville	1002	2B		0.00	0.00	0.00	0.46	0.24	0.20	0.54	0.22		
Edwardsport	1004	CTG1				0.26	27.90	24.10	30.90	26.34	90.11	25.98	28.30
Edwardsport	1004	CTG2				26.24	74.54	17.87	29.88	32.46	94.44	31.53	26.74
F B Culley	1012	2	435.32	406.15	279.17	348.75	344.33	295.39	101.05	145.85	198.72	251.86	98.63
F B Culley	1012	3	1,615.59	1,493.77	1,184.19	1,767.24	1,603.47	1,600.50	1,412.43	1,164.96	1,659.57	1,643.76	951.58
Georgetown	7759	GT1	0.01	0.06	0.07	0.10	0.08	0.03	0.08	0.17	0.15	0.25	0.08
Georgetown	7759	GT2	0.04	0.09	0.10	0.18	0.14	0.02	0.17	0.24	0.16	0.21	0.12
Georgetown	7759	GT3	0.03	0.08	0.10	0.17	0.13	0.02	0.16	0.23	0.14	0.17	0.12
Georgetown	7759	GT4	0.01	0.07	0.08	0.16	0.11	0.04	0.09	0.18	0.15	0.26	0.14

Gibson	6113	1	1,614.36	2,139.53	2,313.50	2,601.41	2,782.44	2,433.96	2,391.07	1,807.19	2,201.77	1,804.20	1,070.49
Gibson	6113	2	1,691.89	2,522.14	2,273.27	2,315.27	1,764.10	2,259.79	2,181.62	2,339.93	2,049.47	1,902.75	1,461.97
Gibson	6113	3	2,721.75	3,172.56	2,111.93	2,608.09	2,588.66	2,349.96	1,704.56	2,113.84	1,871.69	1,980.28	772.09
Gibson	6113	4	3,044.02	3,900.86	3,012.40	2,911.47	3,646.97	2,918.01	3,440.39	3,206.84	3,194.12	3,486.36	2,092.62
Gibson	6113	5	11,870.02	10,138.88	9,275.51	12,010.55	9,886.96	12,093.66	6,380.40	5,494.94	4,330.98	7,039.31	4,269.15
Henry County	7763	1	0.04	0.07	0.04	0.08	0.08	0.06	0.17	0.14	0.25	0.30	0.23
Henry County	7763	2	0.04	0.07	0.05	0.09	0.08	0.06	0.18	0.19	0.28	0.31	0.27
Henry County	7763	3	0.04	0.06	0.05	0.09	0.08	0.06	0.14	0.17	0.21	0.31	0.27
Lawrence County	7948	1	0.01	0.03	0.02	0.04	0.02	0.02	0.02	0.02	0.02	0.07	0.02
Lawrence County	7948	2	0.01	0.03	0.02	0.04	0.02	0.02	0.01	0.02	0.02	0.08	0.03
Lawrence County	7948	3	0.01	0.03	0.02	0.04	0.01	0.02	0.01	0.02	0.02	0.07	0.02
Lawrence County	7948	4	0.01	0.02	0.03	0.04	0.01	0.02	0.01	0.02	0.02	0.07	0.02
Lawrence County	7948	5	0.01	0.02	0.02	0.04	0.01	0.01	0.01	0.02	0.03	0.08	0.02
Lawrence County	7948	6	0.01	0.02	0.02	0.04	0.01	0.01	0.01	0.03	0.03	0.09	0.02
Eagle Valley	991	GT1										3.01	5.08
Eagle Valley	991	GT2										2.64	5.24
Harding Street	990	50	10,043.08	11,158.71	8,633.54	10,530.71	13,323.67	13,174.72	6,850.61	1.25	0.46	0.34	0.32
Harding Street	990	60	10,411.08	8,794.66	7,940.46	10,269.59	12,603.19	13,197.28	5,826.85	1.12	0.40	0.30	0.34
Harding Street	990	70	3,143.79	1,712.55	2,419.87	741.05	2,046.32	3,482.30	2,251.13	271.30	2.28	2.78	2.37
Harding Street	990	GT4	0.09	0.09	0.09	0.06	0.23	0.32	0.22	0.25	0.21	0.39	0.09
Harding Street	990	GT5	0.08	0.10	0.10	0.08	0.25	0.35	0.23	0.27	0.18	0.39	0.11
Harding Street	990	GT6	0.02	0.15	0.17	0.19	0.22	0.19	0.69	0.55	0.77	0.46	0.36
Petersburg	994	1	14,441.92	4,093.69	1,395.06	2,739.10	14,395.30	18,002.10	6,666.04	1,249.12	537.19	626.02	583.32
Petersburg	994	2	1,548.48	2,357.55	2,586.35	4,865.83	8,129.45	30,458.69	11,819.10	3,083.39	1,311.47	785.81	1,160.64
Petersburg	994	3	5,323.87	5,397.06	7,569.10	4,494.97	6,382.77	9,473.35	4,432.33	5,094.19	3,230.74	2,324.43	2,374.77
Petersburg	994	4	18,814.81	17,997.26	13,681.25	3,363.18	4,848.35	8,317.72	4,719.98	3,410.82	2,887.48	2,833.56	2,467.27
Lawrenceburg	55502	1	0.33	0.73	2.27	3.72	1.45	1.97	3.73	4.36	3.83	3.69	4.67
Lawrenceburg	55502	2	0.34	0.84	2.27	3.55	1.45	1.91	3.55	4.13	3.93	3.71	4.68
Lawrenceburg	55502	3	0.32	0.91	2.12	3.63	1.47	1.85	3.75	4.07	4.11	4.15	4.05
Lawrenceburg	55502	4	0.27	0.97	2.18	3.37	1.46	1.67	3.74	4.15	4.03	4.19	3.98
Merom	6213	1SG1	7,077.45	6,271.08	4,125.77	3,004.27	1,590.88	2,023.21	1,229.26	1,814.11	1,126.49	1,999.11	1,672.29
Merom	6213	2SG1	7,551.95	5,668.66	4,687.40	1,373.18	1,224.97	1,292.42	1,349.56	1,329.70	1,511.59	1,803.61	1,225.60
Michigan City	997	12	9,429.90	9,730.22	13,353.54	11,584.24	10,428.80	15,990.64	10,148.07	1,901.03	601.35	996.98	485.25
Montpelier	55229	G1CT1	0.01	0.04	0.04	0.06	0.03	0.03	0.04	0.07	0.72	0.12	0.05
Montpelier	55229	G1CT2	0.02	0.05	0.04	0.06	0.03	0.04	0.04	0.03	0.79	0.10	0.14
Montpelier	55229	G2CT1	0.01	0.04	0.03	0.06	0.03	0.03	0.04	0.06	0.47	0.12	0.07
Montpelier	55229	G2CT2	0.01	0.04	0.04	0.06	0.03	0.04	0.04	0.11	0.35	0.12	0.18
Montpelier	55229	G3CT1	0.02	0.04	0.04	0.06	0.03	0.03	0.04	0.07	0.61	0.13	0.54
Montpelier	55229	G3CT2	0.01	0.04	0.04	0.06	0.03	0.03	0.04	0.13	0.58	0.11	0.53
Montpelier	55229	G4CT1	0.01	0.04	0.04	0.06	0.03	0.03	0.04	0.07	0.88	0.14	0.07

Montpelier	55229	G4CT2	0.01	0.04	0.04	0.06	0.03	0.03	0.03	0.10	0.92	0.14	0.07
Noblesville	1007	CT3	0.11	0.17	0.20	0.59	0.38	0.24	0.78	0.85	0.44	1.02	1.21
Noblesville	1007	CT4	0.11	0.18	0.31	0.68	0.41	0.30	0.84	0.83	0.46	1.11	1.25
Noblesville	1007	CT5	0.11	0.22	0.35	0.68	0.38	0.25	0.82	0.78	0.47	1.19	0.75
R Gallagher	1008	2	8,651.95	6,558.53	727.88	598.03	1,461.27	1,767.73	1,133.30	702.17	461.89	692.69	90.33
R Gallagher	1008	4	5,966.90	6,565.99	585.89	324.40	1,033.99	1,756.72	1,041.39	755.17	396.03	456.26	79.92
R M Schahfer	6085	14	12,225.50	11,951.41	9,211.65	5,423.13	6,193.30	162.17	44.03	58.13	93.18	163.46	114.99
R M Schahfer	6085	15	7,234.37	9,753.41	8,414.21	8,127.07	8,400.65	5,918.91	133.97	103.30	82.52	211.43	131.74
R M Schahfer	6085	16A	0.01	0.03	0.05	0.11	0.03	0.03	0.07	0.03	0.05	0.04	0.02
R M Schahfer	6085	16B	0.01	0.04	0.04	0.07	0.03	0.03	0.07		0.02	0.07	0.02
R M Schahfer	6085	17	7,194.77	2,521.48	828.00	546.05	735.50	1,301.89	652.51	753.32	655.41	643.91	462.47
R M Schahfer	6085	18	5,782.68	2,838.34	898.18	803.08	1,084.05	1,029.38	858.31	526.16	739.27	448.19	458.36
Richmond	7335	RCT1	0.00	0.10	0.02	0.01	0.01	0.16	0.06	0.01	0.02	0.03	0.04
Richmond	7335	RCT2	0.00	0.16	0.02	0.01	0.01	0.18	0.07	0.02	0.02	0.03	0.09
Rockport	6166	MB1	30,139.22	28,721.71	21,820.30	27,848.53	30,838.85	28,666.17	13,802.96	11,401.50	8,576.97	10,386.50	7,076.14
Rockport	6166	MB2	24,656.67	25,520.49	34,912.66	26,541.43	20,797.15	26,312.48	16,086.10	12,939.60	12,206.65	10,854.37	7,265.30
St. Joseph	57794	CTG01A										4.02	5.69
St. Joseph	57794	CTG01B										3.90	5.66
Sugar Creek	55364	CT11	0.82	1.76	2.50	3.33	2.78	2.41	3.57	4.14	3.92	3.30	3.99
Sugar Creek	55364	CT12	0.81	1.77	2.51	3.33	2.58	2.42	3.60	4.15	3.82	3.21	3.85
Vermillion	55111	1	0.02	0.04	0.04	0.05	0.06	0.01	0.06	0.07	0.04	0.14	0.06
Vermillion	55111	2	0.03	0.04	0.03	0.05	0.04	0.01	0.06	0.09	0.02	0.12	0.06
Vermillion	55111	3	0.02	0.06	0.04	0.05	0.06	0.02	0.05	0.05	0.03	0.11	0.06
Vermillion	55111	4	0.02	0.05	0.04	0.05	0.03	0.01	0.07	0.08	0.03	0.11	0.03
Vermillion	55111	5	0.03	0.04	0.04	0.04	0.04	0.01	0.03	0.09	0.04	0.12	0.04
Vermillion	55111	6	0.02	0.04	0.03	0.04	0.03	0.01	0.06	0.07	0.03	0.14	0.06
Vermillion	55111	7	0.02	0.04	0.03	0.05	0.02	0.01	0.07	0.06	0.04	0.13	0.05
Vermillion	55111	8	0.02	0.04	0.04	0.04	0.02	0.01	0.04	0.06	0.02	0.09	0.04
Wabash River	1010	1	479.22	527.03	266.59	356.84	518.22	386.36	514.58	241.14	0.17	0.30	0.27
Wabash River	1010	2	379.62		645.33	372.01	349.58	302.52	87.86				
Wabash River	1010	3	310.10		723.61	309.71	403.85	320.72	292.08				
Wabash River	1010	4	1,033.02	1,194.43	1,006.58	364.77	360.51	431.77	305.05				
Wabash River	1010	5	276.92		382.03	79.34	169.55	260.04	15.26				
Wabash River	1010	6	3,668.13	3,599.20	3,976.33	1,747.59	1,976.43	1,650.99	2,465.89	778.79			
Wheatland	55224	EU-01	0.03	0.08	0.07	0.13	0.12	0.05	0.07	0.14	0.08	0.28	0.15
Wheatland	55224	EU-02	0.02	0.07	0.06	0.05	0.10	0.05	0.07	0.17	0.10	0.24	0.14
Wheatland	55224	EU-03	0.02	0.05	0.05	0.10	0.08	0.04	0.01	0.01	0.07	0.22	0.10
Wheatland	55224	EU-04	0.02	0.05	0.05	0.13	0.06	0.05	0.09	0.15	0.07	0.08	0.11
Whitewater Valley	1040	1	829.43	1,801.25	1,895.45	194.87	179.29	354.76	468.78	572.49	278.90	270.33	223.30
Whitewater Valley	1040	2	3,089.97	3,004.82	3,345.08	378.22	357.58	803.07	923.13	1,154.15	558.10	610.08	471.14

Whiting	55259	CT1	2.01	3.82	3.93	3.39	4.40	3.01	3.93	3.94	3.00	3.33	3.68
Whiting	55259	CT2	3.28	3.43	3.34	3.70	2.48	3.71	3.10	3.80	2.90	3.50	3.63
Worthington	55148	1	0.01	0.02	0.02	0.02	0.01	0.01	0.04	0.05	0.04	0.12	0.06
Worthington	55148	2	0.01	0.02	0.01	0.02	0.00	0.00	0.03	0.05	0.04	0.10	0.05
Worthington	55148	3	0.01	0.02	0.02	0.01	0.00	0.01	0.03	0.03	0.03	0.10	0.05
Worthington	55148	4	0.01	0.02	0.01	0.01	0.00	0.01	0.03	0.04	0.04	0.11	0.05

Table 5 Indiana Electric Generating Units 2009-2019 Combined Ozone Season NO_x Emissions Reported to CAMD

Facility Name	2009 NO_x Ozone Emissions (tons)	2010 NO_x Ozone Emissions (tons)	2011 NO_x Ozone Emissions (tons)	2012 NO_x Ozone Emissions (tons)	2013 NO_x Ozone Emissions (tons)	2014 NO_x Ozone Emissions (tons)	2015 NO_x Ozone Emissions (tons)	2016 NO_x Ozone Emissions (tons)	2017 NO_x Ozone Emissions (tons)	2018 NO_x Ozone Emissions (tons)	2019 NO_x Ozone Emissions (tons)
A B Brown	636.76	857.16	866.08	998.90	835.66	1,225.15	1,010.36	616.45	591.44	841.42	1,181.72
Alcoa	477.03	539.23	705.01	1,048.54	1,254.00	1,320.44	1,306.95	1,452.10	327.61	1,162.30	1,118.51
Anderson	0.25	0.59	5.74	7.09	2.31	0.58	5.45	3.00	2.44	4.09	0.86
Bailly	836.70	1,460.30	782.35	749.28	917.91	811.06	444.64	636.95	584.43	0.02	
Broadway Avenue	11.40	18.54	19.20	18.39	2.51	1.29	11.33	8.78	5.45	9.48	
Cayuga	2,040.71	3,635.78	3,672.77	3,108.30	4,247.29	4,035.07	4,363.04	4,010.26	1,123.25	1,336.58	735.52
Clifty Creek	3,084.37	3,292.71	4,717.05	5,239.28	4,585.14	4,103.51	3,054.35	4,763.02	1,038.90	1,378.34	1,194.18
Connersville		0.68	0.45	1.04	1.89	2.40					
Vermillion				90.41	298.98	243.81	343.75	317.74	300.37	311.38	281.07
Eagle Valley	423.33	766.29	544.99	738.68	604.09	563.93	390.66	517.46	621.16	747.85	559.21
Edwardsport	1.98	8.42	9.96	15.00	9.16	2.09	9.34	16.18	9.56	22.33	12.27
F B Culley	3,445.10	5,444.63	7,393.53	5,569.38	4,487.62	6,050.03	4,748.86	5,140.92	3,237.39	3,570.85	2,380.26
Georgetown	6.00	18.55	14.46	30.30	21.98	11.85	34.94	50.16	58.83	76.87	62.00
Gibson	3.35	18.16	18.28	34.71	7.51	11.00	2.75	14.80	14.20	43.82	13.73
Harding Street										27.03	47.97
Henry County	1,035.11	1,046.25	1,069.49	1,299.02	1,576.10	1,513.36	1,061.14	327.93	259.95	302.16	317.92
Lawrence County	3,643.78	5,020.31	4,349.56	3,948.33	4,212.03	5,372.89	5,320.02	5,187.54	3,474.34	3,586.15	2,584.24
Lawrenceburg	26.89	49.28	65.27	96.53	59.83	123.42	129.15	150.61	143.35	114.77	128.22
Merom	1,724.41	1,475.52	1,330.20	889.34	925.02	925.96	644.39	871.47	738.71	834.10	594.80
Michigan City	585.31	587.35	632.77	577.51	569.64	527.73	403.87	481.61	115.36	398.07	301.52
Montpelier	6.79	33.70	34.46	51.64	41.08	30.44	55.62	53.28	44.46	60.22	79.72
Noblesville	4.08	16.89	14.07	25.29	13.69	18.38	17.79	32.09	14.15	31.12	22.92
Petersburg	739.45	1,004.92	387.89	342.30	320.70	425.49	551.85	429.91	222.71	237.29	45.29
R Gallagher	5,120.76	4,462.29	3,633.94	3,067.75	3,185.42	3,018.94	2,432.65	2,120.47	2,158.80	2,836.70	2,041.53
R M Schahfer	0.14	1.31	4.07	2.56	1.81	0.14	3.20	1.96	3.97	1.94	0.64
Richmond	8,456.59	8,416.90	8,955.09	9,215.40	7,214.25	7,852.83	7,652.38	6,021.68	5,093.57	3,651.86	2,555.12
Rockport										47.87	50.91
St. Joseph	24.20	46.71	32.98	44.30	35.88	28.53	42.39	44.12	50.83	43.86	43.75
Sugar Creek	3.59	10.19	10.63	16.49	11.63	2.67	11.62	19.85	8.05	33.18	11.80
Wabash River	2,467.83	2,387.37	3,346.02	1,178.10	1,636.56	1,421.93	197.66	11.83	6.76	12.93	12.80
Wheatland	7.29	37.36	40.41	75.17	48.56	13.11	33.24	66.66	44.86	111.88	84.65
Whitewater Valley	76.69	184.71	165.07	52.95	34.55	49.61	54.52	75.24	55.55	61.86	69.99
Whiting	29.77	41.18	43.20	46.59	44.08	40.42	26.20	42.00	29.99	39.13	40.10
Worthington	1.97	9.53	7.41	6.92	0.66	1.08	8.66	17.76	15.09	38.75	20.52
Grand Total	34,921.61	40,892.76	42,872.36	38,585.50	37,207.51	39,749.13	34,372.74	33,503.84	20,395.53	21,976.19	16,593.68

Table 6 Electric Generating Units 2009-2019 Ozone Season NO_x Emissions

Facility Name	Facility ID (ORISPL)	Unit ID	2009 NOx Ozone Emissions (tons)	2010 NOx Ozone Emissions (tons)	2011 NOx Ozone Emissions (tons)	2012 NOx Ozone Emissions (tons)	2013 NOx Ozone Emissions (tons)	2014 NOx Ozone Emissions (tons)	2015 NOx Ozone Emissions (tons)	2016 NOx Ozone Emissions (tons)	2017 NOx Ozone Emissions (tons)	2018 NOx Ozone Emissions (tons)	2019 NOx Ozone Emissions (tons)
A B Brown	6137	1	275.47	358.73	442.36	568.76	467.48	617.06	539.498	150.651	268.582	423.88	537.264
A B Brown	6137	2	353.80	481.17	408.06	412.36	361.58	606.72	465.394	452.136	312.828	405.72	639.363
A B Brown	6137	3	6.65	15.87	13.88	15.51	5.03	0.91	3.762	11.887	8.176	8.77	4.202
A B Brown	6137	4	0.85	1.39	1.79	2.26	1.56	0.47	1.709	1.778	1.854	3.05	0.889
Alcoa	6705	4	477.03	539.23	705.01	1,048.54	1,254.00	1,320.44	1,306.95	1452.104	327.611	1,162.30	1,118.51
Anderson	7336	ACT1	0.09	0.22	2.04	1.86	0.73	0.23	2.298	1.148	1.071	1.16	0.289
Anderson	7336	ACT2	0.11	0.23	2.25	3.09	0.98	0.21	2.118	1.112	0.89	1.09	0.311
Anderson	7336	ACT3	0.04	0.14	1.46	2.15	0.61	0.13	1.035	0.74	0.475	1.84	0.256
Bailly	995	10	0.42	1.19	1.36	4.25	1.27	0.68	0.453	0.849	0.092	0.02	
Bailly	995	7	310.04	502.38	213.52	299.46	304.02	303.74	158.549	277.408	294.322		
Bailly	995	8	526.24	956.73	567.46	445.57	612.63	506.64	285.638	358.694	290.019		
Broadway Avenue	1011	1	2.89	3.20	6.64	6.72	0.20						
Broadway Avenue	1011	2	8.51	15.34	12.56	11.67	2.31	1.29	11.327	8.782	5.452	9.48	
Cayuga	1001	1	1,195.94	1,844.62	1,996.41	1,827.89	1,874.00	2,282.02	2,655.47	1690.323	624.929	740.16	426.565
Cayuga	1001	2	842.75	1,789.25	1,673.21	1,273.22	2,368.44	1,751.59	1,705.81	2319.778	498.174	596.33	306.134
Cayuga	1001	4	2.03	1.92	3.15	7.19	4.85	1.46	1.758	0.155	0.146	0.10	2.816
Clifty Creek	983	1	264.52	271.64	516.21	941.94	562.21	504.84	474.826	653.196	178.52	208.86	143.965
Clifty Creek	983	2	276.47	328.13	504.06	729.44	621.82	487.56	497.826	668.559	172.662	164.96	156.519
Clifty Creek	983	3	215.70	341.75	520.48	965.36	586.77	410.86	418.939	678.21	149.128	201.76	167.044
Clifty Creek	983	4	811.41	797.12	1,031.27	831.15	538.78	952.84	550.518	1004.878	239.53	298.16	286.195
Clifty Creek	983	5	785.28	795.92	1,045.23	982.67	1,060.97	887.49	677.093	769.578	226.776	321.14	260.732
Clifty Creek	983	6	730.99	758.16	1,099.82	788.73	1,214.59	859.93	435.148	988.597	72.286	183.45	179.722
Connersville	1002	1A		0.12	0.10	0.20	0.46	0.63					
Connersville	1002	1B		0.10	0.11	0.28	0.46	0.63					
Connersville	1002	2A		0.17	0.11	0.27	0.49	0.57					
Connersville	1002	2B		0.29	0.13	0.29	0.49	0.57					
Edwardsport	1004	CTG1				46.26	138.89	118.45	159.314	171.498	155.775	155.71	148.008
Edwardsport	1004	CTG2				44.15	160.09	125.36	184.438	146.241	144.59	155.67	133.059
F B Culley	1012	2	98.15	165.36	104.17	170.58	134.93	81.91	43.186	255.944	98.432	156.51	97.589
F B Culley	1012	3	325.17	600.93	440.82	568.10	469.15	482.02	347.474	261.518	522.729	591.34	461.624

Georgetown	7759	GT1	0.16	1.51	1.95	2.38	1.97	0.52	1.508	3.39	2.272	5.53	2.051
Georgetown	7759	GT2	0.81	2.86	3.18	4.73	2.80	0.69	3.425	5.28	2.726	6.32	2.871
Georgetown	7759	GT3	0.83	2.28	2.90	3.85	2.08	0.44	2.576	3.871	2.128	4.43	2.997
Georgetown	7759	GT4	0.18	1.77	1.94	4.05	2.31	0.43	1.834	3.639	2.431	6.05	4.349
Gibson	6113	1	426.28	1,498.43	1,504.46	916.92	983.65	1,002.31	761.088	907.034	582.334	828.45	847.152
Gibson	6113	2	699.90	1,203.42	2,043.45	1,607.63	783.31	1,088.04	836.382	1030.648	349.468	462.76	326.383
Gibson	6113	3	1,061.68	1,293.58	1,418.48	1,178.86	1,214.63	1,176.09	911.577	1399.125	534.488	955.39	281.687
Gibson	6113	4	573.94	545.55	981.16	877.21	772.03	753.70	561.459	747.926	673.985	625.43	319.868
Gibson	6113	5	683.30	903.64	1,445.98	988.77	734.01	2,029.90	1,678.35	1056.191	1097.115	698.83	605.165
Henry County	7763	1	2.12	6.61	3.54	10.13	7.39	3.94	11.625	17.753	20.432	25.35	18.877
Henry County	7763	2	1.89	6.20	5.94	10.18	7.39	3.88	11.912	12.439	20.695	25.54	21.109
Henry County	7763	3	1.99	5.74	4.98	9.99	7.20	4.03	11.405	19.965	17.698	25.97	22.014
Lawrence County	7948	1	0.48	3.24	2.88	5.47	1.04	2.36	0.788	2.607	1.878	6.21	2.105
Lawrence County	7948	2	0.73	3.30	2.93	6.02	1.74	2.11	0.445	2.184	1.821	6.48	2.243
Lawrence County	7948	3	0.73	3.61	2.95	6.21	1.46	1.86	0.509	2.336	1.908	6.07	2.189
Lawrence County	7948	4	0.45	2.69	3.60	5.09	1.24	1.76	0.371	2.214	2.154	6.48	2.216
Lawrence County	7948	5	0.34	2.38	3.67	5.91	1.01	1.50	0.33	2.011	2.937	8.50	2.373
Lawrence County	7948	6	0.63	2.95	2.25	6.01	1.01	1.42	0.305	3.451	3.505	10.08	2.599
Eagle Valley	991	GT1										15.40	23.761
Eagle Valley	991	GT2										11.63	24.209
Harding Street	990	50	264.07	309.09	315.32	411.70	304.47	352.01	212.589	36.119	10.757	9.85	9.545
Harding Street	990	60	303.05	192.50	311.39	366.40	316.60	339.59	202.277	32.082	7.74	9.40	8.219
Harding Street	990	70	465.70	504.96	403.71	485.56	922.39	812.72	590.567	191.074	199.164	195.69	257.765
Harding Street	990	GT4	0.65	18.08	15.99	12.31	14.04	3.97	20.615	30.95	13.474	37.29	11.692
Harding Street	990	GT5	1.08	15.90	16.05	15.67	14.45	2.36	17.65	22.562	11.569	32.95	16.736
Harding Street	990	GT6	0.56	5.72	7.03	7.38	4.15	2.72	17.44	15.144	17.243	16.98	13.962
Petersburg	994	1	496.09	613.75	655.05	628.72	837.01	830.24	1,120.92	760.017	781.016	905.09	473.208
Petersburg	994	2	446.63	1,693.58	1,017.78	656.52	729.86	1,327.86	1,256.30	934.509	470.526	413.69	515.592
Petersburg	994	3	748.20	734.89	857.79	940.74	1,103.00	998.25	996.456	1526.874	526.587	446.63	586.745
Petersburg	994	4	1,952.86	1,978.10	1,818.94	1,722.36	1,542.16	2,216.54	1,946.34	1966.142	1696.215	1,820.75	1,008.69
Lawrenceburg	55502	1	7.49	11.58	15.35	24.70	13.10	33.85	39.482	36.319	57.919	30.91	32.075
Lawrenceburg	55502	2	7.21	10.60	16.67	24.58	15.71	37.98	34.221	31.077	31.237	30.11	32.671
Lawrenceburg	55502	3	6.57	14.47	16.17	25.07	13.66	18.36	25.913	42.952	28.044	26.69	32.508
Lawrenceburg	55502	4	5.63	12.63	17.08	22.18	17.36	33.23	29.533	40.266	26.152	27.06	30.967
Merom	6213	1SG1	776.78	642.10	691.69	474.16	489.88	475.45	313.039	493.924	352.092	439.97	337.053
Merom	6213	2SG1	947.63	833.41	638.51	415.19	435.14	450.51	331.347	377.547	386.619	394.13	257.743

Michigan City	997	12	585.31	587.35	632.77	577.51	569.64	527.73	403.869	481.612	115.363	398.07	301.516
Montpelier	55229	G1CT1	0.88	4.27	4.37	6.38	5.17	3.37	5.35	10.693	5.788	7.03	8.968
Montpelier	55229	G1CT2	1.03	5.29	3.95	6.50	4.81	3.19	7.798	0.242	4.916	6.68	8.563
Montpelier	55229	G2CT1	0.87	4.11	3.68	6.16	6.00	4.73	8.992	0.243	5.514	7.90	10.549
Montpelier	55229	G2CT2	0.84	4.13	4.30	6.42	5.38	3.94	7.419	10.033	4.522	8.42	11.173
Montpelier	55229	G3CT1	0.84	4.10	4.88	6.12	4.92	3.70	8.485	0.28	6.385	7.88	10.186
Montpelier	55229	G3CT2	0.74	3.55	4.42	6.54	4.31	3.25	7.861	10.746	5.534	7.27	10.097
Montpelier	55229	G4CT1	0.81	4.29	4.35	6.54	5.50	4.32	9.591	10.846	5.657	7.28	10.219
Montpelier	55229	G4CT2	0.78	3.96	4.52	6.99	5.00	3.94	0.121	10.2	6.147	7.77	9.961
Noblesville	1007	CT3	1.29	7.59	3.45	8.15	3.96	5.53	4.944	11.003	4.034	9.11	8.283
Noblesville	1007	CT4	1.30	4.05	4.43	7.93	4.92	5.81	5.878	9.662	4.578	10.55	10.21
Noblesville	1007	CT5	1.49	5.25	6.18	9.22	4.81	7.04	6.967	11.422	5.536	11.46	4.43
R Gallagher	1008	2	447.46	511.63	213.45	204.00	178.53	234.30	305.314	210.051	107.931	173.33	21.265
R Gallagher	1008	4	291.99	493.28	174.44	138.30	142.17	191.20	246.532	219.863	114.775	63.96	24.022
R M Schahfer	6085	14	1,920.84	946.88	714.98	504.46	436.24	414.55	264.391	149.148	179.711	460.69	378.241
R M Schahfer	6085	15	973.69	1,247.46	1,124.48	991.63	840.43	825.13	666.092	531.09	339.758	765.41	540.18
R M Schahfer	6085	16A	2.19	12.33	16.06	42.53	6.18	3.27	24.123	12.905	18.265	10.00	2.331
R M Schahfer	6085	16B	2.49	11.47	12.81	20.01	5.72	2.46	27.153		5.821	18.77	6.143
R M Schahfer	6085	17	1,094.79	1,168.90	832.04	670.62	988.83	825.51	621.905	900.136	646.083	855.53	536.257
R M Schahfer	6085	18	1,126.76	1,075.25	933.57	838.49	908.03	948.02	828.984	527.187	969.162	726.31	578.374
Richmond	7335	RCT1	0.07	1.08	1.82	0.84	0.82	0.07	1.632	0.992	2.025	1.00	0.277
Richmond	7335	RCT2	0.07	0.23	2.26	1.72	0.99	0.08	1.565	0.97	1.947	0.94	0.363
Rockport	6166	MB1	4,250.46	4,969.43	3,616.20	5,000.87	3,997.01	3,316.93	3,975.78	2577.709	1672.841	1,697.51	1,232.15
Rockport	6166	MB2	4,206.13	3,447.47	5,338.89	4,214.52	3,217.25	4,535.90	3,676.59	3443.97	3420.729	1,954.35	1,322.97
St. Joseph	57794	CTG01A										23.57	25.225
St. Joseph	57794	CTG01B										24.30	25.68
Sugar Creek	55364	CT11	12.63	23.24	15.93	21.61	17.10	13.85	21.174	21.715	25.475	21.69	22.171
Sugar Creek	55364	CT12	11.57	23.47	17.05	22.70	18.78	14.68	21.214	22.401	25.357	22.17	21.578
Vermillion	55111	1	0.45	0.97	1.44	2.15	2.51	0.16	1.895	2.61	1.711	4.53	1.61
Vermillion	55111	2	0.36	1.19	0.99	1.82	1.31	0.29	1.555	2.545	0.503	4.41	1.557
Vermillion	55111	3	0.45	1.55	1.31	1.92	2.24	0.47	1.287	2.208	0.736	3.84	1.699
Vermillion	55111	4	0.36	1.44	1.56	2.07	1.29	0.30	1.572	2.508	1.229	3.83	1.037
Vermillion	55111	5	0.41	1.13	1.42	2.18	1.31	0.37	1.198	3.504	1.163	4.29	1.056
Vermillion	55111	6	0.62	1.23	1.40	2.04	1.43	0.47	1.511	2.669	1.033	5.22	2.173
Vermillion	55111	7	0.45	1.26	1.20	2.34	0.81	0.34	1.654	2.103	1.096	4.02	1.589
Vermillion	55111	8	0.50	1.42	1.30	1.98	0.73	0.27	0.949	1.698	0.575	3.04	1.08

Wabash River	1010	1	87.30	176.84	189.18	150.48	188.45	182.66	197.662	11.829	6.762	12.93	12.796
Wabash River	1010	2	271.17		362.43	157.32	158.00	71.00					
Wabash River	1010	3	189.03		460.56	95.66	167.80	102.76					
Wabash River	1010	4	421.15	475.89	464.86	137.01	186.64	156.96					
Wabash River	1010	5	146.10		188.60	72.51	103.15	102.28					
Wabash River	1010	6	1,353.09	1,734.64	1,680.40	565.11	832.52	806.28					
Wheatland	55224	EU-01	2.50	12.06	11.33	23.63	17.52	3.96	13.05	27.345	12.187	38.12	28.571
Wheatland	55224	EU-02	1.92	10.29	10.95	9.17	14.14	3.90	9.993	21.067	12.767	32.76	23.317
Wheatland	55224	EU-03	1.86	7.46	9.41	18.09	10.18	2.59		0.458	8.927	29.01	16.963
Wheatland	55224	EU-04	1.02	7.55	8.72	24.28	6.72	2.66	10.197	17.794	10.981	11.99	15.802
Whitewater Valley	1040	1	30.23	62.29	67.48	17.60	10.72	14.51	14.784	26.024	15.947	16.10	19.448
Whitewater Valley	1040	2	46.46	122.42	97.59	35.35	23.83	35.09	39.735	49.213	39.607	45.76	50.539
Whiting	55259	CT1	13.94	25.74	24.62	24.14	24.86	16.81	18.617	19.908	14.298	17.13	16.227
Whiting	55259	CT2	15.83	15.44	18.59	22.45	19.22	23.61	7.586	22.093	15.689	22.00	23.875
Worthington	55148	1	0.60	2.95	2.22	2.09	0.26	0.22	2.569	5.205	4.213	10.52	5.539
Worthington	55148	2	0.40	2.11	1.66	1.60	0.03	0.09	1.951	4.803	3.97	9.37	4.98
Worthington	55148	3	0.46	1.81	1.93	1.63	0.05	0.39	1.656	3.339	2.483	8.84	4.622
Worthington	55148	4	0.50	2.66	1.60	1.60	0.31	0.37	2.48	4.414	4.423	10.03	5.374

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Appendix B

Indiana Coal-Fired EGUs Controls, Control Efficiencies and Proposed Shutdowns

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Table 7 Indiana Coal-Fired Electric Generationg Units Controls, Control Efficiencies and Shutdowns

Source Name	County ID	Source ID	Unit ID	PM Control(s)	SO_2 Control(s)	SO_2 Control Efficiency (%)	NO_x Control(s)	NO_x Control Efficiency (%)	SO_3 Control(s)	H_2SO_4 Control(s)	Hg Control(s)	Comments
A B Brown	129	00010	1	Baghouse	Dual Alkali FGD		Low NO_x Burner Technology and Low Excess Air/Selective Catalytic Reduction System		Sorbent Injection System			Shut Down in 2023, replaced with renewables and NG-fired turbines according to source (3-17-2021)
			2	Cold-side Electrostatic Precipitator	Dual Alkali FGD	96.7	Low NO_x Burner Technology and Low Excess Air/Selective Catalytic Reduction System		Sorbent Injection System			Shut Down in 2023; replaced with renewables and NG-fired turbines according to source (3-17-2021) Highest control efficiency for 2015 to 2019
Alcoa	173	00002	4	Cold-side Electrostatic Precipitator	Wet Limestone Fluidized-Gas Desulfurization (2008)	Information not available	Low NO_x Burner Technology with Overfire Air (1998)/Selective Catalytic Reduction System (2004)	Information not available		Reagent Injection System (2009)		Alcoa/Vectren exit purchase agreement for power from Unit 4 in 2023. Unit will remain operational as a non-EGU boiler
Cayuga	165	00001	1	Cold-side Electrostatic Precipitator	Wet Limestone Fluidized-Gas Desulfurization (2008)	98.44	Low NO_x Burner Technology w/ Separated OFA (1993)/Selective Catalytic Reduction System (2015)	88.00	SO_3 Mitigation System (2015)		Mercury re-emission chemical injection system (2015), Calcium Bromide (2016)	Control efficiencies calculated. Shut Down in 2028
			2	Cold-side Electrostatic Precipitator	Wet Limestone Fluidized-Gas Desulfurization (2008)	98.91	Low NO_x Burner Technology w/ Separated OFA (1993)/Selective Catalytic Reduction (2015)	88.00	SO_3 Mitigation System (2015)		Mercury re-emission chemical injection system (2014), Calcium Bromide (2016)	Control efficiencies calculated. Shut Down in 2028
Clifty Creek	077	00001	1	Cold-side Electrostatic Precipitator	Fluidized-Gas Desulfurization System	98% (design basis)	Overfire Air Selective Catalytic Reduction	From 70-90%				
			2	Cold-side Electrostatic Precipitator	Fluidized-Gas Desulfurization System	98% (design basis)	Overfire Air Selective Catalytic Reduction	From 70-90%				
			3	Cold-side Electrostatic Precipitator	Fluidized-Gas Desulfurization System	98% (design basis)	Overfire Air Selective Catalytic Reduction	From 70-90%				
			4	Cold-side Electrostatic Precipitator	Fluidized-Gas Desulfurization System	98% (design basis)	Overfire Air Selective Catalytic Reduction	From 70-90%				
			5	Cold-side Electrostatic Precipitator	Fluidized-Gas Desulfurization System	98% (design basis)	Overfire Air Selective Catalytic Reduction	From 70-90%				
			6	Hot-side Electrostatic Precipitator	Fluidized-Gas Desulfurization System	98% (design basis)	Overfire Air					
FB Culley	173	00001	2	Cold-side Electrostatic Precipitator	Wet Limestone Fluidized-Gas Desulfurization		Low NO_x Burner Technology (Dry Bottom only)					Anticipated Shut Down in 2023, replaced with renewables and NG-fired combustion turbines, as per source (3-17-2021)
			3	Baghouse	Wet Limestone Fluidized-Gas Desulfurization	98.50	Low NO_x Burner Technology (Dry Bottom only) Selective Catalytic Reduction System		Sorbent Injection System			Highest control efficiency averages for 2015 to 2019
Gibson	051	00013	1	Cold-side Electrostatic Precipitator	Wet Limestone Fluidized-Gas Desulfurization System (2007)	98.47	Selective Catalytic Reduction System (2005)	81.00	SO_3 Mitigation System		Mercury re-emission chemical injection system (2015), Calcium Bromide (2015)	Control efficiencies calculated. Shut Down in 2038
			2	Cold-side Electrostatic Precipitator	Wet Limestone Fluidized-Gas Desulfurization System (2007)	98.03	Selective Catalytic Reduction System (2002)	81.00	SO_3 Mitigation System		Mercury re-emission chemical injection system (2015), Calcium Bromide (2015)	Control efficiencies calculated. Shut Down in 2038
			3	Cold-side Electrostatic Precipitator	Wet Limestone Fluidized-Gas Desulfurization System (2006)	98.61	Selective Catalytic Reduction System (2002)	84.00	SO_3 Mitigation System		Mercury re-emission chemical injection system (2015), Calcium Bromide (2015)	Control efficiencies calculated. Shut Down in 2034
			4	Cold-side Electrostatic Precipitator	Wet Limestone Fluidized-Gas Desulfurization System (1994)	96.32	Selective Catalytic Reduction System (2003)	88.00	SO_3 Mitigation System		Calcium Bromide (2015)	Control efficiencies calculated. Shut Down in 2026
			5	Cold-side Electrostatic Precipitator	Wet Limestone Fluidized-Gas Desulfurization System (1982)	93.66	Selective Catalytic Reduction System (2004)	85.00	SO_3 Mitigation System		Mercury re-emission chemical injection system (2015), Calcium Bromide (2015)	Control efficiencies calculated. Shut Down in 2034

Table 7 Indiana Coal-Fired Electric Generationg Units Controls, Control Efficiencies and Shutdowns

Source Name	County ID	Source ID	Unit ID	PM Control(s)	SO_2 Control(s)	SO_2 Control Efficiency (%)	NO_x Control(s)	NO_x Control Efficiency (%)	SO_3 Control(s)	H_2SO_4 Control(s)	Hg Control(s)	Comments
Merom	153	00005	1SG1	Cold-side Electrostatic Precipitator	Wet Limestone Fluidized-Gas Desulfurization System	98.30	Selective Catalytic Reduction System/Low NO_x Burner Technology w/ Overfire Air	90.00	SO_3 Mitigation System		Activated Carbon Injection System (2015)	Highest control efficiency avarages for 2015 to 2019. Shutdown in 2023
			2SG1	Cold-side Electrostatic Precipitator	Wet Limestone Fluidized-Gas Desulfurization System	98.50	Selective Catalytic Reduction System/Low NO_x Burner Technology w/ Overfire Air	90.80	SO_3 Mitigation System		Activated Carbon Injection System (2015)	Control efficiency averages for 2015 to 2019. Shutdown in 2023
Michigan City	091	00021	12	Baghouse (2015)	Fluidized-Gas Desulfurization	84.38	Overfire Air - Selective Catalytic Reduction System	91.61			Activated Carbon Injection System (2015)	Shut Down in 2028; Highest control efficiency averages for 2016 to 2019

Table 7 Indiana Coal-Fired Electric Generationg Units Controls, Control Efficiencies and Shutdowns

Source Name	County ID	Source ID	Unit ID	PM Control(s)	SO_2 Control(s)	SO_2 Control Efficiency (%)	NO_x Control(s)	NO_x Control Efficiency (%)	SO_3 Control(s)	H_2SO_4 Control(s)	Hg Control(s)	Comments
Petersburg	125	00002	1	Cold-side Electrostatic Precipitator	Wet Limestone Fluidized-Gas Desulfurization (1996)	97-99	Low NO_x Burner Technology w/ Closed-coupled/Separated OFA (1995)		Sodium based solution (SBS) injection (2015)		Activated Carbon Injection System (2015)	Highest control efficiency rough estimate provided by source. Unit shut down planned for July 2021
			2	Baghouse (2015)	Wet Limestone Fluidized-Gas Desulfurization (1996)	95-99	Low NO_x Burner Technology w/ Closed-coupled/Separated OFA (1994) Selective Catalytic Reduction System (2004)				Activated Carbon Injection System (2015)	Control efficiency rough estimate provided by source. Unit shut down planned for July 2023
			3	Baghouse (2016)/Cold-side Electrostatic Precipitator	Wet Limestone Fluidized-Gas Desulfurization upgraded in 2006	94-97	Selective Catalytic Reduction System (2004)/ Overfire Air OFA	70-85			Activated Carbon Injection System (2016)	Highest control efficiency rough estimates provided by source.
			4	Cold-side Electrostatic Precipitator	Wet Limestone Fluidized-Gas Desulfurization upgraded in 2011	96-97	TFS Low NO_x Burner Technology w/ Closed-coupled/Separated OFA (2001)/ Overfire Air OFA	70-85			Activated Carbon Injection System (2016)	Highest control efficiency rough estimates provided by source.
R Gallagher	043	00004	2	Baghouse (2007)	Dry Sorbent Injection System (2010)	45.66	Low NO_x Burner Technology w/ Overfire Air	45.66				Control efficiencies calculated. Shut Down in 06/01/2021
			4	Baghouse (2008)	Dry Sorbent Injection System (2010)	48.35	Low NO_x Burner Technology w/ Overfire Air	48.35				Control efficiencies calculated. Shut Down in 06/01/2021
R M Schahfer	073	00008	14	Cold-side Electrostatic Precipitator	Fluidized-Gas Desulfurization System (2013)	99.07	Overfire Air Selective Catalytic Reduction System	85.24		Reagent Injection System	Activated Carbon Injection System (2014)	Shut Down in 06/01/2021; Highest control efficiency average for 2015-2019: NOx control efficiency average for 2016-2019
			15	Cold-side Electrostatic Precipitator	Fluidized-Gas Desulfurization System (2014)	98.1	Low NO_x Burner Technology (Dry Bottom only) (2009)/Selective Non-Catalytic Reduction System			Reagent Injection System	Activated Carbon Injection System (2014)	Shut Down in 06/01/2021; Highest control efficiency average for 2015-2019
			17	Cold-side Electrostatic Precipitator	Wet Limestone Fluidized-Gas Desulfurization (2010)	99.14	Low NO_x Burner Technology w/ Closed-coupled/Separated OFA					Shut Down in 2023; Highest control efficiency average for 2015-2019
			18	Cold-side Electrostatic Precipitator	Wet Limestone Fluidized-Gas Desulfurization (2009)	99.25	Low NO_x Burner Technology w/ Closed-coupled/Separated OFA					Shut Down in 2023; Highest control efficiency average for 2015-2019
Rockport	147	00020	MB1	Cold-side Electrostatic Precipitator	Enhanced DSI System (2020), DSI System (2015)	48.00	Low NO_x Burner Technology (Dry Botton only) and Overfire Air Selective Catalytic Reduction System	57.00	Activated Carbon Injection System			Plant-wide SO2 cap = 10,000 tpy, SO2 rate = 0.15 #/MMBu, NOx rate = 0.090#/MMBtu, Shut Down in 2028; Highest control efficiency average for 2016-2020 (for DSI prior to enhancment)*
			MB2	Cold-side Electrostatic Precipitator	Enhanced DSI System (2020), DSI System (2015)	48.00	Low NO_x Burner Technology (Dry Botton only) and Overfire Air Selective Catalytic Reduction System	61.00	Activated Carbon Injection System			Plant-wide SO2 cap = 10,000 tpy, After 2028 SO2 cap = 5,000 tpy; SO2 rate = 0.15 #/MMBtu, NOx rate = 0.090 #/MMBtu; IRP states lease expiration with AEP in 2022 but unit will continue to operate; Highest control efficiency average for 2016-2020 (for DSI prior to enhancement)*
Whitewater Valley	177	00009	1	Cold-side Electrostatic Precipitator/ Baghouse			Low NO_x Burner Technology (Dry Bottom only)/Ammonia Injection Overfire Air (2004)/Selective Nono-Catalytic Reduction System/Shared Dry Sorbent Injection System (2015)		Shared Activated Carbon Injection System (2015)			
			2	Cold-side Electrostatic Precipitator/ Baghouse			Low NO_x Burner Technology w/ Separated/Ammonia Injection Overfire Air (2003)/Selective Non-Catalytic Reduction/Shared Dry Sorbent Injection System (2015)					

*The SCRs were in service for part of the historic record period with the Unit 1 SCR in full operation for 2018 - 2020 and the Unit 2 SCR in full operation for part of 2020

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