ILLINOIS REGIONAL HAZE
STATE IMPLEMENTATION PLAN
FOR THE
SECOND IMPLEMENTATION PERIOD

AQPSTR 24-01

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I. Summary and Background

The Federal Regional Haze Rule was published by the United States Environmental Protection Agency ("USEPA") on July 1, 1999, (64 Fed. Reg. 35714) to address visibility impairment in 156 protected parks and wilderness areas. The Clean Air Act ("CAA") identifies these areas as "mandatory Class I Federal areas" (CAA Section 169A(a)(1)). There are no Class I areas in Illinois, however the Regional Haze Rule requires that each state submit a State Implementation Plan ("SIP") to provide for reasonable progress toward improving visibility, with the eventual goal of achieving natural visibility conditions in these protected areas by 2064. The states' initial strategies in the first implementation period of the rule (2007 – 2018) were to contain enforceable emission reduction measures that achieve the reasonable progress goals in 10 to 15 years, with reassessment and revision of the goals in 2018 and every 10 years thereafter. Illinois submitted its SIP for the first implementation period on June 24, 2011, which was approved by USEPA on July 6, 2012 (77 Fed. Reg. 39943). The five-year progress report was submitted on February 2, 2017, and approved by USEPA on April 12, 2018 (83 Fed. Reg. 15744). This document satisfies the requirements for periodic comprehensive revisions to Illinois' regional haze SIP for the second implementation period at Title 40 of the Code of Federal Regulations ("CFR") 51.308(f) which spans 2018 to 2028. A progress report for the period will be due January 31, 2025.

This document also describes Illinois' strategy for meeting the reasonable progress goals for the second implementation period by 2028 for Class I areas where emission sources in Illinois have been shown to cause adverse visibility impacts. Illinois, along with Indiana, Michigan, Minnesota, Ohio, and Wisconsin, are members of the Lake Michigan Air Directors Consortium ("LADCO"), one of five regional planning organization ("RPO") funded by the states and USEPA to address regional haze requirements. Technical analyses conducted by LADCO, other states outside the LADCO region, and other RPOs have shown that sources in Illinois are causing or contributing to visibility impairment in several Class I areas in the eastern United States. Illinois is therefore required to submit revisions to its SIP to address the contributions made by emission sources located in Illinois. The analyses conducted by LADCO included preparation of regional emissions inventories, meteorological data, evaluation and application of regional chemical transport models, and the collection and analysis of ambient monitoring data.

To address the Regional Haze Rule requirements, Illinois has developed a long-term emission reduction strategy ("LTS") to address visibility impairment in nearby Class I areas. This LTS is described in this document and relies on "on-the-books" and "on-the-way measures" that are permanent and enforceable for point and area sources. Illinois has had dramatic reductions in visibility impairing pollutants from EGU and non-EGU sources in the first implementation period SIP submittal and the interim progress report, which will continue into the second implementation period and beyond. These reductions have contributed significantly to visibility improvements at the Class I areas impacted by Illinois emissions, and all of those Class I areas are well ahead of uniform progress goals for visibility.

Illinois continued to be a leader in the reduction of all pollutants in the EGU sector with the passage of the Climate and Equitable Jobs Act ("CEJA") in September of 2021 (415 Illinois Compiled Statutes "ILCS" 5/9.15). CEJA immediately places emission limits on the EGU sector to operate at a reduced allowable capacity, requires the retirement of nearly all coal-fired EGUs by January 1, 2030, and subsequent incremental retirements of all remaining coal-fired and gas-fired EGUs by January 1, 2045.

CEJA ensures that Illinois will continue to make contributions to visibility improvement in this implementation period and beyond.

The Federal Regional Haze Rule requires consultation between the states, tribes, and Federal Land Managers ("FLMs") responsible for managing Class I areas. This multi-state and multi-agency consultation process has been facilitated by RPOs established specifically for this purpose. Illinois fully participated in the planning and technical development efforts of LADCO. States in other parts of the country participate in similar RPOs. Illinois has also participated in consultation with those that have requested Illinois' participation in their planning process including other RPOs and states, the USEPA, and representatives from the Federal Land Management agencies (Bureau of Land Management, National Park Service, Fish and Wildlife Service, and Forest Service). This SIP submittal also documents that process.

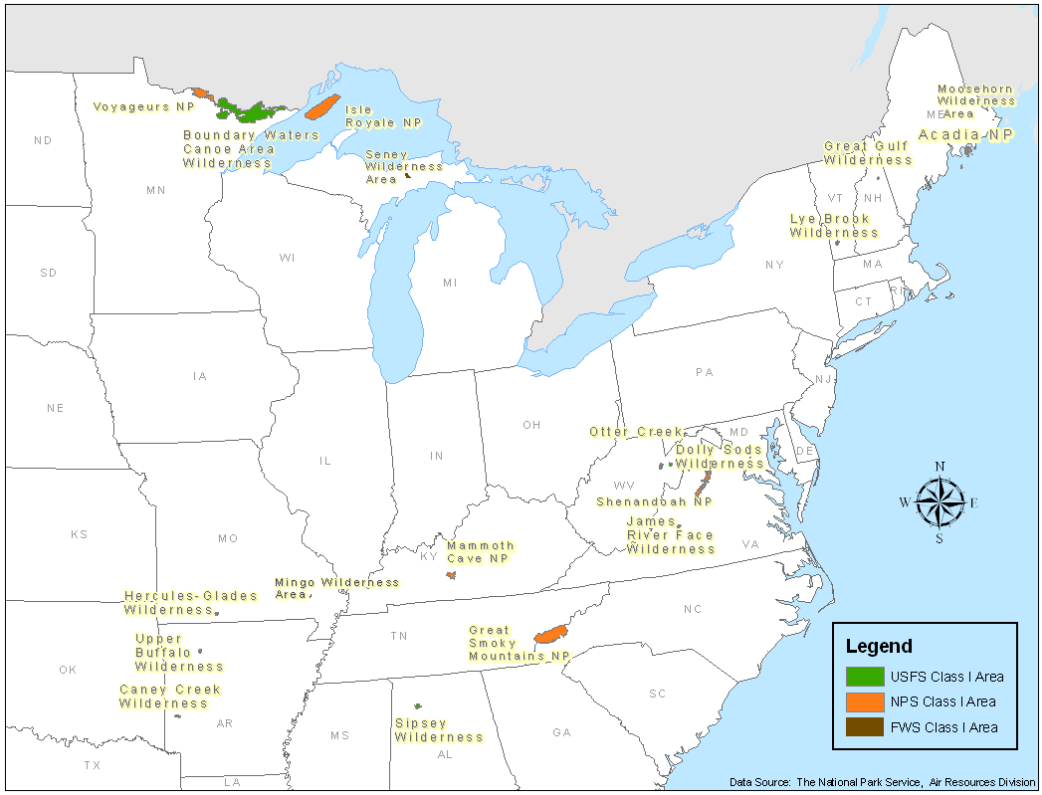
The Illinois EPA, in conjunction with LADCO, has made adequate plans to meet the requirements of the Regional Haze Rule by performing the necessary modeling to determine its impact on visibility in Class I areas, setting goals to reduce the impact of Illinois sources on these areas, and achieving the identified emission reduction targets. Further, Illinois commits to implement the LTS for meeting goals for reasonable progress and other requirements of the Regional Haze Rule. Illinois also commits to maintain adequate monitoring networks, and will continue to provide progress reports, emissions inventories, and future SIP revisions, as required, to meet the requirements of the Regional Haze Rule.

One of the analyses prepared by LADCO during the first implementation period identified the Class I areas that were impacted by each of the states in LADCO. Using several technical approaches, including the modeling of back trajectories, LADCO prepared a list of Class I areas impacted by the six Midwestern states. This analysis, "Draft List of Class I Areas Located Within (or Impacted by) Midwest RPO States" (June 26, 2007), was included as Appendix A of Illinois' Regional Haze SIP for the first implementation period. According to the LADCO analyses, sources in Illinois were causing or contributing to visibility impairment in several Class I areas in the eastern United States. These areas are listed below and are shown in Figure 1.1:

- Sipsey Wilderness Area, Alabama
- Caney Creek Wilderness Area, Arkansas
- Upper Buffalo Wilderness Area, Arkansas
- Mammoth Cave National Park, Kentucky
- Acadia National Park, Maine
- Moosehorn Wilderness Area, Maine
- Isle Royale National Park, Michigan
- Seney Wilderness Area, Michigan
- Boundary Waters Canoe Area Wilderness, Minnesota
- Voyageurs National Park, Minnesota
- Hercules-Glades Wilderness Area, Missouri
- Mingo Wilderness Area, Missouri
- Great Gulf Wilderness Area, New Hampshire
- Brigantine Wilderness Area, New Jersey
- Great Smoky Mountains National Park, Tennessee and North Carolina

This list of impacted sources from the first implementation period serves as a list of areas that can conservatively be considered for the second implementation period, since emissions of visibility impairing pollutants from Illinois sources, generally, has declined since the first implementation period.

Figure 1.1 Federal Class I Areas Impacted by Illinois



The Class I areas that are in the southern Appalachians, particularly Cohutta, Shining Rock, and Joyce Kilmer/Slickrock, are at such a distance from Illinois that they were not modeled explicitly. Rather, modeling was performed for the Class I areas closer to Illinois, such as Sipsey Wilderness, Linville Gorge, and Great Smoky Mountains National Park, and it is presumed that impacts at these areas are conservatively representative of impacts at areas farther from Illinois. This is consistent with the LADCO analysis, which used analyses from other RPOs, as well as their own analyses, to assess the impacts from sources in the Midwest on all Class I areas in the eastern U.S.

Illinois is relying on the LADCO's technical support document, "Modeling and Analysis for Demonstrating Reasonable Progress for the Regional Haze Rule 2018 - 2028 Planning Period" ("LADCO TSD"), to address a number of the requirements of the Regional Haze Rule. The LADCO TSD is included as Appendix B to this document.

II. Baseline, Natural, and Current Visibility Conditions in Class I Areas, Progress to Date, and the Uniform Rate of Progress (40 CFR 51.308(f)(1)(i) through (vi))

To track progress toward the long-term goal of remedying impairment of visibility in mandatory Class I areas, the Regional Haze Rule 40 CFR 51.308(f)(1)(i) through (vi) requires states containing Class I areas to: (i) establish baseline conditions representing visibility for the most impaired and clearest days, (ii) natural visibility conditions for the most impaired and clearest days, (iii) current visibility conditions for the most impaired and clearest days, (iv) progress to date for the most impaired and clearest days, (v) differences between current visibility condition and natural visibility condition, and (vi) the uniform rate of progress toward natural visibility for each Class I Area.

Since Illinois does not contain any Class I areas, Illinois is not required to determine and submit baseline, current and natural conditions for any Class I areas.

III. Long Term Strategy for Regional Haze (40 CFR 51.308(f)(2))

Affected Class I Areas in Other States

The Regional Haze Rule Section 51.308(f)(2) requires that states develop an LTS to make reasonable progress at Class I areas outside of the state that may be affected by emissions from the state.

To help states make this determination, The Regional Haze Guidance documents states (pg. 8) that since "determinations of affected Class I areas were previously made for the first regional haze implementation period, states may consider retaining the same linkages and assumptions from those SIPs, but if states do so then they should consider whether the assumptions about source-receptor relationships have changed since those assessments."

During the first implementation period, Illinois identified the Class I areas impacted by Illinois emissions as those listed in Table 3.1. Since then, overall emissions of visibility-impairing pollutants in Illinois have been reduced significantly, so it is reasonable and conservative to retain the same linkages and assumptions from the first implementation period for Class I areas affected by Illinois in the second implementation period. LADCO provided source apportionment modeling of Class I areas affected by Illinois in the LADCO TSD (Appendix B). USEPA also issued a memorandum "Availability of Modeling Data and Associated Technical Support Document for EPA's Updated 2028 Regional Haze Modeling" ("USEPA TSD"). Table 3.1 includes each Class I area affected by Illinois with the 2028 projected baseline visibility on the 20% most impaired days modeled from both the LADCO and USEPA TSDs, as well as the USEPA-provided 2028 adjusted glidepath.

The LADCO 2028 Projected Baseline Visibility comes from the LADCO TSD in the supplemental excel sheet "2016-based 2028 glidepaths and PSAT tracer contributions," in the summary tab, column "dv_worst_f," as visibility in deci-views under 20% most impaired days for modeled future year 2028. The USEPA 2028 projected baseline visibility and 2028 adjusted glidepaths come from the USEPA TSD in Table 5-2. While LADCO provided projections based on both 2011 and 2016 base year, Table 3.1 shows only the 2016 base projected data, as it is more recent. USEPA projections are based on 2011 base year data.

Table 3.1 Projected Visibility at Class I Areas Affected by Illinois (deciviews)

Class 1 Areas	State	Site ID	LADCO 2028 Projected Baseline Visibility on 20% Most Impaired Days	USEPA 2028 Projected Baseline Visibility on 20% Most Impaired Days	EPA 2028 Adjusted Glidepath
Boundary Waters Canoe Area	MN	BOWA	13.17	13.19	15.83
Brigantine National Wilderness Area	NJ	BRIG	18.58	18.45	21.55
Caney Creek	AR	CACR	16.17	16.97	18.88
Great Gulf Wilderness Area	NH	GRGU	12.37	12.17	18.22
Great Smokey Mountains NP	TN	GRSM	15.98	16.08	22.17
Hercules-Glades	OR	HEGL	17.48	17.44	19.63
Isle Royale National Park	MI	ISLE	14.83	14.87	16.91
Lye Brook National Acadia National Park	VT	LYEB	14.13	13.94	19.25
Mammoth Cave NP	KY	MACA	19.65	19.5	22.74
Mingo National Wilderness Areas	MO	MING	18.94	18.88	20.22
Moosehorn Wilderness Area	ME	MOOS	12.84	12.73	17.76
Seney National Wilderness Area	MI	SENE	16.67	16.82	19.8
Sipsey Wilderness	AL	SIPS	17.75	18	21.16
Upper Buffalo National Wilderness Areas	AR	UPBU	16.65	16.92	19.29
Voyageurs National Park	MN	VOYA	13.36	13.26	15.64

All Class I areas impacted by Illinois have projected 2028 visibility below the USEPA 2028 Adjusted glidepaths as modeled by both LADCO and USEPA. The Class I areas are between 1.28 – 6.19 (average 3.32) dv below the 2028 adjusted glidepath based on the LADCO modeling and is similar based on the USEPA modeling.

LADCO has performed in depth analysis regarding the Class I areas in the LADCO region to determine visibility impacts from projected 2028 emissions. The projections include significant reductions in visibility-impairing pollutants in both Illinois and the region and show significant visibility improvements in those Class I areas. The emission reductions in Illinois' LTS and from the region in this implementation period would be expected to have comparable benefits to visibility in all Class I areas impacted by Illinois. Further, the projections for 2028 and analyses performed by LADCO do not include all elements of the Illinois LTS, so additional improvements in visibility are anticipated beyond USEPA and LADCO projections.

Emissions Inventory – Impacts on Class I Areas in Other Regions

Pursuant to 40 CFR §51.308(f)(2)(iii), Illinois is required to provide a statewide inventory of pollutants that could reasonably be anticipated to cause or contribute to visibility impairment in Class I areas. These pollutants include volatile organic compounds ("VOCs"), nitrogen oxides ("NOx), particulate matter ("PM"), ammonia ("NH_3"), and sulfur dioxide ("SO_2"). Table 3.2 is a summary of statewide emissions of the relevant pollutants from each emission source category based on the 2016 base year inventory data used by LADCO in the LADCO TSD.

Table 3.2 Illinois Statewide Emissions for 2016 (tpy)

Category	NH_3	NOx	$PM_{2.5}$	SO_2	VOC
Point	1,498	78,096	12,674	100,526	41,108
Area	96,053	102,399	80,406	5,946	211,921
On-Road	3,300	117,837	4,217	705	65,574
Off-Road	79	49,234	4,515	94	38,539
Animal		---	---	---	---
Biogenic	---	38,921	---	---	422,736
Total	**102,364**	**387,877**	**109,474**	**107,987**	**800,485**

The 2028 emission projections are listed in Table 3.3. Statewide emissions for 2016 were used to project 2028 emissions for the same categories using USEPA's Economic Growth Analysis System ("EGAS"). The projected emissions from EGUs reflect: (1) the implementation of and amendments to the Illinois Multi-Pollutant Standards ("MPS") and Combined Pollutant Standard ("CPS"); (2) agreements to implement Best Available Retrofit Technology ("BART") at specific units in Illinois; (3) Illinois' LTS from the first Regional Haze implementation period that provided more reductions than presumptive BART; (4) SO_2 regulation amendments for the 2015 SO_2 National Ambient Air Quality Standards ("NAAQS"); and other elements of Illinois' LTS related to EGU emissions.

From Table 3.4, it is expected that emissions of NH_3 will increase from 2016 to 2028 due largely to increases in area source emissions. These increases are offset, however, by significantly greater decreases of the primary visibility impairing pollutants, SO_2 and NOx, expected from Illinois by 2028.

Table 3.3 Projected Illinois Statewide Emissions for 2028 (tpy)

Category	NH_3	NOx	$PM_{2.5}$	SO_2	VOC
Point	2,147	73,061	12,575	45,600	43,695
Area	104,358	88,663	78,804	6,002	212,101
On-road	2,845	41,417	1,987	402	29,271
Off-road	87	25,289	2,281	68	28,271
Animal		---	---	---	---
Biogenic	---	38,921	---	---	422,736
Total	**110,871**	**229,820**	**103,309**	**52,788**	**334,078**

Table 3.4 Comparison of Illinois Statewide Emissions, 2016 to 2028 (tpy)

Category	NH_3	NOx	$PM_{2.5}$	SO_2	VOC
2016	102,364	387,877	109,474	107,987	800,485
2028	110,871	229,820	103,309	52,788	334,078
Difference	**+8,507**	**-158,057**	**-6,165**	**-55,199**	**-466,407**

Projected reductions are largely due to Illinois' MPS/CPS and other regulatory requirements affecting coal-fired EGUs, as well as significant reductions from on-road and off-road mobile sources. Illinois' regulatory programs for EGUs are more stringent than the Federal Cross-State Air Pollution Rule ("CSAPR") and do not rely on the federal interstate trading program. The Reasonable Progress Goals and Illinois' LTS are discussed in Sections IX and VI.

Historical EGU Emissions in Illinois

Below are graphical depictions of the reductions in NOx and SO_2 since the issuance of the Regional Haze Rule from USEPA's Air Markets Program Data for EGUs.

Figure 3.5 Illinois EGU NOx Emissions 1999 to 2020

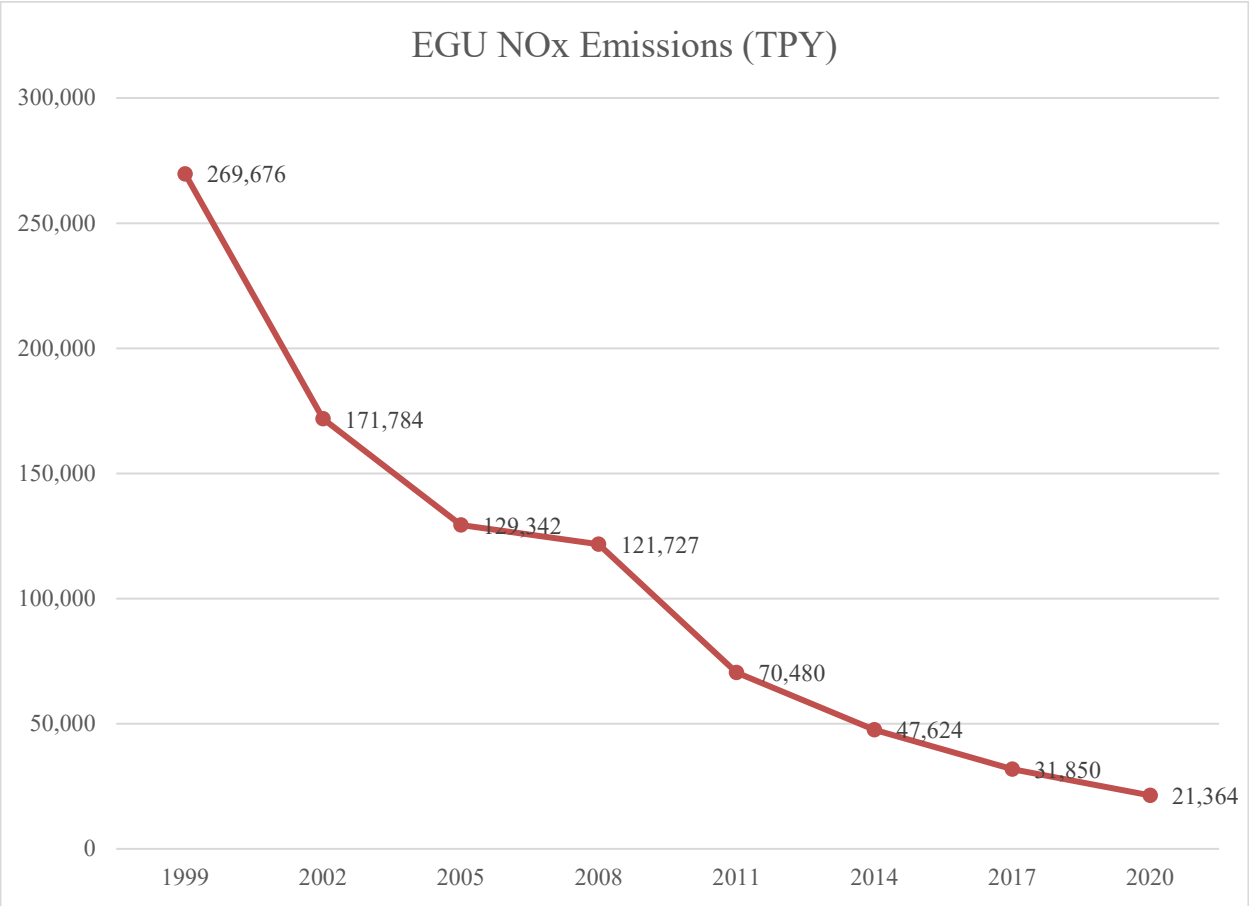
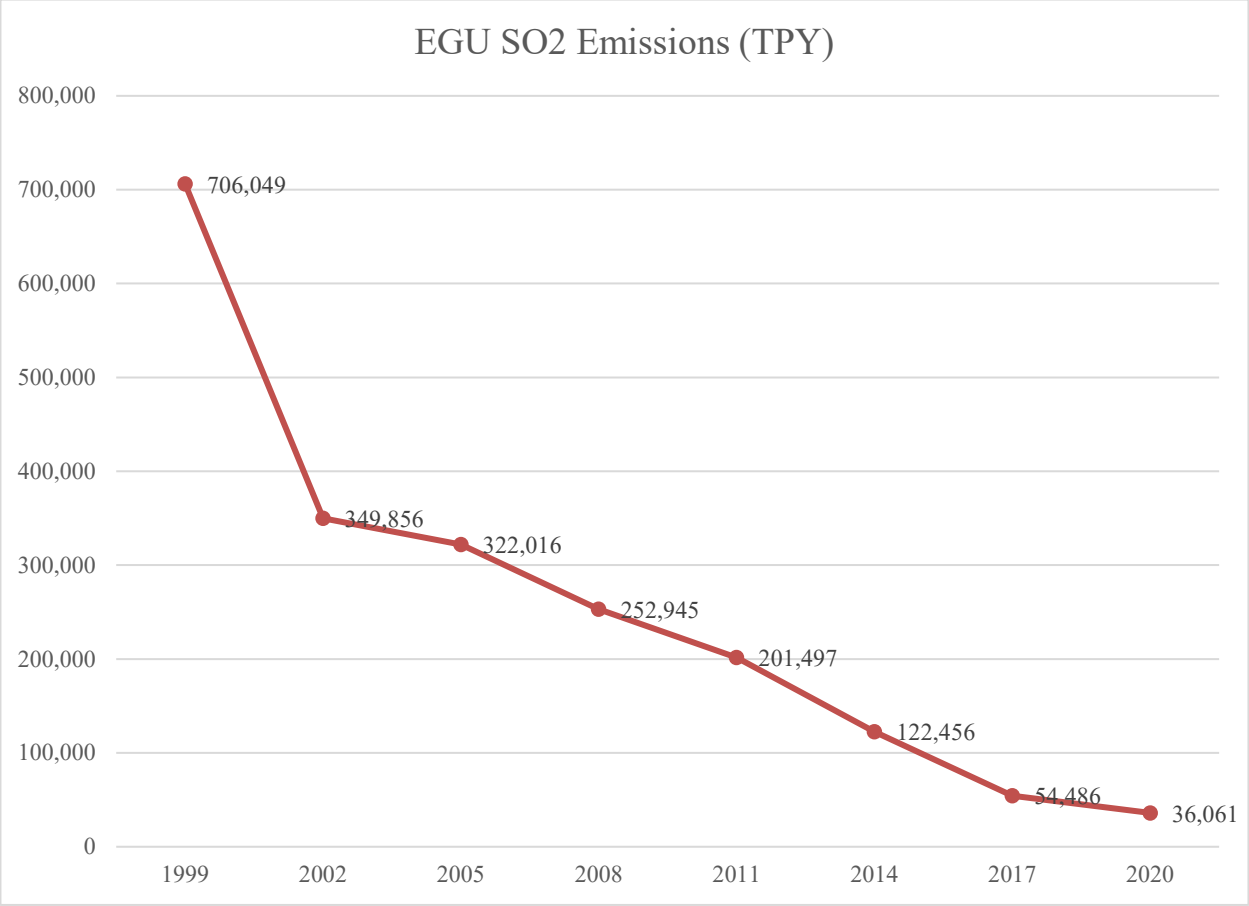


Figure 3.6 Illinois EGU SO_2 Emissions 1999 to 2020



IV. Source Selection for Four Factor Analysis

Section 40 CFR 51.308(f)(2)(i) requires Regional Haze SIPs to include a description of the criteria the state has used to determine sources or groups of sources it evaluated for potential controls, which includes considering evaluating major and minor point sources, mobile sources, and area sources. The Regional Haze Guidance states (pg. 9), "A key flexibility of the regional haze program is that a state is not required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures." For the second implementation period, Illinois EPA is focusing on point sources since they contribute the largest percentage, 56%, of visibility impairment to Class I areas affected by Illinois and are more controllable at the state level, as shown in Table 4.1 below.

The USEPA TSD included source apportionment modeling in Appendix B detailing the percentage breakdown of pollution contributions to Class I areas by sector. Table 4.1 includes that breakdown for all Class I areas affected by Illinois.

Table 4.1 USEPA 2028 Projected, Sector Based Percentage Contributions to Class I Areas

Class I Areas	State	Site ID	Point EGU (%)	Point Non-EGU (%)	Total Point (%)	Nonpoint (%)	Onroad (%)	Oil & Gas (%)	RWC (%)	Anthro Dust (%)	Other Sectors (%)
Boundary Waters Canoe Area	MN	BOWA	29	21	50	10	10	-	11	-	20
Brigantine National Wilderness Area	NJ	BRIG	16	21	37	22	10	-	10	-	21
Caney Creek	AR	CACR	45	23	68	8	6	7	-	-	13
Great Gulf Wilderness Area	NH	GRGU	31	24	55	17	5	-	13	-	9
Great Smokey Mountains NP	TN	GRSM	42	26	68	13	6	-	3	-	9
Hercules-Glades	OR	HEGL	42	18	60	8	8	7	-	-	18
Isle Royale National Park	MI	ISLE	28	23	51	11	10	-	8	-	20
Lye Brook National Acadia National Park	VT	LYEB	25	20	45	20	9	-	12	-	14
Mammoth Cave NP	KY	MACA	46	21	67	8	8	-	5	-	12
Mingo National Wilderness Areas	MO	MING	42	19	61	8	7	-	-	6	19
Moosehorn Wilderness Area	ME	MOOS	26	24	50	20	7	-	14	-	12
Seney National Wilderness Area	MI	SENE	26	24	50	14	11	-	8	-	18
Sipsey Wilderness	AL	SIPS	42	21	63	16	7	3	-	-	10
Upper Buffalo National Wilderness Areas	AR	UPBU	44	19	63	8	6	7	-	-	15
Voyageurs National Park	MN	VOYA	30	23	53	8	8	-	11	-	20
Average			34	22	**56**	**13**	**8**	**6**	**10**	**6**	**15**

While this modeling includes contributions for all states for each Class I area, it is a strong indicator of sector contributions on average per state. Since total point source emissions on average contribute to over half of the emissions to Class I areas, Illinois EPA has chosen to focus on reduction of the state's point source emissions in the second implementation period.

Point Sources

Based on technical support from USEPA and LADCO, Illinois EPA evaluated which point sources in Illinois would be subject to a four factor analysis. This process involved selection of emission sources with the most significant contributions to visibility impairment, which would have the greatest likelihood to achieve cost-effective emission reductions.

Pollutants

Illinois EPA considered PM, SO_2, NOx, VOC and NH_3 as the pollutants contributing to visibility impairment in federal Class I areas. Per the Regional Haze Guidance (pg. 11), "When selecting sources for analysis of control measures, a state may focus on the PM species that dominate visibility impairment at the Class I area affected by emission from the state and then select only sources with emissions of those dominant pollutants and their precursors." During the first implementation period, VOCs and NH_3 emissions were not considered since they were expected to have small contributions to haze, while the most efficient method instead was to reduce the precursors, SO_2 and NOx, thereby reducing PM. Per the Regional Haze Guidance (pg. 12), "EPA believes that, in general, this would also be a reasonable approach for the second implementation period." For the purposes of the source selection process in this implementation period, PM, SO_2, NOx, VOC, and NH_3 were considered, but SO_2 and NOx emissions were the primary focus of the analyses since VOC and NH_3 are still expected to have small contributions to haze.

Estimating Baseline Visibility Impacts for Source Selection

In LADCO's technical memorandum, "Description of the Sources and Methods Used to Support Q/d Analysis for the 2nd Regional Haze Planning Period," LADCO evaluated all sources with cumulative quantity of emissions divided by distance ("Q/d") threshold of 80% and over one ton per year ("TPY") of emissions in the region to determine if they could potentially affect visibility in Class I areas. The focus on these emissions is based on the Regional Haze Guidance document (pg. 12), which states, "In the first implementation period, many states eliminated VOC and ammonia emissions from consideration based on the expectation that anthropogenic VOC emissions make only a small contribution to visibility impairment, and that formation of nitrate and sulfate PM is most effectively reduced by reducing emissions of NOx and SO_2 rather than by anthropogenic emissions of ammonia. EPA believes that, in general, this would also be a reasonable approach for the second implementation period."

Illinois EPA is using the Q/d method as a surrogate for source visibility impacts. The Regional Haze Guidance (pg. 13) provides, "A state may use a source's annual emissions in tons divided by distance in kilometers between the source and the nearest Class I area (often referred to as Q/d) as a surrogate for source visibility impacts, along with a reasonably selected threshold for this metric."

Illinois EPA is using this method for source selection for further four factor analysis, as recommended by the Regional Haze Guidance (pg. 13): "Therefore, it is recommended that use of this technique be limited to source selection for the purpose of developing a list of sources for which a state may conduct a four factor analysis."

The quantity of emissions, Q, is the sum of SO_2, NOx, NH_3, and $PM_{2.5}$ emissions from units from the 2016 base year chosen by LADCO. The sum of all emissions used for Q/d captures a more complete picture of emission contributions from Illinois point sources to visibility impairment in federal Class I areas. The Q/d from individual units and sources were considered in the source selection process.

Using Estimates of Visibility Impacts to Select Sources for Consideration

For the second regional haze implementation period, Illinois EPA set a unit-level Q/d threshold of greater than 4 to begin evaluating individual units to identify sources and emission units which could potentially be cost-effectively controlled to reduce emissions. Illinois EPA then grouped those units by source and considered sources having a Q/d greater than 10 for four factor analysis. Unless a source was otherwise excluded, four factor analysis was then performed on the units at those sources originally identified as having a Q/d greater than 4.

The Illinois source selection method identified the sources and units in the state that have the greatest impact on visibility impairment in Class I areas, including all the largest sources, and would most likely require additional control that is reasonable or cost effective.

Table 4.2 contains all units in Illinois that have a Q/d value of greater than 4. The units with Q/d greater than 4 constitutes 80.7% of all emissions of SO_2, NOx, NH_3, and $PM_{2.5}$ from units with Q/d greater than 1 in Illinois. The LADCO TSD similarly used a cumulative Q/d threshold of 80% to identify sources for possible four factor analysis. Table 4.2 shows those units grouped by facility with facility Q/d totals calculated.

The table is based on LADCO analysis, which used base year data from 2016 as that was the most recent and practical data available at the time of analysis. The 2016 data is projected to 2028, the end of the second implementation period, to incorporate shutdown of units and continued implementation of Illinois' LTS from the first Regional Haze implementation period. Section 51.308(f)(2)(iii) of the Regional Haze Rule requires states to use emission information for the most recent National Emissions Inventory year. However, in situations where it is not possible to utilize the most recent information without excessive revision, the Regional Haze Guidance states (pg. 18), "when it is not possible to fully incorporate the more recent information in all the source selection analysis steps, [a state] may … verify in a reasonable manner, for some or all of the state's sources, that there are no important differences between the older and new emissions information that can be expected to affect the selection of sources." In Illinois, there have not been significant increases in emissions from existing sources nor new sources which would make the use of the 2016 data inappropriate as demonstrated by the decreasing trends in NOx, $PM_{2.5}$, and SO_2 emissions in the 2014-2020 NEI data seen under Tables 11.5 to 11.7.

Table 4.2 Units with Q/d >4 Grouped by Facility with Facility Q/d Totals

Agency Facility ID	Agency Unit ID	Facility Name	Location	2028 NH_3	2028 NOx	2028 $PM_{2.5}$	2028 SO_2	Unit Q/d	Facility Q/d Total
127855AAC	1	Electric Energy Inc	Joppa	0	433	27	1,585	17.5	
127855AAC	2	Electric Energy Inc	Joppa	0	424	26	1,552	17.1	
127855AAC	4	Electric Energy Inc	Joppa	0	342	24	1,378	14.9	
127855AAC	6	Electric Energy Inc	Joppa	0	264	17	1,250	13.1	
127855AAC	5	Electric Energy Inc	Joppa	0	215	14	1,003	10.5	
127855AAC	3	Electric Energy Inc	Joppa	0	218	15	867	9.4	
									82.4
189808AAB	4	Prairie State Generating Station	Marissa	0	1,895	114	4,505	43.0	
189808AAB	5	Prairie State Generating Station	Marissa	0	1,652	110	4,126	38.9	
									81.9
157851AAA	2	Dynegy Midwest Generation LLC	Baldwin	5	1,430	10	1,579	21.7	
157851AAA	13	Dynegy Midwest Generation LLC	Baldwin	0	1,396	28	1,168	18.6	
157851AAA	1	Dynegy Midwest Generation LLC	Baldwin	5	1,207	14	1,269	17.9	
									58.1
199856AAC	4	Southern Illinois Power Coop	Marion	0	533	19	2,070	20.6	
199856AAC	123	Southern Illinois Power Coop	Marion	0	380	3	1,620	15.7	
									36.3
079808AAA	3	Illinois Power Generating Co	Newton	0	1,070	20	4,827	21.7	
079808AAA	13	Illinois Power Generating Co	Newton	0	549	10	2,916	12.7	

									34.4
179801AAA	29	Midwest Generation LLC - Powerton	Pekin	59	1,571	262	4,363	15.7	
179801AAA	31	Midwest Generation LLC – Powerton	Pekin	59	1,571	262	4,363	15.7	
									31.3
143805AAG	4	Illinois Power Resources Generating LLC	Edwards	0	609	14	3,584	10.4	
143805AAG	3	Illinois Power Resources Generating LLC	Edwards	0	1,153	9	2,306	8.6	
									18.9
033025AAJ	1	Rain CII Carbon LLC	Robinson	0	145	74	2,164	9.6	
033025AAJ	2	Rain CII Carbon LLC	Robinson	0	108	59	1,672	7.4	
									17.0
127855AAA	47	Lafarge Midwest Inc	Grand Chain	2	777	3	189	8.4	
127855AAA	66	Lafarge Midwest Inc	Grand Chain	15	295	5	509	7.1	
									15.5
021814AAB	9	Kincaid Generation LLC	Kincaid	0	766	23	1,112	6.4	
021814AAB	8	Kincaid Generation LLC	Kincaid	12	705	8	1,021	5.9	
									12.3
119020AAE	1	Dynegy Midwest Generation LLC	Wood River	0	499	40	1,813	**11.2**	
									11.2
197810AAK	16	Will County Generating Station	Romeoville	1	1,052	277	4,507	11.1	
									11.1
179060ACR	19	Pacific Ethanol Pekin Inc	Pekin	0	321	21	3,904	**10.6**	
									10.6
115015AAE	230	Archer Daniels Midland Co	Decatur	3	405	18	1,339	5.2	
115015AAE	222	Archer Daniels Midland Co	Decatur	4	251	32	1,395	4.9	
									10.1
115015ABX	299	Tate & Lyle Ingredients Americas LLC	Decatur	0	259	87	2,847	**9.5**	
									9.5
155010AAA	1	Dynegy Midwest Generation LLC	Hennepin	0	879	16	2,993	**8.0**	
									8.0
051808AAB	5	Natural Gas Pipeline Co	St. Elmo	0	0	0	1,936	**7.4**	

									7.4
127855AAB	4	Trunkline Gas Co	Grand Chain	0	856	3	1	**7.4**	
									7.4
119040ATN	5	Gateway Energy & Coke Co LLC	Granite City	0	358	28	935	**6.9**	
									6.9
125804AAB	23	Dynegy Midwest Generation LLC Havana Power Station	Havana	5	1,188	55	1,141	**6.5**	
									6.5
135803AAA	1	Illinois Power Generating Co	Coffeen	0	1,203	6	20	**5.1**	
									5.1
097190AAC	33	Waukegan Electric Generating Station	Waukegan	0	625	103	1,591	**5.0**	
									5.0

Exclusion and Selection of Sources for Four Factor Analysis

Sources from Table 4.2 above with facility totals of Q/d less than 10 were not considered for four factor analysis to focus on the sources with the greatest contribution to visibility impairment. Sources with unit Q/d ≥ 4 and facility Q/d ≥ 10 constitute 71.4% of all emissions of SO_2, NOx, NH_3, and $PM_{2.5}$ from all unit sources with Q/d greater than 1 in Illinois.

The Wood River power plant was permanently retired in 2016. The Hennepin, Havana, and Coffeen power plants were permanently retired in 2020. The Edwards, Joppa, Waukegan, and Will County plants were permanently retired in 2022.

The coal-fired units at the Tate & Lyle Ingredients and at Pacific Ethanol Pekin (now "Alto Pekin") sources have been replaced with natural-gas fired units since the 2016 base year. In these cases of coal to natural gas fuel switches, the Q/d value after the fuel switch would be reduced, for Tate and Lyle from 9.5 to 1.03 and for Alto Pekin from 10.6 to 0.85 and would not meet the threshold of 10 used for selection. Additional controls for these units are also unlikely to produce reasonable emissions reductions due to the current low emissions from the fuel switch.

The engines at Natural Gas Pipeline Co. and Trunkline Gas Co. did not meet the Q/d threshold for source selection. It should also be noted that the recently finalized Good Neighbor Plan for the 2015 Ozone NAAQS ("Transport FIP") applies to reciprocating internal combustion engines in the Pipeline Transportation of Natural Gas industry for engine units that are greater than 1000 horsepower. That category includes the engines at Natural Gas Pipeline Co. and Trunkline Gas Co. The significant emission units at those sources will be subject to emission standards the USEPA considers to be equivalent to, or more stringent than, Reasonably Available Control Technology ("RACT"), and additional controls for those units would be unlikely to produce reasonable emissions reductions.

Table 4.3 Sources Excluded from Four Factor Analysis

Facility ID	Name	Location	Reason for Exclusion
155010AAA	Dynegy Midwest Generation LLC	Hennepin	Permanently retired in 2020
125804AAB	Dynegy Midwest Generation LLC Havana Power Station	Havana	Permanently retired in 2020
135803AAA	Illinois Power Generating Co	Coffeen	Permanently retired in 2020
119020AAE	Dynegy Midwest Generation LLC	Wood River	Permanently retired in 2016
143805AAG	Illinois Power Resources Generating LLC	Edwards	Permanently retired in 2022
127855AAC	Electric Energy Inc	Joppa	Permanently retired in 2022
197810AAK	Will County Generating Station	Romeoville	Permanently retired in 2022
097190AAC	Waukegan Electric Generating Station	Waukegan	Permanently retired in June 2022
115015ABX	Tate & Lyle Ingredients Americas LLC	Decatur	Coal-fired units replaced with natural gas fired units since 2016
179060ACR	Pacific Ethanol Pekin Inc	Pekin	Coal-fired units replaced with natural gas fired units since 2016
051808AAB	Natural Gas Pipeline Co	St. Elmo	Did not meet selection criteria, Subject to Good Neighbor Plan
127855AAB	Trunkline Gas Co	Grand Chain	Did not meet selection criteria, Subject to Good Neighbor Plan
119040ATN	Gateway Energy & Coke Co LLC	Granite City	Did not meet selection criteria

The withdrawn permits or additional documentation for the sources and units that have permanently retired are attached as Appendix G to this document.

EGUs Subject to the MPS

All EGUs other than Joppa that are subject to the MPS at Title 35 of the Illinois Administrative Code ("IAC") Section 225.233 were also excluded from four factor analysis. The MPS is federally enforceable as it is included in Illinois' SIP at 40 CFR 52.720 and was approved most recently by USEPA on June 25, 2021 (86 Fed. Reg. 33527). The sources subject to the MPS are Baldwin, Coffeen, Duck Creek, Edwards, Havana, Hennepin, and Newton. As stated above all but the Baldwin and Newton Plants have been retired.

First, sources and units subject to the MPS are effectively controlled by the limits in the MPS and were addressed in the first implementation period SIP. The Regional Haze Guidance states (pg. 22), "It may be reasonable for a state not to select an effectively controlled source. A source may already have effective controls in place as a result of a previous regional haze SIP or to meet another CAA requirement." In the case of the MPS requirements, the fleet-wide emission limits in the Illinois rules were demonstrated to be better than applying presumptive BART limits for the units that were subject to BART. This alone would not have led Illinois to state that effective controls were in place for the MPS units. Subsequent to the most recent regional haze progress report, revisions to the MPS submitted as a SIP revision for Regional Haze to USEPA on January 23, 2020, further reduced the allowable emissions by imposing caps on the NOx and SO_2 emissions of the MPS units that were significantly lower than were anticipated under the previous limits. These caps also continue to be adjusted downward as units in the MPS fleet are retired. (These were also the rule revisions that required the permanent retirement of the Coffeen, Duck Creek, Havana, and Hennepin plants by December 31, 2019.)

Second, both sources subject to the MPS that remain operational in Illinois also have a scheduled retirement date before the end of 2027. Baldwin is scheduled for retirement prior to December 31, 2025, and Newton is scheduled for retirement prior to December 31, 2027.

With all of the above factors considered, any analysis of additional control for these sources including remaining useful life, the time necessary for compliance, and cost-effectiveness of control options would be extremely unlikely to reveal reasonable additional controls.

Tables 4.4 and 4.5 show the emissions of NOx and SO_2 from the MPS sources since the 2016 base year used for Q/d analysis and 2028 projections.

Table 4.4 NOx Emissions (TPY) for EGUs subject to MPS

Facility Name	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Baldwin Energy Complex	4,039	3,231	3,217	2,810	1,785	2,558	2,312
Coffeen	1,697	2,481	2,828	1,649	Ceased	Ceased	Ceased
Duck Creek	1,071	1,478	1,607	1,214	Ceased	Ceased	Ceased
E D Edwards	1,763	2,106	2,517	2,335	2,469	2,373	2,152
Havana	1,188	1,240	1,130	732	Ceased	Ceased	Ceased
Hennepin Power Station	1,203	1,358	1,581	1,162	Ceased	Ceased	Ceased
Joppa Steam	1,895	2,467	2,948	2,698	2,512	3,341	2,342
Newton	1,618	1,538	1,501	1,813	1,880	2,455	2,346
Annual Total	**14,474**	**15,899**	**17,329**	**14,413**	**7,046**	**10,727**	**9,152**

Table 4.5 SO_2 Emissions (TPY) for EGUs Subject to MPS

Facility Name	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Baldwin Energy Complex	4,020	3,122	3,002	2,277	1,475	2,227	2,386
Coffeen	33	48	33	42	Ceased	Ceased	Ceased
Duck Creek	10	25	25	44	Ceased	Ceased	Ceased
E D Edwards	5,890	6,392	6,827	6,937	6,532	5,983	6,698
Havana	1,141	1,090	1,066	633	Ceased	Ceased	Ceased
Hennepin Power Station	4,065	4,619	4,932	2,595	Ceased	Ceased	Ceased
Joppa Steam	7,634	10,410	11,968	10,436	8,243	13,231	10,982
Newton	7,743	4,873	4,639	5,000	4,632	6,453	6,816
Annual Total	**30,536**	**30,579**	**32,492**	**27,964**	**20,882**	**27,894**	**26,882**

There is a downward trend in in emissions of NOx and SO_2 from 2016 to 2022 that is expected to continue until all subject units are retired. Joppa Steam also retired in late 2022 and Baldwin Energy Complex will retire in late 2025, which together accounted for 51% of NOx emissions and 50% of SO2 emissions for EGUs subject to the MPS in 2022.

EGUs Subject to the CPS

Similar to the Illinois EGUs that are subject to the MPS, all EGUs that are subject to the CPS were also excluded. The CPS is federally enforceable as it is included in Illinois' SIP at 40 CFR 52.720 and was approved by USEPA on February 28, 2018 (83 Fed. Reg. 8612). The sources subject to the CPS are Powerton, Will County, and Waukegan.

First, all of the units subject to the CPS were effectively controlled and were addressed in the first implementation period. The CPS requires all subject sources to meet a fleet-wide NOx emission limit of 0.11 lb/mmBtu, and a fleet-wide emission SO_2 emission limit of 0.11 lb/mmBtu. The CPS limits were demonstrated to be better than presumptive BART in the first implementation, and since have become more stringent, as the fleet-wide SO_2 emission limit in the rules had been decreasing annually until it reached its final increment in 2019 at 0.11 lb/mmBtu.

Second, the Waukegan and Will County plants were retired in June 2022. Thus, the only units left operating that are subject to the CPS, those at the Powerton Plant in Pekin, will be required to operate at or below the fleet-wide CPS emission rates above with no ability to average with other sources.

Finally, the remaining units at the Powerton plant are also subject to Illinois' CEJA at 415 ILCS 5/9.15(g). This requires all units discussed above to reduce emissions of all pollutants to 0 no later than January 1, 2030.

With all of the above factors considered, any analysis of additional control for these sources including remaining useful life, the time necessary for compliance, and cost-effectiveness of control options would be extremely unlikely to reveal reasonable additional controls.

Tables 4.6 and 4.7 show the emissions of NOx and SO_2 from the CPS sources trending downward since the 2016 base year used for Q/d analysis and 2028 projections.

Table 4.6 NOx Emissions (TPY) for EGUs subject to CPS

Facility Name	2016	2017	2018	2019	2020	2021	2022
Powerton	2,956	3,333	3,025	1,580	619	1,719	3,107
Waukegan	1,031	1,105	1,050	821	478	1,441	838
Will County	1,052	204	609	411	207	398	199
Annual Total	**5039**	**4642**	**4684**	**2812**	**1304**	**3,558**	**4,144**

Table 4.7 SO_2 Emissions (TPY) for EGUs subject to CPS

Facility Name	2016	2017	2018	2019	2020	2021	2022
Powerton	8,209	4,195	3,403	1,551	639	1,832	3,066
Waukegan	2,734	1,706	1,174	754	417	1,264	813

Will County	4,506	425	875	522	231	482	274
Annual Total	**15,449**	**6,326**	**5,452**	**2,827**	**1,287**	**3,578**	**4,153**

There is a downward trend in emissions of NOx and SO_2 from 2016 to 2022 that is expected to continue until all subject units are retired. Waukegan and Will County retired in 2022, which together make up 25% of NOx emissions and 26% of SO_2 emissions for EGUs subject to the CPS.

Kincaid Generation

While the Kincaid power plant is not subject to the MPS or CPS in Illinois, it was addressed in the first Regional Haze implementation period. The operator of the Kincaid plant agreed in a Memorandum of Understanding to a NOx emission limit of 0.07 lb/mmBtu and an SO_2 limit of 0.15 lb/mmBtu during the first implementation period. These limits were incorporated into federally enforceable permits and submitted as part of Illinois Regional Haze SIP.

The Kincaid plant has a scheduled retirement date of December 31, 2027, and is also subject to Illinois CEJA.

With the above factors considered, any analysis of additional control for these sources including remaining useful life, the time necessary for compliance, and cost-effectiveness of control options would be extremely unlikely to reveal reasonable additional controls.

Source Recommendations by The National Park Service

On March 9, 2020, The National Park Service ("NPS") shared with the Illinois EPA via email a list of sources recommended for further analysis. Most sources recommended by the NPS were also identified and evaluated by the Illinois EPA under Table 4.2 of the source selection process. The three sources that were identified by the NPS and not evaluated by the Illinois EPA were: Conoco Phillips Co (now Wood River Refinery), Marathon Petroleum Co LLC, and Fuyao Glass Illinois Inc.

All three of the sources did not meet Illinois' selection criteria and were therefore not selected for four factor analysis. It should also be noted that the two refinery sources, Wood River and Marathon, were considered during the first implementation period and are unlikely to have reasonable emissions reductions. Additionally, the significant emission units at the three sources are boilers in Petroleum Manufacturing and furnaces in Glass Manufacturing, which will be subject to the Transport FIP and additional controls for those units would be unlikely to produce further reasonable emissions reductions.

Sources Selected for Four Factor Analysis

Prairie State Generating Station – Marissa
Southern Illinois Power Coop – Marion
Rain CII Carbon – Robinson
Lafarge Midwest (now Holcim) – Grand Chain
Archer Daniels Midland – Decatur

Portion of Emissions Captured in Analysis

For the second implantation period, Illinois EPA has focused on emissions from point sources, since they are the largest sector contributing to visibility impairment in Class I areas impacted by Illinois emissions. USEPA's July 8, 2021, memorandum with the subject, "Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period," ("USEPA Clarification Memo") provides (pg. 3), "A state that relies on a visibility (or proxy for visibility impact) threshold to select sources for four factor analysis should set the threshold at a level that captures a meaningful portion of the state's total contribution to visibility impairment to Class I areas." Table 4.8 shows Illinois' NOx and SO_2 point source emissions totals and the percentages of those emissions at sources considered for four factor analysis. It also includes the emissions anticipated to be reduced in the second implementation period, compared to Illinois' total point source emissions in the base year (2016) used for 2028 projections.

Table 4.8 Portion of Statewide Point Emissions Considered for Four Factor Analysis

	NOx	**SO_2**	**TOTAL**
All Statewide Point Emissions (TPY)	78,096	100,526	178,622
Emissions from Sources Considered for Four Factor Analysis (TPY)	22,235	65,954	88,189
% of all Statewide Point Source Emissions from Sources Considered	28.5%	65.6%	49.4%
Potential Emission Reductions from Sources Considered for Four Factor Analysis (TPY)	17,537	48,491	66,028
% Emissions Reduction of All Statewide Point Sources	22.5%	48.2%	37.0%

The sources that Illinois EPA analyzed from Table 4.2 accounted for 49.4% of total NOx and SO_2 emissions from all point sources in Illinois and included all the largest in-state sources. The emission reductions that Illinois anticipates will occur prior to the end of the second implementation period (2028) are due to source shutdowns, scheduled shutdowns, and fuel switches of units from Table 4.2. The sources that were considered for four factor analysis represent 48.2% reduction of point source SO_2 emissions in the state, and a 37% reduction of total NOx and SO_2 emissions from all point sources in the state.

V. Source Four Factor Analysis

The four factor analyses for NOx and SO_2 emissions for each source are summarized below, and the full analyses are attached in Appendix A to this document.

The Regional Haze Guidance provides (pg. 5): "Characterization of factors for emission control measures identify potential emission control measures for the selected sources, develop data on the four statutory factors and on visibility benefits if they will be considered."

The four statutory factors from 40 CFR 51.308(f)(2)(i) considered are: (1) the costs of compliance, (2) the time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4) the remaining useful life of any potentially affected anthropogenic sources. Illinois has considered each of the four factors in the analyses for the following sources.

In many cases, estimates for cost effectiveness of measures are given in the dollars of a year in which a specific information source denoted them, e.g., "2006 $" or "2020 $." In the full analyses (Appendix A), Illinois EPA has converted estimates for measures into 2020 $ using Consumer Price Index data for the sake of evaluation.

Prairie State Generation Station

Prairie State Generation Station is a mine-mouth power plant located near Marissa in Washington County. Its major contributors to visibility impairment are two identical in size dry bottom pulverized coal wall-fired boilers. Boiler 1 started operating in 2011 and Boiler 2 started operating in 2012. Boilers 1 and 2 were both found to have a Q/d of greater than 4 in the selection process for four factor analysis.

PM emissions are controlled by dry ESP and wet ESP. NOx emissions are controlled using low NOx Burners ("LNB") and selective catalytic reduction ("SCR"). SO_2 emissions are controlled by wet limestone flue gas desulfurization ("wet-FGD"). The control efficiency is 99.7% for $PM_{2.5}$ emissions, 87% for NOx emissions, and 98% for SO_2 emissions.

Table 5.1 Emissions from Boilers 1 and 2 in 2016 Base Year (TPY)

Unit	NOx	SO_2
Boiler 1	1,895	4,505
Boiler 2	1,652	4,126

Best Available Control Technology ("BACT")-level add-on controls systems are in place for controlling both NOx and SO_2 emissions under the Prevention of Significant Deterioration ("PSD") program. Updates to these systems were found to likely result in minimal to no emission reductions and would not be cost effective. The Regional Haze guidance provides (pg. 23) "The statutory considerations for selection of BACT and LAER are also similar to, if not more stringent than, the four statutory factors for reasonable progress."

Prairie State power plant currently has LNB and SCR for NOx emissions control and wet-FGD for SO_2 emissions controls in place. For NOx, the USEPA document Base Case v.5.13 has a rate floor NOx emission rate of 0.07 lb/mmBtu when burning bituminous coal, while Prairie State is achieving an average of 0.061 lb/mmBtu by employing LNB and SCR controls. For SO2, Base Case v.5.13 assumed a removal efficiency of 96% while Prairie State is achieving a SO2 emissions reduction rate of 98%. In both NOx and SO2 cases, Prairie State is already achieving emission control efficiencies better than the Base Case, thus control system improvements to the current LNB, SCR and wet-FGD controls would be technically infeasible.

As previously noted, this source is a mine-mouth power plant requiring no transportation of fuel or the associated costs or emissions. Since the source was permitted as a mine-mouth facility, fuel switching

control options cannot be considered in the analyses, as those control options would change the nature of the source to the extent that it would need to be permitted as a completely new source in the state and is technically infeasible. Repowering to IGCC was considered and costs for that conversion were estimated at approximately $17,219 per ton of pollutant reduced (in 2020$/ton).

The time necessary for the Agency to develop, propose, and implement the regulations for imposing additional controls is approximately two years, in addition to a period of two additional years that could be required for the affected source to implement the control measures.

Possible energy and non-air quality environmental impacts included were not an important part of the analysis for conversion of the plant to IGCC. As previously noted, the source has BACT-level add-on pollution control equipment for NOx and SO_2.

Prairie State is subject to a compliance date in the Illinois CEJA law at 415 ILCS 5/9.15(h) that requires emissions from the source to be 0 by January 1, 2045.

Based on the existing BACT-level NOx and SO_2 emissions control systems at Prairie State, and the high cost of alternative control measures, Illinois EPA is not proposing any additional emissions control measures for Prairie State for the second implementation period.

SIPCO

SIPCO is an electric generating company operating two fossil fuel fired boilers and two natural gas fired turbines at its power plant near Marion in Williamson County. Its major contributor to visibility impairment are the two boilers Unit 123 and Unit 4. Unit 123 began operating in 2003 and is rated at 1,400 mmBtu/hr. Boiler 4 began operating in 1975 and has a capacity of 1700 mmBtu/hr. Both units were found to have a Q/d of greater than 4 in the selection process for four factor analysis.

PM emissions are controlled by ESPs, baghouse, and wet scrubber. NOx emissions are controlled using LNB, OFA and SNCR. SO_2 emissions are controlled by limestone injection system and wet-FGD.

Table 5.2 Emissions from Boilers 123 and 4 in 2016 Base Year (TPY)

Unit	NOx	SO_2
Boiler 123	380	1,620
Boiler 4	533	2070

Boiler Unit 4 has ceased operations beginning in 2021, so this analysis is focused on the remaining boiler, Unit 123.

For NOx control, the current systems provide 90% NOx removal efficiency. Unit 123 currently has pre-combustion controls in its fluidized bed combustor and OFA and SNCR for post-combustion control. For SO_2 control, the current controls have an efficiency of 90-94% removal efficiency. Unit 123 has a wet-FGD system that was considered in the analysis. Due to the type of boilers and high removal efficiencies currently in place, improvements to the current control systems were determined to be technically infeasible.

The cost effectiveness of additional NOx and SO_2 reductions due to switching from Illinois Coal to PRB Coal is estimated to be $3,802 per ton of pollutant removed (in $2020/ton), although this is likely a low estimate as the unit was designed and constructed to be able to combust coal, coal waste, and mine waste from local sources. Fuel switching from Illinois coal to natural gas is technically infeasible for fluidized bed combustion boilers. The cost effectiveness of additional NOx and SO_2 reductions due to repowering to IGCC is estimated to be $8,396 per ton of pollutant removed (in $2020/ton). Additional control would yield low NOx and SO_2 reductions and was determined to not be cost effective.

The time necessary for the Agency to develop, propose, and implement the regulations for imposing additional controls is approximately two years, in addition to a period of two additional years that could be required for the affected source to implement the control measures.

Possible energy and non-air quality environmental impacts included: (1) negatively affecting efficiency for meeting auxiliary power requirements, possible hazardous solid waste disposals, reagent storage, as well as increased water usage and discharge of polluted water.

Additionally, Unit 123 is subject to a compliance date in the Illinois CEJA law at 415 ILCS 5/9.15(h) that requires emissions from the source to be 0 by January 1, 2045.

Based on the existing NOx and SO_2 emissions control measures in SIPCO, the efficient energy usage currently in place, the high cost of alternative control measures, and remaining useful life of the boiler, Illinois EPA is not proposing any new NOx and SO_2 reduction measures for SIPCO boiler during the second regional haze period.

Rain CII Carbon

Rain CII Carbon LLC produces calcined petroleum coke from green petroleum coke ("GPC") in the city of Robinson in Crawford County. Its major contributors to haze emissions are two rotary calcining kilns used to heat GPC to a precisely controlled temperature to burn off moisture, VOCs, and other impurities. Kilns 1 and 2 both began operation in 1977.

PM emissions for both kilns are controlled with pyro-scrubbers and baghouses. Kiln 2 also has a multi-cyclone PM collector as an additional control.

Table 5.3 Emissions for Kiln 1 and Kiln 2 for 2016 Base Year (TPY)

Unit	NOx	SO_2
Kiln 1	145	2,164
Kiln 2	108	1,672

For NOx control, combustion controls were not considered as the rotary kilns need to burn off impurities and keep a precisely controlled temperature, such that it would be infeasible to significantly change the way the kilns burn. The post-combustion controls considered were SNCR and SCR. The cost effectiveness of adding SNCR control in 2020 $ was estimated to be around $3,395 per ton of NOx reduced, while the cost for adding an SCR control was estimated to be around $7,701 per ton of NOx

reduced. However, NOx emissions from the source are not the primary pollutant contributing to visibility impairment. NOx emissions from Rain CII are considered low; additional controls would yield minimal NOx reductions and were determined to not be cost effective.

For SO_2 control, semi-dry FGD and wet-FGD were considered. The cost effectiveness for semi-dry FGD was estimated to be around $9,570 per ton of SO_2 reduced in 2020 $, while for wet-FGD it was estimated to be around $29,106 per ton of SO_2 reduced.

The time necessary for the Agency to develop, propose, and implement the regulations would take around two years, in addition to a period of two additional years that could be required for the affected source to implement the control measures.

Possible energy and non-air quality environmental impacts included: (1) for SCR - negatively affecting efficiency for meeting auxiliary power requirements, possible hazardous solid waste disposals, and reagent storage; (2) for SO_2 controls - increased auxiliary power requirements including heat rate and capacity penalties, as well as increased water usage and discharge of polluted water.

The remaining useful life of the kilns is estimated to be 10 to 20 years with proper maintenance.

Based on the size of the yearly NOx and SO_2 emissions, the high cost of control measures, and remaining useful life of the kilns, Illinois EPA will not be proposing any new NOx and SO_2 reduction measures for Rain CII kilns during the second regional haze period.

Holcim US Inc.

Holcim US Inc. manufactures Portland cements and cement-based construction products and is located in Grand Chain, Massac County. Portland cement is made by grinding and heating a mixture of raw materials consisting of limestone, sand, clay, etc. and fuels such as coal and/or petroleum coke in a rotary kiln. Its major contributors to visibility impairment are the source's two kilns. Kiln 1 and Kiln 2 were installed in 1960 and 1975 respectively. Kilns 1 and 2 were both found to have a Q/d of greater than 4 in the selection process for four factor analysis.

PM emissions are controlled by electrostatic precipitators ("ESP") and baghouses. NOx emissions are controlled using LNB and SCR systems. SO_2 emissions are controlled using dry absorbent addition.

Table 5.4 Emissions from Kilns 1 and 2 in 2016 Base Year (TPY)

Unit	NOx	SO_2
Kiln 1	295	509
Kiln 2	777	189

Kiln 2 ceased operation in 2016, and so the analysis should be focused on potential additional control of Kiln 1. It should be noted that emissions from Kiln 1 alone would not meet the selection criteria for four factor analysis.

For NOx control, SNCR, SCR, and regenerative selective catalytic reduction ("RSCR") were considered. Holcim Kiln 1 currently has low NOx burners and SCR controls in place with control efficiency of 80%. The highest NOx reduction control efficiencies as provided by LADCO and USEPA for SCR is 70-90% NOx reduction. Assuming the best-case scenario of 90% reduction would only yield an additional 147 tons/year of NOx reduction. Due to the limited potential for substantial reductions, SCR was determined to not be cost effective. Switching to SNCR or RSCR would yield minimal or no NOx reductions as their NOx reduction control efficiencies are lower than the 70-90% reduction of SCR and was determined to not be cost effective or appropriate.

For SO_2 control, dry FGD, semi-dry FGD, and wet-FGD were considered. The cost effectiveness for dry-FGD was estimated to be between $2,527 - $97,556 per ton of SO_2 reduced (in 2020 $). For semi-dry FGD, cost effectiveness was estimated to be between $2,637 - $51,744 per ton of SO_2 reduced. For wet-FGD, cost effectiveness is estimated to be between $1,648 - $86,570 per ton of SO_2 reduced. The large range in cost effectiveness depends on the utilization and production scale as well as the specific capital costs associated with the design. Specific factors include equipment, installation, engineering, reagent, and waste removal. Kiln 1 began operation in 1960 and was last modified in 1995. Due to the old age of the kiln and its equipment, costs are not likely to be on the low end of these ranges. Kiln 1 currently employs a dry FGD system, a dry absorbent addition ("DAA") system, achieving 70 to 90% control, and so changing to a different desulfurization technology is unlikely to be cost effective or result in significant emission reductions.

The time necessary for the Agency to develop, propose, and implement the regulations for imposing additional controls is approximately two years, in addition to a period of two to five years for the affected source to implement the control measures.

Possible energy and non-air quality environmental impacts include: (1) for SCR – negatively affecting efficiency for meeting auxiliary power requirements, possible hazardous solid waste disposals, reagent storage; and (2) for SO_2 controls – impacts include increased auxiliary power requirements including heat rate and capacity penalties, as well as increased water usage and discharge of polluted water.

Based on the existing NOx and SO_2 emissions control measures currently at Holcim, the high cost of alternative control measures, and remaining useful life of the kilns, Illinois EPA is not proposing any additional NOx or SO_2 reduction measures for the Holcim kilns during the second implementation period.

Archer Daniels Midland Company

Archer Daniels Midland Company ("ADM") is a biochemical and food processing company located in Decatur, Illinois. Its major contributors to visibility impairment are the nine-cogeneration coal-fired bed boilers ("Cogen-FB Boilers"). Boilers 1-5 were installed in 1987 and are rated at 492 mmBtu/hr. Boiler 6 was installed in 1991, rated at 700 mmBtu/hr and Boiler 7 was installed in 1995, rated at 750 mmBtu/hr. Boilers 8 and 9 were installed in 1995 and 1997 respectively, and are rated at 1500 mmBtu/hr. Only Boilers 8 and 9 were found to have a Q/d of greater than 4 in the selection process for four factor analysis, however a four factor analysis was done on all nine boilers due to their similarities.

ADM's boilers are regulated by state regulations, federal programs (New Source Performance Standards ("NSPS") - 40 CFR part 60, subpart Db), and a Consent Decree by USEPA and Illinois EPA limiting NOx and SO_2 emissions.

PM emissions are controlled by baghouses. NOx emissions are controlled using low NOx burners and selective non-catalytic reduction systems at 80% control efficiency. SO_2 emissions are controlled by using a blend of limestone, 60% Western low sulfur coal, and dry sorbent injection systems at 70-90% control efficiency.

Table 5.5 Emissions from Boilers 1-9 in 2016 Base Year (TPY)

	Unit 1	**Unit 2**	**Unit 3**	**Unit 4**	**Unit 5**	**Unit 6**	**Unit 7**	**Unit 8**	**Unit 9**
NOx	135	166	164	170	173	135	186	405	251
SO_2	421	694	664	731	752	586	637	1,339	1,395

For NOx control, selective non-catalytic reduction ("SNCR") and selective catalytic reduction ("SCR") systems were considered. ADM currently has low NOx burners ("LNB") and SNCR controls in place. Updates to SNCR controls would yield minimal NOx reductions and was determined to not be cost effective. The cost effectiveness of switching from SNCR to SCR in 2020 $ was estimated to be between $4,962 - $7,252 per ton of NOx reduced. Repowering to Integrated Gasification Combined Cycle ("IGCC") was also considered and costs for that conversion were estimated at approximately $70,878 per ton.

For SO_2 control, Spray Dryer Absorbers ("SDA"), Flue Gas Desulfurization ("FGD"), and wet-FGD were considered. The cost effectiveness of SDA-FGD was estimated to be between $5,844 - $8,010 per ton of SO_2 reduced (in 2020 $) based on the reported emissions rate, as that is the rate the facility is currently achieving. For wet-FGD the cost effectiveness was estimated to be between $6,353 - $8,930 per ton of SO_2 reduced (in 2020 $) based on the reported emissions rate. As the source already employs dry sorbent injection, additional marginal reductions from SDA or wet-FGD are unlikely to be achieved within these ranges for cost-effectiveness.

The time necessary for the Agency to develop, propose, and implement the regulations for imposing additional controls is approximately two years, in addition to a period of two additional years that could be required for the affected source to implement the control measures.

Possible energy and non-air quality environmental impacts included: (1) for SCR - negatively affecting efficiency for meeting auxiliary power requirements, possible hazardous solid waste disposal, and reagent storage; and (2) for SO_2 controls - impacts include increased auxiliary power requirements including heat rate and capacity penalties, as well as increased water usage and discharge of polluted water.

The remaining useful life of the boilers was estimated to be between 15-22 years, and the units are subject to Illinois' CEJA 415 ILCS 5/9.15(k) that requires emissions from the source to be 0 by January 1, 2045.

Based on existing NOx and SO_2 emissions control measures at ADM, the efficient energy usage currently in place, the high cost of alternative control measures, and remaining useful life of the boilers, Illinois EPA is not proposing any additional NOx or SO_2 reduction measures for ADM boilers during the second implementation period.

VI. Illinois Long-Term Strategy

Pursuant to 40 CFR §51.308(f)(2), Illinois is required to submit a long-term strategy addressing Regional Haze Rule requirements for visibility improvement for the Federal Class I areas impacted by Illinois sources. Illinois did not identify additional control requirements that would be necessary to make reasonable progress at the sources at which four factor analyses were performed. However, Illinois EPA anticipates significant reductions in emissions of visibility impairing pollutants to occur in the second implementation period in addition to those that have occurred since the most recent progress report was submitted.

Illinois' LTS relies on a number of on-the-books and on-the-way measures that are resulting in or projected to produce significant reductions in emissions of NOx and SO_2. These measures include:

Electric Generating Units

- Illinois MPS for EGUs, 86 Fed. Reg. 33527 (June 25, 2021)
- Illinois CPS for EGUs, 83 Fed. Reg. 8612 (February 28, 2018)
- Amendments to MPS (2019 – present) requiring coal-fired EGU shutdowns
- CSAPR (2015 – present) and CSAPR update (2021)
- State Regulations for Stationary Reciprocating Internal Combustion Engines ("RICE") and Turbines, 74 Fed. Reg. 30466 (June 26, 2009)
- Replacement rule for CAA Section 111(d) rules for GHG emissions from EGUs (replacement for Clean Power Plan and ACE Rule)
- Federal Implementation Plan for interstate transport provisions for the 2015 Ozone NAAQS including reductions for EGUs and non-EGUs in the second implementation period
- Retirements of Illinois coal-fired EGUs:

EGUs Already Shutdown

Agency ID	Facility Name	Location	Scheduled Date of Shutdown
119020AAE	Dynegy Midwest Generation LLC	Wood River	November 17, 2016
155010AAA	Dynegy Midwest Generation LLC	Hennepin	January 1, 2020
125804AAB	Dynegy Midwest Generation LLC Havana Power Station	Havana	January 1, 2020
135803AAA	Illinois Power Generation Co	Coffeen	January 1, 2020
197810AAK	Will County Generating Station	Will County	June 1, 2022
097190AAC	Waukegan Electric Generating Station	Waukegan	June 1, 2022
127855AAC	Electric Energy Inc	Joppa	September 1, 2022
143805AAG	Illinois Power Resources Generating LLC	Edwards	December 31, 2022

Additional EGU Units Already Shutdown

Agency ID	Facility Name	Unit #	Location	Scheduled Date of Shutdown
057801AAA	Illinois Power Generating Resources	1	Duck Creek	January 1, 2020
157851AAA	Dynegy Midwest Generation	3	Baldwin	November 5, 2020
199856AAC	Southern Illinois Power Coop	4	Marion	November 11, 2020
167120AAO	CWLP Dallman	31, 32	Springfield	March 1, 2021

EGUs Shutdown Schedule

Agency ID	Facility Name	Location	Scheduled Date of Shutdown
157851AAA	Dynegy Midwest Generation LLC	Baldwin	December 31, 2025
079808AAA	Illinois Power Generating Co	Newton	December 31, 2027
021814AAB	Kincaid Generation LLC	Kincaid	December 31, 2027
179801AAA	Midwest Generation LLC	Powerton	January 1, 2030

Other Point Sources

- NSPS including:
  - Reciprocating Internal Combustion Engine Standards 40 CFR 60 Subparts IIII and JJJJ – Adopted June 2011
  - Industrial/Commercial/Institutional Steam Generating Units 40 CFR 60 Subpart Db – Adopted May 2011
  - Crude Oil and Natural Gas Production, Transmission and Distribution 40 CFR 60 Subpart OOOO – Adopted August 2012
- NESHAP/Maximum Achievable Control Technology ("MACT") Standards including:
  - Reciprocating Internal Combustion Engine Standards 40 CFR 63 Subpart ZZZZ – Adopted January 2013
  - Industrial/Commercial/Institutional Boilers and Process Heaters 40 CFR 63 Subpart DDDDD and JJJJJJ – Adopted March 2011
- Federal Oil and Natural Gas Industry Standards
- State rules for NO_x Reasonably Available Control Technology ("RACT") in Illinois
- Mercury and Air Toxics Standard ("MATS")
- 2015 Illinois amendments for the 2010 SO_2 NAAQS and SO_2 Data Requirements Rule.
- Updates to the "good neighbor" or "interstate transport" provisions for the 2015 Ozone NAAQS

On-Road Mobile Sources

- Federal Motor Vehicle Emission Control Program, low-sulfur gasoline and ultra-low sulfur diesel fuel
- Inspection/maintenance programs, including Illinois' enhanced vehicle inspection and maintenance program
- Control of Hazardous Air Pollutants from Mobile Sources (Mobile Source Air Toxics)
- State Regulations for Stationary Reciprocating Internal Combustion Engines and Turbines
- Tier 3 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements
- On-Highway Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements
- Reformulated gasoline, including in Chicago-Gary-Lake County, IL, IN; and Milwaukee, Racine, WI

Off-Road Mobile Sources

- Federal control programs incorporated into NONROAD model (e.g., nonroad diesel rule), plus the evaporative Large Spark Ignition and Recreational Vehicle standards
- Tier 4 Nonroad Diesel Engine Standards and Diesel Fuel Sulfur Content Restrictions
- Federal railroad/locomotive standards

- Category 3 Marine Diesel Engine Standards Marine Compression-Ignition Engine Standards and Locomotive Engine Standards
- Federal Standards for Certain Commercial Passenger and Freighter Aircraft Engines

Area Sources

- Federal Aerosol Coatings standards
- Federal Portable Fuel Containers standards
- Area Source Boilers, Major Source Boilers, and Commercial/Industrial Solid Waste Incinerators NESHAPs
- Standards and Limitations for Organic Material Emissions for Area Sources (Consumer and Commercial Products and Architectural and Industrial Maintenance Coatings rule), 35 IAC Part 223
- Federal NSPS for Residential Wood Heaters
- Federal Standards for Commercial Passenger and Freighter Aircraft Engines

The MPS, CPS, and Stationary RICE and Turbines are state regulations that are already included in the regulatory part of the SIP under 40 CFR 52.720 and are federally enforceable. Overall emissions have trended downwards due in large part to shutdowns of EGUs and the increased stringency of the MPS and CPS in the second implementation period. Illinois adopted those increased stringent rules for the Regional Haze SIP during the second implementation period to significantly decrease NOx and SO_2 emissions on June 25, 2021 (86 Fed. Reg. 33527). The above measures are the measures relied on to make reasonable progress in the second implementation period. It should be noted that the state will assess the Regional Haze SIP and identify if there are any deficiencies in the upcoming progress report. Under 40 CFR 51.308(h), the State must develop, within one year, additional strategies to address any deficiencies identified in the progress report for the implementation plan.

In addition to the above measures, Illinois' CEJAs is a state regulation which requires the retirement of nearly all coal-fired EGUs in Illinois by January 1, 2030, and the incremental retirement of remaining coal-fired and gas-fired EGUs in Illinois by January 1, 2045. Any source retirements as a direct result of CEJAs will be noted in upcoming Regional Haze progress reports.

Per CEJAs, all EGUs and large greenhouse gas ("GHG")-emitting units that use gas as a fuel and are not publicly owned GHG-emitting units shall permanently reduce all CO_2 equivalent ("CO_2e") and co-pollutant emissions to zero:

- By January 1, 2030, units that have a NOx emission rate of greater than 0.12 lbs/MWh or a SO_2 emission rate greater than 0.006 lb/MWh and are located within 3 miles of an environmental justice ("EJ") community.
- By January 1, 2035, units that began operation prior to September 15, 2021, and have a NOx emission rate of less than or equal to 0.12 lb/MWh and a SO_2 emission rate less than or equal to 0.006 lb/MWh and are located in or within 3 miles of an environmental justice community.
- By January 1, 2040, units that have a NOx emission rate of greater than 0.12 lbs/MWh or a SO_2 emission rate greater than 0.006 lb/MWh and are not located within 3 miles of an environmental justice community.

- By January 1, 2040, all remaining EGUs and large GHG-emitting units that have a heat rate greater than or equal to 7000 BTU/kWh.
- By January 1, 2045, all remaining EGUs and large GHG-emitting units.
- All the GHG-emitting units above must reduce CO_2e emissions by 50% by January 1, 2035, if they are still in operation at that time.

All EGUs and large GHG-emitting units that use coal or oil as a fuel shall permanently reduce all CO_2e and co-pollutant emissions to zero:

- By January 1, 2030, for those units that are not publicly owned GHG-emitting units.
- By December 31, 2045, for all other units.
- By January 1, 2035, reduce CO_2e emissions by 45% by if they are still in operation at that time.

It should also be noted that some of the measures listed above that will yield significant additional emission reductions in Illinois have not been included as "on the books" control measures in the LADCO analyses. These include source retirement provisions of the CEJA legislation in Illinois and revisions to the MPS codified in 35 IAC Part 225 since the LADCO analysis was conducted in 2020.

Existing Measures

For sources where the outcome of the four factor analysis results are no new necessary measures, the source's existing measures are generally needed to make reasonable progress. The following summarizes the current existing emission limits for the units identified in the four factor analyses and their federally enforceable regulatory source.

Prairie State Emission Limits for Coal Fired Boilers 1 and 2

	Limits	**Units**	**Regulatory Source**
NOx	0.07	lb/mmBtu	Construction Permit 01100065
SO_2	0.182	lb/mmBtu	Construction Permit 01100065

SIPCO Emission Limits for Boiler 123

	Limits	**Units**	**Regulatory Source**
NOx	1.6*	lb/MWhr	40 CFR Part 60 Subpart Da, 60.44Da(d)(1)
SO_2	0.6	lb/mmBtu	40 CFR Part 60 Subpart Da, 60.43Da (a)(1)

*Equivalent to 0.47 lb/mmBtu

Rain CII Carbon Emission Limits for Kilns 1 and 2

	Limits	**Units**	**Regulatory Source**
SO_2	2000	ppm	35 IAC 214.301

Holcim US Inc Emission Limits for Kiln 1

	Limits	**Units**	**Regulatory Source**
NOx	3.21	lb/ton clinker	Construction Permit 12060038
SO_2	2000	ppm	35 IAC 214.301

ADM Emission Limits for Cogeneration Coal-fired Bed Boiler 8

	Limits	**Units**	**Regulatory Source**
NOx	0.12	lb/mmBtu	Construction Permit 94020006
SO2	0.7 and at least 90% reduction	lb/mmBtu	Construction Permit 94020006

ADM Emission Limits for Cogeneration Coal-fired Bed Boiler 9

	Limits	**Units**	**Regulatory Source**
NOx	0.10 w/ coal > 2.5 lb S/mmBtu; 0.07 w/ coal ≤ 2.5 lb S/mmBtu	lb/mmBtu	Construction Permit 97050097
SO2	0.7 and at least 92% reduction	lb/mmBtu	Construction Permit 97050097

Prevention of Significant Deterioration

In consideration of the construction of a major stationary source or construction of a major modification of an existing major stationary source of air pollutants generally regulated under the Clean Air Act, the visibility impacts of such sources will remain under the purview of the existing requirements under PSD. Illinois' PSD program is set forth at 35 Ill. Adm. Code 204, approved by USEPA into Illinois' SIP on September 9, 2021, and effective October 12, 2021 (*See* 86 Fed. Reg. 50459).

Under the PSD program, if the emissions from a proposed stationary source or the increase in emissions from a modification to an existing major stationary are significant, as defined by the PSD rules, specific requirements apply to the project. These requirements include that subject sources be equipped with best available control technology or BACT for all PSD pollutants emitted in major or significant amounts; an analysis of the air quality impacts of the project; an additional impacts analysis, which assesses the impacts on soils, vegetation, and visibility in the vicinity of the proposed project caused by any increase in emissions of any subject pollutant from the proposed project under review; and the impacts on air quality due to the growth in emissions that would be associated with a proposed project. In addition, public notice is required to ensure that the public has an opportunity to comment on the proposed PSD determination. Furthermore, there are additional PSD requirements for all PSD projects that propose to locate within 100 kilometers of a Class I area and for all PSD projects proposing to locate a distance greater than 100 kilometers from a Class I area if due to their size may have an impact on a Class I area and that emit certain pollutants, PM_{10}, SO_2 and NO_2. Additional requirements include written notification to the FLM of a permit application for such a proposed project that includes an analysis of the proposed project's anticipated impacts on visibility in the Class I area and the permitting authority's consideration of any visibility analysis performed by the FLM that demonstrates that such a proposed project may have an adverse impact on visibility in a Class I area. The permitting of new and modified sources in Illinois by means of the PSD process includes review by and input from the FLMs, who are charged with direct responsibility for management of Class I areas and have an affirmative responsibility to protect the air quality related values including visibility. Determinations of adverse visibility impacts enable Illinois to reduce the impacts of any new and modified sources on visibility.

Environmental Justice

Illinois' CEJA involves components of environmental justice throughout its equity programs with the purpose of benefiting all communities in the clean energy economy. It provides funding for projects,

communities, and business development as well as to support the development of renewable energy resources, with particular focus in EJ communities. Funding and job programs include: Clean Jobs Workforce Network Program, Jobs and Environmental Justice Grant Program, Illinois Clean Energy Jobs and Justice Fund Act, Illinois Solar for All Program and transportation electrification investment and incentives. CEJA incorporates meaningful engagement with a diverse set of stakeholders including EJ organizations to ensure EJ considerations are incorporated in development, decision making, and implementation of environmental laws. It also aims to ensure maintenance of utilities, improvement of the standards for reliability and resiliency, improvements in power quality, and affordable customer delivery service costs all with a focus in EJ communities.

CEJA prioritizes emissions controls on sources in EJ communities. Nearly all EGUs are required to permanently reduce all carbon dioxide and co-pollutant emissions to zero no later than January 1, 2045, with accelerated schedules for units in EJ communities. Many subject emission units located within 3 miles of an EJ community must reduce to zero by January 1, 2030.

The Illinois EJ Policy is another aspect of Illinois EPA addressing environmental justice in the state. The EJ Policy includes the EJ Notification Process, which sends outreach to EJ areas to their advocacy groups, local government officials, and individuals who request to be notified on permit applications in their EJ areas. Notices are sent based on the type of facility, nature of the permit transaction, and any other relevant factors. The EJ coordinator will coordinate any requests, questions, or concerns to request a public hearing or meeting usually following outreach. The Office of Environmental Justice, and specifically the EJ coordinator, conducts outreach which can include public notices, meetings, hearings, and local siting approval. Illinois EPA's Office of Community Relations works with EJ staff to preemptively identify environmental issues affecting areas of EJ concern in Illinois. The Office of Community Relations' responsibility includes preparing and issuing public hearing notices, preparing and distributing fact sheets, responding to questions from the public, conducting public hearings, and working with other Illinois EPA staff to prepare Responsiveness Summaries following public hearings. Bilingual hearings, publication of notices, and publication of other materials can be arranged where appropriate. Community Relations and the Office of Environmental Justice maintain contact lists of interested individuals, community leaders and organized groups who will receive notices of any significant Illinois EPA action likely to impact the EJ community in which these groups have expressed interest in.

The Illinois EPA implements the EJ Grievance Procedure, which provides a process for filing a timely complaint to the Illinois EPA. The EJ Grievance Procedure also describes the process used by the Illinois EPA to investigate and resolve complaints.

The environmental justice policy can be found on the Illinois EPA website:
https://epa.illinois.gov/topics/environmental-justice/ej-policy.html

VII. Documentation of the Technical Basis, Including Modeling, Monitoring, Cost, Engineering, and Emissions Information Relied Upon to Determine the Emission Reductions Necessary to Make Reasonable Progress (40 CFR 51.308(f)(2)(iii))

For the Illinois' Regional Haze SIP for the second implementation period, Illinois has relied upon technical analyses performed by LADCO for modeling visibility impacts of Illinois sources to Federal

Class I areas and projections for meeting reasonable progress goals. These analyses are included in the LADCO TSD (see Appendix B) and are noted throughout this document where applicable.

Cost and engineering analyses for Illinois' four factor analyses of sources was performed by Illinois EPA, and the full analyses and methodologies are included in this document in Appendix A.

Emissions information in this document include data from, but not limited to, emissions inventories submitted to the USEPA in compliance with the triennial reporting requirements of 40 CFR 51 Subpart A (2017, 2020). However, the Q/d analysis performed by LADCO was based on emissions data from 2016, as it was the best and most recent actual emissions data available at the time of the analysis.

VIII. Additional Factors for Consideration (51.308(f)(2)(iv))

The Regional Haze Guidance at 40 CFR 51.308(f)(2)(iv) requires that when developing its LTS, a state must consider five additional factors. Illinois has considered these factors and discusses the manner in which they are addressed below.

Emission Reductions Due to Ongoing Air Pollution Control Programs, Including Measures to Address Reasonably Attributable Visibility Impairment (51.308(f)(2)(iv)(A))

The following is a list of "on-the-books" control measures that are expected to further reduce visibility impairing pollutants in future years:

Electric Generating Units

- Illinois' CEJA (2021 – present; 0 emissions for all EGUs incrementally, in phases in 2030, 2035, 2040, and 2045)
- Illinois MPS for EGUs, 86 Fed. Reg. 33527 (June 25, 2021)
- Illinois CPS for EGUs, 83 Fed. Reg. 8612 (February 28, 2018)
- Amendments to MPS (2019 – present)
- CSAPR (2015 – present) and CSAPR update (2021)
- State Regulations for Stationary Reciprocating Internal Combustion Engines and Turbines, 74 Fed. Reg. 30466 (June 26, 2009)
- Scheduled retirements of Illinois coal-fired EGUs

Other Point Sources

- NSPS including:
  - Reciprocating Internal Combustion Engine Standards 40 CFR 60 Subparts IIII and JJJJ – Adopted June 2011
  - Industrial/Commercial/Institutional Steam Generating Units 40 CFR 60 Subpart Db – Adopted May 2011
  - Crude Oil and Natural Gas Production, Transmission and Distribution 40 CFR 60 Subpart OOOO – Adopted August 2012

- NESHAP/Maximum Achievable Control Technology ("MACT") Standards including:
  - Reciprocating Internal Combustion Engine Standards 40 CFR 63 Subpart ZZZZ – Adopted January 2013

    - Industrial/Commercial/Institutional Boilers and Process Heaters 40 CFR 63 Subpart DDDDD and JJJJJJ – Adopted March 2011
- Federal Oil and Natural Gas Industry Standards
- State rules for NO_x Reasonably Available Control Technology ("RACT") in Illinois
- Mercury and Air Toxics Standard ("MATS")
- 2015 Illinois amendments for the 2010 SO_2 NAAQS and SO_2 Data Requirements Rule.

On-Road Mobile Sources

- Federal Motor Vehicle Emission Control Program, low-sulfur gasoline and ultra-low sulfur diesel fuel
- Inspection/maintenance programs, including Illinois' enhanced vehicle inspection and maintenance program
- Control of Hazardous Air Pollutants from Mobile Sources (Mobile Source Air Toxics)
- State Regulations for Stationary Reciprocating Internal Combustion Engines and Turbines
- Tier 3 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements
- On-Highway Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements
- Reformulated gasoline, including in Chicago-Gary-Lake County, IL, IN; and Milwaukee, Racine, WI

Off-Road Mobile Sources

- Federal control programs incorporated into NONROAD model (e.g., nonroad diesel rule), plus the evaporative Large Spark Ignition and Recreational Vehicle standards
- Tier 4 Nonroad Diesel Engine Standards and Diesel Fuel Sulfur Content Restrictions
- Federal railroad/locomotive standards
- Category 3 Marine Diesel Engine Standards Marine Compression-Ignition Engine Standards and Locomotive Engine Standards
- Federal Standards for Certain Commercial Passenger and Freighter Aircraft Engines

Area Sources

- Federal Aerosol Coatings standards
- Federal Portable Fuel Containers standards
- Area Source Boilers, Major Source Boilers, and Commercial/Industrial Solid Waste Incinerators NESHAPs
- Standards and Limitations for Organic Material Emissions for Area Sources (Consumer and Commercial Products and Architectural and Industrial Maintenance Coatings rule), 35 IAC Part 223
- Federal NSPS for Residential Wood Heaters
- Federal Standards for Commercial Passenger and Freighter Aircraft Engines

Measures to Mitigate Impacts of Construction Activities (40 CFR 51.308(f)(2)(iv)(B))

Illinois does not contain any Federal Class I areas and construction activities in the state are unlikely to contribute significantly to visibility impairment at the out-of-state Class I areas due to their distance from the state.

In further consideration of construction activities and their effect on regional haze, construction activities in Illinois are subject to federal non-road standards for construction equipment and vehicles. Additionally, construction projects in Illinois are often conducted under contract restrictions requiring additional measures to mitigate environmental impacts. These measures include the following: idling restrictions for construction vehicles and equipment; USEPA-approved controls for off-road diesel equipment; use of newer, cleaner, and more fuel-efficient engines for equipment; and optimizing earthwork and excavation to limit haul trips to the maximum extent possible. Illinois also requires the use of ultra-low sulfur diesel fuel, state-wide, in 35 IAC Part 217. Illinois EPA anticipates that future construction projects will continue to entail similar environmental considerations, and the Illinois EPA will continue to work with other state and federal agencies to ensure that environmental impacts are given due consideration in contracting for construction projects.

Source Retirement and Replacement Schedule (40 CFR 51.308(f)(2)(iv)(C))

Illinois, in its Source Selection for Four Factor Analysis (Section IV) and its LTS (Section VI), details a number of source retirements and coal-to-gas unit replacements. It should be noted that some scheduled retirements of sources that are or were significant emitters of visibility impairing pollutants were not included in LADCO's analyses because those schedules were not known at the time they were performed.

Additionally, with the recent passage of the CEJA, Illinois became a leading state in the nation in the reduction of all pollutants from the EGU sector. CEJA requires the retirement of nearly all coal-fired EGUs in Illinois by January 1, 2030, and the incremental retirement of remaining coal-fired and gas-fired EGUs in Illinois by January 1, 2045.

Basic Smoke Management Practices for Prescribed Fire Used for Agricultural and Wildland Vegetation Management Purposed and Smoke Management Programs (40 CFR 51.308(f)(2)(iv)(D))

In consideration of smoke management techniques for conducting prescribed burns for ecological management and restoration, the Illinois EPA worked with land managers in the State to prepare the "Illinois Smoke Management Plan," included as Appendix F to this document. This plan provides recommended approaches for minimizing smoke during prescribed burns. The plan is voluntary and targets controlled ecological burns. The plan requires the implementation of best management practices for burns and also the use of the Air Quality Index to inform the decision to burn. The plan does not explicitly consider Class I areas as sensitive receptors, since the distance to the nearest Class I area from any point in Illinois is far (at least 100 km) and ecological burns are relatively small and short-lived.

Illinois does not contain any Federal Class I areas and prescribed fires are unlikely to significantly contribute to visibility impairment on the 20 percent most anthropogenically impaired days at any of the Class I areas affected by Illinois.

Anticipated Net Effect on Visibility Due to Projected Changes in Point, Area, and Mobile Source Emissions Over the Period Addressed by the LTS (40 CFR 51.308(f)(2)(iv)(E))

The tables below show that totals of all pollutants are projected to decrease over the LTS period.

Table 8.1 contains the emissions inventory data from 2016 utilized for the base year for NOx, $PM_{2.5}$, SO_2, and VOC. This table is being compared to projected 2028 emissions in Table 8.2 below. The projected 2028 emissions analysis for NOx, $PM_{2.5}$, SO_2, and VOC was completed by LADCO.

Table 8.1 LADCO 2016 Emissions for Point, Area, and Mobile Source (TPY)

	NOx	$PM_{2.5}$	SO_2	VOC
Point	78,096	12,674	100,526	41,108
Area	102,399	80,406	5,946	211,921
Mobile	117,837	4,217	705	65,574
Total	**298,332**	**97,297**	**107,177**	**318,603**

Table 8.2 LADCO Projected 2028 Emissions for Point, Area, and Mobile Sources (TPY)

	NOx	$PM_{2.5}$	SO_2	VOC
Point	73,061	12,575	45,600	43,695
Area	88,663	78,804	6,002	212,101
Mobile	66,706	4,268	470	57,675
Total	**228,430**	**95,647**	**52,072**	**313,471**

IX. Reasonable Progress Goals (40 CFR 51.308(f)(3))

The Regional Haze Rule does not establish presumptive targets for showing reasonable progress goals for Class I areas. Rather, the rule allows states the flexibility to determine reasonable progress goals for Class I areas that improve visibility on the most impaired days and ensure that no degradation occurs on the clearest days. The reasonable progress goals are intended as interim goals that represent incremental progress toward the national goal of mitigating all man-made visibility impairment. The national goal of no man-made impairment is intended to encompass several planning periods of 10 years duration. The first planning period spanned from the beginning of the regional haze program until the year 2018. The second implementation period spans from 2018 to 2028.

Since there are no Class I areas located in Illinois, the State is not required to prepare and submit any analyses regarding the establishment of reasonable progress goals for any Class I areas under 40 CFR 51.308(f)(3). Additionally, since Illinois is not significantly contributing to any Class I area which the RPG is above the URP glidepath, Illinois does not need to provide the "robust demonstration" for not requiring additional emission reductions according to 40 CFR 51.308(f)(3)(ii)(A) and (B).

Illinois has participated in the efforts of LADCO to perform such analyses for Class I areas located in other LADCO states. A detailed description of these analyses can be found in Section 5.0 of the LADCO TSD (see Appendix B).

X. No Need for Additional Monitoring in Illinois (40 CFR 51.308(f)(4))

40 CFR 51.308(f)(4) requires that, " If the Administrator, Regional Administrator, or the affected Federal Land Manager has advised a State of a need for additional monitoring to assess reasonably attributable visibility impairment at the mandatory Class I Federal area in addition to the monitoring currently being conducted, the State must include in the plan revision an appropriate strategy for evaluating reasonably attributable visibility impairment in the mandatory Class I Federal area by visual observation or other appropriate monitoring techniques."

Illinois has not been advised of any such need for additional monitoring, and so has not included any plan revisions due to this requirement.

XI. Progress Report Requirements (40 CFR 51.308(f)(5))

40 CFR 51.308(f)(4) requires states to address the requirements in 40 CFR 51.308(g)(1) through (5) for the period since the most recent progress report, so this plan revision will also serve as a progress report. Those requirements are addressed in this Section XI. Illinois' most recent progress report was adopted in Illinois in October 2016 and submitted to USEPA in February 2017. The following will address those requirements in the period since then.

Description of the Status of Implementation of SIP Measures (40 CFR 51.308(g)(1))

In the first regional haze implementation period, Illinois relied primarily upon three control strategies. These were source-specific permits for two EGU sources, consent decrees for two petroleum refineries, and emission reductions from the great majority of the EGU sources in the state resulting from the MPS and CPS. In addition to all of these measures remaining in place, most Illinois coal-fired EGU sources have shut down or are scheduled to shut down by the end of the second implementation period as detailed under the LTS in Section VI.

The source-specific permits were for the operators of the City Water, Light & Power, City of Springfield ("CWLP") and Kincaid Generation, LLC ("Kincaid"). The CWLP permit required Dallman 31 and 32 units an annual average NOx emission rate of 0.11 lbs/mmBtu and annual SO_2 emission rate of 0.23 lbs/mmBtu beginning in 2017 and forward. The Kincaid permit continues to require their units an annual average NOx emission rate of 0.07 lbs/mmBtu and in 2017 an annual average SO_2 emission rate of 0.15 lbs/mmBtu.

The federal consent decrees for CITGO Petroleum Corporation and ExxonMobil Oil Corporation mandate control at least as stringent as BART and continue to remain in place.

The MPS became more stringent beginning in calendar year 2019 by limiting annual NOx emissions to less than 19,000 tons and annual SO_2 emissions to less than 34,500 tons from all EGUs in each MPS group. Furthermore, from May 1 to September 30 of each year, NOx emissions are limited to less than 11,500 tons from all EGUs and have a NOx average emission rate limit of 0.10 lb/mmBtu in each MPS group.

The CPS has become more stringent due to the scheduled decreasing SO_2 fleet-wide emission rate in the regulation that reached the limit of 0.11 lb/mmBtu in 2019 and subsequent years. The CPS "fleet" was reduced to a single source in 2022, and as such, there will be no more averaging of emissions available.

The most recent progress report also included a list of modeled on-the-books control strategies, all of which remain in place unless they have been replaced with more stringent regulations, e.g., CAIR has replaced CSAPR, and CSAPR has since also been revised for additional pollutant reductions.

The list of measures from the most recent progress report is reproduced below.

On-Road Mobile Sources
- Federal Motor Vehicle Emission Control Program, low-sulfur gasoline, and ultra-low sulfur diesel fuel
- Inspection and maintenance programs, including Illinois' enhanced vehicle inspection and maintenance program, Indiana's vehicle emissions testing program, Ohio's E-check program, and Wisconsin's vehicle inspection program (note: a special emissions modeling run was done for the Cincinnati/Dayton area to reflect the removal of the state's E-check program and inclusion of low RVP gasoline)
- Reformulated gasoline, including in Chicago-Gary-Lake County, IL, IN; and Milwaukee, Racine, WI

Off-Road Mobile Sources
- Federal control programs incorporated into NONROAD model (e.g., nonroad diesel rule), plus the evaporative Large Spark Ignition and Recreational Vehicle standards
- Heavy-duty diesel (2007) engine standard/low sulfur fuel
- Federal railroad/locomotive standards
- Federal commercial marine vessel engine standards

Area Sources
- Consumer solvents
- Architectural and industrial maintenance coatings
- Aerosol coatings
- Portable fuel containers

Electric Generating Units
- Title IV (Acid Rain - Phases I and II)
- NOx SIP Call
- Transport Rule (Part I)

Other Point Sources
- VOC 2-, 4-, 7-, and 1 0-year MACT standards
- Combustion turbine MACT
- Consent decrees (refineries, ethanol plants, and ALCOA)
- NOx RACT in Illinois, Wisconsin, and Ohio

Summary of Emission Reductions Achieved (40 CFR 51.308(g)(2))

40 CFR 51.308(g)(2) requires a summary of the emission reductions achieved throughout the state through implementation of the measures described in the state’s description for (g)(1), in this case Section XI.

NOx and SO_2 emissions for the remaining sources subject to the MPS have declined since the most recent progress report and can be found in Section IV of this document in Tables 4.4 and 4.5.

NOx and SO_2 emissions for the remaining sources subject to the CPS have also declined since the most recent progress report and can be found in Section IV of this document in Tables 4.6 and 4.7.

NOx and SO_2 emissions at the two sources that required source-specific permits for the first implementation period, Kincaid Generating Station and CWLP – Dallman, have also declined since the most recent progress report and can be seen in Tables 11.1 and 11.2. For both Kincaid and CWLP, there is a downward trend in SO_2 and NOx emissions from 2016 to 2022.

Table 11.1 NOx (TPY) Emissions for Kincaid and CWLP – Dallman

Source	2016	2017	2018	2019	2020	2021	2022
Kincaid	1478	1597	1536	1016	374	820	730
Dallman	773	1015	1061	835	380	448	417

Table 11.2 SO_2 (TPY) Emissions for Kincaid and CWLP – Dallman

Source	2016	2017	2018	2019	2020	2021	2022
Kincaid	2133	2365	2262	1491	733	1897	1784
Dallman	1119	1590	1595	1199	400	719	425

NOx and SO_2 emissions at the two petroleum refineries that were examined for the first implementation period, ExxonMobil and CITGO, have remained stable or declined since the most recent progress report and can be seen in Tables 11.3 and 11.4. The consent decrees for these sources are still in force, and additional controls have not been required at these sources since the most recent progress report.

Table 11.3 NOx (TPY) Emissions for ExxonMobil and CITGO

Source	2016	2017	2018	2019	2020	2021	2022
ExxonMobil	1273	1167	1113	956	929	818	887
CITGO	645	665	600	621	523	563	535

Table 11.4 SO_2 (TPY) Emissions for ExxonMobil and CITGO

Source	2016	2017	2018	2019	2020	2021	2022
ExxonMobil	420	434	363	644	551	345	376
CITGO	225	263	216	268	149	207	176

Visibility Progress (40 CFR 51.308(g)(3))

There are no Class I areas located in Illinois, thus the requirements for the progress report in 40 CFR 51.308(g)(3) are not applicable to Illinois.

Statewide Emissions Progress (40 CFR 51.308(g)(4))

Pursuant to 40 CFR 51.308(g)(4), Tables 11.5, 11.6, and 11.7 provide emissions data from three triennial inventories for all sources and activities in the state, including the most recent inventory submitted from 2020. All of these have been submitted to USEPA in compliance with the requirements in 40 CFR 51 Subpart A.

Table 11.5 2014 Statewide Emission Totals (TPY)

	Point	Area	On-Road	Off-Road	Animal	Total
Statewide						
CO	66,072.10	147,491.43	730,668.47	582,077.91		1,526,309.91
NH3	1,900.83	68,177.43	3,867.93	108.65	44,441.50	118,496.34
NOx	99,752.50	58,012.09	174,773.76	116,965.27		449,503.62
PM10	23,959.23	549,656.98	10,073.86	7,511.88		591,201.94
PM2.5	14,260.95	118,444.33	5,285.89	7,074.05		145,065.21
SO_2	182,199.95	5,688.08	1,039.69	2,575.85		191,503.57
VOC	42,344.80	172,830.91	73,769.38	72,795.16		361,740.27

Table 11.6 2017 Statewide Emission Totals (TPY)

	Point	Area	On-Road	Off-Road	Animal	Total
Statewide						
CO	47,477.01	303,674.17	546,960.45	533,467.82		1,431,579.46
NH_3	1,765.48	18,720.07	3,165.50	126.81	50,002.20	73,780.06
NOx	65,502.07	51,650.19	117,591.80	114,978.09		349,722.15
PM10	18,934.54	575,725.58	8,334.25	7,081.93		610,076.30
PM2.5	11,323.96	132,093.00	3,994.98	6,737.13		154,149.07
SO_2	86,826.04	6,212.59	416.86	2,406.13		95,861.61
VOC	38,762.31	215,803.51	53,085.96	53,147.11		360,798.89

Table 11.7 2020 Statewide Emission Totals (TPY)

	Point	Area	On-Road	Off-Road	Animal	Total
Statewide						
CO	65,184.76	239,247.15	459,715.97	434,425.90		1,198,573.78
NH_3	1,526.22	51,677.25	2,734.50	84.08	65,414.89	121,436.94
NOx	55,150.79	49,635.02	71,170.69	66.965.39		286,073.50
PM10	17,532.31	560,792.60	6,469.42	3729.23		588,523.56
PM2.5	10,232.09	98,370.25	2,522.46	3548.04		114,672.84
SO_2	61,747.63	2,021.74	307.29	38.67		64,115.33
VOC	36,670.48	208,607.16	31,618.53	32,588.92		309,485.09

Assessment of Changes Potentially Impeding Visibility Progress (40 CFR 51.308(g)(5))

Illinois EPA has not identified any significant changes in anthropogenic emissions within Illinois that have occurred since the most recent progress report that would limit or impede progress in improving

visibility. There have been no significant unexpected increases in emissions since the most recent progress report or since the Illinois Regional Haze SIP submittal for the first implementation period. Likewise, there have been no projected decreases in pollutant emissions anticipated in the first implementation Regional Haze SIP or most recent progress report that have not been realized.

As Illinois does not contain any Federal Class I areas, Illinois is not required to assess whether emissions increases outside the state are causing a Class I area within the state to be adversely affected.

XII. Monitoring Strategy (40 CFR 51.308(f)(6))

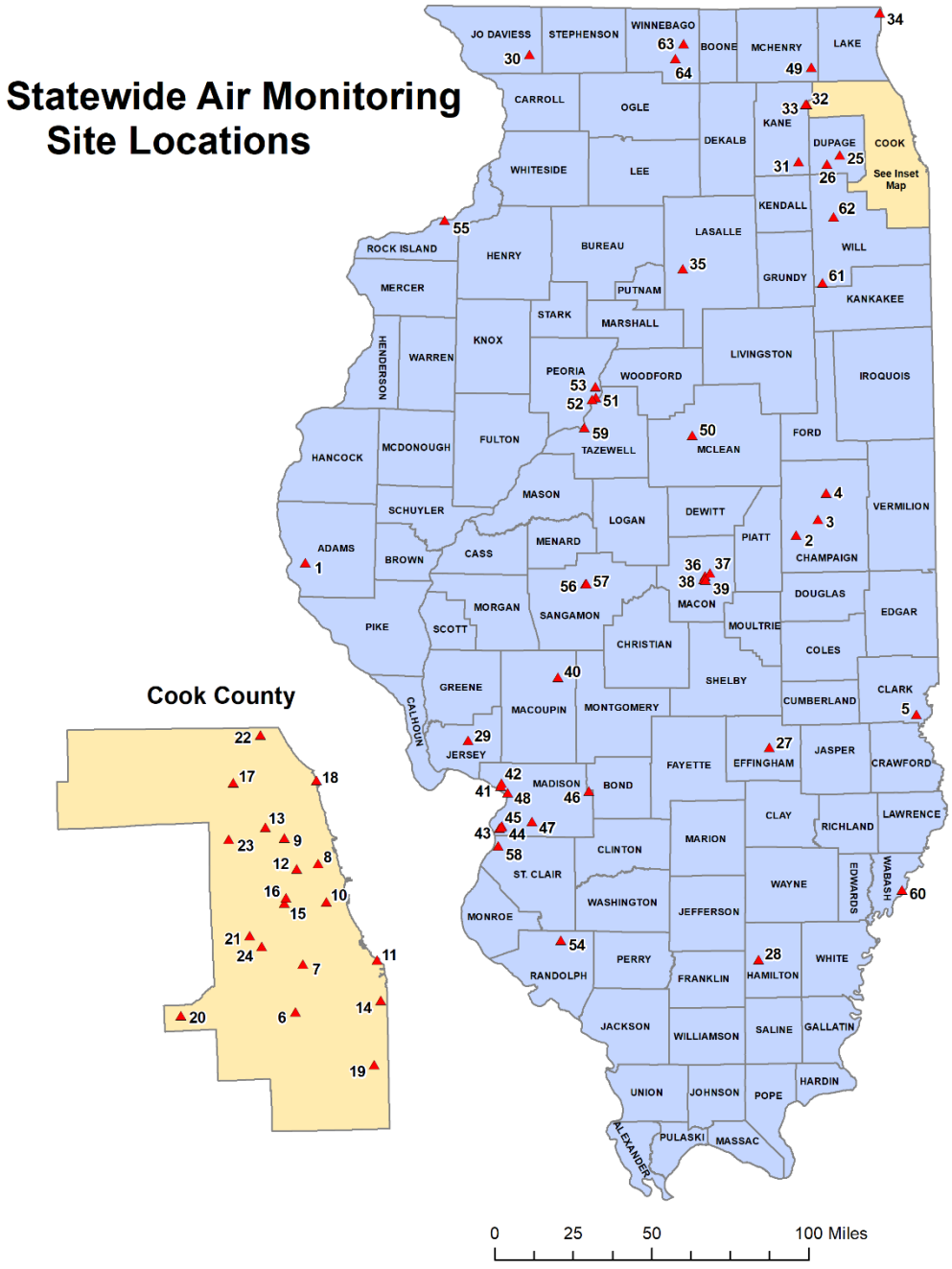
Pursuant to 40 CFR §51.308(f)(6) of the Federal Regional Haze Rule, Illinois currently maintains a monitoring network to measure and report levels of various pollutants, including those that contribute to impairment of visibility in Class I areas. The monitoring program relies upon Illinois' network of monitoring sites that include SLAMS (State and Local Air Monitoring Sites), SPM (Special Purpose Monitors), $PM_{2.5}$ speciation sites (trend and State), NCore (National Core Station), near-road sites, and PAMS (Photochemical Assessment Monitoring Sites). Since there are no Class I areas located in the state, Illinois does not operate any monitoring sites under the Federal IMPROVE (Interagency Monitoring of Protected Visual Environments) program. However, the Illinois State Water Survey operates a monitoring site at Bondville, which is a rural location near Champaign in Central Illinois, that conforms with the IMPROVE protocol.

Figure 12.1 illustrates Illinois' ambient monitoring network. Specific site information, including the pollutants measured, site locations (address and latitude/longitude), and the sampling schedule are included in the Illinois Ambient Air Monitoring 2023 Network Plan, Appendix E to this document.

Illinois is required, pursuant to 40 CFR §51.308(f)(6)(iii), to establish procedures for using monitoring data, along with other information, to determine the contribution of emissions from Illinois sources to visibility impairment at all affected Class I areas outside of the state. These procedures were established in conjunction with the LADCO and are discussed in detail in Sections 7.0 and 8.0 of the LADCO TSD (see Appendix B).

The monitoring network in Illinois will be maintained and will continue to measure pollutants that contribute to visibility degradation. In addition, Illinois will continue to determine its contribution to visibility impairment in mandatory Class I Federal areas, and to assess whether reasonable progress goals addressing regional haze are being achieved.

Figure 12.1 Ambient Air Monitoring Locations in Illinois



XIII. Consultation

Illinois is required by the Regional Haze Rule to participate in a consultation process with FLMs and states that have Class I areas impacted by emissions from sources in Illinois. Below is a description and documentation of the consultation process.

Illinois has participated in meetings and conference calls with states within the LADCO and with the other RPOs outside the Midwest to discuss their assessments of visibility conditions, analyses of culpability, and possible measures that could be taken to meet visibility goals.

Consultation with States and Tribes with Class I Areas in LADCO and Other Regions

Throughout the planning process for the second implementation period and since the most recent regional haze progress report, Illinois has participated in regular calls meetings, discussions, consultation, and correspondence facilitated by LADCO. During this process, Illinois has taken part in monthly calls with representatives of the other LADCO states (IN, MI, MN, OH, WI), USEPA Region 5, representatives of FLM agencies, and occasionally from other states, tribes, and RPOs. These meetings facilitated by LADCO have occurred monthly since December of 2017, and have involved discussions of state emissions data, modeling methodologies and results, methodologies for selecting sources for four factor analysis, development of state SIP submittals, and other consultation. Minutes of these meetings are and have been publicly available on the LADCO website, and upon request.

Illinois also consulted with other states from outside the LADCO region by participating in the inter-RPO process that was used to develop coordinated strategies necessary to meet the requirements of the Regional Haze Rule.

Illinois relied on the technical work performed by LADCO, and informed by the inter-RPO process, to project visibility conditions for the end of the second implementation period in 2028 pursuant to 40 CFR 51.308(f)(2)(ii). LADCO projected significant visibility improvements when compared to the 2016 base year used for all of the Class I areas located in LADCO member states and found the conditions at all of those Class I areas to be below the unadjusted uniform rate of progress “glidepaths” at each of the areas, and well below adjusted glidepaths at each area. Figures 13.1 through 13.4 show projected visibility conditions, historical conditions, the 2064 conditions for meeting the goals of the Regional Haze Rule, and the glidepaths toward those goals.

Figure 13.1 Visibility Projections for Boundary Waters Canoe Area National Wilderness Area, MN

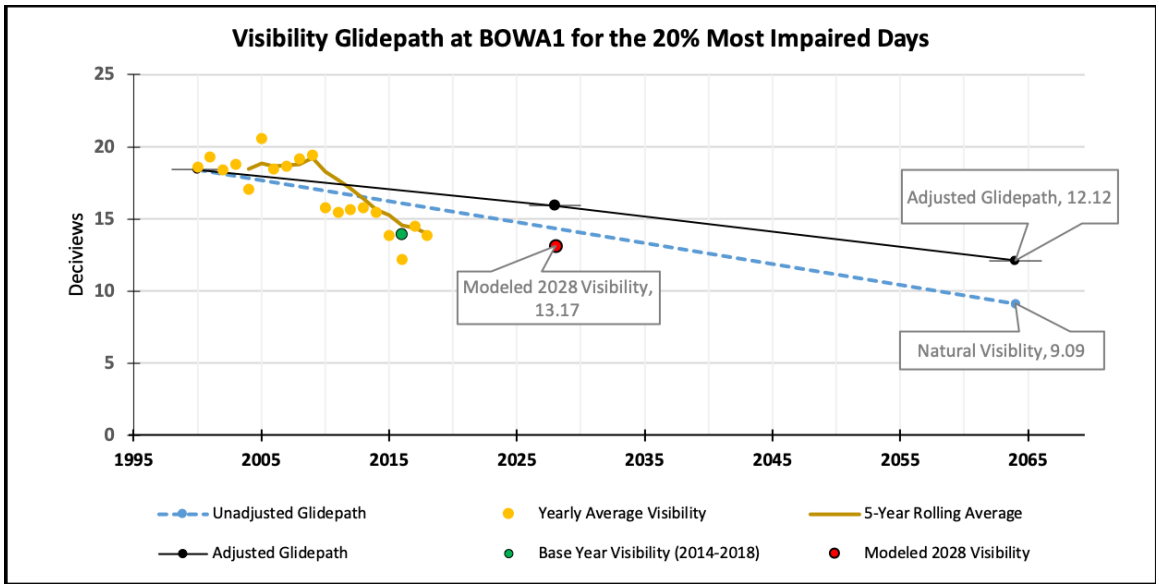


Figure 13.2 Visibility Projections for Isle Royale National Park, MI

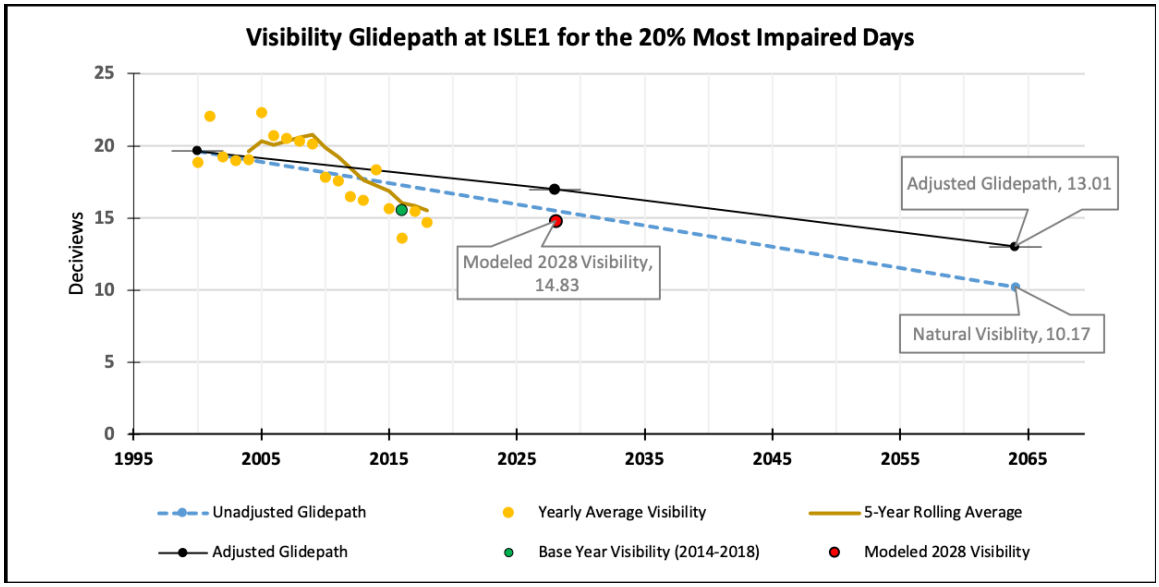


Figure 13.3 Visibility Projections for Seney National Wilderness Area, MI

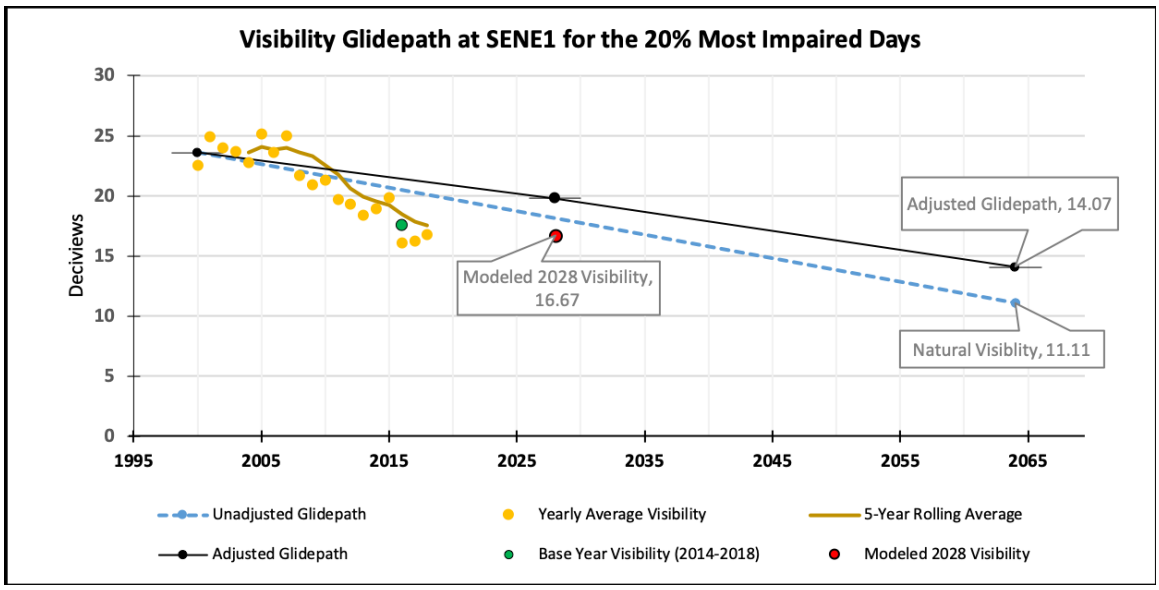
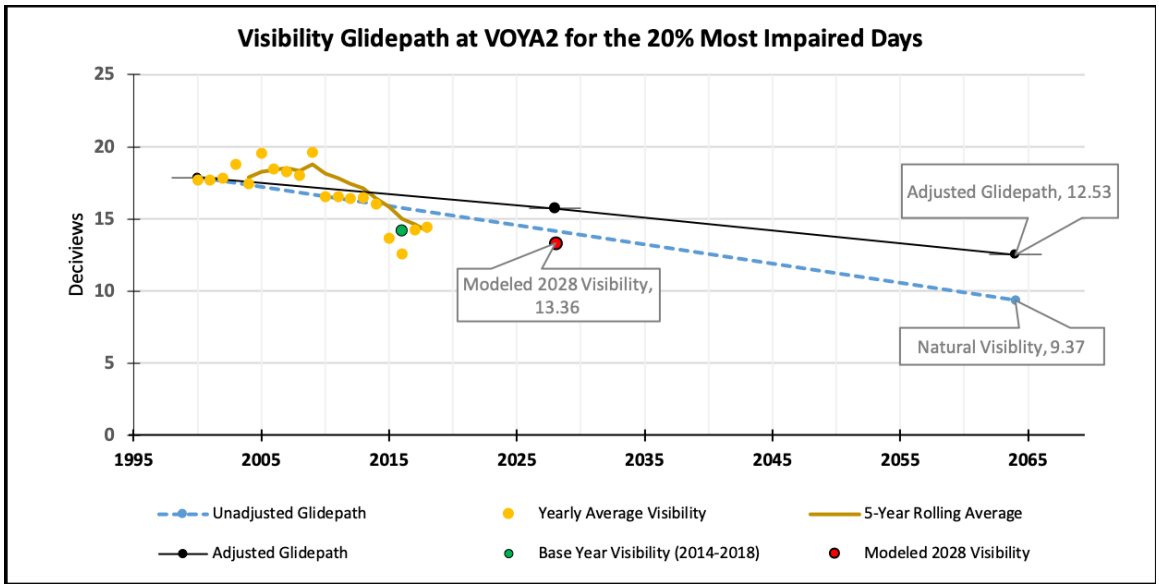


Figure 13.4 Visibility Projections for Voyageurs National Park, MN



Consultation with other states and RPOs, in addition to information included in the USEPA TSD, confirm that the projected visibility conditions at the other Class I areas closest to Illinois are similarly below the glidepaths for 2028. These areas include Mammoth Cave in Kentucky and the Mingo Wilderness Area and Hercules Glade Wilderness Area in Missouri, which are the class 1 areas closest to Illinois and should be impacted the most by Illinois. Significant emission reductions throughout the region have led to these projections, including the substantial emission reductions achieved and anticipated in Illinois before the projected year.

Specific Consultation Requests

Arkansas

Illinois EPA received a letter dated February 4, 2020, from the Arkansas Department of Energy and Environment (see Appendix C) stating that its study had identified Prairie State Generating Station as reasonably anticipated to impact visibility conditions at the Upper Buffalo Class I area located in Arkansas. It was further requested that Illinois EPA "consider whether performing a four factor analysis is appropriate for the listed source in accordance with 40 CFR 51 .308(0(2)(i) and, if so, whether any control measures for sulfur dioxide or nitrogen oxides are necessary to make reasonable progress towards natural visibility at Upper Buffalo during the 2021 - 2028 planning period." Illinois EPA replied to the contact person designated in the letter that Illinois had already considered the source for analysis and would indeed be conducting a four factor analysis for the source. That analysis has been included with this SIP submission.

Mid-Atlantic Northeast Visibility Union ("MANE-VU")

MANE-VU, August 25, 2017, issued an "Ask" with regard to the second implementation period that was directed to Alabama, Florida, Illinois, Indiana, Kentucky, Louisiana, Michigan, Missouri, North Carolina, Ohio, Tennessee, Texas, Virginia, and West Virginia (see Appendix D). The Ask recommended the following strategies:

1. *Electric Generating Units (EGUs) with a nameplate capacity larger than or equal to 25MW with already installed NOx and/or* SO_2 *controls - ensure the most effective use of control technologies on a year-round basis to consistently minimize emissions of haze precursors, or obtain equivalent alternative emission reductions;*
2. *Emission sources modeled by MANE-VU that have the potential for 3.0 Mm-1 or greater visibility impacts at any MANE-VU Class I area, as identified by MANE-VU contribution analyses (see attached listing) - perform a four factor analysis for reasonable installation or upgrade to emission controls;*
3. *States should pursue an ultra-low sulfur fuel oil standard similar to the one adopted by MANE-VU states in 2007 as expeditiously as possible and before 2028, depending on supply availability, where the standards are as follows:*
    a. *distillate oil to 0.0015% sulfur by weight {15 ppm),*
    b. *#4 residual oil to 0.5% sulfur by weight,*
    c. *#6 residual oil to 0.5% sulfur by weight.*
4. *EGUs and other large point emission sources larger than 250 MM BTU per hour heat input that have switched operations to lower emitting fuels - pursue updating permits, enforceable agreements, and/or rules to lock-in lower emission rates for S02, NOx and PM. The permit, enforcement agreement, and/or rule can allow for suspension of the lower emission rate during natural gas curtailment;*
5. *Each State should consider and report in their SIP measures or programs to: a) decrease energy demand through the use of energy efficiency, and b) increase the*

use within their state of Combined Heat and Power (CHP) and other clean Distributed Generation technologies including fuel cells, wind, and solar.

Illinois considered all of these strategies for meeting its requirements under the Regional Haze Rule, as follows.

Strategy 1: Illinois already required the consistent use of installed controls for NOx and SO2. This issue was also addressed with updates to CSAPR that were targeted specifically for this purpose. At that time the adjustment to Illinois' allowance budget to ensure consistent use of controls was minimal.

Strategy 2: No sources in Illinois were listed.

Strategy 3: Illinois has state-wide SO_2 standards meeting those in the Ask.

Strategy 4: Illinois is not aware of any sources in the state that have undergone fuel-switching without also having undergone permitting transactions requiring appropriate emission rates.

Strategy 5: Illinois considered including the measures identified in its regional haze SIP, but concluded that while energy efficiency, CHP, and other clean energy technologies are a priority in Illinois, many of those measures are not easily quantifiable and putting those measures in the Regional Haze SIP is not required.

Coordination with Federal Land Managers (40 CFR 51.308(i))

Title 40 CFR 51.308(i) requires coordination between Illinois and the FLMs. Opportunities have been provided by LADCO for FLMs to review and comment on each of the technical documents developed by LADCO and included in this SIP. As noted above, FLM agencies were included on monthly calls with Illinois, LADCO, other states, and USEPA, and Illinois EPA prepared their SIP submittal prior to the consultation process informed by input from that process. Illinois has provided Agency contacts to the FLMs as required. In development of this plan, the FLMs were consulted in accordance with the provisions of 40 CFR §51.308(i)(2).

During the consultation process, the FLMs were given the opportunity to address their assessments of the impairment of visibility in any Class I areas, to provide recommendations on the development of reasonable progress goals, and to provide recommendations on the development and implementation of strategies to address visibility impairment. On August 14, 2023, Illinois EPA shared with FLMs and USEPA a draft Regional Haze SIP providing at least 60 days before holding a public hearing as required under 40 CFR 51.308(i)(2). On October 13, 2023, Illinois EPA received comments from the FLMs on the draft Regional Haze SIP. The following is a summary of the requests from the FLM comments:

Summary of Recommendations from the NPS:

- Revising the source selection criteria threshold to be a facility wide Q/d greater than 4 to capture more Illinois facilities and emission units.
- Provide additional analysis and documentation of the four factor analyses for better documentation of rationale.

- Identify the specific criteria and cost-effectiveness threshold used for SIP determinations for this second regional haze implementation period.
- Evaluate and implement additional cost-effective measures including improved scrubber efficiency and DSI for Prairie State Generating Station, replacing or upgrading the existing DSI for Archer Daniels Midland, and DSI for SIPCO.
- Conduct four factor analyses for all nine coal-fired boilers at Archer Daniel Midland.
- Obtain facility-specific vendor quotes for the two kilns at Rain Carbon and implement the cost-effective controls at the facility.
- Update the cost effectiveness for fuel-switching and repowering options to reflect shutdown of unit 4 at SIPCO.
- Conduct additional four factor analyses for Wood River refinery, Marathon refinery, and Fuyao Glass and implement any cost-effective measures identified.
- Make the pending shutdown of certain EGUs federally enforceable and included in the SIP.

Summary of Recommendations from the USFS:

- Reevaluate the source selection threshold to include units that could have cost-effective controls identified, particularly at Archer Daniels Midland.
- Select a cost-effectiveness threshold higher (in $/ton) than the previous implementation period.
- Calculated cost per ton for each pollutant individually for certain control technologies.
- Revisit cost threshold and control costs to provide better context on control technologies and reconsider their implementation.
- Add language to ensure enforceability of shutdown of Holcim Kiln 2 and use of 60% low sulfur fuel at ADM.

Illinois EPA response to FLM comments are included in Appendix H.

XIV. Public Participation Requirements for SIP Submittal

[This section will be completed after public notice and any requested public hearings take place.]

APPENDIX A: Illinois Four Factor Analyses

Prairie State 4-Factor Analysis

1.0 Prairie State Generating Station Regional Haze Four-Factor Analysis

The four-factor analysis for the Prairie State Generating Station in this document is for determining whether the source is already reasonably controlled or requires additional control in order to make reasonable progress.

2.0 Prairie State Generation Station Source Description

The source is a mine-mouth electric generating plant which operates two fossil fuel fired boilers rated at 7450 mmBtu/hr each for electric generation at the plant near Marissa in Washington County Illinois.

2.1 Emission Units Description

The source has several emission units that include storage tanks, coal handing systems, and boilers. The main emission units at this source are the two identical dry bottom pulverized coal wall-fired boilers built by Bechtel Engineering Company. The Illinois EPA emission inventory identifies the boilers as emission point sources four and five and describes them as Boiler 1 and 2. Boiler 1 started operating in 2011 and boiler 2 started operating in 2012. The main fuel to produce heat is coal and natural gas is used as the startup fuel.

2.2 Source Existing Control Systems

The source has several emission control systems, and the boilers are the main emission units controlled by several control systems. PM emissions are controlled by dry electrostatic precipitators ("dry ESP") and wet Electrostatic Precipitators ("wet-ESP"). NOx emissions are controlled using low-NOx burners ("LNB") and Selective Catalytic Reduction ("SCR"). Mercury emissions are controlled by powdered Activated Carbon Injection ("ACI") and ESPs. SO_2 emissions are controlled by wet Flue Gas Desulfurization ("wet FGD").

Table 2.2A lists a summary of emission units, control systems, and reported control system efficiencies.

Table 2.2A List of Boilers and Control systems (Construction Permit 01100065)

Agency Emission Point Source #	Boiler Name and Description	Emission Control Systems	Reported Control Efficiency (%)
0004	Boiler 1 – Pulverized coal dry bottom wall-fired boiler	LNB	--
		SCR	87
		dry ESP	99.7
		ACI	90
0005	Boiler 2 – Pulverized coal dry bottom wall-fired boiler	wet FGD	98
		wet ESP	99.2

Based on the emission control systems the facility has in place, PM2.5 emissions are 99.7% controlled, NOx emissions are 87% controlled, and SO_2 emissions are 98% controlled. Table 2.2B lists four years of reported emissions in tons per year (TPY). Based on the control system efficiency and the amount of reported emissions, the four-factor analysis for this facility will be limited to the emissions of NOx and SO_2.

Table 2.2B Source Reported Emissions

Pollutant	Reported Emissions (TPY)			
	2016	**2017**	**2018**	**2019**
PM2.5	224.34	227.03	242.54	250.71
NOx	3,548.97	3,768.89	4,049.11	4,138.15
SO_2	8,630.61	9,358.65	10,279.81	10,728.3

2.3 Source NOx and SO_2 Emissions

The source burns fossil fuels to extract heat energy for electricity generation. Fossil fuels are a complex mixture of organic and inorganic compounds, containing carbon, hydrogen, oxygen, sulfur, nitrogen and other minerals including mercury. The process of extracting heat-energy involves chemical reactions which produce the haze forming pollutants NOx and SO_2. The source is permitted to emit 0.07 lb/mmBtu of NOx and 0.182 lb/mmBtu of SO_2.

2.3.1 Current NOx Emissions Assessment

NOx emissions from coal-burning boilers are from the formation of NOx in the boiler. NOx forms in three ways: thermal NOx, prompt NOx, and fuel NOx. Thermal and fuel NOx are the main contributors of NOx formation in coal-fired boilers. Thermal NOx is the result of oxidation of the atmospheric nitrogen, and fuel NOx is the result of oxidation of nitrogen bound in the coal (USEPA AP-42). Table 2.3A lists the current allowable emissions and performance in terms of lb/mmBtu. Table 2.3B lists unit characteristics from USEPA National Electric Energy Data System (NEEDS v6 December 2019) and calculated emissions rates.

Table 2.3A Boilers 2019 Reported and Allowable NOx Emission Rates

Units	Reported Operating (hr/yr)	Reported Operating Rate (ton/hr)	Reported Heat Content (Btu/lb)	Reported (lb/hr)	Based on Report-calculated (lb/mmBtu)	Allowable (lb/mmBtu)
Boiler 1	7393	515.14	8435	538.97	0.0620	0.07
Boiler 2	8138	506.54	8403	527.05	0.0619	0.07

Table 2.3B USEPA Provided Prairie State Generation Coal Unit Characteristics (NEEDS v6 December 2019)

Boiler ID	On-line Year	Capacity (MW)	Heat Rate (Btu/kWh)	2019 SO_2 (tons)	2019 NOX (tons)	2019 Heat Input (mmBtu)	2019 Generation (MWh)	Calculated	
								2019 NOx (lb/mmBtu)	2019 SO_2 (lb/mmBtu)
1	2011	812	9,515	5,277	1,985	64,863,820	6,082,164	0.0612	0.1627
2	2012	816	9,521	5,464	2,140	70,219,452	6,821,053	0.0610	0.1556

2.3.2 Current Units SO_2 Emission Assessment

SO_2 emissions from fossil fuel fired combustion sources are dependent on the sulfur content of the fossil fuel and are not affected by any other combustion source parameters such as size of the combustion source, design, or grade of the fossil fuel being burned. Approximately 95 percent of emissions of oxides of sulfur are in the form of SO_2, and the rest are in the form of SO3, sulfuric acid mist, and a small-amount of sulfates [USEPA AP-42, 2010]. The Prairie State mine-mouth power plant burns Illinois bituminous coal with reported sulfur content of 3.73%. Table 2.3C lists the current boiler emissions as reported for year 2019 and allowable emission rates and performance in terms of lb/mmBtu.

Table 2.3C Boilers Allowable and 2019 Reported SO_2 Emission Rates

Units	2019 Reported (lb/hr)	Based on Report-calculated (lb/mmBtu)	Allowable (lb/mmBtu)
Boiler 1	1423.07	0.1627	0.182
Boiler 2	1343.8	0.1556	0.182

2.3.3 Units Existing NOx and SO_2 Control systems

The current emission inventory and facility reports show NOx and SO_2 emissions are controlled using Best Available Control Technology ("BACT"). NOx emissions are controlled using LNB and SCR systems which achieve reductions over 90%. SO_2 emissions are controlled using wet FGDs achieving 98% reduction. Therefore, in this analysis, the more detailed cost of compliance for additional NOx and SO_2 emissions reductions for the Prairie State power plant is limited to improvement of the control system, fuel switching, and/or repowering.

3.0 Control Measures

Prairie State is a mine-mouth power plant requiring no transportation of fuel or the associated costs. Since the source was permitted as a mine-mouth facility, fuel switching control options cannot be considered in the analyses, as those control options would change the nature of the source to the extent that it would need to be permitted as a completely new source in the state. Due to this, Due to this, and based on the add-on BACT-level control systems the source has in place, the control measures evaluation for this source are limited to: (1) making improvements to the existing NOx and SO_2 control systems for higher emissions reduction, and (2) repowering to Integrated Gasification Combine Cycle ("IGCC").

3.1 Existing Control Systems Improvements

Based on the USEPA provided documents, Power Sector Modeling Platform v.5.13 (EPA # 450R13002, November 2013) (Base Case v.5.13) and Platform v6 (May 2018), Prairie State power station has BACT-level add-on control systems in place for controlling NOx emissions using LNB and SCR. The plant is permitted to emit NOx at the rate of 0.07 lb/mmBtu, and it is reporting NOx emissions averaging 0.061 lb/mmBtu. The source SO_2 emissions are controlled using an add-on wet FGD control systems. The plant is permitted to emit at the rate of 0.182 lb/mmBtu, and it is reporting SO_2 emission averaging 0.16 lb/mmBtu.

From USEPA, the document, Base Case v.5.13, describes the SCR control system:

"*the NOx reduction in a SCR system takes place by injecting ammonia (NH3) vapor into the flue gas stream where the NOx is reduced to nitrogen (N2) and water (H2O) abetted by passing over a catalyst bed typically containing titanium, vanadium oxides, molybdenum, and/or tungsten.*"

The control system has a NOx percent removal efficiency of 90% with rate floor of 0.07 lb/mmBtu when burning bituminous coal. Prairie State power station burns Illinois coal and is achieving a NOx emission rate of 0.061 lb/mmBtu on average by employing LNB and SCR control systems. Based on the USEPA provided Excel spreadsheet tool for calculating costs in year 2016 dollars, the SCR control system alone has a cost effectiveness of $2613 per ton of NOx removed. Therefore, based on the control systems rate floor of 0.07 lb/mmBtu, the control system improvement for additional NOx reduction would be technically infeasible.

For SO_2, Base Case v.5.13 listed wet FGD control systems as Limestone Forced Oxidation ("LSFO") and describes the wet FGD control system: "*In wet FGD systems, the polluted gas stream is brought into contact with a liquid alkaline sorbent (typically limestone) by forcing it through a pool of the liquid slurry or by spraying it with the liquid*". The control system is assumed to achieve removal efficiency of 96% with a rate floor of 0.06 lbs/mmBtu. The Prairie State power station wet FGD control system is achieving SO_2 reduction of 98% which is above USEPA Base Case v.5.13 assumed removal efficiency of 96%. Based on the USEPA provided Excel spreadsheet tool for calculating costs in year 2016 dollar, the wet FGD control system for Prairie State power station has a cost effectiveness of $407 per ton of SO_2 removed. Based on USEPA Base Case v.5.13 assessment of current RACT-level control systems technology and Prairie State power station of burning Illinois high sulfur coal to extract heat-energy, the assumed rate floor of 0.06 lbs/mmBtu would not be achievable by improving the control system, therefore control system improvement for additional SO_2 reduction would be technically infeasible.

3.2 Repowering to Integrated Gasification Combined Cycle Control Option

The USEPA provided document "The Menu of Control Measures" describes the IGCC control measure applicable for EGU boiler as:

"*Repowering improves power plant efficiencies and implies significant waste reduction. Typical repowering entails steps in which the coal handling system and the boiler are replaced with new combustion turbines and a heat recovery boiler. The only significant part of the plant that is maintained is the original turbine generator. The IGCC is a repowering option that requires extensive gasification equipment to generate synthetic gas from coal in order to feed the gas turbines. IGCC plants offer the capability of removing the Hg from the compressed syngas prior to combustion where the gas volume treated is much less than the low pressure, post-combustion flow volume.*"

This control measure, repowering to IGCC, achieves control efficiency of 99% SO_2 reduction and the document presents cost effectives in 2006$ as:

"Cost effectiveness is variable depending on nameplate capacity: - capital cost = $1,027 per kW, - fixed O&M cost = $33.37 per kW per year, and - variable O&M cost = $3.17 mills per kW"

For Prairie State power plant based on current allowable source wide SO_2 emissions of 11,878 TPY (2 boilers – heat rate 7450 mmBtu/hr each, 8760 hrs/yr, and allowable emission rate of 0.182 lb/mmBtu) and total plant size of 1600 MW (2 boilers – 800 MW each), control efficiency of 99%, control system useful life of 40 years, capital recovery factor of 0.0623 (based on 40 years useful life and 5.5% interest rate); and for NOx 28.6% reduction based on allowable emissions rate of 0.07 lb/mmBtu and rate floor of SCR control system of 0.05 lb/mmBtu reduction of 298 TPY, the cost effectiveness of the IGCC control measure in terms of 2006$/ton is $13,348.49 per ton of both NOX and SO_2 emissions removed. Table 3-4 presents the costs and cost effectiveness for IGCC control measure.

Table 3.4 Repowering to Integrated Gasification Combined Cycle Control Option

Cost Factor	Description and Notes	Costs
Total capital cost (2006$) Prairie State two boilers, nameplate capacity 800 MW each	Capital cost = $1,027 per kW, total capital cost of the control system (based on total boilers nameplate capacity of 1600 MW)	$1,643,200,000.00
Capital recovery factor ("CFR") for annualizing cost per year	For annualizing the capital cost , the total capital investment multiplied by a capital recovery factor (CRF = (i (1+ i)n)/((1+ i)n - 1), Where n = Useful Life (40 years) and i= interest rate (5.5%)) equated to 0.0623	$102,371,360.00
Fixed O&M cost (2006$)	Fixed O&M cost = $33.37 per kW per year based on 1600 MW, total cost per year	$53,392,000.00
Variable O&M cost (2006$)	Variable O&M cost = $3.17 mills per kW, based on total capacity 4789 MW and major overhauls on a three-year cycle, cost per year	$5,072.00
CFR for annualizing	For annualizing capital cost, the total capital investment multiplied by a capital recovery factor	$1,880.19

variable O&M cost (2006$)	(CRF = (i (1+ i)n)/((1+ i)n - 1), Where n = major overhauls on a three-year cycle (3 years) and i= Interest Rate (5.5%)), CFR equated to 0.3707	
Total annual cost of the control measure (2006$)	Total capital cost per year + fixed O&M cost per year + variable O&M cost per year	$155,765,240.19
Control option NOx emission reduction	28.6% reduction from current allowable NOx emission rate of 0.07 lb/mmBtu, based on rate floor of 0.05 lb/mmBtu (the 0.05 lbs/mmBtu floor is the same as the NOx rate floor for new retrofit SCR on units burning natural gas, the source will still need NOx control system and assumed the control system to achieve a rate floor of 0.05 lb/mmBtu (298.3 TPY NOx reduction)	--
Control option SO_2 emission reduction	99% reduction, based on the allowable emission rate of 0.182 lb/mmBtu and 99% emission reduction (11669.13 TPY SO_2 reduction)	--
Cost effectiveness 2006$/ton	Based on NOx emission reduction of 298.3 TPY and SO_2 emission reduction of 11669 TPY	$13,348.49
Cost effectiveness 2020$/ton	The 2020$/ton costs effectiveness is converted from the study year to year 2020 using consumer price index data through November 2020.	$17,219.55

4.0 Four Factor Analysis

The guidance state:

> *"Characterization of factors for emission control measures. Identify potential emission control measures for the selected sources, develop data on the four statutory factors and on visibility benefits if they will be considered. See 40 CFR 51.308(f)(2)."*

The protection of visibility rule codified in 40 CFR Part 51 Subpart P section 51.308(f)(2)(i) concerning the four-factor analysis states:

> *"The State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment. …The State must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy."*

The four factors analysis for the Prairie State power plant evaluated two boilers for additional NOx and SO_2 emissions control measures for reasonable progress based on the following:

1. Costs of compliance.

2. Time necessary for compliance.
3. Energy and non-air quality environmental impacts of compliance.
4. Remaining useful life of any potentially affected anthropogenic sources.

4.1 Factor 1 – Costs of Compliance

Prairie State power station has in place BACT-level add-on control systems for controlling both NOx and SO_2 emission. The potential theoretically feasible control measure evaluated in this four-factor analysis (repowering to IGCC) is economically infeasible at $17,219 per ton of pollutant removed in 2020$. At this time, the high costs effectiveness of these control measures is not justified. Therefore, Illinois EPA will not be proposing any of these control measures be implemented at Prairie State Generating Station.

4.2 Factor 2 - Time Necessary for Compliance

The time necessary for compliance includes the time the Agency needs to develop, propose, and implement the SIPs and regulation, which usually takes around two years. The time needed for affected sources to implement the proposed control measure is two to five years. Based on the current BACT-level NOx and SO_2 emission control systems in place and sources actual NOx and SO_2 emission rates of 0.061 lb/mmBtu and 0.161 lb/mmBtu respectively, again Illinois EPA will not be proposing any new additional NOx or SO_2 control measures for Prairie State power station. Therefore, more detail analysis of the time necessary for compliance by implementing control measures of fuel switching or repowering to IGCC does not apply and is not evaluated.

4.3 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

As mentioned previously, Prairie State power station has add-on control systems for controlling both NOx and SO_2 emissions. The technique behind during combustion NOx controls is to limit both thermal and fuel NOx formation by reducing the peak flame temperature and by delaying mixing of the fossil fuel and air. In coal-fired boilers these would result lower thermal energy, increases unburned carbon as well as increases incomplete oxidation, increasing CO emissions, thus decreases boiler efficiency. The unburn carbon as an elemental carbon can also affect salable fly ash and may interfere with performance of the ESP control systems (USEPA EGU-ACT 1994). Post-combustion NOx control systems the source has in place, SCR would also affect efficiency negatively for meeting auxiliary power requirements as well as issues with possible hazardous solid waste disposals, reagent storage, and ammonia slips. The wet FGD for SO_2 emission control would also increase auxiliary power requirements that include heat rate and capacity penalties. Other wet FGD control system environmental impacts may include increased water usage and discharges of polluted water from a control device as well as solid or hazardous waste generation. Again, based on the current NOx and SO_2 control systems the source has in place and emission rates of the source, at this time Illinois EPA will not be proposing any new NOx or SO_2 control measures for Prairie State power plant.

4.4 Factor 4 - Remaining Useful Life of Potentially Affected Sources

Useful life of boilers at power generating sources vary widely. According to the EIA: "*The U.S.*

coal units that retired in 2018 had an average capacity of 350 megawatts (MW) and an average age of 46 years, compared with an average capacity of 129 MW and average age of 56 years for the coal units that retired in 2015" (https://www.eia.gov/todayinenergy/detail.php?id=40212). The USEPA assesses the useful life of coal fired boilers to be 40 years. Table 4-4A lists USEPA Base Case v5.13 assumptions of useful life and life extension costs for doubling the useful life of different unit types.

Table 4.4A EGU Combustion Unit Useful Life

Plant Type	Lifespan without Life Extension Expenditures	Life Extension Cost as Proportion of New Unit Capital Cost (%)	Capital Cost of New Unit (2011$/kW)	Life Extension Cost (2011$/kW)
Biomass - Fluidized Bed	40	6.6	4429	291
Coal Steam	40	7	3160	221
Combined Cycle	30	9.3	1047	98
IGCC	40	7.4	3254	241

Source: USEPA, "Life Extension Cost Assumptions Used in EPA Base Case v.5.13, Chapter 4", 2013. https://www.epa.gov/sites/production/files/2015-07/documents/chapter_4_generating_resources_0.pdf

Illinois emissions unit data record shows Prairie State power station boilers stared operating in 2011 and 2012. Prairie State power plant may operate its coal-fired boilers for the foreseeable future and keep the BACT-level control systems in place at all time. Again, based on the current NOx and SO_2 control systems the source has in place and emission rates of the source, at this time Illinois EPA will not be proposing any new NOx or SO_2 control measures for Prairie State power plant.

4.5 Four-Factor Analysis Conclusion

Based on BACT-level control systems the source has in place for significant NOx and SO_2 emissions and the high cost of the alternative control measure as evaluated in this analysis, Illinois EPA will not be proposing any new emissions control measures for Prairie State boilers in this regional haze second implementation period (2018-2028).

SIPCO 4-Factor Analysis

1.0 Southern Illinois Power Cooperative Regional Haze Four-Factor Analysis

The four-factor analysis for Southern Illinois Power Cooperative ("SIPCO") in this document is determining whether the source is already reasonably controlled or requires additional control in order to make reasonable progress.

2.0 Southern Illinois Power Cooperative Source Description

SIPCO is an electric generating facility operating near Marion, Illinois. It operates two natural gas fired turbines and two fossil fuel fired boilers for electric generation that use heat to convert water into steam for driving turbine electric generators (USEPA AP-42).

2.1 Haze forming Main Emission Units Description

The source has several emission units that include storage tanks, coal handing systems, turbines, and boilers. The main emission unit at this source is the coal fired boiler, Unit #123. Boiler Unit #123 started operating in 2003.

Boiler Unit #123 is circulating fluidized bed ("CFB") coal-fired boiler built in 2001, has a firing capacity of 1400 mmBtu/hr, and is served by its own stack. CFB boilers operate by moving fossil fuel into a fluid-like through suspension in a gas or liquid state, then combusting the fossil fuel while in the suspended state. The boiler is designed to burn a variety of solid fuels, including coal, coal refuse, petroleum coke, tire derived fuel, and wood chips. This boiler can fire fuel oil or natural gas as auxiliary fuel during startup and for flame stabilization (Title V permit).

2.2 Source Existing Control Systems

The source has several emission control systems for the boilers. PM emissions are controlled by electrostatic precipitators ("ESP"), baghouse, and wet scrubber. NOx emissions are controlled using low-NOx burners ("LNB") with water injection system, overfire air ("OFA"), selective noncatalytic reduction ("SNCR"), and selective catalytic reduction ("SCR"). SO_2 emissions are controlled by limestone injection system and wet limestone flue gas desulfurization ("Wet-FGD"). Table 2.1 lists a summary of emission units, control systems, and reported control system efficiencies.

Table 2.1 List of Boilers and Control systems

Emission Unit	Description	Emission Control Equipment	Control System Efficiencies (%)
Boiler Unit #123	Circulating Fluidized Bed coal fired boiler 1,400 mmBtu/hr (120 MW)	Fluidized Bed Limestone Injection	90
		SNCR	

		Baghouse	99

Based on the emission control systems the facility has in place, PM2.5 emissions are 95-99.3% controlled, NOx emissions are 65-80% controlled, and SO_2 emissions are 90% controlled. Based on the control system efficiency and the size of reported emissions in terms of ton per year ("TPY") as shown in Table 2.2 of the for the years 2015-2019, the four-factor analysis for this facility will be limited to NOx and SO_2 emissions only.

2.3 Source NOx and SO_2 Emissions

The source's boiler burn fossil fuels to extract heat. Fossil fuels are a complex mixture of organic and inorganic compounds, containing carbon, hydrogen, oxygen, sulfur, nitrogen and other minerals including mercury. The process of extracting heat-energy involves chemical reactions which produce NOx and SO_2. The source is regulated under IAC title 35 permit program and federal programs (NSPS-40 CFR part 60, subparts D and Da) that limit emissions of NOx and SO_2. Table 2.2 shows data from the last five periodic emission inventories for the source and from its 2019 emission report. Table 2.3 shows NOx and SO_2 emission data at the unit level for 2015 to 2019.

Table 2.2 Source NOx and SO_2 Reported Emissions

Pollutant	Reported Emissions (TPY)					
	2005	**2008**	**2011**	**2014**	**2017**	**2019**
NOx	4,480.20	3,300.00	1,676.40	3,510.90	903.20	1,197.80
SO_2	7,220.00	4,942.00	8,502.10	8,651.60	3,830.80	5,843.70

Table 2.3 Unit-level Emissions 2015 - 2019

Unit	Pollutant	Reported Emissions (TPY)				
		2015	**2016**	**2017**	**2018**	**2019**
123	NOx	421	380	389	410	389
123	SO_2	1,622	1,620	1,510	1,962	2,039

2.3.1 Current Boilers NOx Emissions Assessment

NOx emissions from coal-burning boilers are from the formation of NOx in the boiler. NOx forms in three ways: thermal NOx, prompt NOx, and fuel NOx. Thermal and fuel NOx are the

main contributors of NOx formation in coal-fired boilers. Thermal NOx is the results of oxidation of the atmospheric nitrogen in high temperature of the boiler, and fuel NOx is the results of oxidation of nitrogen bound in the coal (USEPA AP-42).

SO_2 emissions from coal-burning boilers are entirely dependent on sulfur content of the coal and are not affected by any other boiler parameters such as size of the boiler, design, or grade of the coal being burned. Approximately 95 percent emission of oxides of sulfur is in the form of SO_2, and the rest are in the form of SO3, sulfuric acid mist and small-amount of sulfates (USEPA AP-42, 2010). SIPCO power plant has one boiler that currently burn bituminous and waste coal with reported sulfur content of 3.0%.

Table 2.4 lists USEPA National Electric Energy Data System v6 ("NEEDS v6") provided coal unit characteristics. Table 2.5 lists NOx and SO_2 emissions information from NEEDS v6 and calculated emissions rates.

Table 2.4 NEEDS v6 October 2020 Provided Coal Unit Characteristics

Boiler ID	Capacity (MW)	Heat Rate (Btu/kWh)	On-Line Year	Firing	Fuels	SO_2 Wet/Dry Scrubber	Scrubber Efficiency	NOx Comb Control*	NOx Post-Comb Control	SO_2 Permitted Rate (lbs/mmBtu)
Unit #123	120	11487	2003	FBC	Bituminous, Waste Coal	Reagent Injection	0.9	CF	SNCR	0.6

*Listed as NOx combustion controls with no info on control system efficiency: CF is Fluidized Bed Combustor and OFA is Overfire Air combustion control systems.

Table 2.5 NEEDS v6 December 2019 Provided NOx and SO_2 Emissions and Calculated Emissions Rates

Boiler ID	Capacity (MW)	Heat Rate (Btu/kWh)	2019 Heat Input (mmBtu)	2019 Generation (MWh)	2019 NOX (tons)	2019 SO_2 (tons)	Calculated	
							2019 NOx lb/mmBtu	2019 SO_2 lb/mmBtu
Unit #123	120	11,733	10,174,512	702,099	389	2,039	0.08	0.40

2.3.2 Current Boilers SO_2 Emissions Assessment

The current emission inventory and facility reports shows the NOx and SO_2 emissions from the boilers are controlled using Reasonable Available Control Technology ("RACT"). NOx emissions are controlled using OFA and SNCR systems achieving over 90% emission reduction, and SO_2 emissions are controlled using dry FGD achieving 90% emissions reduction. Therefore, the more detail cost of compliance in this analysis for additional NOx and SO_2 emission reduction for SIPCO power plant is limited to improvement of the control system, fuel switching, and/or repowering to Integrated Gasification Combine Cycle ("IGCC").

3.0 Control Measures

Based on the add-on BACT-level control systems the source has in place, the control measures evaluated for this source are limited to: (1) to make improvement on the existing NOx and SO_2 control systems for higher emissions reduction; (2) fuel switch from Bituminous coal to Powder River Basin ("PRB") coal; (3) fuel switching from coal into natural gas; and (4) repowering to Integrated Gasification Combine Cycle ("IGCC"). Since SIPCO unit 4 has ceased, the control measures evaluated are for unit 123 only.

3.1 Existing Control Systems Improvements

Based on the USEPA provided document Power Sector Modeling Platform version 6 (EPA documentation Platform v6 EPA, May 2018), SIPCO power station has RACT-level add-on control systems in place for controlling NOx emissions using CF, OFA, and SNCR. The boiler is permitted to emit NOx at the rate of 0.47 lb/mmBtu and have been reporting NOx emissions averaging approximately 0.08 lb/mmBtu. The boiler SO_2 emissions are controlled using dry sorbent and are permitted to emit at the rate of 0.6 lb/mmBtu or a 90% control efficiency and have been reporting SO_2 emissions of approximately 0.40 lb/mmBtu.

3.1.2 NOx Control System Improvement

The BACT-level NOx control system available for coal-fired boilers is the SCR control system. USEPA provided document, Platform v6, describes the SCR control system as:

"*NOx reduction in a SCR system takes place by injecting ammonia (NH3) vapor into the flue gas stream where the NOx is reduced to nitrogen (N2) and water (H2O) abetted by passing over a catalyst bed typically containing titanium, vanadium oxides, molybdenum, and/or tungsten.*"

The control system has a NOx percent removal efficiency of 90% with rate floor of 0.07 lb/mmBtu when burning bituminous coal. SIPCO power plant burns Illinois bituminous coal for generating heat energy and achieving NOx emission rate of approximately 0.08 lb/mmBtu on average by employing these control systems: CF, OFA, SNCR. Further, the source's boiler is a cyclone with NOx control systems OFA and SCR and circulating fluidized bed ("CFB")/fluidized bed combustors ("FBC") with NOx control system CF and SNCR. The USEPA provided document, "Alternative Control Techniques Document - NOx Emissions from Utility Boilers" state:

"*An influential factor on the NOx emissions of an FBC boiler is the quantity of calcium oxide, used for SO_2 emissions control, present in the bed material. Higher quantities of calcium oxide result in higher base emissions of NOx. Therefore, as SO_2 removal requirements increase, base NOx production will increase. This linkage between SO_2 removal and base NOx production is important in understanding NOx formation in FBC boilers".*
https://www3.epa.gov/airquality/ctg_act/199403_nox_epa453_r-94-023_utility_boilers.pdf.

Therefore, based on the type of the boilers and the NOx control systems the source has in place, control system improvement for additional NOx reduction would be technically infeasible.

3.1.3 SO_2 Control System Improvement

For SO_2, USEPA Platform v6 listed BACT-level SO_2 control system as Limestone Forced Oxidation ("LSFO") - a wet FGD technology described as: "*In wet FGD systems, the polluted gas stream is brought into contact with a liquid alkaline sorbent (typically limestone) by forcing it through a pool of the liquid slurry or by spraying it with the liquid.*" The control system is assumed to achieve removal efficiency of 98% with a rate floor of 0.06 lbs/mmBtu.

A dry FGD technology is presented as Lime Spray Dryer and is described as: "*In dry FGD systems the polluted gas stream is brought into contact with the alkaline sorbent in a semi-dry state through use of a spray dryer. The removal efficiency for SDA drops steadily for coals whose SO_2 content exceeds 3 lbs SO_2/MMBtu , the technology is therefore provided to only plants which have the option to burn coals with sulfur content no greater than 3 lbs SO_2/MMBtu".* The control system is assumed to achieve removal efficiency of 95% with a rate floor of 0.08 lbs/mmBtu.

SIPCO power plant controls SO_2 emissions using dry and wet FGD control systems and achieving SO_2 emission reduction between 90-94%, which is close to USEPA Platform v6 assumed removal efficiency of 95%. Based on USEPA Platform v6 assessment of current RACT-level control systems technology and SIPCO burning Illinois high sulfur coal, the assumed rate floor of 0.08 lbs/mmBtu would not be achievable by improving the current control systems, therefore control system improvement for additional SO_2 reduction would be technically infeasible.

3.2 Fuel Switching from Illinois Coal to Powder River Basin Coal

Switching from high sulfur to low sulfur coal directly limits the amount of SO_2 formation during the combustion process. The control option may have some drawback, the USEPA provided document states:

"Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined" (USEPA, EPA/600/7-90/021d, November 1990).

The evaluation of cost for SIPCO power plant for control measure, switching from Illinois coal to PRB coal, will be limited to cost difference of the coals and transportation costs.

US Energy Information Administration ("USEIA") provided information on coal power plant costs that includes transportation costs. Table 3.1A and Table 3.1B lists USEIA provided historic coal costs. The cost information is provided as: "Average Weekly Coal Commodity Spot Prices", Table 3.2 lists transportation costs and described as: "Real Average Annual Coal Transportation Costs, By Primary Transport Mode and Supply Region".

Table 3.1A Average Weekly Coal Commodity Spot Prices (dollars per short ton)

Source of Coal	11/06/20	11/13/20	11/20/20	11/27/20	12/04/20
Central Appalachia *12,500 Btu, 1.2 SO_2*	$51.20	$52.75	$52.75	$52.75	$54.35
Northern Appalachia *13,000 Btu, < 3.0 SO_2*	$42.50	$43.80	$43.80	$43.80	$45.15
Illinois Basin *11,800 Btu, 5.0 SO_2*	$34.10	$34.10	$34.10	$34.10	$34.10
Powder River Basin *8,800 Btu, 0.8 SO_2*	$11.65	$11.60	$11.60	$11.60	$11.55
Uinta Basin *11,700 Btu, 0.8 SO_2*	$30.05	$29.95	$29.95	$29.95	$29.85

"Source: With permission, S&P Global

Note: Prompt quarter delivery coal prices by each region are shown above. The prompt quarter is the quarter that follows the current quarter. For example, the second quarter is the prompt quarter of a period from January to the end of March. In the row headings, the Btu values represent heat content per pound of coal, and the SO_2 values reflect pounds of SO_2 per MMBtu. Because the historical spot price data are proprietary, they cannot be released by EIA; see S&P Global. S&P Global."

Source: USEIA, https://www.eia.gov/coal/markets/#tabs-prices-1

Table 3.1B Average Weekly Coal Commodity Spot Prices ($/mmBtu)

Source of Coal	11/06/20	11/13/20	11/20/20	11/27/20	12/04/20
Central Appalachia *12,500 Btu, 1.2*	$2.05	$2.11	$2.11	$2.11	$2.17

Source of Coal	11/06/20	11/13/20	11/20/20	11/27/20	12/04/20
SO_2					
Northern Appalachia *13,000 Btu, < 3.0 SO_2*	$1.63	$1.68	$1.68	$1.68	$1.74
Illinois Basin *11,800 Btu, 5.0 SO_2*	$1.44	$1.44	$1.44	$1.44	$1.44
Powder River Basin *8,800 Btu, 0.8 SO_2*	$0.66	$0.66	$0.66	$0.66	$0.66
Uinta Basin *11,700 Btu, 0.8 SO_2*	$1.28	$1.28	$1.28	$1.28	$1.28

Source: USEIA https://www.eia.gov/coal/markets/#tabs-prices-2

Table 3.2 Average Annual Coal Transportation Costs (2017 dollars per ton)

Coal Supply Region	2011	2012	2013	2014	2015	2016	2017	2018	2019 (Preliminary)
Railroad									
Northern Appalachia	20.20	21.70	22.71	21.62	21.24	20.63	19.74	18.66	15.35
Central Appalachia	24.13	24.40	25.22	25.00	23.53	22.25	22.76	22.73	18.20
Southern Appalachia	W	W	W	W	W	W	-	W	W
Illinois Basin	15.78	16.34	16.11	15.76	16.73	15.84	16.12	15.23	14.51

Coal Supply Region	2011	2012	2013	2014	2015	2016	2017	2018	2019 (Preliminary)
Powder River Basin	21.67	22.32	22.93	22.98	21.36	20.33	20.41	20.33	19.49
Uinta Region	21.84	20.39	16.37	16.66	12.04	13.33	12.17	10.70	9.72
Railroad Total [1]	**21.48**	**21.87**	**22.16**	**22.07**	**20.75**	**19.73**	**19.77**	**19.53**	**18.34**
Waterway									
Northern Appalachia	4.35	4.11	4.26	4.70	3.76	3.69	3.70	3.76	3.58
Central Appalachia	6.13	5.96	6.94	6.49	7.07	6.06	4.96	4.51	4.71
Southern Appalachia	4.01	W	4.77	W	W	W	-	-	-
Illinois Basin	8.81	7.94	7.49	7.30	6.51	5.99	5.56	5.73	5.41
Powder River Basin	21.24	-	-	19.33	W	W	W	-	-
Uinta Region	W	-	-	-	W	W	-	-	-
Waterway Total [1]	**6.95**	**5.92**	**5.97**	**6.18**	**5.25**	**4.88**	**4.54**	**4.60**	**4.36**
Truck									
Northern Appalachia	6.22	6.48	6.20	6.32	6.92	6.86	7.66	9.65	7.98
Central Appalachia	W	W	18.83	8.63	W	W	W	W	W
Southern Appalachia	W	W	-	W	-	-	-	-	-
Illinois	5.92	5.88	6.82	6.34	5.65	4.98	5.33	5.21	4.50

Coal Supply Region	2011	2012	2013	2014	2015	2016	2017	2018	2019 (Preliminary)
Basin									
Powder River Basin	7.17	W	W	5.35	W	W	W	W	W
Uinta Region	5.49	6.52	6.31	6.81	5.66	4.84	W	W	W
Truck Total [1]	**5.95**	**6.40**	**6.74**	**6.45**	**6.09**	**5.66**	**6.10**	**6.74**	**5.56**

"Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

W = Withheld to avoid disclosure of individual company data.

[1] *Value for Dollars per Ton reflects weighted average of all shipments; Value for Number of Shipments reflects sum of shipments.*

Notes: *Rates are based on a weighted average of the difference between the commodity cost and total delivered cost of coal shipments to plants in the electric power sector. In addition, the rates are based on the primary transport mode selected by a plant's owner or operator so may include other secondary or tertiary modes. Values are presented in 2017 dollars and were converted using the Implicit Price Deflators for Gross Domestic Product, as published by the U.S. Bureau of Economic Analysis. For the composition of coal basins, refer to the definition of "coal-producing regions" in EIA's glossary at www.eia.gov/tools/glossary."*

Source: USEIA, Real Average Annual Coal Transportation Costs, By Primary Transport Mode and Supply Region, https://www.eia.gov/coal/transportationrates/

USEPA platform v6 did not provided detail costs for fuel switching from high sulfur coal to low sulfur coal as it did for coal-to-gas control option. Therefore, the costs for control measure for switching from Illinois coal to PRB coal is based on USEPA platform v6, USEIA provided fuel costs and SIPCO boiler total heat rate instead. Table 3.3 listed the costs for SIPCO power plant for fuel switching from Illinois coal to PRB coal control measure using the recent costs.

Table 3.3 Illinois Coal to PRB Coal Switching Control Option Costs

Cost Factor	Description	Estimated Source-wide Costs
PRB coal cost	For buying PRB coal cost, using source total heat input of 12,264,000 mmBtu/yr (based on SIPCO boilers heat rate, total heat input and hours per year (1400*8760) and heat content of 8,800	$8,048,250 (2020$)

Cost Factor	Description	Estimated Source-wide Costs
	Btu/lb, equated to 696,818 ton/yr and price of $11.55/ton. The cost is added to control measure.	
PRB coal railroad transportation cost	Based on 696,818 ton/yr and transportation cost of $19.49/ton. The cost is added to the cost of the control measure.	$13,580,986 (2020$)
Illinois coal cost	Boiler Unit #123 using unit heat input 1400 mmBtu/hr, 8760 hr/yr, and price of $1.44 per mmBtu of 71% Illinois coal use and $0.0 per mmBtu of 29% coal refuse use (for coal refuse costs, assumed the source incur transportation costs only)	(-$12,362,112) (2020$)
SIPCO transportation cost	Based on 519,661 ton/yr and USEPA Platform v6 provided info transportation cost of $3.94/ton (2016$), the cost is subtracted from the cost of the control measure.	(-$2,211,262) (2020$)
Total annual cost of the control measure	Sum of costs from PRB coal and PRB coal transportation, minus savings from Illinois coal and Illinois coal transportation. Total costs converted using Consumer Price Index ("CPI") data of 2016 through May 2020 for adjusting the 2016 data, total annual cost of the control measure in 2020$	$ 7,055,862 (2020$)
NOx emission reduction	37% reduction from current NOx emission rate of 0.1 lb/mmBtu, based on rate floor of average 0.075 lb/mmBtu (the 0.05 lbs/mmBtu floor is the same as the NOx rate floor for new retrofit average SNCR and SCR on units burning subbituminous coal (143.9 TPY reduction)	--
SO_2 emission reduction	84% reduction from current emission rate of 0.51 lb/mmBtu, based on average of dry and wet-FGD rate floor of 0.07 lb/mmBtu (1712 TPY reduction)	--
Cost effectiveness 2020$/ton NOx and SO_2	Based on the estimated emissions reduction of 143.9 TPY of NOx and 1712 TPY SO_2	$3,802

Cost Factor	Description	Estimated Source-wide Costs
emissions removed		

3.3 Fuel Switching from Coal to Natural Gas Control Measure

Natural gas and fuel oils have low sulfur content compared to coal. Based on feasibility and cost effectiveness of fuel oil and natural gas, only natural gas is evaluated as a potential cost-effective control measure. Switching from coal to natural gas will lower SO_2 emissions but there will still be NOx emissions needed to be controlled, therefore the control measure cost effectiveness is evaluated for SO_2 emission reduction only. The two main capital costs for fuel switching from coal to natural gas control option are: building a natural gas pipeline from the main distribution line to the boiler and boiler modification. The main variable cost is the difference in price between coal and natural gas in terms $/mmBtu.

The USEPA provided document "The Menu of Control Measures" 2012, describes the control measure applicable to EGU boilers as:

> *"Fuel substitution involves replacing the current fuel with a fuel which emits less of a given pollutant when burned. For many older boilers, fuel switching is an especially attractive option because the capital investment is usually small when compared to that of control devices. Cost effectiveness varies depending on the ranks of the old and new fuels and is estimated based on the emission factors".*

The control measure is not applicable for boiler Unit #123. Based on USEPA platform v6, stating: "*Not applicable for fluidized bed combustion (FBC) and stoker boilers".*

3.4 Repowering to Integrated Gasification Combined Cycle Control Option ("IGCC")

The USEPA provided document "The Menu of Control Measures" describes the IGCC control measure applicable for EGU boiler as:

> "*Repowering improves power plant efficiencies and implies significant waste reduction. Typical repowering entails steps in which the coal handling system and the boiler are replaced with new combustion turbines and a heat recovery boiler. The only significant part of the plant that is maintained is the original turbine generator. The IGCC is a repowering option that requires extensive gasification equipment to generate synthetic gas from coal in order to feed the gas turbines. IGCC plants offer the capability of removing the Hg from the compressed syngas prior to combustion where the gas volume treated is much less than the low pressure, post-combustion flow volume*".

This control measure, repowering to IGCC, achieves control efficiency of 99% SO_2 reduction. The document presents cost effectives in 2006$ as:

"Cost effectiveness is variable depending on nameplate capacity: - capital cost = $1,027 per kW, - fixed O&M cost = $33.37 per kW per year, and - variable O&M cost = $3.17 mills per kW"

Based on SIPCO boiler 123 total capacity rate of 140 MW, Table 3.5 presents the costs and cost effectiveness for IGCC control measure.

Table 3.4 Repowering to Integrated Gasification Combined Cycle Control Option

Cost Factor	Description and Notes	Costs
SIPCO boiler rated 140 MW	Based on Platform v6 provided info, total SIPCO boilers' capacity 140 MW	--
Total capital cost (2006$)	Capital cost = $1,027 per kW estimated useful life of 40 years, total capital cost of the control system	$143,780,000
Capital recovery factor ("CFR") for annualizing cost per year (2006$)	For annualizing the capital cost , the total capital investment multiplied by a capital recovery factor (CRF = (i (1+ i)n)/((1+ i)n - 1), Where n = useful life (40 years) and i= interest rate (5.5%)) equated to 0.0623	$8,957,494
Fixed O&M cost (2006$)	Fixed O&M cost = $33.37 per kW per year based on 140 MW, total cost per year	$4,671,800
Variable O&M cost (2006$)	Variable O&M cost = $3.17 mills per kW, based on total capacity 140 MW and major overhauls on a three-year cycle, cost per year	$443.80
CFR for annualizing variable O&M cost (2006$)	For annualizing capital cost, the total capital investment multiplied by a capital recovery factor (CRF = (i (1+ i)n)/((1+ i)n - 1), Where n = major overhauls on a three-year cycle (3 years) and i= Interest Rate (5.5%)), CFR equated to 0.3707	$164.50
Total annual cost of the control measure (2006$)	Total capital cost per year + fixed O&M cost per year + variable O&M cost per year	$13,629,458.50
Control option NOx emission reduction	The source will still need NOx control system, thus assumed to be 52% NOx reduction for this control measure) 108.89 TPY NOx reduction (388.91 TPY NOx)	--
Control option SO_2 emission reduction	99% reduction, based on the allowable emission rate of 1.2 lb/mmBtu and 99% emission reduction (2017.69 TPY SO_2 reduction)	--

Cost effectiveness 2006$/ton	Based on NOx emission reduction of 108.89 TPY and SO_2 emission reduction of 2017.69 TPY	$6,409.09
Cost effectiveness 2020$/ton NOx and SO_2 emissions removed	Using Consumer Price Index ("CPI") data of 2006 through November 2020, the cost effectiveness in 2020$	$8,395.90

4.0 Four Factor Analysis

The guidance state:

> *"Characterization of factors for emission control measures Identify potential emission control measures for the selected sources, develop data on the four statutory factors and on visibility benefits if they will be considered. See 40 CFR 51.308(f)(2)"*

40 CFR 51.308(f)(2)(i) lists the four factors for analysis as:

1. Costs of compliance.
2. Time necessary for compliance.
3. Energy and non-air quality environmental impacts of compliance.
4. Remaining useful life of any potentially affected anthropogenic sources.

4.1 Factor 1 - Costs of Compliance

SIPCO has in place pre-combustion and post-combustion add-on control systems for controlling both NOx and SO_2 emission. The potential theoretically feasible control measure evaluated in this four-factor analysis are improvement to current control system, fuel switching, and repowering to IGCC.

SIPCO has in place pre-combustion control system, CF and OFA; and an add-on control system; SCR and SNCR for controlling NOx and dry and wet FGD control systems for controlling SO_2 emissions. The control measures evaluated for additional NOx and SO_2 reduction cost effectiveness ranges from $3802 to $8395 per ton of pollutant removed in 2020$.

4.2 Factor 2 - Time Necessary for Compliance

The time necessary for compliance includes the time the Agency need to develop, propose, and implement regulations, which usually takes around two years. For affected sources, the time needed to implement the evaluated control measures usually requires two to five years.

4.3 Factor 3 - Energy and Non-Air Quality Environmental Impacts of Compliance

As mentioned previously, SIPCO power station has add-on control systems for controlling both NOx and SO_2 emissions. The technique for during combustion NOx controls is to limit both thermal and fuel NOx formation by reducing the peak flame temperature and by delaying mixing of the fossil fuel and air. In coal-fired boilers these would result lower thermal energy, increases

unburned carbon as well as increased incomplete oxidation, increasing CO emissions, and decreasing boiler efficiency. The unburnt carbon as an elemental carbon can also affect salable fly ash and may interfere with performance of the ESP control systems (USEPA EGU-ACT 1994). For the post-combustion NOx control systems that the source has in place, SCR would also affect efficiency negatively for meeting auxiliary power requirements as well as adding issues with possible hazardous solid waste disposals, reagent storage, and ammonia slips. The wet FGD for SO_2 emission control would also increase auxiliary power requirements that include heat rate and capacity penalties. Other environmental impacts may include increased water usage, discharges of polluted water from a control device, and solid or hazardous waste generation.

4.4 Factor 4 - Remaining Useful Life of Potentially Affected Sources

Useful life of boilers at power generating sources are widely varied. US Energy Information Administration ("USEIA") provided information on coal power plant retirement activity stating:

"*The U.S. coal units that retired in 2018 had an average capacity of 350 megawatts (MW) and an average age of 46 years, compared with an average capacity of 129 MW and average age of 56 years for the coal units that retired in 2015*" (https://www.eia.gov/todayinenergy/detail.php?id=40212).

USEPA assesses the useful life of coal-fired boilers to be 40 years. Table 4.1 lists the USEPA Platform v6 assumptions for the useful life and life extension costs for doubling the useful life of different EGU unit types.

Table 4.1 EGU Combustion Unit Useful Life

Plant Type	**Lifespan without Life Extension Expenditures**	**Life Extension Cost (2016$/kW)**	**Capital Cost of New Unit (2016$/kW)**	**Life Extension Cost as Proportion of New Unit Capital Cost (%)**
Biomass - Fluidized Bed	40	291	4429	6.6
Coal Steam	40	212	3639	5.84
Combined Cycle	30	89	978	9.06
IGCC	40	241	3254	7.4

Source: USEPA, "Life Extension Cost Assumptions Used in USEPA Platform v6, Chapter 4 section 4.2.8", 2018. https://www.epa.gov/sites/production/files/2018-08/documents/epa_platform_v6_documentation_-ch4_august_7_2018_updated_table_4-16.pdf

Illinois EPA records show boiler Unit #123 in 2003. Illinois EPA is expecting SIPCO power plant to operate boiler Unit #123 for more than 10 years while maintaining RACT-level control systems at all times.

4.5 Four-Factor Analysis Conclusion

Based on the size of yearly emissions, the cost of the control measure evaluated in this analysis, and the remaining useful life of the boilers, Illinois EPA will not be proposing any new NOx or SO_2 reduction measures for SIPCO's boilers in the second implementation period.

Rain 4-Factor Analysis

1.0 Rain CII Carbon LLC Regional Haze Four-Factor Analysis

The four-factor analysis for Rain CII Carbon LLC ("Rain") in this document is to determine whether this source is reasonably controlled or requires additional control in order to make reasonable progress.

2.0 Rain CII Carbon LLC - Source Description

The source, located in the city of Robinson, Crawford County, produces calcined petroleum coke from green petroleum coke ("GPC"), a by-product of the crude oil refining process. The highly purified calcined coke is used in the production of aluminum, steel, graphite electrode, titanium dioxide, and other metallic and non-metallic materials.

2.1 Main Emission Units Description

The source has several emission units that include liquid storage tanks, soda ash and coke storage bins, petroleum coke handing systems (coke crushers, screeners, conveyers, etc.), coke rotary coolers, energy recovery boiler, and GPC calcining kilns. The main emission units for the four-factor analysis at this source are two rotary kilns manufactured by Kiln-Allis Chalmers, Ft. Worth Steel. The calcining process consists of a rotary kiln, pyro-scrubber, rotary cooler, and baghouse. Each of the two calcining kilns are permitted to process 28 tons per hour of GPC. Rotary coolers are used in the calcining lines. To produce highly purified carbon, the calcining process heats GPC to a precisely controlled temperature to burn-off VOM, moisture, and other impurities. The units use natural gas as startup and for controlling the temperature. The main heating energy of the process is the combustion of residual hydrocarbons inherent in the coke feed and the consumption of approximately 20% of the GPC.

2.2 Source Existing Control Systems

The source has several emission control systems for the kilns which are the main emission units controlled. VOM and PM emissions are controlled by pyro-scrubbers, multi-clone PM collector, and baghouses achieving an average control efficiency between 99.6 - 99.9%. Table 2.1 lists a summary of the main emission units and control systems.

Table 2.1 List of GPC Calcining Kilns and Control Systems

Emission Unit	Date Constructed	Stack	Control system	Monitoring Devices
Pet-Coke Calcining kiln #1 (37 mmBtu/hr)	1971	S1	Pyro-scrubber #1	Thermocouples 1A & 1B at Pyro-scrubber #1 inlet
			Baghouse #1	Pressure Gauge and Inlet Temp. Monitor on Baghouse #1
Pet-Coke Calcining	1971	S3	Pyro-scrubber #2	Thermocouples 2A & 2B at Pyro-scrubber #2 inlet #2

kiln #2 (37 mmBtu/hr)			Multi-clone PM collector	
			Baghouse #2	Pressure Gauge and Inlet Temp. Monitor on Baghouse #2

2.3 Source NOx and SO_2 Emissions

The main emission units at this source are the two GPC calcining kilns for purifying the petroleum coke. GPC coke is primarily carbon and contains lesser quantities of organic and inorganic compounds including hydrocarbons, hydrogen, oxygen, sulfur, nitrogen, and heavy metals. The process of calcining GPC involves heating the coke which produces PM, NOx, SO_2, and VOM. The source PM and VOM emissions are controlled using a pyro-scrubber and baghouse. Based on the control system efficiency and the size of reported emissions in terms of ton per year ("TPY") shown in Table 2.2, the four-factor analysis will be limited to the emissions of NOx and SO_2 emissions only.

Table 2.2 Source Reported Emissions

	Reported Emissions (TPY)				
Pollutant	**2015**	**2016**	**2017**	**2018**	**2019**
PM2.5	151.8	142.7	246.7	150.5	187.7
NOx	225.4	255.0	371.3	277.7	342.5
SO_2	2,160.4	3,836.2	6,810.1	4,162.6	5,451.6
VOM	0.63	0.9	1.95	3.0	3.7

2.3 Current Calcining Kilns NOx and SO_2 Emissions Assessment

NOx emissions from calcining kilns as a combustion unit are from the formation of NOx in the kilns. NOx forms in three ways: thermal NOx, prompt NOx, and fuel NOx. Fuel NOx is the main contributor of NOx formation in kilns and at this source is the result of oxidation of nitrogen bound in the GPC.

SO_2 emissions from calcining kilns are entirely dependent on the sulfur content of the GPC and are not affected by any other kiln parameters such as size of the kiln and design. Approximately 95 percent of emissions of oxides of sulfur are in the form of SO_2, and the rest are in the form of SO_3, sulfuric acid mist, and a small amount of sulfates [USEPA AP-42, 2010].

Table 2.3 lists the 2019 stack test report. Based on the source permit requirement, the report contains SO_2 emission only.

Table 2.3 Kilns Reported 2019 Stack Test Emissions

Unit	**SO_2 (ppmv)**	**SO_2 (lb/hr)**	**SO_2 (lb/ton GPC)**
Kiln #1 Stack	1173	533	19.1
Kiln #2 Stack	1105	494	17.7

3.0 NOx and SO_2 Control Measures Evaluation

3.1 NOx Control measures Evaluation

Referring to USEPA-provided documents, NOx is formed by several methods and as a result, NOx emissions can be reduced or controlled by different methods. The methods are grouped into two control systems as combustion controls and post combustion controls. Combustion controls reduce NOx formation during the combustion process by use of such as flue gas recirculation ("FGR"), overfire air ("OFA"), low NOx burners ("LNB"), ultra low NOx burners ("ULNB"), and reburn or use of combination of these during combustion control systems. The calcining process is used for burning off VOM, moisture, and other impure content of the petroleum coke by heating it in a rotary kiln to a precise, controlled temperature ranging between approximately 2150 – 2462 degrees Fahrenheit. Thus, NOx combustion controls would not be feasible as it would affect these precise temperatures necessary for producing highly purified carbon compounds and therefore is not evaluated.

Post combustion controls are a process of the flue gas treatment after the formation of NOx emissions and include selective noncatalytic reduction ("SNCR") and selective catalytic reduction ("SCR").

More detailed information about these NOx control technologies can be found in the USEPA-provided documents such as AP-42 and the Alternative Control Techniques document. Estimates of control system cost effectiveness applicable to kilns are provided by several sources including LADCO and USEPA, but there is no information specifically applicable to NOx control cost for GPC calcining units. Table 3.1 lists NOx control systems cost effectiveness for sources closely associated to GPC calcining kilns.

Table 3.1 List of NOx Control Systems for GPC Kilns

NOX Control Technology	Applicable Source Category	Percentage Control Efficiency	Cost Effectiveness ($/ton reduced)
SNCR	Kilns at Lime and Cement Plants, preheater and preheater/pre-calciner cement kilns; dependent on fuels burned, kiln use, and kiln configuration	45%	$1,400 (2015 $, LADCO)
	By-Product Coke Manufacturing - Oven Under-firing, applies to all by-product coke manufacturing operations with oven under-firing and uncontrolled NOx emissions greater than 10 tons per year	60%	$2,632 (2006 $, USEPA)
SCR	Kilns at Lime and Cement Plants, preheater and preheater/pre-calciner cement kilns; dependent on fuels	70 – 90%	$600-$17,700 (2015 $, LADCO)

NOX Control Technology	Applicable Source Category	Percentage Control Efficiency	Cost Effectiveness ($/ton reduced)
	burned, kiln use, and kiln configuration		
	In-Process - Process Gas - Coke Oven Gas, applicable to operations with in-process process gas usage from Coke Oven Gas	90%	$5,970 (2006 $, USEPA)

LADCO, "*Four-Factor Analysis for Regional Haze"*, 2015. https://www.ladco.org/wp-content/uploads/Documents/Reports/Regional_Haze/Round2/2015_LADCO-4-Factor-Analysis-Regional-Haze.pdf

USEPA, "*Menu of Control Measures,"* 2012.

3.2 SO_2 Control measures Evaluation

Referring to USEPA-provided documents, SO_2 emissions are almost entirely dependent on the sulfur content of the input material, which mean SO_2 is formed when sulfur within the processed material is oxidized.

The techniques for controlling SO_2 emissions from GPC calcining kilns can be categorized as pre-combustion and post-combustion controls. Pre-combustion control applicable to pet-coke calcining kilns is to process sulfur free or lower-sulfur-content GPC. The second way of controlling SO_2 emission is post combustion control i.e., after it has been formed. The two main post combustion SO_2 emissions control systems are dry or wet Flue Gas Desulfurization ("FGD"), also known as scrubbers, with several varieties within the dry/wet FGD systems. The dry FGD for pet-coke kilns operates by capturing and routing the off-acid gas stream containing SO_2 into a dry scrubbing control system which uses a dry sorbent material for controlling SO_2 emissions. In wet FGD systems the kiln off-gas stream is scrubbed with a liquid sorbent by forcing the polluted gas through liquid slurry or by spraying it with the liquid scrubbing sorbent.

USEPA provided in the document "Menu of Control Measures", a control system applicable to GPC calciner kilns:

> *"In 2008-2010, the SCAQMD conducted a BARCT* [Best Available Retrofit Control Technology] *assessment to capture advancement in SO_2 control technology, identified the BARCT levels for seven source categories, determined the associated cost-effectiveness values, and amended the Regional Clean Air Incentives Market Program (RECLAIM) to reflect the BARCT levels. For coke calciners, the cost-effectiveness of achieving a SO_2 Performance Standard of 10ppmv is $23,036 (in 2010 $)."*

In 2015, the Bay Area Air Quality Management District ("BAAQMD") in California, in the document titled "WORKSHOP REPORT Draft Regulation 9, Rule 14," presents three SO_2 emission control systems applicable to GPC calcining kilns. These are dry FGD, semi-dry FGD,

and wet FGD. The document also provided cost effectiveness estimates for semi-dry FGD applicable to GPC kilns. Table 3.2 lists cost effectiveness as provided by BAAQMD, USEPA, and LADCO documents.

Table 3.2 List of SO_2 Control Systems for Pet-Coke Calcining Kilns

SO_2 Control Technology	Applicability and Description	Percentage Control Efficiency	Cost Effectiveness ($/ton reduced)
Dry FGD	Kilns at Lime/Cement Plants, Sorbent Injection – sorbent injected into the flue gas stream through direct injection	25% - 50%	$2,400-$9,000 (cement 2015 $, LADCO)
	Kilns at Lime/Cement Plants, Spray Dryer – an absorbent reagent introduced into the flue gas stream through spray in an absorption tower	90% - 95%	$2,300-$88,800 (cement 2015 $, LADCO)
Semi-dry FGD	Kilns at GPC Calciner, the flue gas is introduced into an absorbing vessel into finely atomized sorbent slurry	80% - 90%	$8,700 (2015 $, BAAQMD)
	Kilns at Lime/Cement Plants, Advanced Flue Gas Desulfurization – A slurry reagent is sprayed onto cooled/humidified flue gas	95% - 99.5%	$2,400-$47,100 (cement 2015 $, LADCO)
Wet FGD	Kilns at GPC Calciner, A scrubbing reagent is introduced into the flue gas stream, creating liquid or sludge waste	Achieve a performance level of 10ppmv SO_2	$22,563 (2006 $, USEPA)
	Kilns Lime/Cement Plants, A scrubbing reagent is introduced into the flue gas stream, creating liquid or sludge waste	40% - 99%	$10,000 (lime 2015 $, LADCO) $1,500-$78,800 (cement 2015 $, LADCO)

BAAQMD, *"WORKSHOP REPORT Draft Regulation 9, Rule 14",* 2015. https://www.baaqmd.gov/~/media/files/planning-and-research/rules-and-regs/workshops/2015/rule-9-14/0914_wr_051215.pdf
LADCO, "*Four-Factor Analysis for Regional Haze*," 2015.
USEPA, "*Menu of Control Measures*," 2012.

4.0 Four Factor Analysis

The Regional Haze Guidance states:

"Characterization of factors for emission control measures Identify potential emission control measures for the selected sources, develop data on the four statutory factors and on visibility benefits if they will be considered. See 40 CFR 51.308(f)(2)"

The four factors analysis for the Rain CII Carbon LLC GPC kilns are assessed for additional NOx and SO_2 emission control measures for reasonable progress following the rule in the area of:

1. Costs of compliance.
2. Time necessary for compliance.
3. Energy and non-air quality environmental impacts of compliance.
4. Remaining useful life of any potentially affected anthropogenic sources.

4.1 Factor 1 - Costs of Compliance

4.1.1 NOx Cost of Compliance

Estimates for cost effectiveness of add-on NOx control systems were evaluated from various sources including LADCO, USEPA, and BAAQMD. Table 4.1 summarizes the feasibility and cost effectiveness of the control options evaluated in this analysis. The 2020 $/ton costs effectiveness is converted from the study year to year 2020 using Consumer Price Index data through October 2020.

Table 4.1 Summary of Feasibility and Cost Effectiveness for NOx Control Options

Control Measure Evaluated	Study Year Cost Effectiveness ($/ton)	Cost Effectiveness (2020$/ton)
Combustion control systems such as LNB	Not feasible	Not feasible
SNCR	$2,632 (2006 $)	$3,395
SCR	$5,970 (2006 $)	$7,701

4.1.2 SO_2 Cost of Compliance

As mentioned in the previous section, SO_2 control systems cost effectiveness for Rain CII Carbon LLC's kilns, has been checked from various sources that include LADCO, USEPA, and BAAQMD. Table 4.2 summarizes the feasibility and cost effectiveness of the control option evaluated in this analysis. The 2020$/ton costs effectiveness is converted from the study year to year 2020 using Consumer Price Index data through October 2020.

Table 4.2 Summary of Feasibility and Cost Effectiveness for SO_2 Control Options

Control Measure Evaluated	Feasibility	Study Year Cost Effectiveness ($/ton)	Cost Effectiveness (2020$/ton)
Dry FGD	Feasible	Cost info not found	--

		specifically applicable to pet-coke calcining kilns	
Semi-dry FGD	Feasible	$8,700 (2015 $)	$9,570
Wet FGD	Feasible	$22,563 (2006 $)	$29,106

4.2 Factor 2 - Time Necessary for Compliance

The time necessary for compliance includes the time the Agency needs to develop, propose, and implement regulations, which usually takes around two years. For affected sources, the time needed to implement the proposed control measure could require two to five years.

4.3 Factor 3 - Energy and Non-Air Quality Environmental Impacts of Compliance

For post-combustion NOx control systems, SNCR would affect efficiency minimally, but SCR control systems evaluated in this analysis would affect efficiency negatively for meeting auxiliary energy requirements as well as adding issues with possible hazardous solid waste disposals, reagent storage, and ammonia slips. The FGD systems for SO_2 emission control evaluated in this analysis would also increase auxiliary power requirements that include heat rate and capacity penalties. Further, for FGD control systems, non-air quality environmental impacts may include increased water usage and discharges of polluted water from a control device as well as solid or hazardous waste generation.

4.4 Factor 4 - Remaining Useful Life of Potentially Affected Sources

The remaining useful life of GPC rotary calcining kilns depends on the inner lining of the kiln known as refractory. The refractory is used to protect the main body of the kiln and to minimize heat loss. The lifespan of the refractory depends on the material used, which varies from a few months to several years. Thus, the useful life of pet-coke calcining kiln can be extended with proper maintenance of the refractory. LADCO provided a document, "Four-Factor Analysis for Regional Haze in the Northern Midwest Class I Areas," which assesses the useful life of lime/cement kilns and states:

> "*According to MARAMA's Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I areas, the remaining useful life of each emission unit is a minimum of at least 10 years. With proper maintenance and upkeep, some units can operate for 20-30 years more."*

Illinois EPA data show the Rain CII Carbon GPC calcining kilns began operating in 1971. Illinois EPA estimates the remaining useful life of the kilns to be 20 years. This estimate was not considered in any estimates for cost effectiveness of potential control options.

4.5 Four-Factor Analysis Conclusion

Based on the high cost of the control measures evaluated in this analysis, the limited emissions reduction potential, and remaining useful life of the kiln; Illinois EPA will not be proposing any

additional NOx or SO_2 reduction measures for the Rain CII Carbon kilns for the second implementation period.

Holcim 4-Factor Analysis

1.0 Holcim US Inc. Regional Haze Four-Factor Analysis

The four-factor analysis for Holcim US ("Holcim") in this document is for determining whether the source is already reasonably controlled or requires additional control to make reasonable progress.

2.0 Holcim US Source Description

Holcim US, also known as Lafarge, manufactures Portland cements and cement-based construction products located in Grand Chain, Massac County. Portland cement is made by grinding and heating a mixture of raw materials consisting of limestone, sand, clay, gypsum, boiler bottom ash, fly ash, iron ore, shale, alumina, spent industrial catalysts, sand, coal refuse, and fuels such as coal and/or petroleum coke in a rotary kiln. The kilns' source of heat energy is coal, oil, gas, coke, and/or other organic waste materials. The final processed product from the kiln is called clinker, a hard-black glassy compound, which is cooled, ground, and mixed with a small amount of gypsum to produce Portland cement.

2.1 Main Emission Units Description

The source has several emission units that include raw material handling such as conveyors and storage, the process product, clinker handling and storage, milling process, cement storage and loadout. The main haze forming emission units for the four-factor analysis at this source are the two rotary cement kilns manufactured by FL Smidth & Co. The kiln is a large cylindrical furnace mainly heated by fossil fuels and waste organic materials to a temperature ranging between 2500-3000 ^{o}F.

The source's two kilns are long dry slightly inclined rotating cylinders kilns. The process begins by loading a milled raw cement making material feed into the uphill end of kiln while fuel and air are introduced into the kiln from downhill end. As the kiln rotates, the raw feed and combustion hot air flow counter current. In Kiln #1 the raw feed is introduced directly into the kiln via a bucket elevator. Kiln #2 is equipped with a 1-state preheater where the raw kiln feed is introduced into a series of cyclones before loading into kiln. In the cyclones, the raw material during processing flows counter current with the kiln exhaust, thus recovering heat from the exhaust gases and from the cooled clinker waste heat to preheat the raw feed.

The main emissions of the kilns are from burning of the fuels and heating of the raw feed materials. Additional emissions also result from the grinding, cooling, and materials handling during the manufacturing process.

2.2 Source Existing Control Systems

The source has several emission control systems for the cement kilns. PM emissions are controlled by electrostatic precipitator ("ESP") and baghouses achieving an average control efficiency of 99.8%. NOx emissions are controlled using low NOx burners ("LNB") and

selective catalytic reduction ("SCR") systems achieving over 80% emission reduction. SO_2 emissions are controlled using dry absorbent addition ("DAA") system achieving 70-90% SO_2 emissions reduction. Table 2.1 lists a summary of the main emission units, control systems, and continuous emissions monitoring systems ("CEMS").

Table 2.1 List of Kilns and Control Systems

Emission Unit	Date Constructed	Control system	Monitoring Devices
Kiln #1	1960	LNB, SCR, DAA, ESP, and Baghouse	CEMS for: SO_2 CO, NOx, THC, Hg, and HCL; CPMS for PM; D/F-Temperature monitor
Kiln #2	1975	LNB and Baghouse	CEMS for: SO_2, CO, NOx, THC, Hg, and HCl; CPMS for PM; D/F-Temperature monitor

2.3 Source NOx and SO_2 Emissions

The source's kilns burn fossil fuels to extract heat for the process of manufacturing Portland cement. Based on the control system efficiency and the size of reported emissions in terms of ton per year ("TPY"), shown in Table 2.2, the four-factor analysis for this facility will be limited to the emissions of NOx and SO_2 emissions only.

Table 2.2: Source Reported Emissions

	Reported Emissions (TPY)				
Pollutant	**2015**	**2016**	**2017**	**2018**	**2019**
PM2.5	11.27	15.55	18.48	14.47	11.77
NOx	750.44	1,078.29	475.61	386.89	498.65
SO_2	259.42	698.18	409.31	332.38	208.59
VOM	41.41	32.87	10.23	8.37	10.86

2.4 Kilns NOx and SO_2 Emissions Assessment

The main NOx formation in cement kilns is from thermal NOx, which is the result of the high temperature requirement in producing clinker.

SO_2 emissions from cement kilns are entirely dependent on sulfur content of the processed material and are not affected by any other kiln parameters such as size of the kiln or design. Table 2.3 lists the current kilns emissions lb/hr as reported for year 2019 and calculated performance in terms of lb/clinker produced.

Table 2.3 Kiln 2019 Reported Emissions and Performance

Emission Unit	Production Rate (ton/hr)	NOx Emission (lb/hr)	SO_2 Emission (lb/hr)	NOx Emissions (lb/ton of clinker produced)	SO_2 Emissions (lb/ton of clinker produced)
Kiln #1	56.33	159.71	66.66	2.78	1.18
Kiln #2	0	0	0	0	0
Kiln #2 is idle since 2016					

3.0 NOx and SO_2 Control Measure Evaluation

Based on the control systems the source has in place and the nature of cement making, switching of raw material and heat producing fuels may not be feasible for achieving measurable emissions reductions. Therefore, the control measure evaluation for this source will be limited to add-on control options.

3.1 NOx Control measures Evaluation

Referring to the LADCO-provided document, "Four-Factor Analysis for Regional Haze in the Northern Midwest Class I Areas" ("2015 LADCO Four Factor Analysis"), NOx is formed by several methods and as a result, NOx emissions can be reduced or controlled by different methods. The methods are grouped into three control options: pre-combustion NOx controls, combustion modifications, and post-combustion NOx controls. Pre-combustion NOx controls is mainly fuel substitution and changing feed composition. Combustion controls reduce NOx formation during the combustion process by use of LNB, mid-kiln firing, tuning/optimization, or combination of these during control systems. Post combustion controls are a process of the flue gas treatment after the formation of NOx emissions and include selective noncatalytic reduction ("SNCR"), SCR, and regenerative selective catalytic reduction ("RSCR").

More detailed information of these NOx control technologies can be found in the 2015 LADCO Four Factor Analysis and USEPA-provided documents such as AP-42 and combustion source alternative control techniques documents.

The USEPA described the SNCR control system applicable to Cement Manufacturing - dry process as:

> "*SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to dry-process cement manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year."*

SCR control systems applicable to cement kilns provided by the 2015 LADCO Four Factor Analysis are described as:

> "*In SCR, anhydrous ammonia is injected into NOx containing exhaust gas and directed through a catalyst bed to reduce NOx to nitrogen and water. Catalysts typically used include vanadium pentoxide, zeolite, or titanium dioxide. To*

complete the reaction, a temperature range of 480° - 800°F is required. Due to this temperature requirement, SCR application works best for preheater and/or precalciner kilns and can be applied to other types of cement kilns". The document further states: "*Application of SCR on cement kilns does not currently exist in North America but a long-term pilot project (Kirchdorf, Austria) along with three industrial applications (Solnhofen, Germany, Monselice, Italy, and Sarche di Calavino, Italy) exist in Europe (Environmental Quality Management, Inc., 2008). SCR NOx reduction observed ranges from 70 to 90 percent.*"

Table 3.1 lists LADCO and USEPA provided NOx control options applicable for cement manufacturing kilns.

Table 3.1 List of Potential NOx Control Options for Cement and Lime Manufacturing Kilns

NOx Control System	Description	NOx Reduction (%)	Cost Effectiveness ($/ton reduced)
Process modifications-tuning/optimization	NOx reductions result from the increase in productivity and reduced energy use, that include process optimizing such as flame shaping and temperature profile	25	No info found
Staged combustion in pre-calciner	In the first stage, fuel combustion is carried out in a high temperature fuel-rich environment and the combustion is completed in the fuel-lean low temperature second stage	30-45	No info found
LNB	Advanced burner design that controls oxygen, flame temperature, and/or residence time	10-25	$577 (USEPA 2006 $) $970-$1270 (USEPA 1994 $)
LNB + Indirect Firing	Reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another.	10-40	$200-$21,100 (LADCO 2015 $)
Mid-kiln firing of tires in long kilns and/or Biosolid Injection Technology	The injection of solid fuel into the calcining zone of a long kiln, this allows for part of the fuel to be burned at a lower temperature, reducing NOx formation.	11-55	$600-$3,600 (LADCO 2015 $) $470-$610 (USEPA 1994 $)

LNB + Mid-Kiln Firing	Advanced burner design that controls oxygen, flame temperature, and/or residence time with fuel injection at mid-point of kiln system	45	No info found
SNCR	By uses ammonia/urea without a catalyst to selectively reduce NOx emissions	30-70	$1,400 (LADCO 2015 $) $1,364 (USEPA 2006 $)
SCR	By uses ammonia/urea in the presence of a catalyst to selectively reduce NOx emissions	70-90	$600-$17,700 (LADCO 2015 $) $3,170-$3630 (USEPA 1994 $)
RSCR	A reducing agent such as ammonia is introduced into the flue gas stream to form nitrogen gas in the presence of a catalyst and heat exchangers	75	$5,500 (LADCO 2015 $)

Source: LADCO Four Factor Analysis
https://www.ladco.org/wp-content/uploads/Documents/Reports/Regional_Haze/Round2/2015_LADCO-4-Factor-Analysis-Regional-Haze.pdf
USEPA, *"ACT NOx Emissions from Cement Manufacturing,"* 1994.
https://www3.epa.gov/airquality/ctg_act/199403_nox_epa453_r-94-004_cement_manufacturing.pdf
USEPA, *"Menu of Control Measures,"* 2012.

3.2 SO_2 Control measures Evaluation

The techniques for controlling SO_2 from cement kilns can be categorized as pre-combustion and post-combustion controls. Pre-combustion control applicable to cement kilns is to process sulfur free or lower-sulfur raw materials and fossil fuels, as well as adding dry sorbent to the raw material/fossil fuels. Control of SO_2 emissions is also achievable post combustion control. The two main post combustion SO_2 emission control systems for cement kilns are dry or wet flue gas desulfurization ("FGD"), also known as scrubbers, with several varieties within the dry/wet FGD systems.

Dry FGD for cement kilns operates by capturing and routing the off-acid gas stream containing SO_2 into a dry scrubbing control system which uses a dry sorbent material for controlling SO_2 emissions. Wet FGD systems scrub the kiln off-gas stream with a liquid sorbent by forcing the polluted gas through a liquid slurry or by spraying it with the liquid scrubbing sorbent.

USEPA's "Menu of Control Measures" and the 2015 LADCO Four Factor Analysis provide several SO_2 control options applicable for cement kilns. Table 3.2 lists cost effectiveness from USEPA and LADCO provided documents applicable for cement kilns.

Table 3.2 List of SO_2 Control Systems for Cement Kilns

SO_2 Control Systems	Description	Percentage Control Efficiency	Cost Effectiveness ($/ton reduced)
Dry FGD	Dry Sorbent Injection into flue gas to absorb SO_2	25% - 50%	$2,400-$9,000 (2015 $, LADCO)
	Spray Dryer spray in an absorption tower to absorb SO_2	90% - 95%	$2,300-$88,800 (2015 $, LADCO)
Semi-dry FGD	Spray dryer absorption, spray lime slurry into an absorption tower where SO_2 is absorbed by the slurry	95% - 99.5%	$2,400-$47,100 (2015 $, LADCO)
		90%	$3,400-$5,700 (2006 $, USEPA)
	Cement Kilns - Preheater Process Kiln, spray lime slurry into an absorption tower where SO_2 is absorbed by the slurry	90%	$23,000-$57,000 (2006 $, USEPA)
Wet FGD	Transfer of waste materials from a gas to a contacting liquid, to remove SO_2 in the waste gas creating liquid waste	40% - 99%	$1,500-$78,800 (2015 $, LADCO)
		90%	$3,400-$5,700 (2006 $, USEPA)
	Cement Kilns - Preheater/Precalciner Kiln, transfer of waste materials from a gas to a contacting liquid, to remove SO_2 in the waste gas creating liquid waste	90%	$23,000-$34,000 (2006 $, USEPA)

LADCO, "*Four-Factor Analysis for Regional Haze in the Northern Midwest Class I Areas,*" 2015. https://www.ladco.org/wp-content/uploads/Documents/Reports/Regional_Haze/Round2/2015_LADCO-4-Factor-Analysis-Regional-Haze.pdf
USEPA, "*Menu of Control Measures,*" 2012.

4.0 Four Factor Analysis

The Regional Haze Guidance states:

> *"Characterization of factors for emission control measures Identify potential emission control measures for the selected sources, develop data on the four statutory factors and on visibility benefits if they will be considered. See 40 CFR 51.308(f)(2)."*

40 CFR 51.308(f)(2)(i) lists the four factors for analysis as:

1. Costs of compliance.
2. Time necessary for compliance.
3. Energy and non-air quality environmental impacts of compliance.
4. Remaining useful life of any potentially affected anthropogenic sources.

4.1 Factor 1 - Costs of Compliance

Holcim has very effective add-on post-combustion control systems for controlling both NOx and SO_2 emissions for Kiln #1, but no add-on post-combustion control systems for Kiln #2. Emission reductions from updates to control systems on Kiln #1 would be minimal and not cost-effective. The potential control measures evaluated in this four-factor analysis are add-on control systems for controlling NOx and SO_2 for Kiln #2.

4.1.1 NOx Cost of Compliance

NOx control systems' cost effectiveness for the Holcim kilns have been evaluated using various sources that include LADCO and USEPA analysis. Table 4.1 summarizes the feasibility and cost effectiveness of the control options evaluated. The 2020 $/ton cost effectiveness is converted from the study year to the year 2020 using Consumer Price Index data through November 2020.

Table 4.1 Summary of Feasibility and Cost Effectiveness for NOx Control Options

Control Measure Evaluated	Feasibility	Study Year Cost Effectiveness ($/ton)	Cost Effectiveness (2020 $/ton)
SNCR	Feasible	$1,364 (2006 $)	$1,762
RSCR	Feasible	$5,500 (2015 $)	$6,042
SCR	Feasible	$600-$17,700 (2015 $)	$659-$19,445

It should be noted that switching to SNCR or RSCR would yield minimal to no NOx emission reductions as their NOx reduction control efficiencies are lower than the 70-90% reduction of SCR and was determined to not be cost effective or appropriate. The highest NOx reduction control efficiencies as provided by LADCO and USEPA for SCR is 70-90% NOx reduction. Assuming the best-case scenario of 90% reduction would only yield an additional 147 tons/year of NOx reduction based on 2016 emissions. Due to the limited potential for substantial reductions, SCR was determined to not be cost effective.

4.1.2 SO_2 Cost of Compliance

SO_2 control systems cost effectiveness for the Holcim kilns, as mentioned above, have been evaluated from various sources that include LADCO and USEPA analysis. Table 4.2 summarizes the feasibility and cost effectiveness of the control options evaluated in this analysis. The 2020 $/ton costs effectiveness is converted from the study year to year 2020 using Consumer Price Index data through October 2020. The large range in cost effectiveness depends on the utilization and production scale as well as the specific capital costs associated with the design. Specific factors include equipment, installation, engineering, reagent, and waste removal. Kiln 1 began operation in 1960 and was last modified in 1995. Due to the old age of the equipment, costs are not likely to be on the low end of these ranges.

Table 4.2 Summary of Feasibility and Cost Effectiveness for SO_2 Control Options

Control Measure Evaluated	Feasibility	Study Year Cost Effectiveness ($/ton)	Cost Effectiveness (2020 $/ton)
Dry FGD	Feasible	$2,300-$88,800 (2015 $)	$2,527-$97,556
Semi-dry FGD	Feasible	$2,400-$47,100 (2015 $)	$2,637-$51,744
Wet FGD	Feasible	$1,500-$78,800 (2015 $)	$1,648-$86,570

4.2 Factor 2 - Time Necessary for Compliance

The time necessary for compliance includes the time the Agency need to develop, propose, and implement regulations, which usually takes around two years. For affected sources, the time needed to implement the evaluated control measures usually requires two to five years.

4.3 Factor 3 - Energy and Non-Air Quality Environmental Impacts of Compliance

For post-combustion NOx control systems, SNCR would minimally affect meeting auxiliary energy requirements. The SCR control system evaluated in this analysis would affect efficiency negatively for meeting auxiliary power requirements, as well as adding issues including possible hazardous solid waste disposals, reagent storage, and ammonia slips.

The FGD systems for SO_2 emission controls evaluated in this analysis would also increase auxiliary power requirements that include heat rate and capacity penalties. Further, for FGD control systems, non-air quality environmental impacts may include increased water usage and discharges of polluted water from a control device as well as solid or hazardous waste generation.

4.4 Factor 4 - Remaining Useful Life of Potentially Affected Sources

The remaining useful life of the rotary kilns depends on the inner lining of the kiln known as the refractory, which is used to protect the main body of the kiln and minimize heat loss. The lifespan of the refractory varies from a few months to several years and is dependent on the material used. Thus, the useful life of the kiln can be extended with proper maintenance of the refractory. The 2015 LADCO Four Factor Analysis' assessment of the useful life of lime/cement kilns states:

> "*According to MARAMA's Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I areas, the remaining useful life of each emission unit is a minimum of at least 10 years. With proper maintenance and upkeep, some units can operate for 20-30 years more."*

Illinois emissions unit data record shows Holcim's Kiln #1 began operating in 1960 and Kiln #2 in 1975. Illinois EPA estimates the remaining useful life of Kiln #1 to be 10 to 20 years. Kiln #2 ceased operation in 2016.

4.5 Four-Factor Analysis Conclusion

Based on the quantity of current annual NOx and SO_2 emissions, the high cost of the control measures evaluated in this analysis, and the remaining useful life of the kilns, Illinois EPA will not be proposing any new NOx and SO_2 reduction measures for Holcim's kilns in the second implementation period.

ADM 4-Factor Analysis

1.0 Archer Daniels Midland Company – Decatur Regional Haze Four-Factor Analysis

The four-factor analysis for Archer Daniels Midland Company – Decatur ("ADM Decatur") in this document is for determining whether the source is already reasonably controlled or requires additional control in order to make reasonable progress.

2.0 Archer Daniels Midland Company – Decatur Source Description

The source is a biochemical and food processing company located in Decatur, Illinois. It operates a variety of grain processing activities including milling and oil refining, and it produces food and beverage ingredients, renewable chemicals, biofuels (ethanol and biodiesel), and other bioproducts.

2.1 Main Emission Units Description

The source has several emission units that include grain milling, storage and process tanks, dryers, wastewater treatment, coal and limestone handing systems, and boilers. The main emission units for the four-factor analysis at this source are the nine-cogeneration coal-fired fluidized bed boilers (Cogen-FB). FB boilers are described as:

> *"Fluidized-bed combustors ("FBC") are boilers of a more recent design and were developed for solid fuel combustion. In FBC, combustion takes place in suspension as in a PC boiler, but instead of individual burners controlling the air/fuel mixing, fuel and a mixture of inert material (e.g., sand, silica, ash, sorbent products) are kept suspended above the bed by an upward flow of combustion air through the fuel bed. This fluidization improves mixing of fuel and air, as well as allowing for higher residence times in the furnace (the retention time of the fuel in the bed). FBC are inherently suited for various fuels, including low-grade fuels such as petroleum coke, coal refuse, municipal waste, and biomass materials"* (USEPA 2010). *https://www.epa.gov/sites/production/files/2015-12/documents/iciboilers.pdf*

Cogeneration is the use of heat to generate electricity first and then the residual heat is used for other purposes such as to make hot water or steam for other process use. The boilers' main fuel to produce heat is low-sulfur coal and Illinois high sulfur coal blends (coal, natural gas, wood, tires, as well as limestone for limiting SO_2 emission).

It should be noted that ADM has announced plans to construct a new power plant at the facility employing the Allam-Fetvedt Cycle and carbon sequestration to produce electricity with virtually no emissions of SO_2 or NOx. The technology to be deployed operates by burning natural gas (very low sulfur) in an oxygen-fuel mixture which when combusted produces very little NOx. The excess CO_2 that is produced in the process is also in a high-pressure and high purity state and is ready for sequestration without additional energy needed for further

compression. However, as there is no specific information about this situation as of yet, the analysis herein used the existing source information.

2.2 Source Existing Control Systems

The source has several emission control systems for the boilers. PM emissions are controlled by baghouses achieving an average control efficiency of 99%. NOx emissions are controlled using low NOx burners ("LNB") and a selective non-catalytic reduction ("SNCR") system achieving over 80% emission reduction. SO_2 emissions are controlled using a blend of limestone, 60% low-sulfur Powder River Basin ("PRB") coal and dry sorbent injection ("DSI") systems achieving 70%-90% emission reduction. Table 2-1 lists a summary of the main emission units and control systems.

Table 2.1 List of Boilers and Control systems

Emission Unit Cogen-FB	Description	Date Constructed	Stack	Control system
Boilers #1 through #5	Coal-fired fluidized bed boilers rated at 492 mmBtu/hr each	1987	S1	Baghouses, LNB, SNCR, and DSI
Boilers #6	Coal-fired fluidized bed boiler rated at 700 mmBtu/hr	1991	S2	Baghouses, LNB, SNCR, and DSI
Boilers #7	Coal-fired fluidized bed boiler rated at 750 mmBtu/hr	1995	S1	Baghouses, LNB, SNCR, and DSI
Boilers #8	Coal-fired fluidized bed boiler rated at 1500 mmBtu/hr	1995	S3	Baghouses, LNB, SNCR, and DSI
Boilers #9	Coal-fired fluidized bed boiler rated at 1500 mmBtu/hr	1997	S4	Baghouses, LNB, Optimized SNCR, and DSI

Based on the emission control systems the facility has in place, $PM_{2.5}$ emissions are 99% controlled, NOx emissions are 80% controlled, and SO_2 emissions are 70-90% controlled. Based on the control system efficiency and the size of reported emissions in terms of ton per year ("TPY") as shown in Table 2-2 of the last four years, the four-factor analysis for this facility will be limited to the emissions of NOx and SO_2 emissions only.

Table 2.2 Source Reported Emissions

Pollutant	Reported Emissions (TPY)			
	2016	2017	2018	2019
PM2.5	350.08	579.36	548.45	675.18
NOx	2,096.10	2,106.36	2,079.37	2,174.30

SO_2	7,363.56	9,527.36	9,012.24	8,497.31

2.3 Source NOx and SO_2 Emissions

The source's boilers burn fossil fuels to extract heat. Fossil fuels are a complex mixture of organic and inorganic compounds, containing carbon, hydrogen, oxygen, sulfur, nitrogen, and other elements including mercury. The process of extracting heat-energy involves chemical reactions which produce NOx and SO_2. The source is regulated under IAC title 35 and federal programs (NSPS-40 CFR part 60, subparts Db) that limit emissions of NOx and SO_2. In addition, the source implemented emission reductions under a joint USEPA and Illinois EPA Consent Decree. Table 2.3 shows data from the last five periodic emission inventories for the source and from its 2019 emission report.

Table 2.3A Source NOx and SO_2 Reported Emissions

	Reported Emissions (TPY)					
Pollutant	**2005**	**2008**	**2011**	**2014**	**2017**	**2019**
NOx	4,509.90	2,761.12	2,355.3	2,523.88	2,106.35	2,174.30
SO_2	9,564.12	9,502.83	8,733.60	10,011.57	9,527.35	8,497.31

2.3.1 Current Boilers NOx and SO_2 Emissions Assessment

NOx emissions from coal-burning boilers are from the formation of NOx in the boiler. NOx forms in three ways: thermal NOx, prompt NOx, and fuel NOx. Thermal and fuel NOx are the main contributors of NOx formation in coal-fired boilers. Thermal NOx is the result of oxidation of the atmospheric nitrogen, and fuel NOx is the result of oxidation of nitrogen bound in the coal (USEPA AP-42).

SO_2 emissions from coal-burning boilers are entirely dependent on sulfur content of the coal and are not affected by any other boiler parameters such as size of the boiler, design, or grade of the coal being burned. Approximately 95 percent emission of oxides of sulfur is in the form of SO_2, and the rest are in the form of SO3, sulfuric acid mist, and a small amount of sulfates (USEPA AP-42, 2010).

The source reports detailed annual emissions and performs annual accuracy tests on its continuous emission monitoring systems ("CEMS"). Table 2.3 lists 2018 reported heat inputs, emissions (TPY), and calculated performance in terms of lb/mmBtu based on the report emissions.

Table 2.3B Boilers 2018 Reported Operating Parameters and Calculated Emission Rates

Unit	Heat input mmBtu coal	Heat input mmBtu natural gas	Coal blend TPY	Natural gas mscf	Reported NOx TPY	Reported SO_2 TPY	Calculated based on facility-reported information	
							NOx lb/mmBtu	SO_2 lb/mmBtu

Boiler #1	14,184,635	1,042	168,004	1,005	677	874	0.096	0.123
Boiler #2	14,184,635	1,595	163,715	1,539	677	859	0.096	0.121
Boiler #3	14,184,635	5,306	165,492	5,117	677	793	0.096	0.112
Boiler #4	10,220,389	1,796	167,436	1,732	465	810	0.091	0.159
Boiler #5	10,220,389	2,776	156,391	2,677	465	796	0.091	0.156
Boiler #6	10,220,389	4,707	155,813	4,540	465	626	0.091	0.123
Boiler #7	14,184,635	8,793	141,624	8,480	677	733	0.095	0.103
Boiler #8	9,030,942	4,957	354,200	4,781	464	1,857	0.103	0.411
Boiler #9	8,877,375	6,938	415,674	6,691	261	1,586	0.059	0.357

3.0 Control Measures

The NSPS for ICI boilers with heat inputs greater than 100 mmBtu/hr constructed after September 18, 1978, codified in 40 CFR Part 60 Subparts Db regulates PM, NOx, and SO_2 with set limitations equivalent to that of Reasonably Available Control Technology ("RACT"). The NSPS regulatory limitations for coal fired ICI boilers NOx and SO_2 emissions are 0.70 lb/mmBtu and 1.2 lb/mmBtu respectively. In addition, the source implemented emission reduction under the consent decree. Therefore, based on the NSPS regulatory and consent decree emission limitations, and the control systems the source has in place, the control measures evaluation for this source are limited to: (1) to make improvement on the existing NOx and SO_2 control systems or upgrading the control system for higher emissions reduction; (2) fuel switch from partial Illinois coal use to 100% PRB coal; (3) fuel switching from coal into natural gas; and (4) repowering to Integrated Gasification Combined Cycle ("IGCC").

3.1 NOx and SO_2 Control Measures Evaluation

Referring to USEPA provided documents, NOx is formed by several methods and as a result, NOx emissions can be reduced or controlled by different methods. The methods are grouped into two control systems as combustion controls and post combustion controls. Combustion controls reduce NOx formation during the combustion process by use of such as flue gas recirculation ("FGR"), overfire air ("OFA"), LNB, Ultra low NOx burners ("ULNB"), and reburn or use of combination of these during combustion control systems. Post combustion controls are a process of the flue gas treatment after the formation of NOx emissions and include SNCR and selective catalytic reduction ("SCR").

More detailed information of these NOx control technologies can be found in the USEPA provided documents such as AP-42 and the Alternative Control Techniques Document. Rough

cost estimates of the control effectiveness are provided by several sources including LADCO and USEPA. Table 3.1 lists USEPA-provided costs, compiled from several sources that include ICI-ACT and the Menu of Control Measures, feasible and commercially available potential NOx control systems for ICI coal-fired boilers. Table 3.1 lists the control technology, control efficiency, and cost effectiveness.

Table 3.1 List of NOx Control Systems for Coal-fired ICI Boilers

NOx Control Technology	Description of the Control Systems	Percentage Control Efficiency	Cost Effectiveness 400 mmBtu/hr (1992 $/ton)	Cost Effectiveness (2006 $/ton)
LNB	Limits NOx formation by restricting excess oxygen, reduces temperature, and reduces residence time	50	$1,170-$1,530	Cost effectiveness varies by boiler size. - 50 MMBTU/hr: $3,140 - $12,187. - 100 MMBTU/hr: $1,526 - $6,093. - 250 MMBTU/hr: $610 - $2,435. - 750 MMBTU/hr: $203 - 813.
OFA	Limits NOx formation by reducing combustion temperature and limiting excess oxygen		--	--
LNB+OFA	Low NOx coal-and-air nozzles with cross-coupled overfire Air	51	--	$1,373 for NOx<1 TPD and $434 for NOx>1 TPD
SNCR	Flue gas treatment using chemical without catalytic	40-75	$1,010-$1,400	$2,297 for NOx<1 TPD and $1,424 for NOx>1 TPD
SCR	Flue gas treatment using chemical with catalytic	80	$3,400-$4,200	$2,373 for NOx<1 TPD and $971 for NOx>1 TPD

Sources: USEPA, ICI-ACT Document - NOx Emissions from ICI Boilers, EPA-453/R-94-022, March 1994. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=2000INCA.pdf
USEPA, "Menu of Control Measures," 2012.

The techniques for controlling SO_2 from coal-fired boilers can be categorized as pre-combustion and post-combustion controls. Pre-combustion control may be classified further into three categories: boiler modification to improve thermal efficiency, fuel washing/treatment, and fuel switching. The second way of controlling SO_2 emission is during or post combustion control,

i.e., during formation or after it has been formed. There are several methods for capturing SO_2 emissions from coal-fired boilers. The two main post combustion SO_2 emissions control systems are dry or wet Flue Gas Desulfurization ("FGD"), also known as scrubbers with several verities within the dry/wet FGD systems. Table 3.2 presents SO_2 control measures applicable to large coal fired boilers from the USEPA "Menu of Control Measures" and platform v6, which are compiled by USEPA from several sources.

Table 3.2A List of SO_2 Control Measures

Control Measure	Description of the Control Measure	Control Efficiency (%)	Cost Effectiveness (2006 $/ton reduced)
Chemical coal cleaning	Remove inorganic sulfur and organic sulfur compounds in coal	50-85	--
Physical coal cleaning and coal washing	Removes inorganic sulfur and improves the quality of coal by Removes impurities and increasing its heat content	35-40	$420
Fuel switching from bituminous coal to lignite coal	Fuel switching from high sulfur coal to less sulfur coal	80	$160-$240
Fuel switching from subbituminous coal to lignite	Fuel switching from high sulfur coal to less sulfur coal	27	$160-$240
Fuel switching away from coal: bituminous coal to No. 2 oil	Fuel switching involves replacing the current fuel with a fuel which emits less	91	based on cost differential and emission factors
Fuel switching from coal to natural gas	Fuel switching to natural gas reduce SO_2 emissions almost to zero	99.9	based on cost differential and emission factors
Dry FGD – Lime Spray Dryer System (LSD)	The control system is a semi-dry FGD uses a fine spray of slaked lime (Ca(OH)2) to absorb SO_2 in the scrubber	70-96	$160-$300 for units >200 MW
			$517-$4,133 for units <200 MW
Wet FGD – Limestone Forced Oxidation System (LSFO)	The control system is a wet FGD uses limestone (CaCO3) for SO_2 scrubbing	52-98	$200-$500 for units >400 MW
			$517-$5,166 for units <400 MW
Wet FGD - Magnesium	The control system uses slaked lime, containing calcium	52-98	$200-$500 for units >400 MW

Control Measure	Description of the Control Measure	Control Efficiency (%)	Cost Effectiveness (2006 $/ton reduced)
Enhanced Lime System (MEL)	hydroxide (Ca(OH)2) and magnesium hydroxide (Mg(OH)2) for SO_2 scrubbing		$517-$5,166 for units <400 MW
Repowering to IGCC	Replaced the boiler with new combustion turbines and a heat recovery boiler.	99	Cost effectiveness is variable depending on nameplate capacity: - capital cost = $1,027 per kW - fixed O&M cost = $33.37 per kW per year - variable O&M cost = $3.17 mills per kW

Source: USEPA, "Menu of Control Measures," 2012, compiled from several sources

3.1.1 NOx Existing Control Systems Improvements or/and Upgrading the Control System

The source uses LNB and SNCR to control NOx emissions. LNB controls NOx emissions by limiting oxygen in the primary combustion zone that limits fuel NOx formation; and reduces flame temperature and residence time at peak temperature limits thermal NOx formation (USEPA, ACT NOx Emissions from ICI Boilers, EPA-453/R-94-022, 1994). The other control system employed by ADM is SNCR. In addition to Air Pollution Control Cost Manual, USEPA provided an Excel spreadsheet tool for estimating site-specific cost effectiveness for EGU coal-fired boilers. The Excel spreadsheet tool was developed by USEPA by contractor Sargent & Lundy through Eastern Research Group. The Excel spreadsheet tool was used in USEPA Power Sector Modeling Platform Base Case v.5.13 and in the latest updated Platform v6 for assessing control costs.

The boilers' site-specific information was acquired by following the ACT for ICI boilers guidance, in which there is a conversion factor of 0.293 to convert from mmBtu/hr to MWt, and used and heat rate of 10,000 Btu/kWhr for all boilers. The rest of inputs used were a retrofit factor 1, capacity factor 85%, and the removal efficiency is based on the rate floor of the control system given in the Excel spreadsheet tool. Table 3.2 lists inputs to the Excel file based on the reported CEMS info.

Table 3.2B Excel File Boilers Input Information

Emission Unit Cogen-FB	Unit size (mmBtu/hr)	Calculated Unit size (MWt)	NOx Rate (lb/mmBtu)	SO_2 Rate (lb/mmBtu)	SNCR (% NOx reduction floor 0.08-0.1)	SCR (% NOx reduction floor 0.05-.07)	SDA (%SO_2 reduction floor 0.08)	Wet FGD (%SO_2 reduction floor 0.06)
Boilers #1 through #5	492	144	0.0896*	0.518*	0*	33*	85*	89*
Boilers #6	700	205	0.091	0.568	1	34	86	89
Boilers #7	750	220	0.108	0.519	17	44	85	88

Boilers #8	1500	440	0.107	0.496	16	44	84	88
Boilers #9	1500	440	0.060	0.376	0	0	79	84

*Average emission rates and average % reduction

Based on the rate floor of the SNCR control system between 0.08-0.1 lb/mmBtu, improvement of the control system for additional NOx reduction would not be reasonable. For upgrading into SCR control system, using NSPS allowable emission rates of NOx 0.07 lb/mmBtu and allowable emission rate of SO_2 1.2 lb/mmBtu the Excel spreadsheet tool generated cost effectiveness in 2016$ between $4,577 - $6,690 per ton NOx removed.

3.1.2 SO_2 Existing Control Systems Improvements or/and Upgrading the Control System

For SO_2 emissions, the source uses a blend of limestone, 60% low-sulfur PRB coal, and DSI control systems to limit SO_2 emissions and achieving emissions reduction between 70-90%. Based on the reported emissions and the control measures in place, control system improvement would not be reasonable.

For upgrading the current control systems, USEPA Platform v6 presented two control technologies, Limestone Forced Oxidation ("LSFO") and Lime Spray Dryer ("LSD"). Platform v6, describes the control systems as:

> *"Two commercially available Flue Gas Desulfurization (FGD) scrubber technology options for removing the* SO_2 *produced by coal-fired power plants are offered in EPA Platform v6: Limestone Forced Oxidation (LSFO) — a wet FGD technology and Lime Spray Dryer (LSD) — a semi-dry FGD technology which employs a spray dryer absorber (SDA). In wet FGD systems the polluted gas stream is brought into contact with a liquid alkaline sorbent (typically limestone) by forcing it through a pool of the liquid slurry or by spraying it with the liquid. In dry FGD systems the polluted gas stream is brought into contact with the alkaline sorbent in a semi-dry state through use of a spray dryer. The removal efficiency for SDA drops steadily for coals whose* SO_2 *content exceeds 3 lbs* SO_2*/MMBtu, the technology is therefore provided to only plants which have the option to burn coals with sulfur content no greater than 3 lbs* SO_2*/MMBtu. In EPA Platform v6 when a unit retrofits with an LSD* SO_2 *scrubber, it loses the option of burning certain high sulfur content coals"* (USEPA Platform v6 chapter 5).

Based on USEPA Platform v6, these control systems achieve efficiency of 98% SO_2 removal for LSFO and 95% for LSD. Table 3.2 shows the Platform v6 costs for capacities of 100 MW and 300 MW in 2016$.

Table 3.2C LSFO and LSD Control Technologies Costs (2016$), USEPA Platform v6

Control System Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	100 MW		300 MW	
					Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)

LSFO	10000	-1.78	1.82	2.47	919	24.7	667	11.9
	11000	-1.96	2.00	2.70	956	25.1	694	12.2
LSD	10000	-1.32	1.33	2.89	779	18.2	571	9.2
	11000	-1.45	1.47	3.17	812	18.5	594	9.4
USEPA Platform v6 Notes: "LSFO - Minimum Cutoff: ≥ 25MW, Maximum Cutoff: None, and Assuming 3 lb/MMBtu SO_2 Content Bituminous Coal. LSD - Minimum Cutoff: ≥ 25MW, Maximum Cutoff: None, and Assuming 2 lb/MMBtu SO_2 Content Bituminous Coal."								
"The Variable O&M costs in this table do not include the cost of additional auxiliary power (VOMP) component in the Sargent & Lundy tool as for modeling purposes, IPM reflects the auxiliary power consumption through capacity penalty."								

ADM's nine boilers are rated between 144-440 MW and with an estimated heat rate of each boiler is 10,000 Btu/kWh, Platform v6 did not provide scaling factor for calculating costs for site specific to be used for ADM units. The documents, in addition to the cost range listed in Table 3-2, provide an Excel spreadsheet for calculating costs for three SO_2 control technologies, listed as Dry Sorbent Injection ("DSI"), Spray Dryer Absorbers ("SDA"), and wet-FGD. As mentioned in previous section, the USEPA description of Excel spreadsheet is: "The Retrofit Cost Analyzer (RCA) is an Excel-based tool that can be used to estimate the cost of building and operating pollution control such as SCR, Wet FGD, Dry FGD, DSI, ACI and PM." The spreadsheet has several variables set with default values and allows user input for calculating costs. Table 3.3A lists costs range per boiler of the two SO_2 control systems which are derived using known ADM boilers operating parameters and allowable SO_2 emission rate (i.e., inlet SO_2 1.2 lb/mmBtu, size 144-440 MW, and heat rate 10,000 Btu/kWh). The known inputs and control system efficiency are adjusted to the control system rate floor given in the tool (SDA-FGD rate floor of 0.06 lb/mmBtu, and wet-FGD rate floor of 0.06 lb/mmBtu which are equated to 95% control efficiency). Table 3.3B lists cost ranges per boiler of the two SO_2 control systems based on reported CEMS performance test emission rates, which equated into 88% SO_2 emissions removal target.

Table 3.3 USEPA Provided Spreadsheet Generated SO_2 Control System Cost (2016 $) based on Reported Emission Rate

Control Systems	Removal Target (%)	Total Project Cost per Boiler	Total Annual Cost per Boiler	Annual Tons SO_2 Removed per Boiler	Cost Effectiveness ($/Ton)
SDA-FGD	88	$97,733,000 - $217,448,000	$17,604,000 - $39,247,000	2,382 – 7,280	$5,391 - $7,389
Wet-FGD	88	$108,676,748 - $239,762,377	$19,626,000 - $42,666,000	2,382 – 7,280	$5,861 - $8,238
Data Inputs: Unit Size = 144-440 MW Heat Rate = 10,000 Btu/kWh SO_2 Inlet Rate = 0.505 lb/mmBtu Capacity Factor = 85%					

Type of Coal = PRB

3.1.3 Fuel Switch from Illinois Coal Blend to PRB Coal

Switching from high sulfur to low sulfur coal directly limits the amount of SO_2 formation during the combustion process, however this control option may have some drawbacks. The USEPA-provided document states:

> *"Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined"* (USEPA, EPA/600/7-90/021d, November 1990).

The source has already implemented fuel switching by switching from Illinois high-sulfur coal to a blend of PRB coal, Illinois coal, natural gas, wood, and tires, as well as limestone for further limiting SO_2 emission. The source's current fuel blend has been optimized to limit SO_2 emissions to the extent possible while maintaining the proper operation of the units due the to the factors noted in the quotation above. Additional fuel switching from Illinois coal to PRB coal as potential SO_2 reducing control measure was not evaluated further.

3.1.4 Fuel Switching from Coal into Natural Gas

Natural gas and fuel oils have low sulfur content compared to coal. The USEPA provided document "The Menu of Control Measures," describes the control measure applicable to EGU boiler as:

> *"Fuel substitution involves replacing the current fuel with a fuel which emits less of a given pollutant when burned. For many older boilers, fuel switching is an especially attractive option because the capital investment is usually small when compared to that of control devices. Cost effectiveness varies depending on the ranks of the old and new fuels and is estimated based on the emission factors."*

Platform v6 chapter 5 section 5.7.1 describes the technical aspect of coal to gas control measure, that involves major modifications, including installation of new gas burners, windbox, heating surfaces, and modification of the pollution control equipment. Further, the control measure may involve operational changes to sootblowers, spray flows, air heaters, and emission controls. USEPA Platform v6 presents a detail cost of the control measures and applicability, Table 3.4 lists a copy of USEPA evaluation of the control measure as listed in Platform v6 that shows the control measure costs and applicability, stating: "Not applicable for fluidized bed combustion (FBC) and stoker boilers." ADM's nine coal-fired boilers are fluidized bed combustion boilers, therefore the coal-to-gas control option for ADM boilers is not feasible thus the control measure is not evaluated.

Table 3.4 Fuel Switching Coal-to-Gas Control Option Costs

Table 5-18 Cost and Performance Assumptions for Coal-to-Gas Retrofits in EPA Platform v6		
Factor	**Description**	**Notes**
Applicability:	Existing pulverized coal (PC) fired and cyclone boiler units of a size greater than 25 MW:	Not applicable for fluidized bed combustion (FBC) and stoker boilers.

3.1.5 Repowering to IGCC

The USEPA provided document "The Menu of Control Measures" describes the IGCC control measure applicable for EGU boiler as:

> "*Repowering improves power plant efficiencies and implies significant waste reduction. Typical repowering entails steps in which the coal handling system and the boiler are replaced with new combustion turbines and a heat recovery boiler. The only significant part of the plant that is maintained is the original turbine generator. The IGCC is a repowering option that requires extensive gasification equipment to generate synthetic gas from coal in order to feed the gas turbines. IGCC plants offer the capability of removing the Hg from the compressed syngas prior to combustion where the gas volume treated is much less than the low pressure, post-combustion flow volume.*"

Repowering to IGCC, achieves control efficiency of 99% SO_2 reduction and the document presents cost effectiveness in 2006 $ as:

> *"Cost effectiveness is variable depending on nameplate capacity: - capital cost = $1,027 per kW, - fixed O&M cost = $33.37 per kW per year, and - variable O&M cost = $3.17 mills per kW"*

Based on ADM boilers total capacity rates of 6910 mmBtu/hr, Table 3.5 presents the costs and cost effectiveness for IGCC control measure.

Table 3.5 Repowering to Integrated Gasification Combined Cycle Control Option

Cost Factor	Description and Notes	Costs
ADM nine boilers rated between 492-1500 mmBtu/hr (Table 3-2 of this document)	Total boilers nameplate capacity 6910 mmBtu/hr, converted using conversion factor of 0.293 and converted into 4789 MW	--
Total capital cost (2006 $)	Capital cost = $1,027 per kW estimated useful life of 40 years, total capital cost of the control system	$4,918,303,000
Capital recovery factor ("CFR") for annualizing cost per	For annualizing the capital cost, the total capital investment multiplied by a capital recovery factor (CRF = (i (1+ i)n)/((1+ i)n - 1), Where n = Useful Life	$306,410,277

year	(40 years) and i= interest rate (5.5%)) equated to 0.0623	
Fixed O&M cost (2006 $)	Fixed O&M cost = $33.37 per kW per year based on 4789 MW, total cost per year	$159,808,930
Variable O&M cost (2006 $)	Variable O&M cost = $3.17 mills per kW, based on total capacity 4789 MW and major overhauls on a three-year cycle, cost per year	$15,181
CFR for annualizing variable O&M cost (2006 $)	For annualizing capital cost, the total capital investment multiplied by a capital recovery factor (CRF = (i (1+ i)n)/((1+ i)n - 1), Where n = major overhauls on a three-year cycle (3 years) and i= Interest Rate (5.5%)), CFR equated to 0.3707	$5,627
Total annual cost of the control measure (2006 $)	Total capital cost per year + fixed O&M cost per year + variable O&M cost per year	$466,224,834
Control option NOx emission reduction	44% reduction from current average NOx emission rate of 0.091 lb/mmBtu, based on rate floor of 0.05 lb/mmBtu (the 0.05 lbs/mmBtu floor is the same as the NOx rate floor for new retrofit SCR on units burning natural gas, the source will still need NOx control system and assumed the control system to achieve a rate floor of 0.05 lb/mmBtu (276.4 tpy NOx reduction)	--
Control option SO_2 emission reduction	99% reduction, based on the allowable emission rate of 1.2 lb/mmBtu and 99% emission reduction (8,209.1 TPY SO_2 reduction)	--
Cost effectiveness 2006 $/ton	Based on NOx emission reduction of 276.4 TPY and SO_2 emission reduction of 8209.1 TPY	$54,944

4.0 Four Factor Analysis

The Regional Haze Guidance states:

> *"Characterization of factors for emission control measures Identify potential emission control measures for the selected sources, develop data on the four statutory factors and on visibility benefits if they will be considered. See 40 CFR 51.308(f)(2)."*

40 CFR 51.308(f)(2)(i) lists the four factors for analysis as:

5. Costs of compliance.
6. Time necessary for compliance.
7. Energy and non-air quality environmental impacts of compliance.
8. Remaining useful life of any potentially affected anthropogenic sources.

4.1 Factor 1 - Costs of Compliance

ADM has in place pre-combustion and post-combustion add-on control systems for controlling both NOx and SO_2 emission. The potential theoretically feasible control measures evaluated in this four-factor analysis are improvements to current control systems, add-on control systems for improving the current control system, fuel switching, and repowering to IGCC.

4.1.1 NOx Cost of Compliance

NOx control systems cost effectiveness for ADM boilers has been evaluated using various sources that include USEPA Platform v6. ADM has in place pre-combustion control system, LNB, and an add-on control system of SNCR for controlling NOx. Table 4-1 summarizes the feasibility and cost effectiveness of the control options evaluated in this analysis. The 2020 $/ton costs effectiveness is converted from the study year to year 2020 using Consumer Price Index data through October 2020.

Table 4.1 Summary of Feasibility and Cost Effectiveness for NOx Control Options

Control Measure Evaluated	Feasibility	Study Year Cost Effectiveness ($/ton)	Cost Effectiveness (2020 $/ton)
Current SNCR Improvement	Current control system is achieving rate floor, therefore not feasible and is not evaluated	--	--
Switching from SNCR to SCR	Feasible	$4,577 – $6,690 (2016 $)	$4,962 – $7,252
Coal-to-Gas	Based on USEPA Platform v6 info, not feasible for FBC boilers therefore is not evaluated	--	--
Repowering to IGCC	Feasible	$54,944 (based on total NOx and SO_2 emission reductions (2006 $))	$ 70,878

In addition, ADM nine boilers are cogeneration or combined heat and power generation ("CHP") units, operating at minimum 40% to 64% higher efficiency than single use boilers.

USEPA descripts the efficiency benefit of the CHP system as:

> "*The average efficiency of fossil-fueled power plants in the United States is 33 percent. This means that two-thirds of the energy used to produce electricity at most power plants in the United States is wasted in the form of heat discharged to the atmosphere… By recovering this wasted heat, CHP systems typically achieve total system efficiencies of 60 to 80 percent for producing electricity and useful*

thermal energy. Some systems achieve efficiencies approaching 90 percent". (https://www.epa.gov/chp/chp-benefits).

Therefore, based on NOx control systems the source has in place, efficient use of energy, and high cost of the alternative control measure as evaluated in this analysis, Illinois EPA is not proposing any new NOx reduction measures for ADM boilers.

4.1.2 SO_2 Cost of Compliance

As mentioned above, ADM's boilers' SO_2 control systems cost effectiveness has been evaluated from various sources that include USEPA Platform v6. ADM's boilers SO_2 emissions are controlled using a blend of limestone, 60% western low sulfur coal and DSI systems achieving 70%-90% emission reduction. Table 4.2 summarizes the feasibility and cost effectiveness of the control options evaluated in this analysis. The 2020 $/ton costs effectiveness is converted from the study year to 2020 $ using Consumer Price Index data through October 2020.

Table 4.2 Summary of Feasibility and Cost Effectiveness for SO_2 Control Options

Control Measure Evaluated	Feasibility	Study Year Cost Effectiveness ($/ton)	Cost Effectiveness (2020 $/ton)
SDA-FGD	Feasible	$5,391 – $7,389 (2016 $)	$5,844 - $8,010
Wet-FGD	Feasible	$5,861 – $8,238 (2016 $)	$6,353 - $8,930
Coal-to-Gas	Based on USEPA Platform v6 info, not feasible for FBC boilers therefore is not evaluated	--	--
Repowering to IGCC	Feasible	$54,944 (based on total NOx and SO_2 emission reductions (2006 $))	$ 70,878

As discussed in the NOx cost of compliance section, ADM's nine boilers are cogeneration, CHP units, operating at 40% to 64% higher efficiency than single use boilers. Therefore, based on SO_2 control measures the source has in place, efficient use of energy, and high cost of the alternative control measure as evaluated in this analysis, Illinois EPA is not proposing any new SO_2 reduction measures for ADM's boilers.

4.2 Factor 2 – Time Necessary for Compliance

The time necessary for compliance includes the time the Agency need to develop, propose, and implement regulations, which usually takes around two years. For affected sources, the time needed to implement the evaluated control measures usually requires two to five years. Based on the current RACT-level NOx and SO_2 emission control systems in place, Illinois EPA is not

proposing any new additional NOx or SO_2 control measures for ADM in the second implementation period. Therefore, more detailed analysis for factor 2, time necessary for compliance for new control measures, is not necessary and not evaluated.

4.3 Factor 3 - Energy and Non-Air Quality Environmental Impacts of Compliance

As mentioned previously, ADM has pre-combustion and post-combustion control systems for controlling NOx emissions. The techniques for pre-combustion NOx controls are to limit both thermal and fuel NOx formation by reducing the peak flame temperature and by delaying mixing of the fossil fuels and air. In coal-fired boilers these would result lower thermal energy, increased unburned carbon as well as increased incomplete oxidation, increasing CO emissions, and decreasing boiler efficiency. The unburnt carbon as an elemental carbon can also affect salable fly ash and may interfere with performance of the PM control systems (USEPA EGU-ACT 1994). For the post-combustion NOx control systems in place, SNCR would affects efficiency minimally, but SCR control systems evaluated in this analysis would affect efficiency negatively for meeting auxiliary power requirements as well as adding the issues involved with possible hazardous solid waste disposals, reagent storage, and ammonia slips.

The FGD systems for SO_2 emission controls evaluated in this analysis would also increase auxiliary power requirements that include heat rate and capacity penalties. Further, FGD control systems, non-air quality environmental impacts could include increased water usage and discharges of polluted water from control devices as well as solid or hazardous waste generation.

4.4 Factor 4 - Remaining Useful Life of Potentially Affected Sources

ADM ICI boilers are large boilers comparable to EGU boilers and the useful life of EGU boilers vary widely. US Energy Information Administration provided information for coal power plant retirement activity states:

> "*The U.S. coal units that retired in 2018 had an average capacity of 350 megawatts (MW) and an average age of 46 years, compared with an average capacity of 129 MW and average age of 56 years for the coal units that retired in 2015*" (https://www.eia.gov/todayinenergy/detail.php?id=40212).

USEPA assesses the useful life of coal-fired boilers to be 40 years. Table 4.3 lists the USEPA Base Case v5.13 assumptions for the useful life and life extension costs for doubling the useful life of different unit types.

Table 4-3 EGU Combustion Unit Useful Life

Plant Type	Lifespan without Life Extension Expenditures	Life Extension Cost as Proportion of New Unit Capital Cost (%)	Capital Cost of New Unit (2011$/kW)	Life Extension Cost (2011$/kW)
Biomass -	40	6.6	4429	291

Fluidized Bed				
Coal Steam	40	7	3160	221
Combined Cycle	30	9.3	1047	98
IGCC	40	7.4	3254	241

Source: USEPA, "Life Extension Cost Assumptions Used in EPA Base Case v.5.13, Chapter 4", 2013. https://www.epa.gov/sites/production/files/2015-07/documents/chapter_4_generating_resources_0.pdf

Illinois EPA records show ADM's boilers began operation between 1987 - 1997, therefore based on USEPA coal-fired boiler retirement activity information, the remaining useful life for ADM's boilers is between 15-30 years.

4.5 Four-Factor Analysis Conclusion

Based on NOx and SO_2 emissions control measures the source already has in place, efficient use of energy, high cost of alternative control measures as evaluated in this analysis, and remaining useful life of the boilers, Illinois EPA is not proposing any new NOx or SO_2 reduction measures for ADM's boilers in the second implementation period.

APPENDIX B: LADCO Regional Haze TSD



Modeling and Analysis for Demonstrating Reasonable Progress for the Regional Haze Rule 2018 - 2028 Planning Period

Technical Support Document

Lake Michigan Air Directors Consortium

9501 W. Devon Ave., Suite 701

Rosemont, IL 60018

Please direct question/comments to adelman@ladco.org

June 17, 2021

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Document Change Log

Version	Date	Comments/Changes
1	January 11, 2021	First draft to LADCO states
2	January 15, 2021	Updates to sections 2, 4, and 6
3	January 19, 2021	Updates to sections 4, 7, 8, and 8; grammatical/style edits throughout
4	January 27, 2021	Draft for comments to the LADCO regional haze workgroup; incorporated comments from WI DNR and MPCA
5	April 15, 2021	Draft final that integrated comments through March from LADCO states, EPA, and the Federal Land Managers; includes copy editing by LADCO staff
6	May 5, 2021	Removed references to LADCO 2016-based PSAT simulation
7	June 6, 2021	Added results from LADCO 2016abc and 2028abc PSAT simulations
8	June 17, 2021	Added a line to Table 8-1 providing a sum of other lines (contribution to b_{ext} on the most impaired days)

Errata/Known Issues

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Executive Summary

LADCO prepared this Technical Support Document to support the development of regional haze state implementation plans (SIPs) for the second haze implementation period. The approaches documented here include emissions inventory processing; chemical transport modeling and evaluation; analysis of ambient monitoring data for haze species; and the calculation of reasonable progress metrics for comparison to regional haze goals. LADCO presents the modeling and analysis results for two base years (2011 and 2016), both projected to 2028, in order to provide robust assessment of expected future year air quality. LADCO also analyzed the stationary point source emission inventory to screen sources for their potential contribution to haze in downwind Class I areas. LADCO calculated distance weighted emissions (Q/d) for the 2028 stationary point inventories.

Analysis of observed ambient fine particle concentrations ($PM_{2.5}$) at surface monitors in the LADCO region in 2019 shows that the 24-hour design values are at least five $\mu g/m^3$ below the level of the NAAQS. The highest concentrations are in the urban areas, and the lowest concentrations are in the far northern parts of the region, including near LADCO's Class I areas, and in the Appalachian portions of Ohio and eastern Kentucky. The annual and 24-hour $PM_{2.5}$ design values for all LADCO states decreased by 33% to 51% between 2002 and 2019. The chemical composition of the $PM_{2.5}$ in the region has changed as concentrations have decreased. Fine particles have transitioned from containing primarily ammonium sulfate aerosols in 2001 to containing similar proportions of ammonium nitrate, ammonium sulfate, and organic carbon at the more rural IMRPOVE monitoring sites in 2018. The reductions in PM concentrations produced significant improvements to regional haze. Total light extinction from haze decreased by roughly 40 percent from 2000-2004 to 2014-2019 at all LADCO-region Class I monitors, with similar reductions on the clearest and most impaired days.

LADCO selected 2011 and 2016 as modeling years because they were available in U.S. EPA modeling platforms that included projections to 2028, the last year of the current regional haze implementation period. The U.S. EPA modeling platforms represented the state-of-the-science for the modeling software, and emissions and meteorology data. U.S. EPA used both platforms for regional haze modeling studies, providing further justification for selecting these years. LADCO chose to model two different

base years to provide additional weight of evidence for our member states to use in their RHR reasonable progress SIPs. LADCO used the CAMx regional air quality model to estimate base and future year PM concentrations and haze conditions. We configured CAMx with the Particulate Matter Source Apportionment Tool (PSAT) to calculate emissions tracers for identifying upwind sources of haze at downwind Class I areas.

Starting in March 2018, LADCO produced a series of Q/d analyses for use by the LADCO member states for regional haze planning. LADCO used a cumulative Q/d threshold of 80% to identify sources for possible for-factor analysis. We provided the results of the Q/d analysis to the LADCO-member states in a spreadsheet to use to screen sources for further analysis.

LADCO's projections of haze in 2028 for both modeling platforms show that all of the LADCO-region Class I areas are predicted to be ahead of the uniform rate of progress (URP) toward natural visibility conditions. Predicted 2028 visibility conditions based on the 2016 modeling platform shows that the visibility in the Class I areas in Minnesota and Michigan is about 1 deciview below the unadjusted glidepath line (i.e., URP). Accounting for the adjustment due to international anthropogenic contributions, LADCO estimated 2028 visibility on the 20% most impaired days to be about 2.5 dv below the URP line.

1 Introduction

The Lake Michigan Air Directors Consortium (LADCO) was established by the states of Illinois, Indiana, Michigan, and Wisconsin in 1989. The four states and EPA signed a Memorandum of Agreement (MOA) that initiated the Lake Michigan Ozone Study and identified LADCO as the organization to oversee the study. Additional MOAs were signed by the states in 1991 (to establish the Lake Michigan Ozone Control Program), January 2000 (to broaden LADCO's responsibilities), and June 2004 (to update LADCO's mission and reaffirm the commitment to regional planning). In March 2004, Ohio joined LADCO. Minnesota joined the Consortium in 2012. LADCO consists of a Board of Directors (i.e., the State Air Directors), a technical staff, and various workgroups. The main purposes of LADCO are to provide technical assessments for and assistance to its member states, to provide a forum for its member states to discuss regional air quality issues, and to facilitate training for staff in the member states.

One of LADCO's responsibilities is to provide technical air quality modeling guidance and support to the LADCO states. LADCO prepared this Technical Support Document (TSD) to support our member-states' Regional Haze State Implementation Plans (SIPs) for the second haze implementation period. The approaches documented here include emissions inventory processing; chemical transport modeling and evaluation; analysis of ambient monitoring data for haze species; and the calculation of reasonable progress metrics for comparison to regional haze goals. LADCO presents the modeling and analysis results for two base years (2011 and 2016), both projected to 2028, in order to provide robust assessment of expected future year air quality.

1.1 Regional Haze

Particulate matter (PM) impairs visible light in the atmosphere either as distinct pollution plumes or as more uniformly distributed "regional haze". Regional haze is defined at 40 CFR 51.301 as "visibility impairment that is caused by the emission of air pollutants from numerous anthropogenic sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources." Fine particles less than 2.5 μm in diameter ($PM_{2.5}$) exist in the atmosphere as either primary emitted species or secondary species formed through chemical reactions. When these particles absorb and scatter light they alter the "clarity, color, and visible

distance" in the atmosphere. The important PM species for visibility impairment include sulfate, nitrate, ammonium, elemental carbon, organic carbon and soil dust particles. (U.S. EPA 82 FR 3278 January 2017).

Section 169A of the 1977 amendments to the Clean Air Act (CAA) established a visibility protection program for the nation's areas of "great scenic importance", otherwise known as Class I areas. CAA Section 169A established as a national goal the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution" (U.S. EPA 82 FR 3278 January 2017).

In 1999, U.S. EPA promulgated the Regional Haze Rule (RHR) to establish more comprehensive visibility protections in the nation's Class I areas (Figure 1-1). There are 156 Class I areas, including four in the LADCO region[1]: Isle Royale National Park and Seney National Wildlife Refuge in Michigan; and Boundary Waters Canoe Area and Voyageurs National Park in Minnesota. EPA's visibility rule (64 FR 35714, July 1, 1999) requires reasonable progress in achieving "natural conditions" in all Class I areas by the year 2064.

For haze SIPs, the Clean Air Act sets "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution." The RHR required that all states submit regional haze SIPs every 10 years and review these SIPs every 5 years. Requirements for regional haze SIPs (pursuant to 40 CFR 51.308(d)) include setting reasonable progress goals, determining baseline conditions, determining natural conditions, providing a long-term control strategy, providing a monitoring strategy (air quality and emissions), and establishing best available retrofit technology (BART) emissions limitations and associated compliance schedule. During the first regional haze implementation period, which culminated with regional haze SIPs that were due on December 17, 2007, LADCO effectively served as a Regional Planning Organization (RPO) for its member states[2]. These first regional haze SIPs addressed the initial 10-year implementation period (i.e., reasonable progress by the year 2018).

[1] Although Rainbow Lake in northern Wisconsin is also a Class I area, the visibility rule does not apply because the Federal Land Manager determined that visibility is not an air quality related value there, meaning that….

[2] A sub-entity of LADCO, known as the Midwest Regional Planning Organization (MRPO), was responsible for the regional haze activities of the multi-state organization during the first RHR planning period.



Figure 1-1. Class I areas by Federal Land Manager

In January 2017, US EPA issued a final rule updating the regional haze program, including revising portions of the visibility protection rule promulgated in 1980 and the Regional Haze Rule promulgated in 1999 (U.S. EPA 82 FR 3278 January 2017). This rule clarifies the obligations of the states and U.S. EPA during the second haze implementation period, which tracks progress in improving visibility out to the year 2028. To aid states in developing second round regional haze SIPs, U.S EPA issued their "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" (U.S. EPA, 2019a).

LADCO followed the recommendations in the aforementioned Regional Haze SIP guidance document (U.S. EPA, 2019a) and referred to the U.S. EPA (2019b) Technical Support Document for EPA's Updated 2028 Regional Haze Modeling and the U.S. EPA (2018) Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, and Regional Haze to inform the development of this document.

1.2 Project Overview

LADCO conducted emission inventory analysis and regional air quality modeling to support the development of Regional Haze SIPs**.** These SIP revisions are plans that describe how states will make reasonable progress toward meeting the visibility goals of the RHR. LADCO used the Comprehensive Air Quality Model with Extensions (CAMx[3]) to simulate PM and haze for two base years, 2011 and 2016. LADCO used CAMx to forecast haze conditions at the end of the second RHR planning period (2028) with emissions inventories projected to 2028 from each of these base years.

LADCO also performed analysis on the stationary point source emission inventory to screen sources for their potential contribution to haze in downwind Class I areas. LADCO calculated distance weighted emissions (Q/d)[4] for the 2028 stationary point inventories. LADCO worked with the states to apply these Q/d estimates for screening sources to subject to the four-factor analysis required by the RHR.

This document describes how LADCO used CAMx modeling to simulate base and future year air quality, and to evaluate if the Class I areas in and near the LADCO region are projected to meet or exceed the uniform rate of progress toward natural visibility conditions in 2064. The CAMx modeling outputs of this work are being provided to the LADCO state air programs to support their RHR SIP revisions that are due to EPA on July 31, 2021.

1.3 Organization of the Technical Support Document

This technical support document (TSD) is organized into the following sections.

- Section 2: Current and historical PM and haze conditions in the LADCO region
- Section 3: CAMx 2011 and 2016 modeling platforms; the platforms include base and future year (2028) emissions inventories, photochemical modeling data and configurations, and model performance evaluation methods
- Section 4: Emissions summaries of the 2011, 2016, and 2028 data used for the modeling in this TSD.
- Section 5: Q/d methods and results used to screen stationary point sources for four factor analysis.

[3] www.camx.com
[4] where Q = emissions in tons/year and d = distance from the Class I areas in km

- Section 6: CAMx model performance evaluation results for both 2011 and 2016.
- Section 7: Second RHR planning period reasonable progress results and analysis.
- Section 8: CAMx source apportionment modeling results and analysis.
- The TSD concludes with a summary of significant findings and observations from the LADCO modeling.

A Supplemental Materials document includes supporting figures and tables for the results presented in this TSD.

An Electronic Docket on the LADCO website includes supporting spreadsheets, memos, and additional figures produced by LADCO during the second regional haze implementation period.

2 Ambient Air Quality Data and Visibility Analysis

In this section LADCO presents an analysis of the historical and current PM and haze conditions at monitors in the Great Lakes region. The goals of this section are to show the current status of ambient PM air quality and haze in the LADCO region and to illustrate the progress with these air quality indicators over time.

The primary contributor to reduced visibility is $PM_{2.5}$. An extensive network of regulatory and special-purpose monitors around the country measure ambient $PM_{2.5}$ concentrations. Measurements of speciated $PM_{2.5}$ components are made at a smaller network of sites. In particular, $PM_{2.5}$ composition measurements are used to track haze at the mostly rural Class I areas in the Interagency Monitoring of Protected Visual Environments (IMPROVE) network. In this section, we discuss the current status of and trends in both haze and $PM_{2.5}$ in the LADCO region, with a focus on the four Class I areas in the region.

2.1 Current $PM_{2.5}$ Conditions and Historical Trends

Concentrations of $PM_{2.5}$ are frequently reported as design values (DVs), which can be compared with the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS). These DVs are calculated as annual and daily (24-hour) averages.[5] We present both forms of $PM_{2.5}$ DVs in this section, along with a discussion of trends in DVs and $PM_{2.5}$ composition.

Figure 2-1 shows the annual and 24-hour 2019 $PM_{2.5}$ DVs within the LADCO region and neighboring states. $PM_{2.5}$ DVs at all monitors in the LADCO region are below the levels of both $PM_{2.5}$ NAAQS. In particular, all 24-hour DVs are at least five $\mu g/m^3$ below the level of the NAAQS. The highest concentrations are in the urban areas, and the lowest concentrations are in the far northern parts of the region, including near LADCO's Class I areas, and in the Appalachian portions of Ohio and eastern Kentucky.

[5] The annual $PM_{2.5}$ DV is the three-year average of the annual mean concentration at a monitoring location. The 24-hour $PM_{2.5}$ DV is the three-year average of the 98th percentile of daily average $PM_{2.5}$ at a monitor. Design values are labeled by the last year of the three-year average. For example, the 2019 annual $PM_{2.5}$ DV is the three-year average of the annual average $PM_{2.5}$ concentrations for the years 2017-2019. We downloaded design values from EPA's Air Quality Design Values webpage: https://www.epa.gov/air-trends/air-quality-design-values.

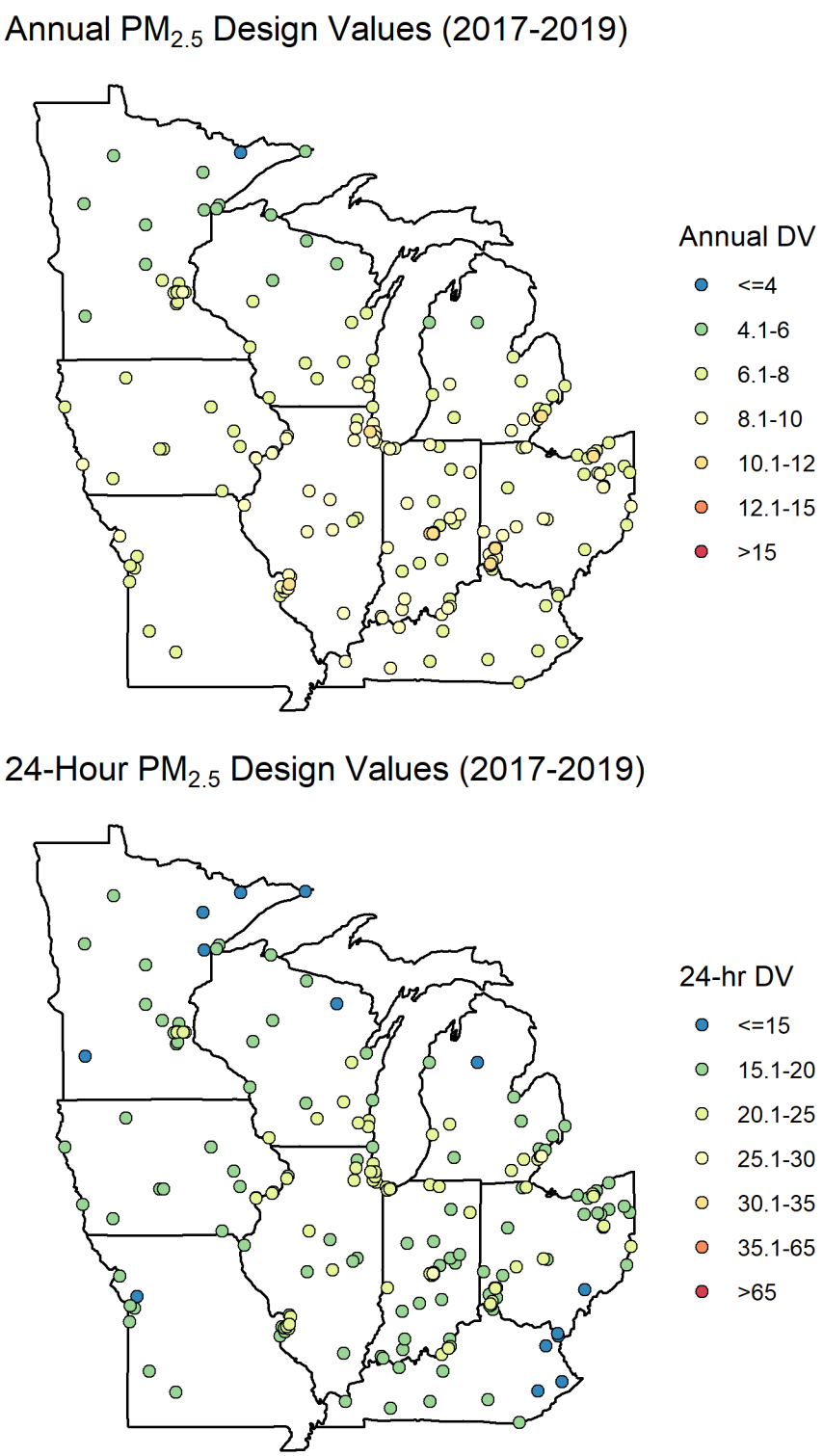


Figure 2-1. 2017-2019 annual (top) and 24-hour (bottom) $PM_{2.5}$ design values (DVs) in μg/m³. For comparison, the annual $PM_{2.5}$ NAAQS is 12 μg/m³, and the 24-hour NAAQS is 35 μg/m³.

$PM_{2.5}$ design values have decreased dramatically in all states in the LADCO region over the last 19 years, as shown in Figure 2-2. The annual and 24-hour $PM_{2.5}$ design values for all states decreased by 33% to 51% since 2002. Ohio started with the highest concentrations and had the largest reductions, whereas Minnesota started with the lowest levels and had the smallest reductions. As a result of these differential changes, $PM_{2.5}$ levels in the six states have converged to much more uniform concentrations among the states. The pace of reduction in $PM_{2.5}$ DVs was especially large after the year 2007. The pace of reductions appears to have decreased somewhat in the last several years. However, state average concentrations are currently at least 14 $\mu g/m^3$ below the level of the 24-hour NAAQS and at least 3 $\mu g/m^3$ below the annual NAAQS.

Figure 2-3 shows how the chemical composition of the $PM_{2.5}$ has changed as its concentrations have decreased. This figure shows the chemical composition of $PM_{2.5}$ at LADCO state monitors in the primarily rural IMPROVE network. Concentrations of all of the major measured $PM_{2.5}$ species have decreased at the regional surface monitors since 2001, with the largest reductions (70%) from ammonium sulfate aerosols and the smallest reductions (7%) from organic carbon.[6] The disproportionately large reductions in ammonium sulfate reflect the dramatic reductions in sulfur dioxide emissions from stationary point sources resulting from regulatory control programs and economically driven shifts away from coal combustion. As a result, the chemical composition of fine particles has transitioned from containing primarily ammonium sulfate aerosols in 2001 to containing similar proportions of ammonium nitrate, ammonium sulfate, and organic carbon at these rural sites in 2018.

[6] The other components had intermediate levels of reduction. Ammonium nitrate concentrations decreased by 20 percent, elemental carbon by 17 percent, and soil by 44 percent. Sea salt was a very small component but increased during this time by 58 percent.

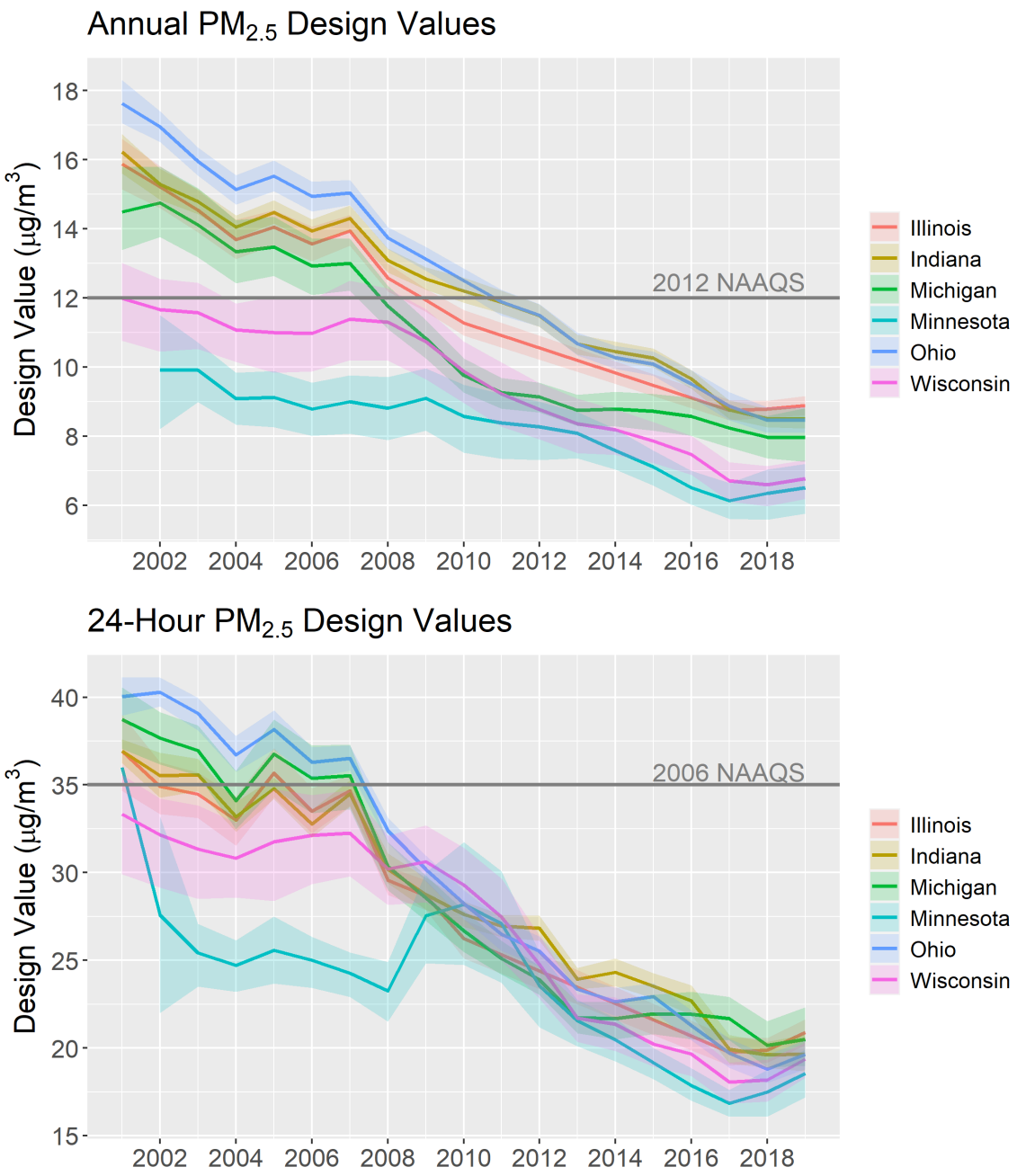


Figure 2-2. Trends in annual (top) and 24-hour (bottom) $PM_{2.5}$ design values in the LADCO states.[7] The levels of the NAAQS are shown for comparison. Dark lines show the state mean, whereas the shaded region shows the 95 percent confidence interval. Plots include monitors with at least six valid design values.

[7] Note that design values were invalidated for Illinois for the years 2011 through 2016. Illinois values in this figure were interpolated between the preceding and subsequent design values.

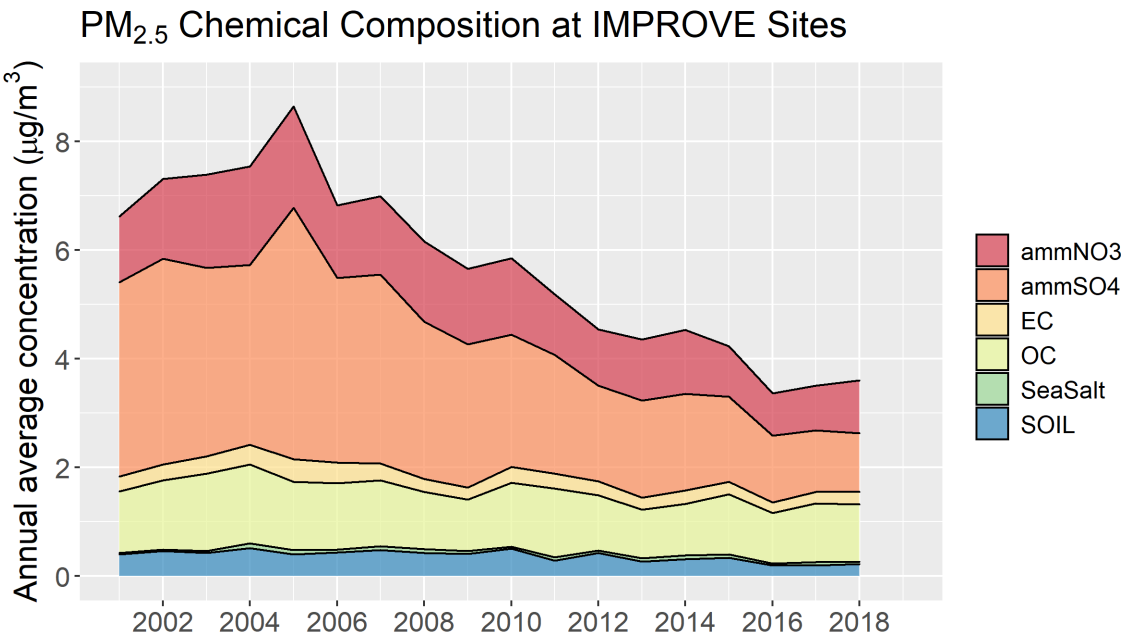


Figure 2-3. Chemical composition of $PM_{2.5}$ at the mostly rural IMPROVE monitoring sites in the LADCO region.[8]

2.2 Current Haze Conditions and Historical Trends

Visibility measurements are reported using either a light extinction coefficient (reported as inverse megameters, Mm^{-1}) or using the deciview haze index. Light extinction represents by how much light is attenuated per unit distance due to a combination of scattering and absorption by gases and particles. The deciview index is a logarithmic transformation of light extinction values[9] and is easier to relate to perceivable changes in visibility. Deciview values would be near zero for a pristine atmosphere and increase with increasing haze. We use both measures in this document. Light extinction is estimated from speciated particle measurements at IMPROVE monitoring sites using the IMPROVE algorithm and then converted to the deciview haze index.[10] We downloaded all visibility data from the Federal Land Manager Environmental Database except as noted.[11]

[8] Components are: ammNO3 = ammonium nitrate, ammSO4 = ammonium sulfate, EC = elemental carbon, OC = organic carbon, SeaSalt = sea salt, and SOIL = inorganic soil components. Data were downloaded from the Federal Land Manager Environmental Database at http://views.cira.colostate.edu/fed/QueryWizard/.

[9] The relationship is: $dv = 10 \ln (b_{ext} / 10\ Mm\text{-}1)$, where dv = deciviews and b_{ext} = the total light extinction coefficient.

[10] These calculations are described in greater detail in Section 7.1.

[11] http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx?appkey=SBCF_VisSum or http://views.cira.colostate.edu/fed/QueryWizard/.

Visibility at all of the mostly rural IMPROVE monitors in the eastern U.S. improved from 2002 to 2019, as reflected in lower deciview values (Figure 2-4). The haziest areas were located in the middle of this large area, from Iowa and Illinois down to Alabama. The cleanest areas were primarily located along the western and northern parts of this region. The largest reductions in haze over this time period (up to 47%) were found in the southeast and northeast. Reductions at the four LADCO Class I Area monitors were between 27% and 33% during this time. Visibility improvements have been even better than those laid out in the glidepaths for these sites to reach background conditions by 2064, as shown in Section 7.2.

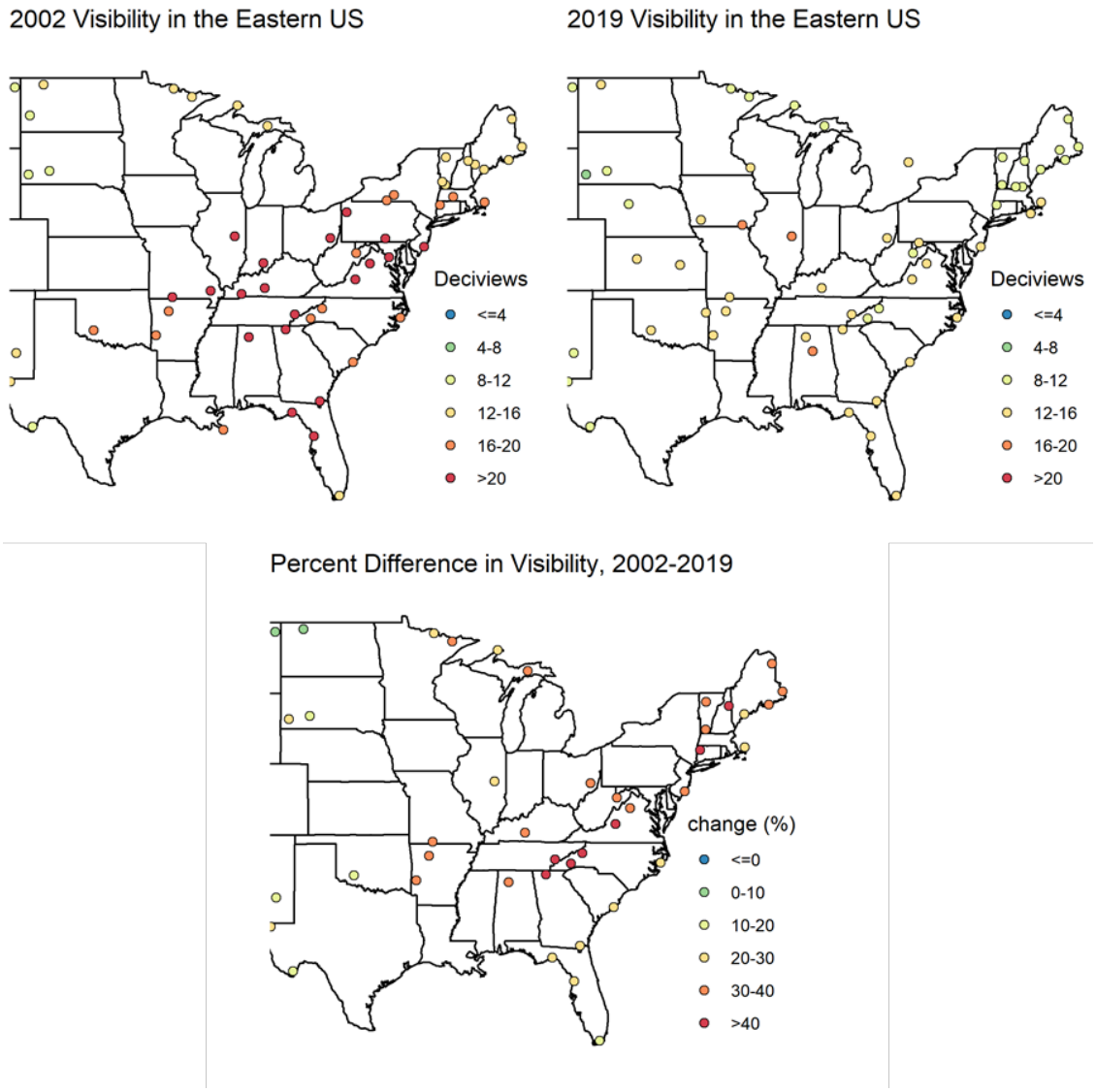


Figure 2-4. Visibility (in deciviews) at sites in the eastern United States in 2002 (left) and 2019 (right), and the percent difference in visibility in these two years (bottom).

Figure 2-5 breaks apart the visibility trends at the four LADCO Class I Area monitors based on the haziness of the day. From 2000 to 2018, visibility on the most impaired days improved by 18% to 26%, with the largest improvements at the Boundary Waters and Seney sites. Visibility improvements were even greater on the clearest days, with improvements of 26% to 34%, with the smallest improvement at Seney.

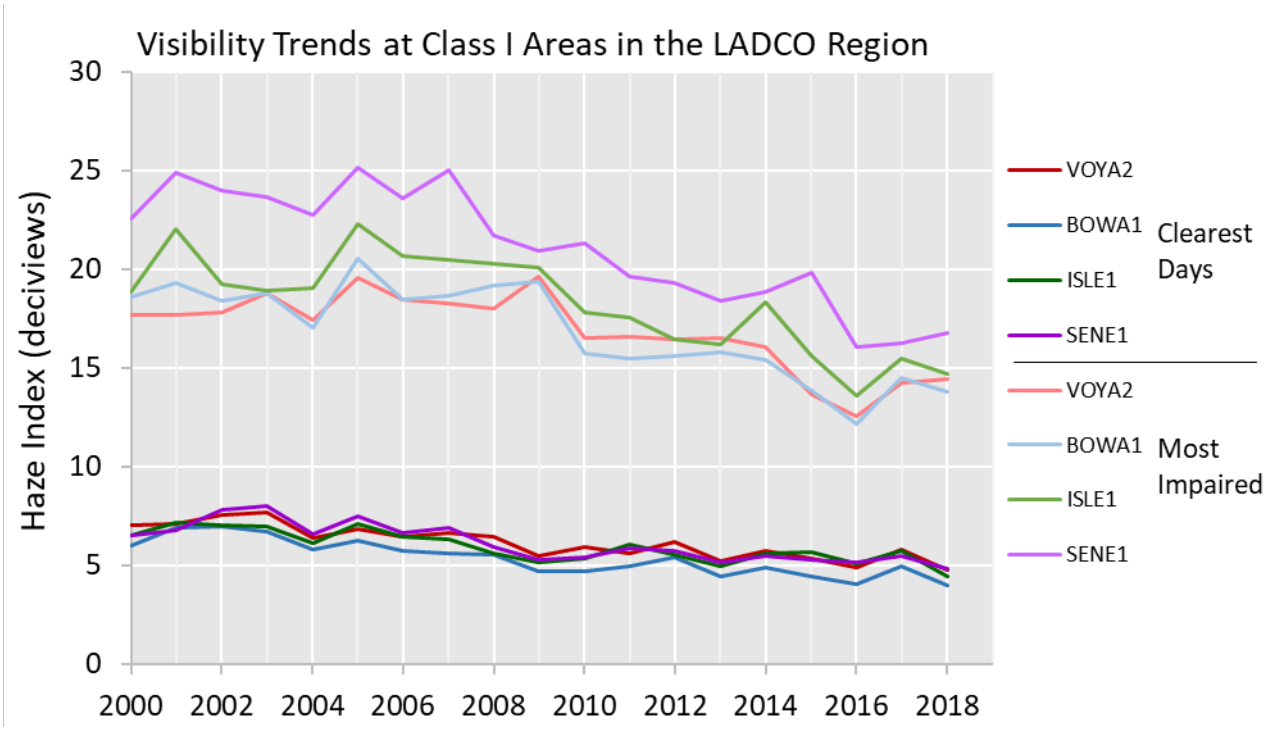


Figure 2-5. Visibility trends (in deciviews) at LADCO Class I Area monitors on the clearest and most impaired days.[12]

Table 2-1 shows the breakdown of the chemical components that contributed to haze at the four LADCO Class I area monitors in the years 2000-2004 and 2014-2019. Figure 2-6 shows the magnitudes and composition of light extinction for every year since 2000 for Minnesota's Voyageurs National Park. Supplemental Materials Section S1 includes comparable figures for the other three LADCO region Class I areas. This chemical speciation of visibility impacts is based upon the $PM_{2.5}$ chemical speciation at these

[12] Site abbreviations are: VOYA2 = Voyageurs National Park (MN), BOWA1 = Boundary Waters Canoe Area (MN), ISLE1 = Isle Royale National Park (MI), and SENE1 = Seney (MI). Data were downloaded from the WRAP Technical Support System at https://views.cira.colostate.edu/tssv2/Express/HazeAnalysisTools.aspx.

sites (similar to that shown in Figure 2-3) but directly indicates the magnitude of the visibility impacts from each chemical component. The composition of light extinction will be somewhat different than the measured chemical composition of $PM_{2.5}$ because different chemical components have different degrees of impact on light and thus on visibility; for example, elemental carbon (soot) has a disproportionate impact on light and thus on haze.

Light extinction on the most impaired days was 6 to 12 times as large as that on the clearest days. On the clearest days, ammonium sulfate has historically been the largest component of haze, as shown in Table 2-1, Figure 2-6 and Section S1. Ammonium nitrate is a much more important component on the most impaired days than it is on the clearest days; in the years 2014-2018, it was the greatest contributor at all LADCO region Class I area sites.

Total light extinction from haze decreased by roughly 40 percent from 2000-2004 to 2014-2019 at all LADCO Class I monitors, with similar reductions on the clearest and most impaired days. However, different components contributed to these reductions on the different types of days. On the clearest days, there were large reductions in light extinction from all of the major components. On the most impaired days, there were large reductions in light extinction from ammonium sulfate, however, reductions from ammonium nitrate were much smaller, particularly at the Michigan sites. The slow pace of ammonium nitrate reductions led to its being the largest contributor to light extinction in recent years, as mentioned above. In general, haze seems to have peaked in the early- to mid-2000s, then steadily decreased. Total light extinction from haze may have plateaued in the last few years.

Analysis of the back-trajectories of polluted air masses provides insight into potential source locations impacting visibility. Figure 2-7 shows the back-trajectory-based residence times for air masses reaching the LADCO Class I monitors on the 20% most impaired days, weighted for distance from the monitor. For all four areas, the most polluted air masses most frequently arrived from the south and west. Supplemental Materials Section S2 includes similar figures that show how residence times vary based on the trajectory end-point altitude and the weighting of the residence time. All of these analyses show the importance of transport from the south on the most impaired days. This analysis suggests that sources in Minnesota, Wisconsin, Iowa, Illinois and Indiana are most likely to contribute to haze in the LADCO Class I areas. The more westerly source regions contribute more to visibility impairment in the Minnesota

Class I areas, and more easterly source region have a larger contribution to impairment in the Michigan Class I areas.

2.3 Summary

Overall, concentrations of $PM_{2.5}$ and haze have decreased significantly over the last two decades in the LADCO region. As a result, all monitors in the region are meeting the $PM_{2.5}$ NAAQS, and visibility at the regional Class I sites is better than the sites' glide paths. Concentrations of ammonium sulfate, which forms in part from atmospheric sulfur dioxide, have undergone particularly large reductions during this time due to control programs targeting that pollutant. As a result, ammonium nitrate and organic carbon have become relatively more important contributors to fine particulate matter and haze. Air masses on the most impaired days most frequently arrived at LADCO Class I sites from the south, suggesting that emission sources to the south likely contributed most to degraded visibility at these sites.

Table 2-1. Five-year average composition of light extinction (in Mm^{-1}) for LADCO region Class I Area monitors in the years 2000-2004 and 2014-2018.

	Light Extinction (Mm^{-1})											
	Voyageurs NP			Boundary Waters			Isle Royale NP			Seney		
Parameter	2000-2004	2014-2018	Change	2000-2004	2014-2018	Change	2000-2004	2014-2018	Change	2000-2004	2014-2018	Change
Clearest Days												
Ammonium Sulfate	4.2	2.2	-47%	4.1	2.2	-47%	4.6	2.7	-41%	4.8	2.6	-47%
Ammonium Nitrate	0.8	0.4	-46%	0.7	0.4	-42%	0.7	0.4	-41%	0.8	0.5	-40%
Organic Mass	2.1	1.4	-35%	2.0	1.2	-41%	1.2	1.0	-20%	1.6	1.1	-30%
Elemental Carbon	0.6	0.3	-52%	0.6	0.2	-57%	0.4	0.2	-40%	0.5	0.2	-50%
Soil	0.1	0.0		0.1	0.0		0.1	0.1		0.1	0.1	
Coarse Mass	0.7	0.6	-14%	0.7	0.6	-12%	0.7	0.6	-20%	0.7	0.5	-24%
Sea Salt	0.1	0.2		0.1	0.1		0.1	0.2		0.1	0.1	
Total	**8.6**	**5.1**	**-41%**	**8.3**	**4.7**	**-43%**	**7.8**	**5.2**	**-34%**	**8.6**	**5.1**	**-41%**
Most Impaired Days												
Ammonium Sulfate	20.3	11.7	-42%	25.8	11.9	-54%	32.5	15.5	-52%	58.1	18.7	-68%
Ammonium Nitrate	20.7	14.1	-32%	20.1	14.4	-28%	21.3	16.8	-21%	28.1	22.9	-18%
Organic Mass	6.4	3.7	-41%	6.6	3.9	-41%	6.7	4.4	-35%	10.8	5.5	-49%
Elemental Carbon	2.4	1.4	-41%	2.5	1.4	-46%	3.1	1.7	-46%	3.9	2.2	-43%
Soil	0.3	0.2	-33%	0.4	0.2	-53%	0.3	0.2	-33%	0.5	0.2	-57%
Coarse Mass	1.6	1.4	-10%	1.5	1.4	-3%	2.1	1.7	-16%	1.6	1.4	-13%
Sea Salt	0.1	0.3		0.1	0.2		0.1	0.3		0.0	0.2	
Total	**51.7**	**32.9**	**-36%**	**57.0**	**33.4**	**-41%**	**66.1**	**40.6**	**-39%**	**102.9**	**51.2**	**-50%**

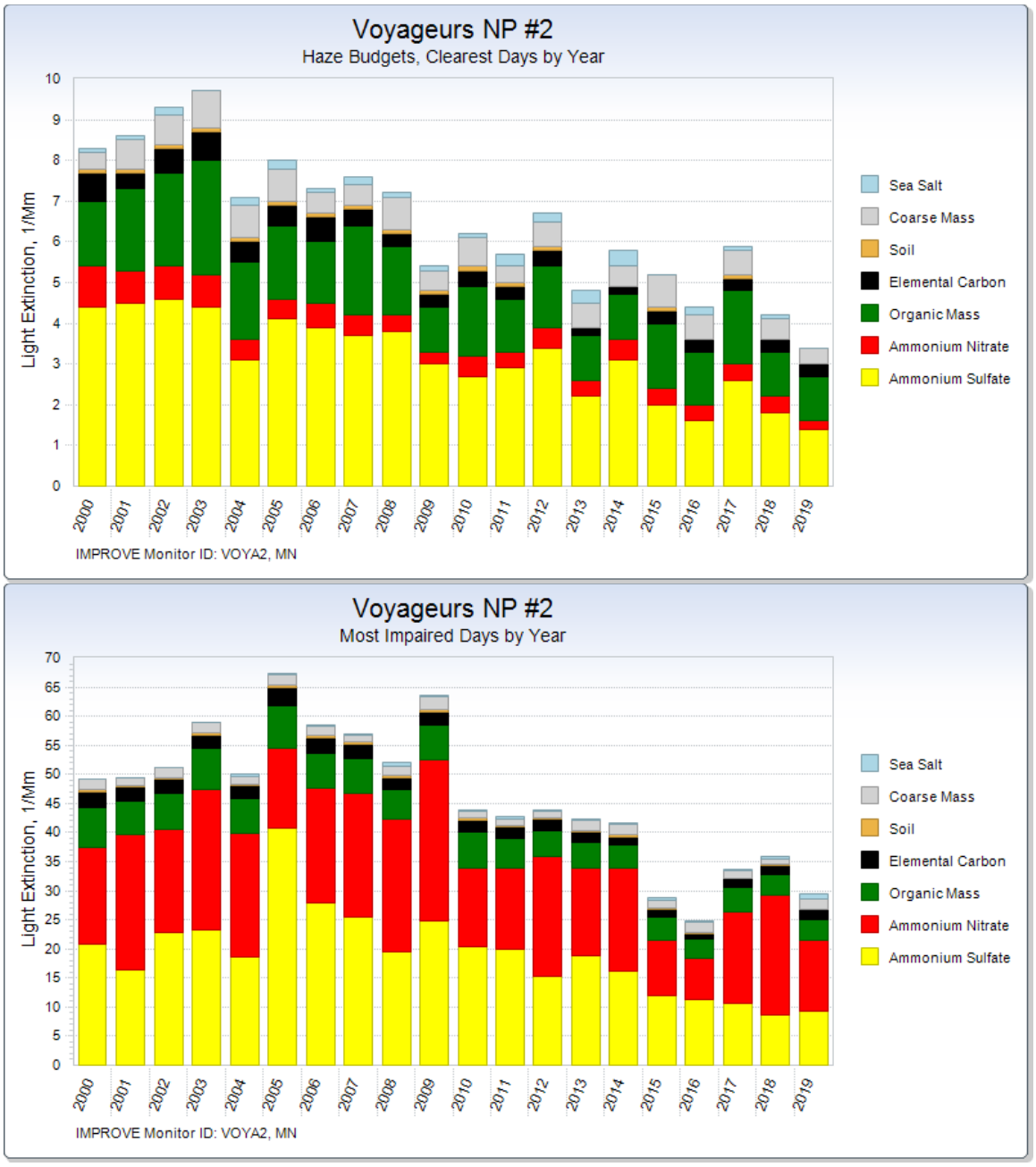


Figure 2-6. Composition of light extinction for Minnesota's Voyageurs National Park, shown for the clearest (top) and most impaired (bottom) days.

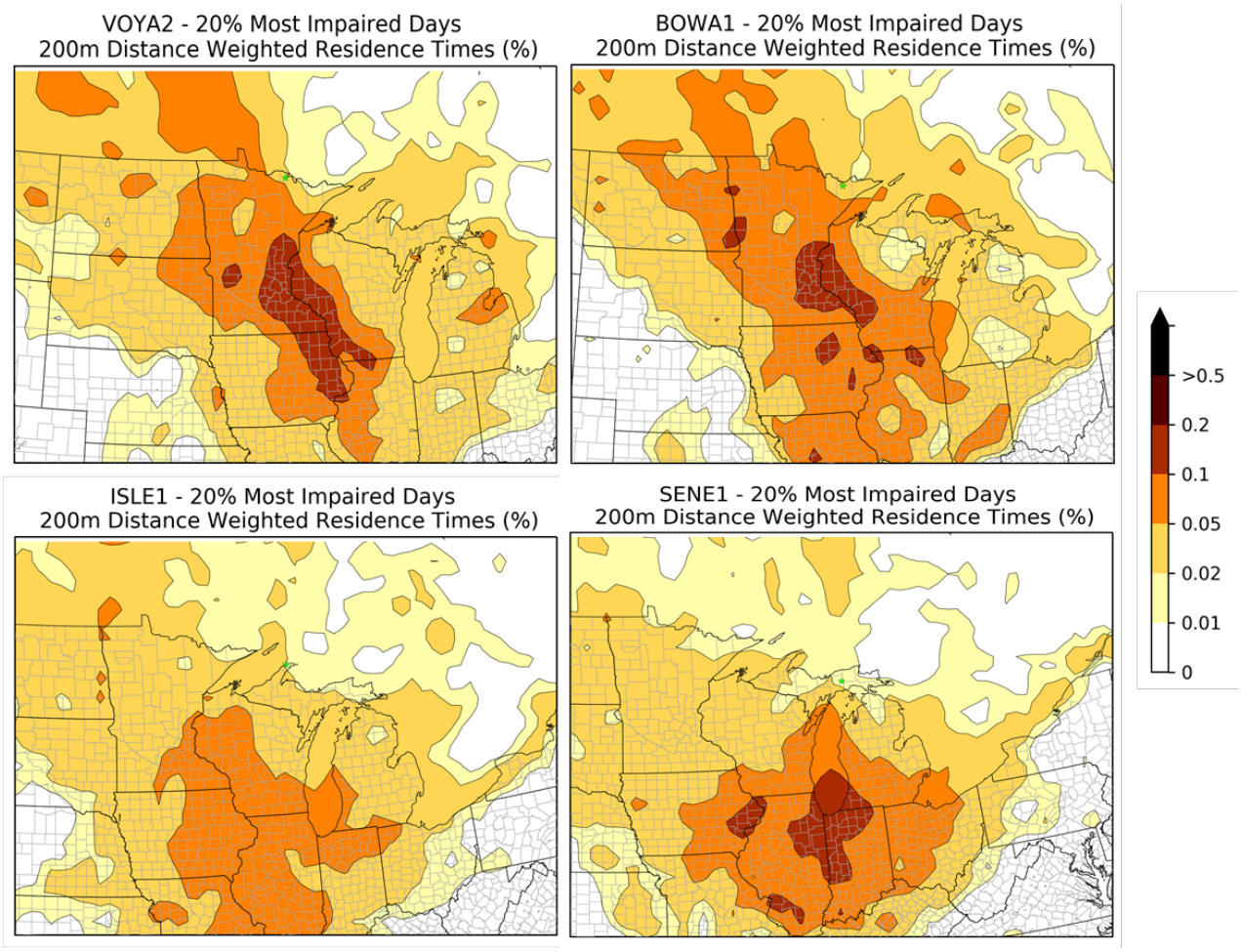


Figure 2-7. Distance weighted residence times for air masses reaching the four LADCO Class I areas on the 20% most impaired days for the years 2012 to 2016. Residence times were determined from 72-hour HYSPLIT back-trajectories ending at 200m altitude.[13]

[13] Residence time is the normalized cumulative time that trajectories reside in a specific geographic area, weighted by the distance from the receptor (end point). Analyses were conducted by Ramboll for the Central States Air Resource Agencies (CenSARA) using the 12-km North American Model (NAM) meteorology for hours 6, 12, 18 and 24. The project report is available in the electronic docket for this TSD. Additional figures for the LADCO Class I areas are available in the Supplemental Materials document. Complete results and figures are available at https://censara.org/ftpfiles/Ramboll/.

3 Air Quality Modeling Platform

This section describes the details of the regional air quality modeling platforms used by LADCO to estimate haze conditions in 2028. The models described in this section are gridded, Eulerian chemistry-transport models designed to simulate, among other things, the PM species that contribute to regional haze. An air quality modeling platform is the complete collection of data, software, and scripts required for conducting regional modeling simulations. Air quality models are a key decision support tool for air quality planning because they integrate our knowledge of air pollution into software to predict future atmospheric conditions based on forecast changes in emissions.

LADCO selected two base modeling years (2011 and 2016) from which to project visibility conditions in 2028. We used two base years for a few different reasons:

1. The 2011 base year modeling platform was the best available option at the start of the second implementation period
2. When the 2016 base year modeling platform became available in 2020 it represented an improvement to the emissions data, particularly for the stationary source projections to 2028
3. Using two meteorology years for modeling provides additional weight of evidence to the states for use in demonstrating progress under the RHR

The goal of this section is to describe the details of the model simulations, including the input data and software used by LADCO to calculate future year visibility. We will present model emissions summaries, model performance and results in subsequent sections of the document.

3.1 Modeling Years Justification

LADCO selected 2011 and 2016 as modeling years because they were available in U.S. EPA modeling platforms that included projections to 2028, the last year of the current regional haze implementation period. The U.S. EPA modeling platforms represented the state-of-the-science for the modeling software, and emissions and meteorology data. U.S. EPA used both platforms for their preliminary (US. EPA, 2017) and updated (U.S. EPA, 2019) regional haze modeling studies, providing further justification for selecting these years. LADCO chose to model two different base years to provide additional weight of evidence for our member states to use in their RHR reasonable progress SIPs.

The availability of emissions inventories with projections to 2028 was a major factor in selecting these two base years. The triennial National Emissions Inventory (NEI) was conducted for the year 2011. Since its first release in 2014, the NEI2011 underwent several revisions, with the final update to version 6.3 released in October 2017 as part of the U.S. EPA's preliminary regional haze modeling platform (US EPA, 2017). Given the use of 2011-based data for evaluating regional haze progress during this implementation period by the U.S. EPA (2017), Metro4/SESARM (2018), and the Ozone Transport Commission (OTC, 2018), LADCO believes that using 2011-based data and emissions projections is justified.

In 2017 a group of multi-jurisdictional organizations (MJOs), states, and EPA established 2016 as the new base year for a national air quality modeling platform[14]. The group concluded that if only one recent year could be selected, then 2016 would serve as a good base year because of fairly typical O_3 conditions and average wildfire conditions. Following from the base year recommendations from that group, several modeling centers, including U.S. EPA and LADCO, developed data and capabilities for simulating and evaluating air quality in 2016.

Following from the selection of 2016 as the base year for a national modeling platform, starting in late 2017, the MJOs, states, and EPA formed the National Emissions Inventory Collaborative to develop a 2016 emissions inventory and modeling platform. Over 200 participants collaborated across 12 workgroups to develop base and future year emissions to support upcoming regulatory modeling applications. This effort was designed to involve a broad group of air pollution emissions experts in the development of a new national emissions modeling platform. LADCO used the 2016 and 2028 inventories developed by the Collaborative for the modeling presented here because they were the most recent inventory data available at the initiation of this project.

LADCO selected 2028 as the future projection year because it aligns with the end of the second regional haze implementation period and is a comparison point in the uniform rate of progress toward natural visibility in 2064.

[14] Base Year Selection Workgroup Final Report

3.2 Electricity Generating Unit (EGU) Emissions Forecasts

LADCO relied upon U.S. EPA's inventory estimates from their 2011 and 2016 modeling platforms for most emissions sectors, as described in Sections 3.3.2 and 3.4.2. However, LADCO replaced the Integrated Planning Model (IPM) EGU inventories in the U.S. EPA 2011 and 2016 modeling platforms with inventories derived from the Eastern Regional Technical Advisory Committee (ERTAC) EGU model (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 model that did not produce large 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 for EGUs from U.S. 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 generation rates. The model then balances the system for all units and hours that exceed physical or regulatory limits by redistributing the power and associated emissions to underutilized units in the system. ERTAC EGU applies future year controls to the emissions estimates and tests for reserve capacity, generates quality assurance reports, and converts the outputs to Sparse Matrix Operator Kernel Emissions model (SMOKE)-ready 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 creating new coal plants to meet forecasted power demand. As an alternative, the model now allows portability of generation to different fuels like renewables and natural gas.

Differences between the IPM and ERTAC EGU emissions forecasts arise from alternative forecast algorithms, and from the data used to inform the model predictions.

3.2.1 2011 EGU Emissions Estimates

The 2011 based ERTAC EGU projections were the first year of estimates available from the ERTAC model. There were five different generations of improvements to the inputs, code, and methods in the model before the release of version 2.7 in 2017, which is the version used by LADCO for this application. Between 2011 and 2017 there were widespread shutdowns of coal EGUs across the country as natural gas and renewable generation integrated more widely into the power markets. During this period combined cycle natural gas plants changed from mostly handling peak loads to serving as base load EGUs. ERTAC EGU 2.7 reflected the transformation in the U.S power sector away from coal to less carbon intensive fuels.

3.2.2 2016 EGU Emissions Estimates

The IPM forecasts used for the U.S. EPA "2016fh" modeling platform were updated based on comments from states and stakeholders received through April 2019. LADCO replaced the IPM EGU forecasts in our 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 U.S. available in September 2020.

3.2.3 2028 EGU Emissions Forecasts

LADCO used ERTAC 16.1 forecasts to estimate 2028 EGU emissions. Figure 3-1 shows the ERTAC 16.1 2028 emissions projections for NOx and SO_2 as a circle plot. The size of the circles in the plot reflect the magnitude of the annual total future year emissions at individual EGU sources in the LADCO region. Figure 3-2 shows the EGU facility specific SO_2 emissions changes between 2016 and 2028 as forecast by ERTAC EGU 16.1. Red bubbles indicate lower emissions in 2028, while blue bubbles indicate higher emissions in 2028. The emissions increases are projected to occur primarily at natural gas EGUs to offset the lost generation capacity from the coal unit shutdowns. There were no new coal units in the LADCO region forecast by ERTAC EGU from 2016 to 2028.

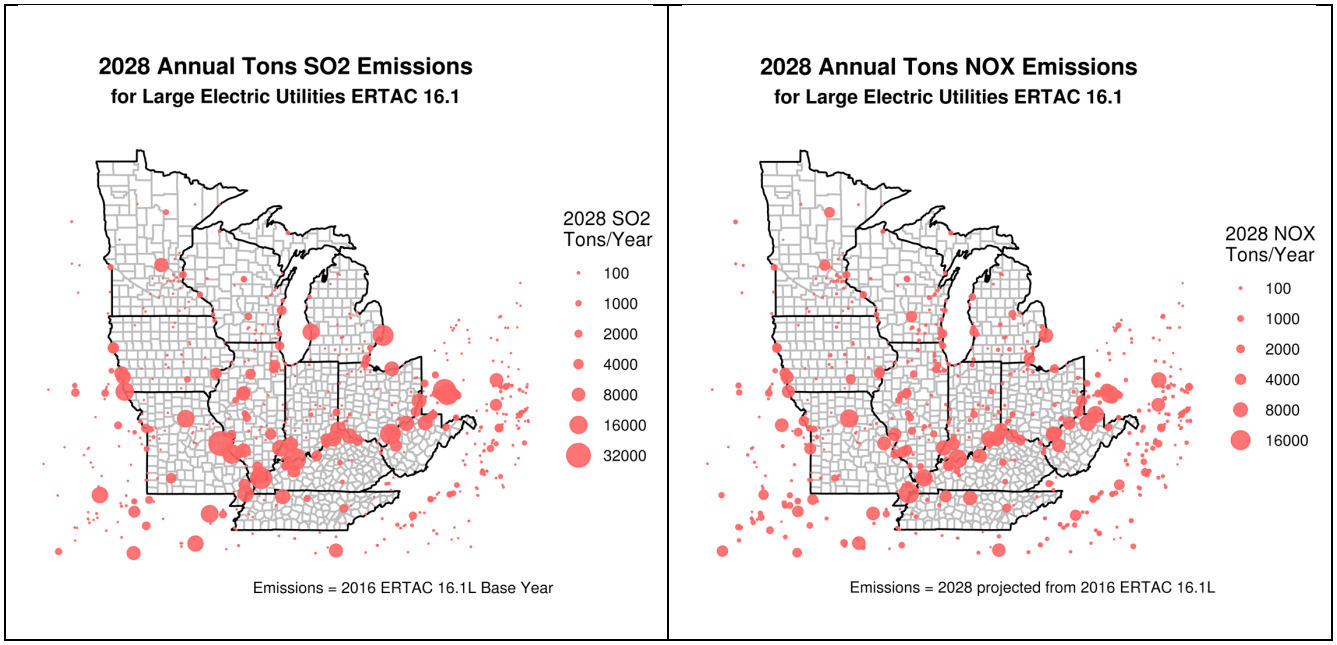


Figure 3-1. ERTAC EGU 16.1 2028 SO_2 (l) and NOx (r) emissions bubble plots

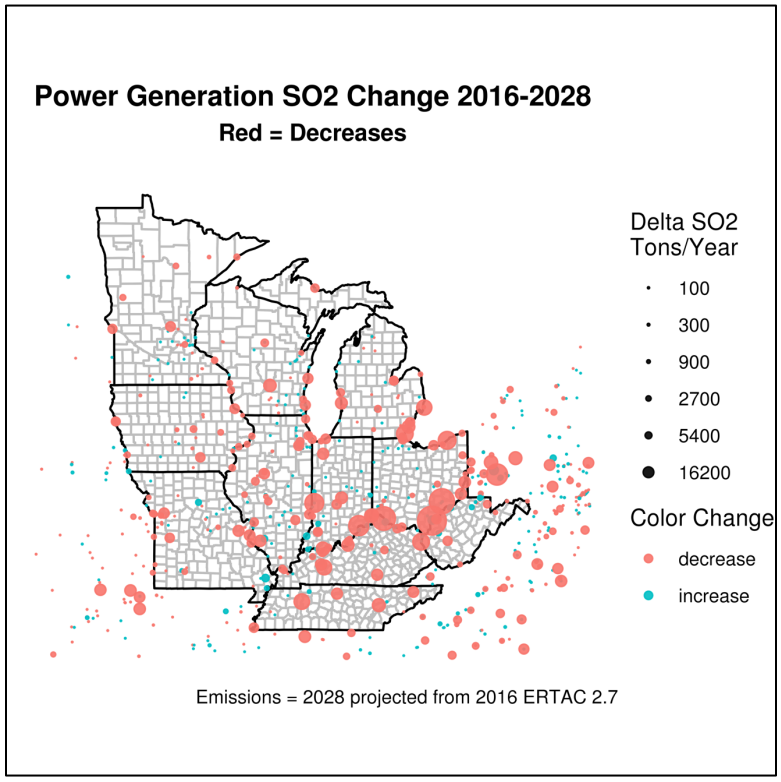


Figure 3-2. ERTAC EGU 16.1 SO_2 emissions difference (2016-2028) bubble plot

3.3 2011 Modeling Platform

LADCO based our 2011 modeling platform on the data and software used by the U.S. EPA for their Preliminary 2028 Regional Haze Modeling (U.S. EPA, 2017). EPA projected the 2011 base year emissions to 2028 to forecast regional haze conditions in the Class I areas. The components of the 2011 modeling platform are described below and in greater detail by U.S. EPA (2016a; 2016b).

3.3.1 Air Quality Model Configuration

LADCO used CAMx 6.40 (Ramboll, 2018) as the photochemical grid model for this application. CAMx is a three-dimensional, Eulerian air quality model that simulates the chemical transformation and physical transport processes of air pollutants in the troposphere. It includes capabilities to estimate the concentrations of primary and secondary gas and particle phase air pollutants, and dry and wet deposition, from urban to continental spatial scales. As CAMx associates source-level air pollution emissions estimates with air pollution concentrations, it can be used to design and assess emissions reduction strategies pursuant to NAAQS attainment goals.

LADCO selected CAMx for this study because it is a component of recent U.S. EPA modeling platforms for investigating the drivers of regional haze in the U.S. As CAMx is a component of U.S. EPA studies with a similar scope to this project (e.g., U.S. EPA, 2017), LADCO was able to leverage the data and software elements that are distributed with recent U.S. EPA regulatory modeling platforms. Using these elements saved LADCO significant resources relative to building a modeling platform from scratch.

Figure 3-3 shows the U.S. EPA modeling domain for the continental U.S. A 12-km uniform grid (12US2) covers all of the continental U.S. and includes parts of Southern Canada and Northern Mexico. The domain has 35 vertical layers with a model top at about 17,550 meters (50 mb). LADCO used the same 12US2 domain for this project because it supported the use of meteorology, initial and boundary conditions, and emissions data that were readily available from U.S. EPA.

Table 3-1 summarizes the CAMx science configurations and options LADCO used for the 2011 and 2028 CAMx modeling for this application. We used the Piecewise Parabolic Method (PPM) advection solver for horizontal transport along with the spatially varying (Smagorinsky) horizontal diffusion approach. We used K-theory for vertical diffusion using the CMAQ-like vertical diffusivities from WRFCAMx. The CB6r4

gas-phase chemical mechanism was selected because it includes the latest chemical kinetic rates and represents improvements over the other alternative CB05 and SAPRC chemical mechanisms as well as active methane chemistry. Additional CAMx inputs were as follows:

Meteorological Inputs: LADCO used the U.S. EPA 2011 WRF data for this study (US EPA, 2014). The U.S. EPA used version 3.4 of the WRF model, initialized with the 12-km North American Model (NAM) from the National Climatic Data Center (NCDC) to simulate 2011 meteorology. U.S. EPA prepared the WRF data for input to CAMx with version 4.3 of the WRFCAMx software.

Initial/Boundary Conditions: LADCO used 2011 initial and boundary conditions for CAMx generated by the U.S. EPA from the GEOS-Chem Global Chemical Transport Model (US EPA, 2017). EPA generated hourly, one-way nested boundary conditions (i.e., global-scale to regional-scale) from a 2011 2.0 degree x 2.5 degree GEOS-Chem simulation. Following the convention of the U.S. EPA regional haze modeling, LADCO used year 2011 GEOS-Chem boundary conditions for modeling 2028 air quality with CAMx.

Photolysis Rates: LADCO prepared the photolysis rate inputs as well as albedo/haze/ozone/snow inputs for CAMx. Day-specific O_3 column data were based on the Total Ozone Mapping Spectrometer (TOMS) data measured using the satellite-based Ozone Monitoring Instrument (OMI). Albedo were based on land use data. For CAMx there is an ancillary snow cover input that will override the land use-based albedo input. LADCO used the TUV photolysis rate processor to prepare clear-sky photolysis rates for CAMx. If there were periods of more than a couple of days where daily TOMS data were unavailable in 2011, the TOMS measurements were interpolated between the days with valid data; in the case where large periods of TOMS data were missing, monthly average TOMS data were used. CAMx was also configured to use the in-line TUV to adjust for cloud cover and account for the effects that modeled aerosol loadings have on photolysis rates; this latter effect on photolysis may be especially important in adjusting the photolysis rates due to the occurrence of particulate matter (PM) concentrations associated with emissions from fires.

Landuse: LADCO used landuse/landcover data from the U.S. EPA WRF simulation.

Spin-Up Initialization: LADCO used a minimum of ten days of model spin up (e.g., December 21-31, 2010) for the 12 km modeling domain. LADCO ran monthly CAMx simulations, initializing each month with a 10-day spin-up period.

LADCO used CAMx to simulate the entire year for 2011 and 2028. LADCO selected a CAMx configuration that was consistent with previous regional haze modeling applications performed by LADCO and U.S. EPA. U.S. EPA (2017) provides complete details of their 2011 CAMx simulation, including a performance evaluation.

Table 3-1. LADCO 2011 and 2016 CAMx modeling platform configurations

Science Options	CAMx 2011 Configuration	CAMx 2016 Configuration
Model Codes	CAMx v6.40	CAMx v7.0
Simulation Period	December 21, 2010 – December 31, 2011	December 21, 2015 – December 31, 2016
Horizontal Grid Mesh	12 km, 396 col x 246 rows	12 km, 396 col x 246 rows
Vertical Grid Mesh	25 CAMx layers collapsed from 35 WRF layers	35 WRF layers (no collapsing)
Grid Interaction	None	None
Initial Conditions	10 day spin-up on 12 km grid	10 day spin-up on 12 km grid
Boundary Conditions	12km from GEOS-Chem	12km from hemispheric CMAQ
Emissions		
Baseline Emissions Processing	Sparse Matrix Operator Kernel Emissions (SMOKE), EPA's MOtor Vehicle Emission Simulator (MOVES) and Biogenic Emission Inventory System (BEIS)	
Emissions Modeling Platform	U.S. EPA 2011 "EN" with ERTAC 2.7 EGU Point and hourly CEMs	U.S. EPA 2016 "FH" Platform with ERTAC 16.1 EGU Point and hourly CEMs
Chemistry		
Gas Phase Chemistry	CB6r4	CB6r4
Aerosol Chemistry	CF + SOAP	CF + SOAP
Meteorology		
Model Codes	WRF v3.4	WRF v3.8
Meteorological Processor	WRFCAMx v4.3	WRFCAMx v4.6
Horizontal Diffusion	Spatially varying	Spatially varying
Vertical Diffusion	CMAQ-like in WRF2CAMx	CMAQ-like in WRF2CAMx
Diffusivity Lower Limit	Kz_min = 0.1 to 1.0 m^2/s or 2.0 m^2/s	Kz_min = 0.1 to 1.0 m^2/s or 2.0 m^2/s
Dry Deposition	Zhang dry deposition scheme (CAMx)	Zhang dry deposition scheme (CAMx)
Wet Deposition	CAMx-specific formulation	CAMx-specific formulation
Gas Phase Chemistry Solver	Euler Backward Iterative (EBI) -- Fast Solver	Euler Backward Iterative (EBI) -- Fast Solver

Science Options	CAMx 2011 Configuration	CAMx 2016 Configuration
Vertical Advection Scheme	Implicit scheme w/ vertical velocity update (CAMx)	Implicit scheme w/ vertical velocity update (CAMx)
Horizontal Advection Scheme	Piecewise Parabolic Method (PPM) scheme	Piecewise Parabolic Method (PPM) scheme
Integration Time Step	Wind speed dependent	Wind speed dependent
Source Apportionment	PSAT with 26 state and region tags	

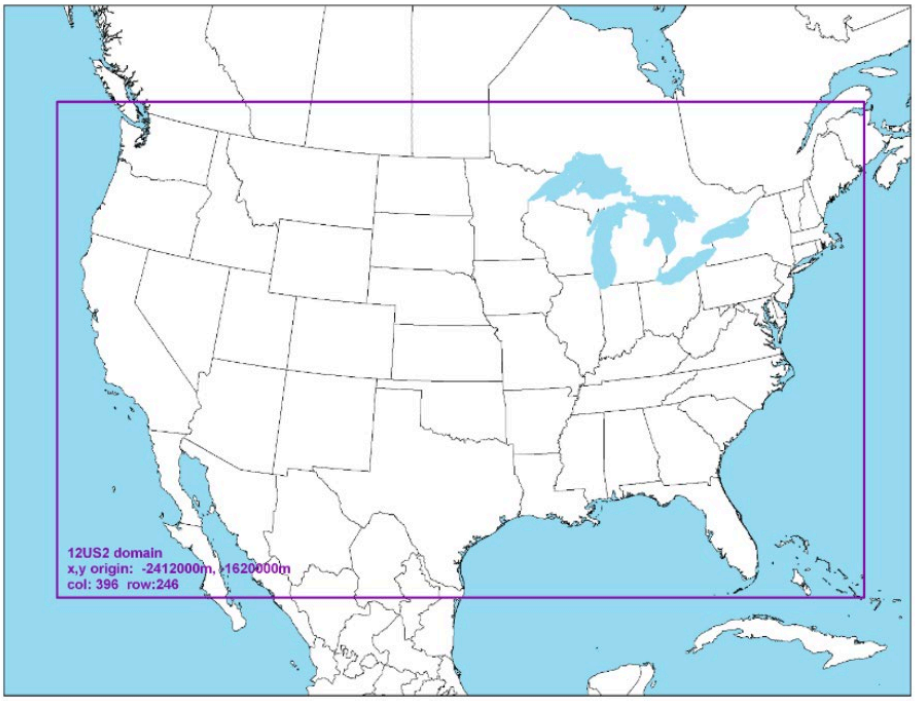


Figure 3-3. CAMx 12-km modeling domain (12US2)

3.3.2 2011 and 2028 Emissions Data

LADCO based the 2011 and 2028 emissions data for this study on the U.S. EPA 2011v6.3 ("EN") emissions modeling platform (US EPA, 2017b). U.S. EPA generated this platform for their assessment of interstate transport for the 2015 O_3 NAAQS (U.S. EPA, 2016a), and used these data for their preliminary regional haze modeling for Round 2 of the RHR (U.S. EPA, 2017a). LADCO also used these data in support of our member states' interstate transport SIPs for the 2015 ozone NAAQS (LADCO, 2018). While the U.S. EPA made several changes to the forecasted 2028 emissions in the "EN" platform relative to the earlier "EL" platform, the changes to the base year (2011) model between the two platforms were minor (US EPA, 2017b).

LADCO replaced the EGU emissions in the U.S. EPA EN platform with 2028 EGU forecasts estimated with the ERTAC EGU Tool version 2.7 (MARAMA, 2012), as described in Section 3.2. Since there are differences in the way that EGUs are classified in ERTAC and U.S. EPA's IPM, LADCO used ERTAC's 2028 non-EGU point inventory to replace the same sector in U.S. EPA's 2011 EN modeling platform. We used the U.S. EPA EN platform emissions estimates for all other inventory sectors. Table 3-2 shows the 2011 and 2028 inventory components used by LADCO to forecast regional haze.

Table 3-2. LADCO 2011 emissions modeling platform inventory components

Sector	Abbreviation	Base Year Data Source	Future Year Data Source
Agriculture	ag	U.S. EPA 2011ek	U.S. EPA 2028el
Area and Fugitive Dust	afdust	U.S. EPA 2011ek	U.S. EPA 2028el
Biogenic	beis	U.S. EPA 2011en	U.S. EPA 2011en
C1/C2 Commercial Marine	cmv_c1c2	U.S. EPA 2011en	U.S. EPA 2028en
C3 Commercial Marine	cmv_c2	U.S. EPA 2011en	U.S. EPA 2028en
Nonpoint	nonpt	U.S. EPA 2011en	U.S. EPA 2028en
Offroad Mobile	nonroad	U.S. EPA 2011en	U.S. EPA 2028en
Nonpoint Oil & Gas	np_oilgas	U.S. EPA 2011ek	U.S. EPA 2028en
Onroad Mobile	onroad	U.S. EPA 2011el	U.S. EPA 2028en
Point Oil & Gas	pt_oilgas	U.S. EPA 2011ek	U.S. EPA 2028en
Electricity Generation	ptegu	U.S. EPA 2011el	ERTAC EGU 2.7
Industrial Point	ptnonipm	U.S. EPA 2011en	MARAMA 2011v2[15]
Rail	rail	U.S. EPA 2011ek	U.S. EPA 2028el
Residential Wood Combustion	rwc	U.S. EPA 2011ek	U.S. EPA 2028el
Agricultural Fires	ptagfire	U.S. EPA 2011ek	U.S. EPA 2011ek
Wild and Prescribed Fires	ptfire	U.S. EPA 2011ek	U.S. EPA 2011ek
Mexico Anthropogenic	Multiple	U.S. EPA 2011ek	U.S. EPA 2011ek
Canada Anthropogenic	Multiple	U.S. EPA 2011en	U.S. EPA 2011en

3.4 2016 Modeling Platform

3.4.1 Air Quality Model Configuration

LADCO based our CAMx air quality modeling platform for this application on the configuration that the U.S. EPA used for their updated regional haze modeling (US EPA, 2019b). LADCO used CAMx 7.0 (Ramboll, 2020) as the photochemical grid model for this application. Similar to the 2011 modeling

[15] MARAMA developed a non-EGU point inventory for use with the ERTAC EGU2.7 emissions from the 2011NEIv2

platform, LADCO was able to leverage data and software elements that U.S. EPA distributed for regulatory rulemaking.

The LADCO 2016 CAMx modeling used a similar configuration as the 2011 modeling platform. The horizontal domains are the same between the two simulations (12US2 modeling domain). The 2016 CAMx simulation used all 35 of the WRF vertical layers with no layer collapsing.

Table 3-1 summarizes the CAMx science configurations and options LADCO used for the 2016 and 2028 CAMx modeling for this application. We used the Piecewise Parabolic Method (PPM) advection solver for horizontal transport along with the spatially varying (Smagorinsky) horizontal diffusion approach. We used K-theory for vertical diffusion using the CMAQ-like vertical diffusivities from WRFCAMx. The CB6r4 gas-phase chemical mechanism was selected because it includes the latest chemical kinetic rates and represents improvements over the other alternative CB05 and SAPRC chemical mechanisms as well as active methane chemistry. Additional CAMx inputs were as follows:

Meteorological Inputs: LADCO used the U.S. EPA 2016 WRF data for this study (US EPA, 2019c). The U.S. EPA used version 3.8 of the WRF model, initialized with the 12-km North American Model (NAM) from the National Climatic Data Center (NCDC) to simulate 2016 meteorology. Complete details of the WRF simulation, including the input data, physics options, and four-dimensional data assimilation (FDDA) configuration are detailed in the Meteorology Model Performance for Annual 2016 Simulation WRFv3.8 report (US EPA, 2019c). LADCO prepared the WRF data for input to CAMx with version 4.6 of the WRFCAMx software.

Initial/Boundary Conditions: LADCO used 2016 initial and boundary conditions for CAMx generated by the U.S. EPA from a northern hemisphere simulation of the Community Multiscale Air Quality (CMAQ) model (US EPA, 2019d). EPA generated hourly, one-way nested boundary conditions (i.e., hemispheric-scale to regional-scale) from a 2016 108-km x 108-km polar stereographic CMAQ simulation of the northern hemisphere. Following the convention of the U.S. EPA 2016 regional haze modeling (U.S. EPA, 2019b), LADCO used year 2016 CMAQ boundary conditions for modeling 2016 and 2028 air quality with CAMx.

Photolysis Rates: LADCO prepared the photolysis rate inputs in the same manner as for the 2011 modeling platform described above.

Landuse: LADCO used landuse/landcover data from the U.S. EPA WRF 2016 simulation.

Spin-Up Initialization: A minimum of ten days of model spin up (e.g., December 21-31, 2015) was used for the 12 km modeling domain. LADCO ran quarterly CAMx simulations, initializing each quarter with a 10-day spin-up period.

LADCO used CAMx to simulate the entire year for 2016 and 2028. LADCO selected a CAMx configuration that was consistent with previous regional haze modeling applications performed by U.S. EPA. U.S. EPA (2019b) provides complete details of their 2016 CAMx simulation, including a performance evaluation.

3.4.2 2016 and 2028 Emissions Data

LADCO collected 2016 and 2028 emissions data for this study primarily from the U.S. EPA 2016 v1 ("2016fh_16") emissions modeling platform (U.S. EPA, 2020). U.S. EPA and the 2016 Emissions Inventory Collaborative[16] generated this platform for use in O_3 NAAQS and Regional Haze SIPs.

In addition to a base year emissions estimate for use in a model performance evaluation, LADCO developed a typical-year emissions estimate for comparison with the 2028 forecast (see Section 4.2.3). The typical emissions included three taconite facility industrial point sources. All three sources temporarily shut down in 2016 and restarted operations in 2017, and are included in the 2028 inventory. LADCO also removed an emissions record from the 2016 inventory for the Wisconsin Rapids wastewater treatment facility that incorrectly added 5,000 tons/year of NOx to the inventory for this source. Table 3-3 shows the sources in Minnesota that LADCO included in the typical year emissions that are not included in the 2016 actual base year emissions.

Table 3-3. LADCO typical year inventory sources

Facility	State	NOx Emissions (tons/year)	SO_2 Emissions (tons/year)
US Steel Keetac	MN	5,009	533
Northshore Mining Silver Bay	MN	785	151
United Taconite Fairlane	MN	374	275

[16] http://views.cira.colostate.edu/wiki/wiki/10202

LADCO replaced the 2028 EGU emissions in the U.S. EPA "2016fh" emissions modeling platform with 2028 EGU forecasts estimated with the ERTAC EGU Tool version 16.1 (MARAMA, 2012), as discussed above. LADCO also used the ERTAC non-EGU point inventory in our 2016 modeling platform to ensure consistency with the EGU sector.

Figure 3-4 through Figure 3-9 show 2016 daily total EGU NOx emissions by fuel type for each of the LADCO states. These figures show that in 2016 the NOx emissions from power generation in the LADCO region were primarily emitted by sources that burn coal, that there is significant day to day variation in power plant emissions, and that the summer and winter seasons are the peak periods of EGU NOx emissions.

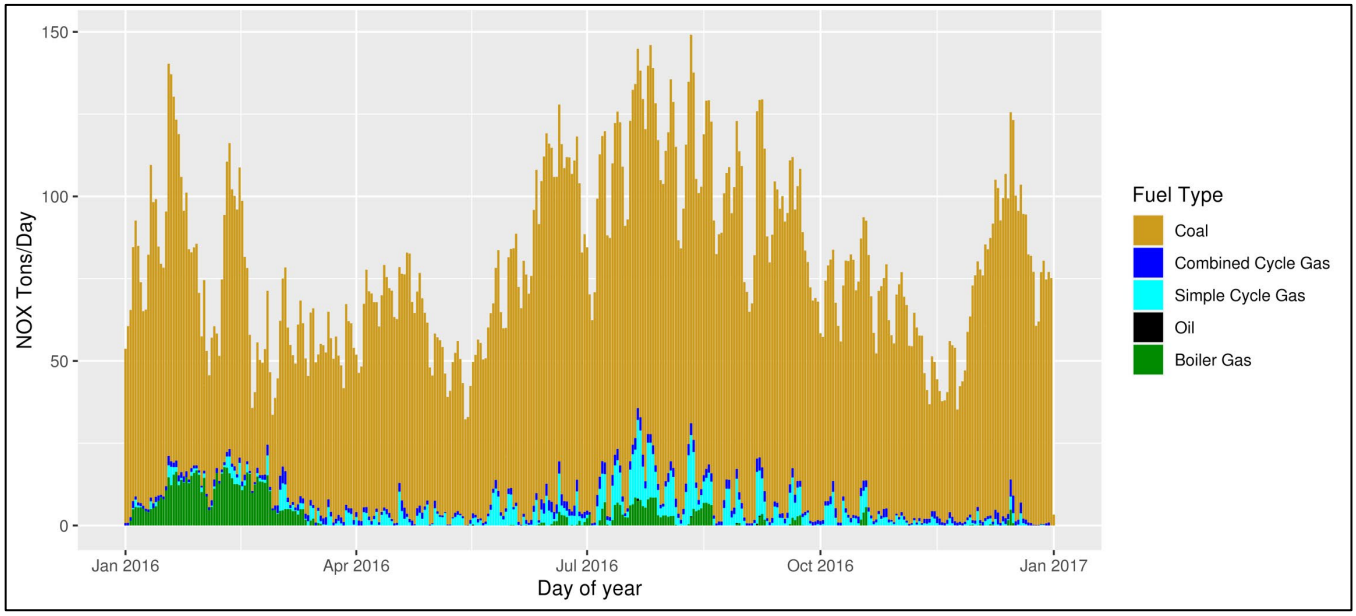


Figure 3-4. Illinois power generation 2016 daily NOx emissions by fuel type

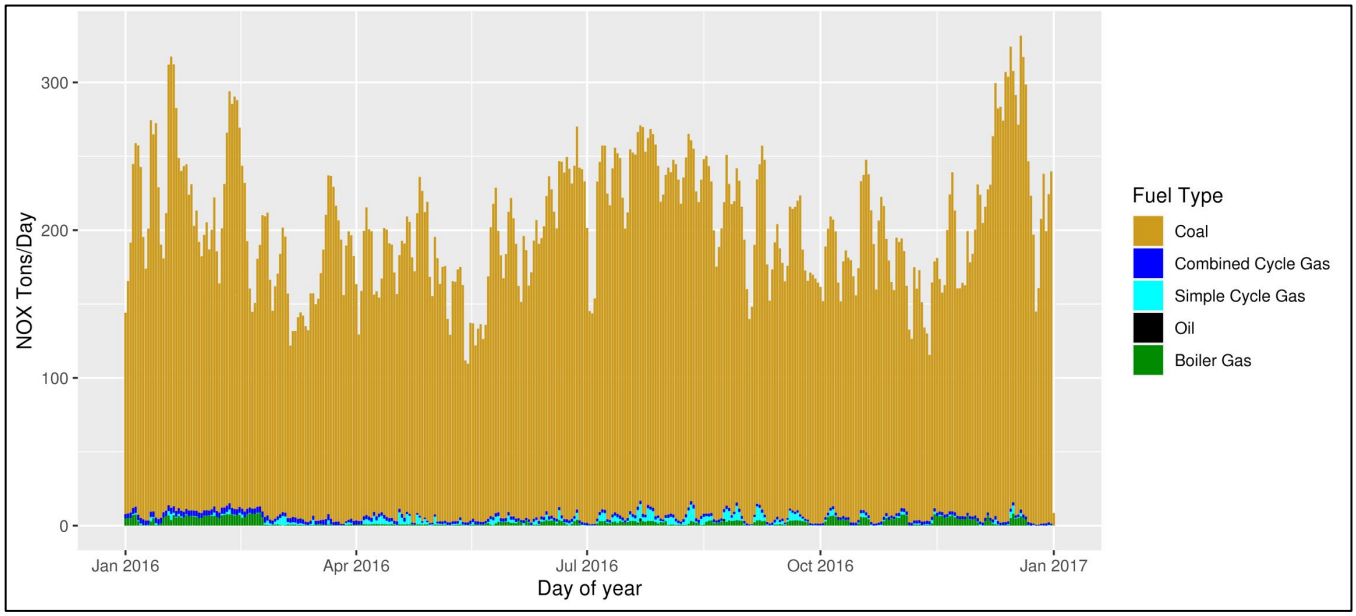


Figure 3-5. Indiana power generation 2016 daily NOx emissions by fuel type

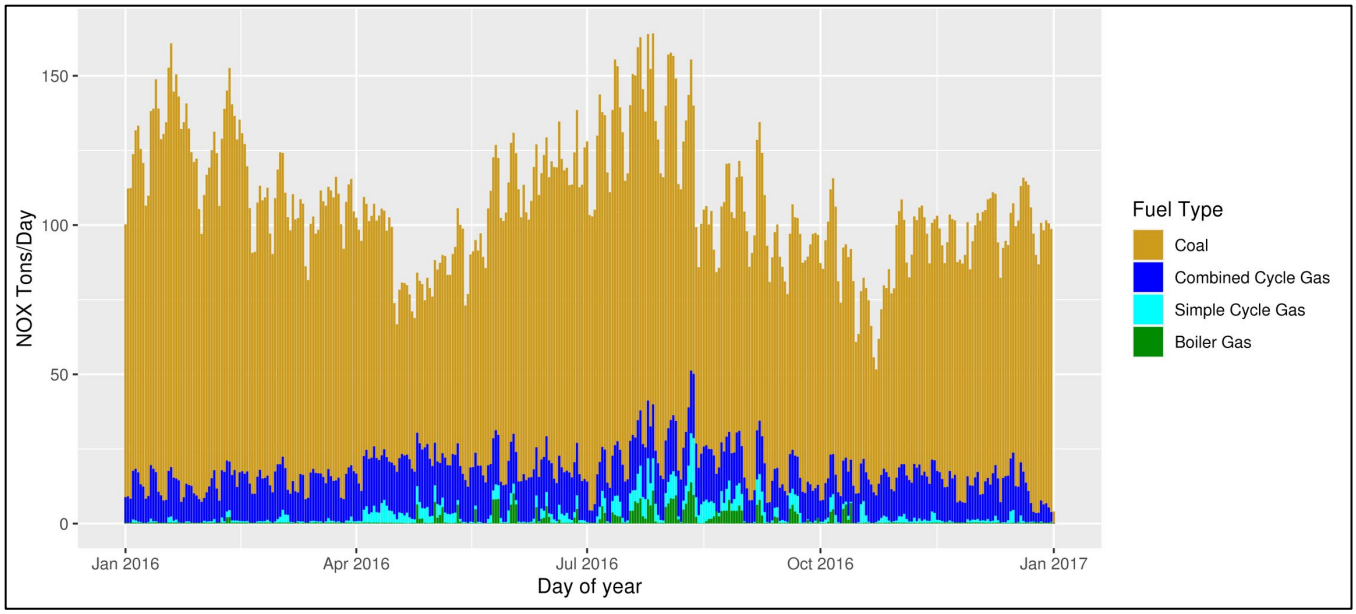


Figure 3-6. Michigan power generation 2016 daily NOx emissions by fuel type

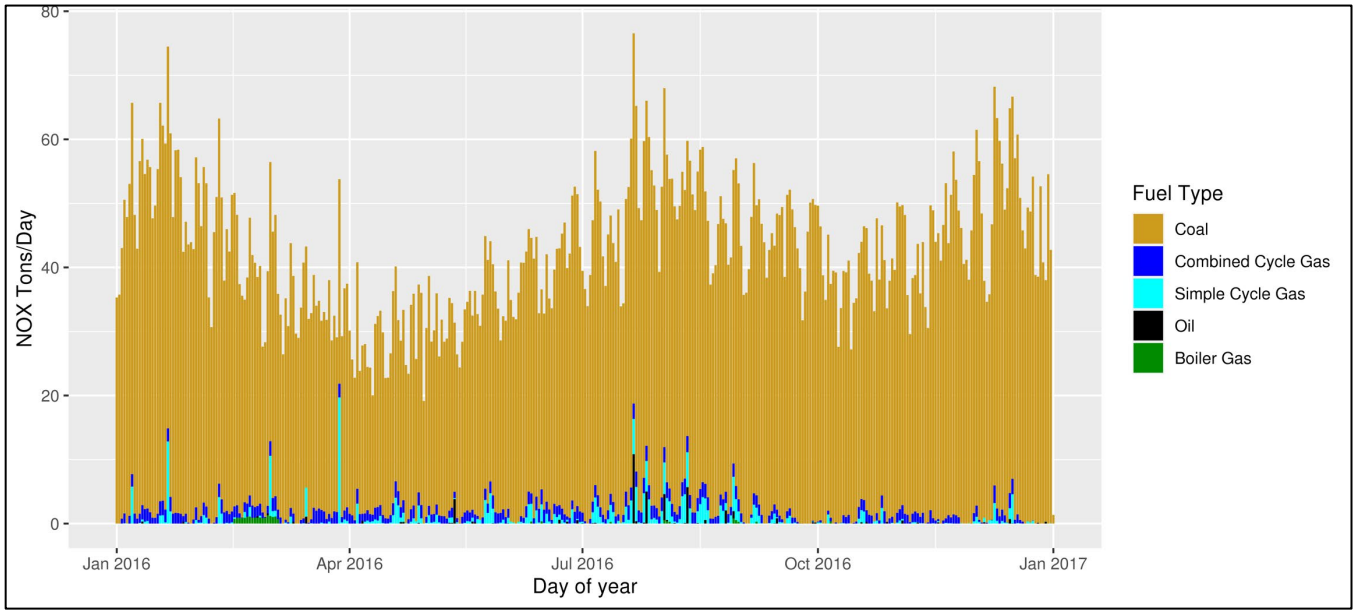


Figure 3-7. Minnesota power generation 2016 daily NOx emissions by fuel type

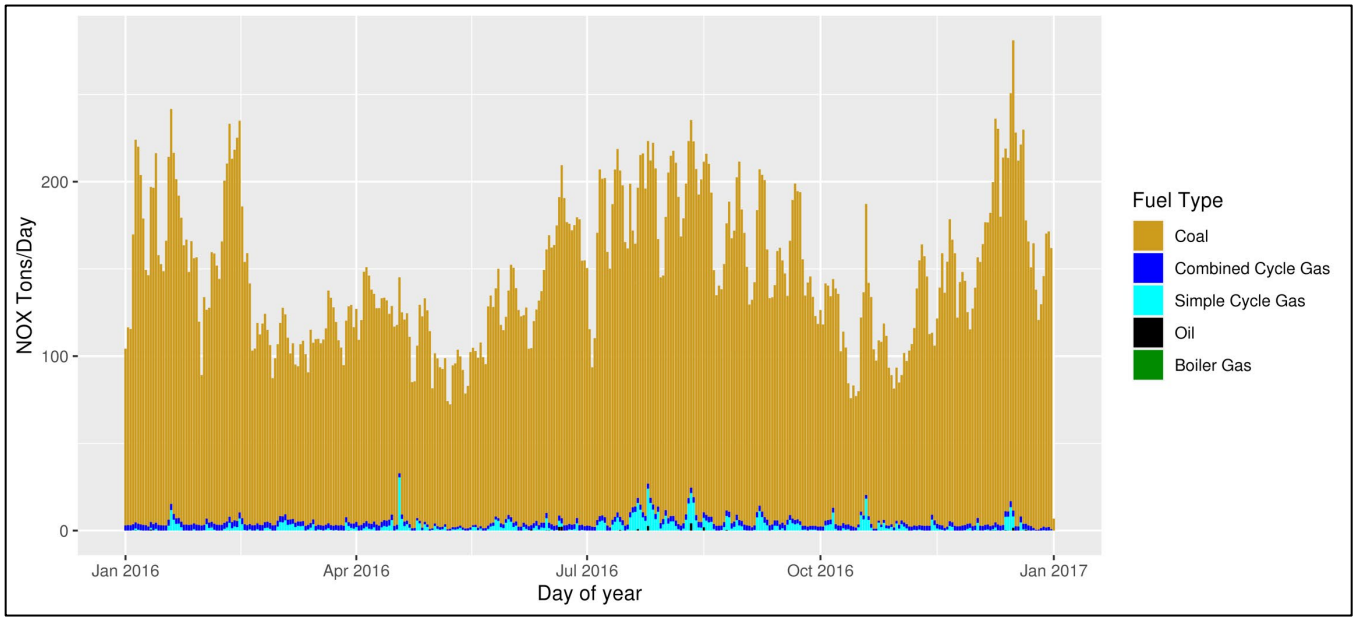


Figure 3-8. Ohio power generation 2016 daily NOx emissions by fuel type

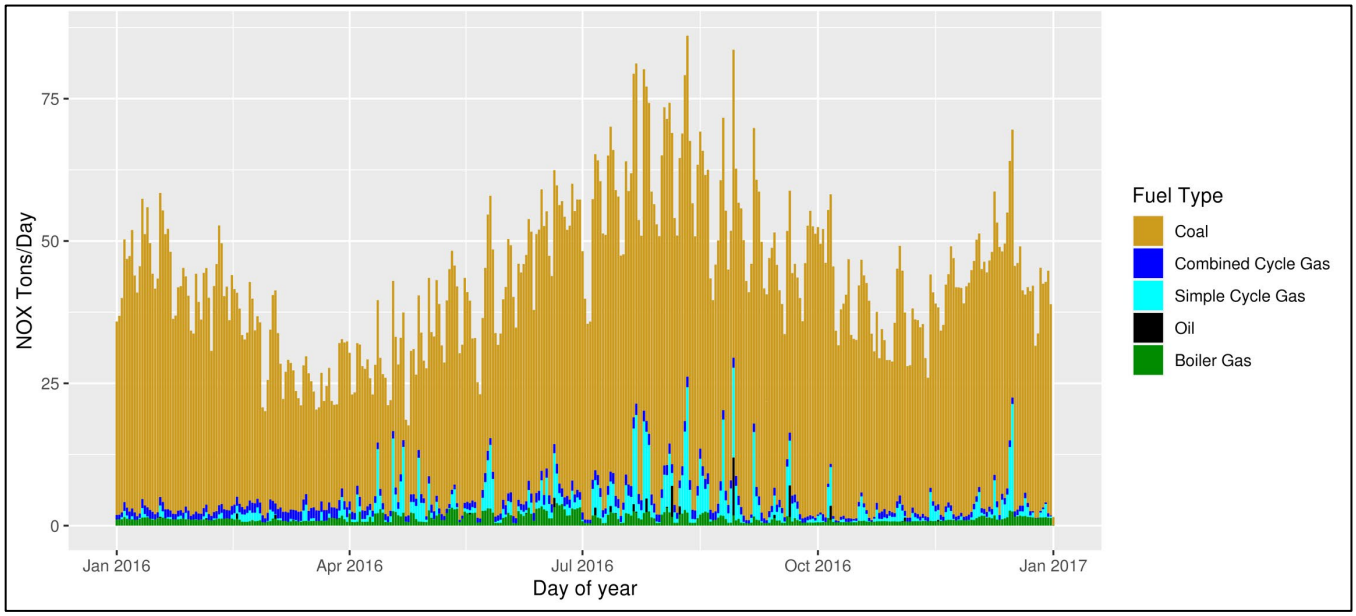


Figure 3-9. Wisconsin power generation 2016 daily NOx emissions by fuel type

LADCO modified the ERTAC EGU 16.1 inventory forecasts for 2028 for the 2016 base year modeling to exclude the emissions from 62 EGU units that announced shutdowns that will occur before 2028. These announcements came after the ERTAC EGU 16.1 emissions were developed. LADCO zeroed out the 2028 emissions from these units in our 2016-based modeling forecasts for 2028. Supplemental materials Section S3 lists the additional units that LADCO removed from our 2016-based 2028 modeling.

Figure 3-10 compares 2016 and 2028 daily total SO_2 emissions from all EGUs in the LADCO region. The two lines in the figure illustrate the daily temporal variability in SO_2 emissions from electricity generating point sources across the LADCO region.

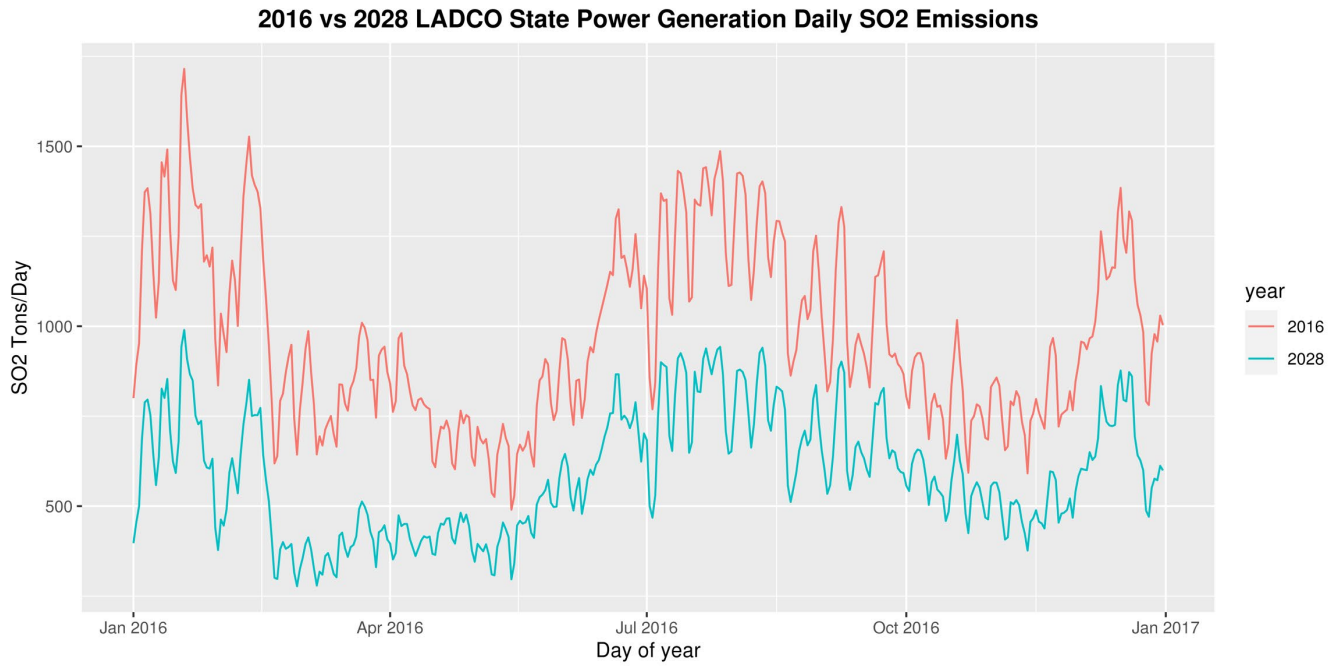


Figure 3-10. Daily total LADCO region SO_2 emissions from EGUs in 2016 and 2028

The Electronic Docket to this TSD includes a spreadsheet with point source facility (EGU and non-EGU) annual emissions totals for 2016 and 2028.

Table 3-4 lists the 2016 base year and 2028 future year inventory components that LADCO used to simulate 2016 and 2028 air quality for this application.

Table 3-4. LADCO 2016 emissions modeling platform inventory components

Sector	Abbreviation	Base Year Data Source	Future Year Data Source
Agriculture	ag	U.S. EPA 2016fh	U.S. EPA 2028fh
Fugitive Dust	afdust	U.S. EPA 2016fh	U.S. EPA 2028fh
Airports	airports	U.S. EPA 2016fi	LADCO 2028v1b
Biogenic	beis	U.S. EPA 2016fh	U.S. EPA 2016fh
C1/C2 Commercial Marine	cmv_c1c2	U.S. EPA 2016fh	U.S. EPA 2028fh
C3 Commercial Marine	cmv_c2	U.S. EPA 2016fh	U.S. EPA 2028fh
Nonpoint	nonpt	U.S. EPA 2016fh	U.S. EPA 2028fh
Offroad Mobile	nonroad	U.S. EPA 2016fh	U.S. EPA 2028fh
Nonpoint Oil & Gas	np_oilgas	U.S. EPA 2016fh	U.S. EPA 2028fh
Onroad Mobile	onroad	U.S. EPA 2016fh	U.S. EPA 2028fh
Point Oil & Gas	pt_oilgas	U.S. EPA 2016fh	U.S. EPA 2028fh
Electricity Generation	ptertac	ERTAC 16.1	ERTAC 16.1
Industrial Point	ptnonertac	U.S. EPA 2016fh	MARAMA 16.1 2028
Minnesota Taconite	ptmntaconite	Provided by MPCA	Provided by MPCA
Rail	rail	U.S. EPA 2016fh	U.S. EPA 2028fh
Residential Wood Combustion	rwc	U.S. EPA 2016fh	U.S. EPA 2028fh
Agricultural Fires	ptagfire	U.S. EPA 2016fh	U.S. EPA 2016fh
Wild and Prescribed Fires	ptfire	U.S. EPA 2016fh	U.S. EPA 2016fh
Mexico Anthropogenic	othar/othpt/	U.S. EPA 2016fh	U.S. EPA 2028fh
Canada Anthropogenic	othar/othpt	U.S. EPA 2016fh	U.S. EPA 2028fh

3.5 Source Apportionment Modeling

LADCO used the CAMx Particulate Matter Source Apportionment Tool (PSAT) to calculate emissions tracers for identifying upwind sources of haze at downwind monitoring sites.

3.5.1 2011 Source Apportionment Configuration

LADCO configured CAMx to use the point source override option in PSAT for tagging states, regions, and inventory sectors for the 2011-based 2028 simulation. LADCO applied state and region tags in the emissions processing sequence rather than using a geographic spatial mask of the emissions data. This approach ensures that the emissions for each source area are accurately apportioned to the state in which they are located. LADCO modified the U.S. EPA 2023en U.S. Source Apportionment (USSA)

emissions modeling platform, and applied it to the "EN" 2028 modeling platform to prepare emissions for this simulation. Table 3-5 lists the 26 tags used in the simulation.

For this simulation, LADCO used PSAT to trace the PM and haze impacts from primary and secondary nitrate and sulfate precursors, primary and secondary organic aerosols, and soil dust.

Table 3-5. LADCO CAMx 2028_{2011} PSAT tags

Tag	Description	Tag	Description
1	Biogenic	14	KS
2	IL	15	NE
3	WI	16	ND
4	IN	17	SD
5	OH	18	WV
6	MI	19	KY
7	MN	20	ME, NH, VT, MA, RI, CT, NY, NJ, PA, DE, MD, DC
8	IA	21	VA, NC, SC, TN, GA, AL, MI, FL
9	MO	22	NM, AZ, CO, UT, WY, MT, ID, WA, OR, CA, NV
10	AR	23	Canada/Mexico
11	LA	24	Fire
12	TX	25	Offshore
13	OK	26	Tribes

3.5.2 2016 Source Apportionment Configuration

For the 2016-based 2028 PSAT simulation LADCO used a combination of a geographic spatial mask to tag states and regions, and the CAMx point source override option to tag individual point sources and inventory source groups. Table 3-6 lists the PSAT tags used for the 2016-based 2028 CAMx simulation. PSAT tags 2 through 15 used a geographic spatial mask of the 12-km modeling grid to apportion emissions to the states and regions. Emissions in grid cells with fractional coverage across multiple states were assigned to the state with the dominant coverage in the grid cell. PSAT tags 16 through 25 were used to tag emissions from specific point sources and source groups, including commercial marine, fires, and industrial point sources in Indiana (tags 18-25). Appendix C lists the NAICS and SCC codes associated with each of the PSAT tags for the Indiana point sources.

For this simulation, LADCO used PSAT to trace the PM and haze from primary and secondary nitrate and sulfate precursors, primary carbonaceous aerosols, and soil dust. LADCO used two source groups to

distinguish anthropogenic and biogenic sources within each of the tags. LADCO did not use the CAMx PSAT organic aerosol tracer for this simulation.

Table 3-6. LADCO CAMx 2028_{2016} PSAT tags

Tag	Description	Tag	Description
1	Other	14	NM, AZ, CO, UT, WY, MT, ID, WA, OR, CA, NV, ND, SD
2	IL	15	Canada/Mexico
3	WI	16	Commercial Marine (C1/C2/C3)
4	IN	17	Fires
5	OH	18	Rockport EGU (IN)
6	MI	19	Gibson EGU (IN)
7	MN	20	All other IN EGUs
8	IA	21	IN Cement Manufacturing
9	MO	22	IN Iron and Steel
10	TX	23	IN Plastics and Resin
11	LA, OK, KS, NE, AR	24	IN Aluminum Production
12	ME, NH, VT, MA, RI, CT, NY, NJ, PA, DE, MD, DC	25	All other IN point sources
13	WV, KY, VA, NC, SC, TN, GA, AL, MI, FL		

3.6 CAMx Model Performance Evaluation Approach

This section describes the approaches LADCO took to evaluate CAMx model performance. Section 6 describes the results of this evaluation. The CAMx model performance evaluation (MPE) presented here focuses on PM and haze species at surface monitors in and near the LADCO region. As this TSD is focused on regional haze, particular attention is paid to model performance at monitors in the Class I areas. LADCO used the Atmospheric Model Evaluation Tool (AMET) version 1.3 to pair the model results and surface observations in space and time, generate bi-variate statistics of model performance, and to produce MPE plots.

LADCO evaluated the CAMx 2011 and 2016 modeled PM concentrations and reconstructed visibility against concurrent measured surface ambient concentrations using graphical displays of model performance and statistical model performance measures. LADCO compared the statistical measures against established

model performance goals and criteria following the procedures recommended in EPA's photochemical modeling guidance documents (e.g., EPA, 2018).

3.6.1 Available Ambient Monitoring Data for the Model Evaluation

LADCO used the following routine air quality measurement data networks operating in in 2011 and 2016 to assess CAMx model performance:

EPA AQS Surface Air Quality Data: Data files containing hourly-averaged concentration measurements at a wide variety of state and EPA monitoring networks are available in the Air Quality System (AQS) database throughout the U.S. The AQS consists of many sites that tend to be mainly located in and near major cities. The standard hourly AQS AIRS monitoring stations typically measure hourly ozone, NO_2, NOx and CO concentration and there are thousands of sites across the U.S. The Federal Reference Method (FRM) network measures 24-hour total $PM_{2.5}$ mass concentrations using a 1:3 day sampling frequency, with some sites operating on an everyday frequency. The Chemical Speciation Network (CSN) measures speciated $PM_{2.5}$ concentrations including sulfate (SO_4), nitrate (NO_3), ammonium (NH_4), elemental carbon (EC), organic carbon (OC), and elements at 24-hour averaging time period using a 1:3 or 1:6 day sampling frequency

IMPROVE Monitoring Network: The Interagency Monitoring of Protected Visual Environments (IMPROVE) network collects 24-hour average $PM_{2.5}$ and PM_{10} mass and speciated $PM_{2.5}$ concentrations (with the exception of ammonium) using a 1:3 day sampling frequency. IMPROVE monitoring sites are mainly located at more rural Class I area sites that correspond to specific National Parks, Wilderness Areas and Fish and Wildlife Refuges across the U.S., with a large number of sites located in the western U.S. There are also some IMPROVE protocol sites in urban areas.

3.6.2 Model Performance Statistics, Goals and Criteria

EPA's modeling guidance (2018) notes that PM models might not be able to achieve the same level of model performance as ozone models. Indeed, $PM_{2.5}$ species are defined by the measurement technology used to measure them and different measurement technologies can produce quite different $PM_{2.5}$ concentrations. To account for the variability in PM measurements, researchers developed PM model performance goals and criteria that are less stringent than ozone model performance goals (Boylan, 2004; Boylan and Russell, 2006; Simon et al., 2012). More recently Emery et al. (2017) conducted a meta-

analysis of 38 peer-reviewed articles reporting air quality model performance for PM species. Table 3-7 lists the recommendations of the authors for performance goals and criteria for different PM model species. The MPE metrics recommended by the authors are shown in Table 3-8.

Table 3-7. PM model performance goals and criteria (Emery et al., 2017)

Species	NMB*		NME*		r*	
	Goal	Criteria	Goal	Criteria	Goal	Criteria
24-hr $PM_{2,5}$, SO_4, NH_4	≤±10%	≤30%	≤±35%	≤50%	>0.70	>0.40
24-hr NO_3	≤±15%	≤65%	≤±65%	≤115%	None	None
24-hr OC	≤±15%	≤50%	≤±45%	≤65%	None	None
24-hr EC	≤±20%	≤40%	≤±50%	≤75%	None	None

* NMB = normalized mean bias; NME = normalized mean error; r = correlation coefficient.

These model performance goals are not used to assign passing or failing grades to model performance, but rather to help interpret the model performance and intercompare across locations, species, time periods and model applications. The model inputs to CAMx vary hourly, but tend to represent average conditions that do not account for unusual or extreme conditions. For example, an accident or large event could cause significant increases in congestion and motor vehicle emissions that are not accounted for in the average emissions inputs used in the model.

Emery et al. (2017) compiled and interpreted the PM model performance from 38 air quality modeling studies in the peer-reviewed literature and developed the following recommendations on what should be reported in a model performance evaluation:

- Photochemical modeling studies should report model performance as Normalized Mean Bias (NMB) and Error (NME), and correlation coefficient (*r*). The confidence interval of *r* should be included with the results (Table 3-8).
- Concentration cutoffs should not be used for PM species because of the lower background concentrations of PM
- Temporal scales for 24-hr total and speciated PM should not exceed 3 months (or 1 season); spatial scales should range from urban to ≤1000 km.

- It is important to report processing steps in the model evaluation and how the predicted and observed data were paired and whether data are spatially/temporally averaged before the statistics are calculated.
- Predicted values should be taken from the grid cell that contains the monitoring site, although bilinear interpolation to the monitoring site point can be used for higher resolution modeling (< 12 km).
- Spatial displays should be used in the model evaluation to evaluate model predictions away from the monitoring sites. Time series of predicted and observed concentrations at a monitoring site should also be used.
- Graphical plots are useful for evaluating models in conjunction with statistics. Specifically, time series (either as individual sites, or as means and variability over multiple sites), scatter diagrams (time-paired regression or time-unpaired rank-ordered comparisons), and cumulative distribution plots are particularly useful for understanding model performance and model behavior over entire ranges of concentrations.
- For regulatory applications, extend the general MPE to focus bias and error calculations on the number of modeled days used in developing the relative reduction factors (RRFs) for each PM species.

LADCO incorporated these and the recommendations of U.S. EPA (2018) into the LADCO CAMx model performance evaluation for the 2011 and 2016 modeling platforms used for this TSD. The LADCO evaluation products include qualitative and quantitative evaluation metrics for total $PM_{2.5}$ and PM species.

Table 3-8. Definition of model performance evaluation statistical measures used to evaluate the CTMs.

Statistical Measure	Mathematical Expression	Notes
Correlation Coefficient (r)	$\frac{\sum_{i=1}^{N}[(P_i - \bar{P})x(O_i - \bar{O})]}{\sqrt{\sum_{i=1}^{N}(P_i - \bar{P})^2 x \sum_{i=1}^{N}(O_i - \bar{O})^2}}$	Range: 0,1 r = 1 is perfect correlation r = 0 is totally uncorrelated P = Predicted O = Observed
Normalized Mean Error (NME)	$\frac{\sum_{i=1}^{N}\lvert P_i - O_i\rvert}{\sum_{i=1}^{N} O_i}$	Range: 0%, +∞ Reported as % P = Predicted O = Observed
Normalized Mean Bias (NMB)	$\frac{\sum_{i=1}^{N}(P_i - O_i)}{\sum_{i=1}^{N} O_i}$	Range: -100%, +∞ Reported as % P = Predicted O = Observed

4 Emissions Summaries

In this section we summarize the base and future year emissions modeling results used to forecast haze conditions in 2028. The emissions projections from the base years to 2028 are the foundation of the air quality model forecasts of future year PM concentrations and haze conditions. The emissions plots and tables in this section illustrate and quantify how the U.S. emissions modeling community, including LADCO, U.S. EPA, and state air quality planning agencies forecasted air pollution emissions at the time of the second regional haze implementation period.

4.1 2011 Modeling Platform

As described in Section 3.3.2, LADCO based the 2011 and 2028 emissions data for this study on the U.S. EPA 2011v6.3 ("EN") emissions modeling platform (US EPA, 2017b). LADCO replaced the EGU emissions in the U.S. EPA EN platform with 2028 EGU forecasts estimated with the ERTAC EGU Tool version 2.7 (MARAMA, 2012). ERTAC EGU 2.7 integrated state-reported information on EGU operations and forecasts as of May 2017. Table 3-2 shows the 2011 and 2028 inventory components used by LADCO to forecast regional haze.

The following sections summarize the 2011 and 2028 emissions used by LADCO for simulating regional haze conditions during these years.

4.1.1 2011 Emissions Summary

LADCO state total emissions for the 2011 modeling platform are shown in Table 4-1. These emissions totals do not include biogenic sources. In Figure 4-1 and Figure 4-2 we show tile plots of daily total 2011 NOx and SO_2 emissions, respectively, gridded to the 12US2 modeling domain. Table 4-2 shows the 2011 emissions for each LADCO state by emissions inventory sector.

Table 4-1. 2011 annual total emissions by state for all anthropogenic sectors (tons/year)

State	NH_3	NOx	$PM_{2.5}$	SO_2	VOC
Illinois	11,490	542,488	55,566	287,832	812,683
Indiana	7,061	464,561	53,483	425,201	570,781
Michigan	10,939	458,442	73,816	273,598	1,027,207
Minnesota	20,332	342,334	139,857	70,655	990,775
Ohio	13,520	565,513	98,549	680,042	732,132
Wisconsin	7,610	283,971	60,426	147,113	768,382

Onroad and nonroad mobile sources are the primary sources of NOx emissions in the LADCO region. The point sector, which include EGUs, is the primary source of SO_2 emissions. Biogenic emissions are the primary source of volatile organic compounds (VOCs) at a regional and annual total level.

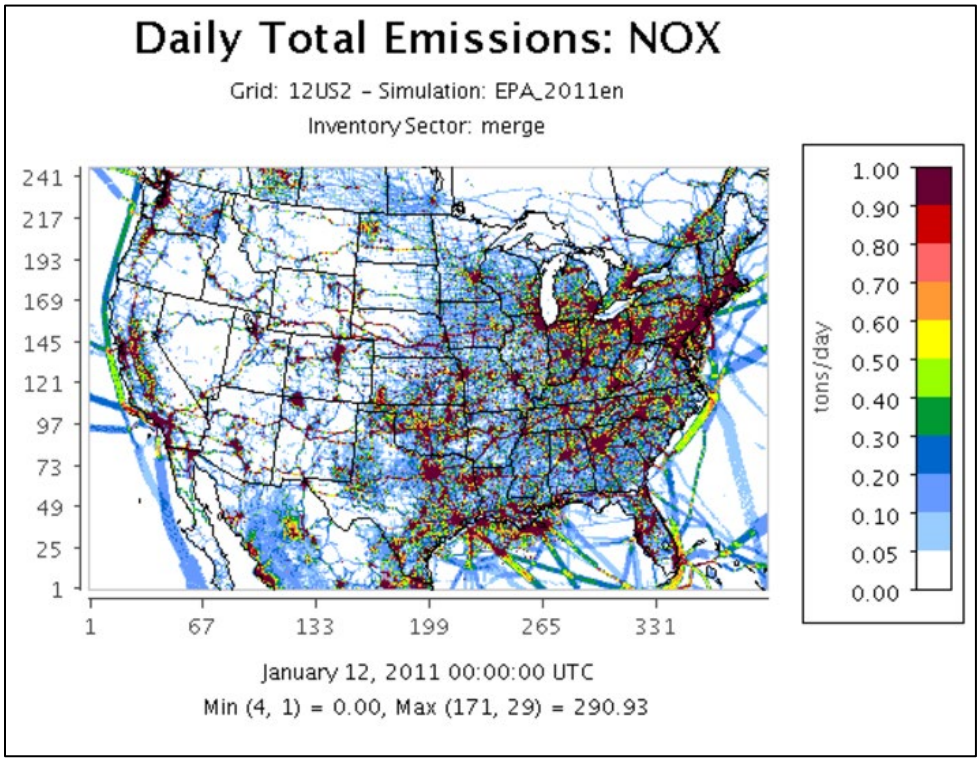


Figure 4-1. Daily total gridded 2011 NOx emissions for an example weekday (tons/day)

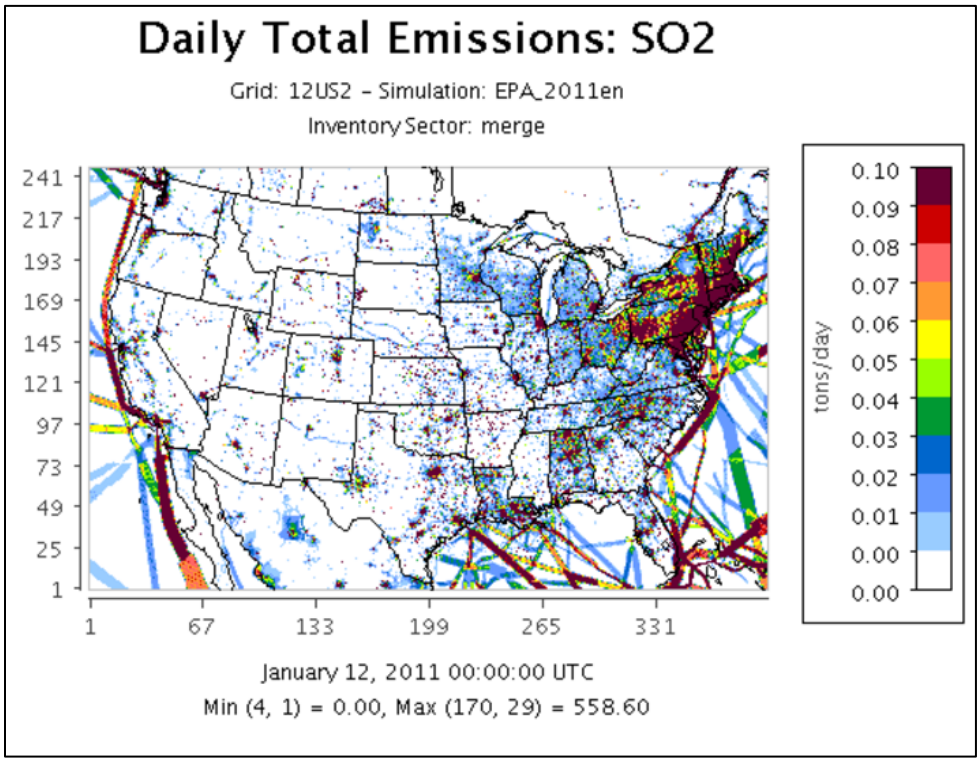


Figure 4-2. Daily total gridded 2011 SO_2 emissions for an example weekday (tons/day)

Table 4-2. 2011 annual emissions totals

State	Group	2011 Emissions (tons/year)				
		NH_3	NOX	$PM_{2.5}$	SO_2	VOC
Illinois	Biogenics		35,836			440,546
	Fires	1,041	1,004	5,561	519	14,966
	NonPoint	5,185	43,506	15,770	5,102	145,085
	Nonroad	128	135,410	9,068	1,393	71,976
	Onroad	3,420	176,709	6,174	1,073	67,386
	Point	1,716	150,024	18,992	279,745	72,724
Indiana	Biogenics		21,016			286,402
	Fires	423	445	2,306	225	6,107
	NonPoint	2,087	17,275	18,723	2,453	104,253
	Nonroad	66	67,906	4,707	352	42,212
	Onroad	3,334	171,438	5,403	817	83,362
	Point	1,151	186,481	22,344	421,354	48,445
Michigan	Biogenics		14,351			576,931
	Fires	511	442	2,695	239	7,342
	NonPoint	5,190	32,713	48,181	3,804	157,047
	Nonroad	93	67,127	6,382	2,593	123,697
	Onroad	4,101	194,625	6,186	953	106,140
	Point	1,044	149,184	10,374	266,007	56,050
Minnesota	Biogenics		26,137			516,225
	Fires	13,111	10,924	70,357	6,177	190,325
	NonPoint	3,240	25,065	41,491	5,895	118,203
	Nonroad	76	73,758	5,866	644	76,960
	Onroad	2,445	123,520	4,375	587	68,356
	Point	1,461	82,931	17,768	57,352	20,705
Ohio	Biogenics		17,952			340,817
	Fires	163	165	876	84	2,343
	NonPoint	4,335	38,660	34,226	4,809	147,055
	Nonroad	96	95,195	6,685	912	70,411
	Onroad	4,790	250,433	8,050	1,085	129,619
	Point	4,136	163,108	48,712	673,152	41,886
Wisconsin	Biogenics		15,078			480,085
	Fires	596	566	3,179	294	8,571
	NonPoint	2,930	23,065	39,299	2,987	113,317
	Nonroad	64	53,101	4,559	544	84,430
	Onroad	2,342	127,174	4,585	587	60,066
	Point	1,677	64,987	8,803	142,700	21,911
Grand Total		70,953	2,657,309	481,697	1,884,441	4,901,958

4.1.2 2028_{2011} Emissions Summary

LADCO state total 2028_{2011} emissions[17] projections for the LADCO 2011 modeling platform are shown in Table 4-3. These emissions totals do not include biogenic sources. Figure 4-3 and Figure 4-5 are tile plots of daily total 2028 NOx and SO_2 emissions, respectively, gridded to the 12US2 modeling domain. Figure 4-4 and Figure 4-6 show differences in daily total NOx and SO_2 emissions between 2011 and 2028, respectively. Table 4-4 shows the 2028_{2011} emissions for each LADCO state by emissions inventory sector.

Table 4-3. 2028_{2011} annual total emissions by state for all anthropogenic sectors (tons/year)

State	NH_3	NOX	$PM_{2.5}$	SO_2	VOC
Illinois	10,936	292,583	42,154	168,040	705,028
Indiana	5,906	246,805	43,526	196,016	468,536
Michigan	9,663	210,960	62,158	89,274	841,588
Minnesota	20,010	188,083	131,497	42,452	893,958
Ohio	11,503	254,645	70,536	195,434	584,024
Wisconsin	6,234	146,140	52,115	50,233	673,886

As shown in Table 4-5 the U.S. EPA 2011 EN emissions used by LADCO project that in 2028 there will be significant reductions in NOx emissions in the LADCO member states from nonroad mobile (> 50% reductions), onroad mobile (> 70%), and industrial point sources (> 25%) relative to the 2011 base year. Additionally, the shutdowns of large EGUs will result in more than a 40% reduction in total SO_2 emissions. LADCO estimates that the combination of gasoline and diesel onroad vehicles will account for significant decreases in $PM_{2.5}$ (60% reductions) and VOC (70% reductions) emissions across the region.

[17] The subscript with the future year (i.e., 2028_{2011}) indicates the base year from which the future year emissions are projected. We use this convention to distinguish between the two 2028 simulations presented in this TSD.

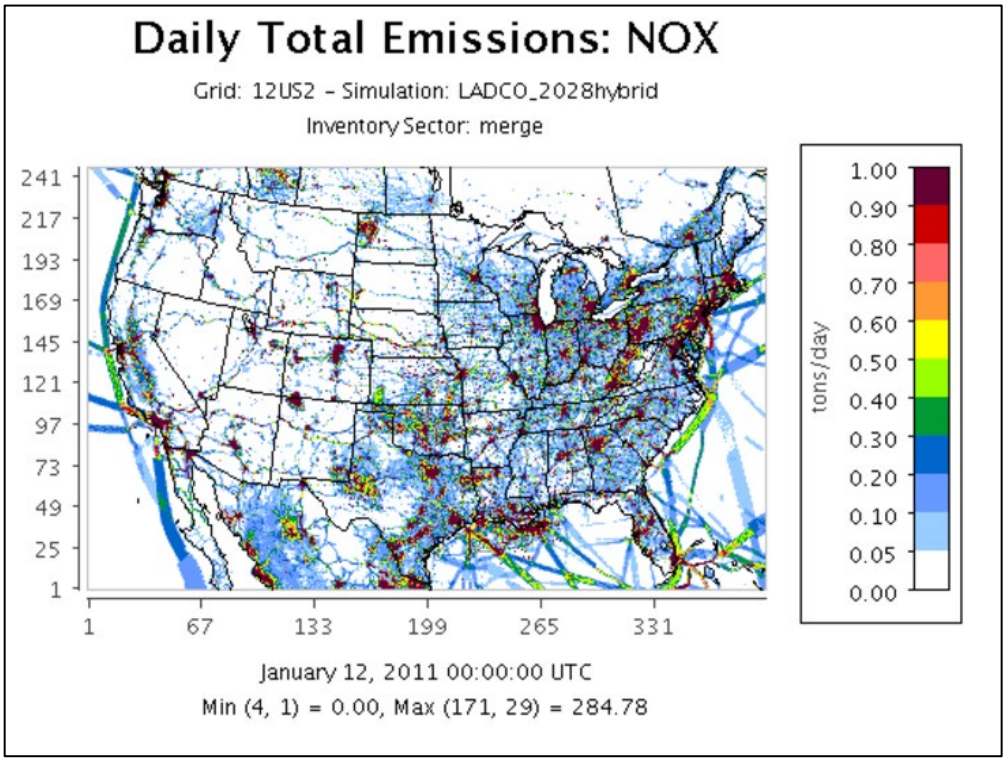


Figure 4-3. Daily total gridded 2028_{2011} NOx emissions for an example weekday (tons/day)

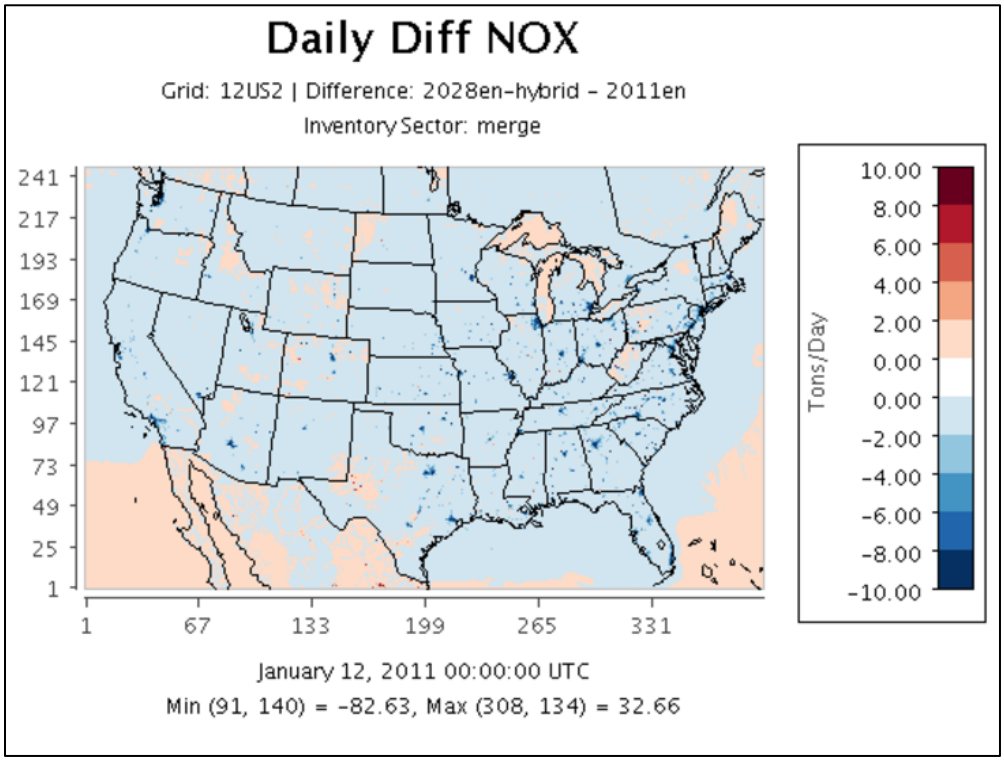


Figure 4-4. Difference (2028-2011) in daily total gridded NOx emissions for an example weekday (tons/day)

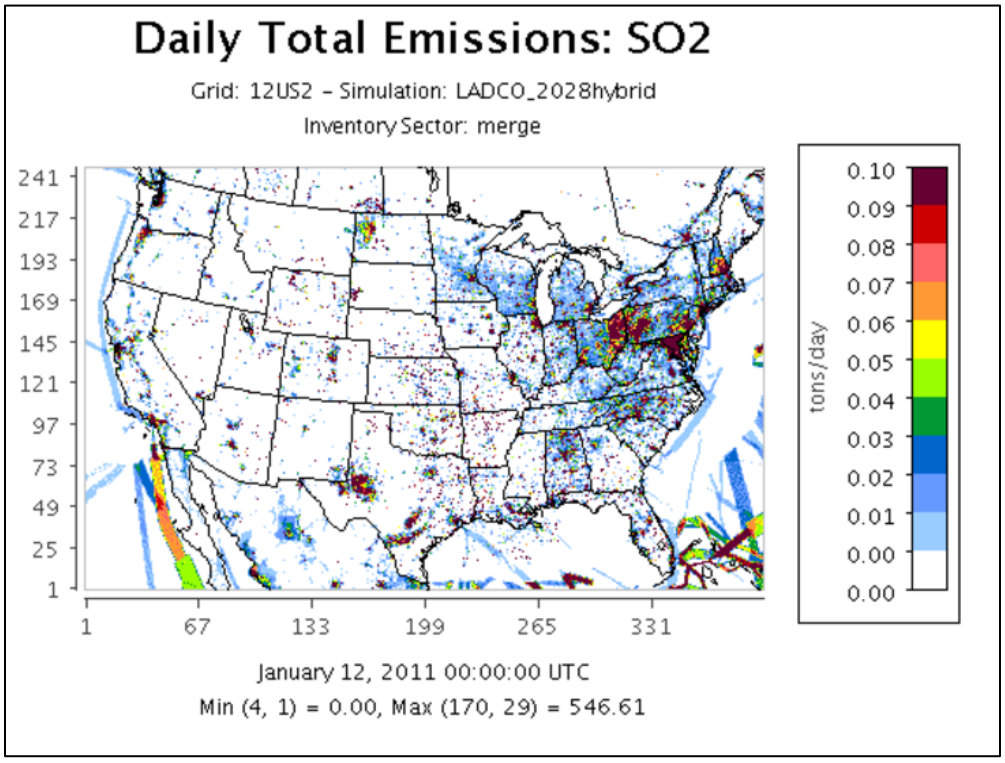


Figure 4-5. Daily total gridded 2028_{2011} SO_2 emissions for an example weekday (tons/day)

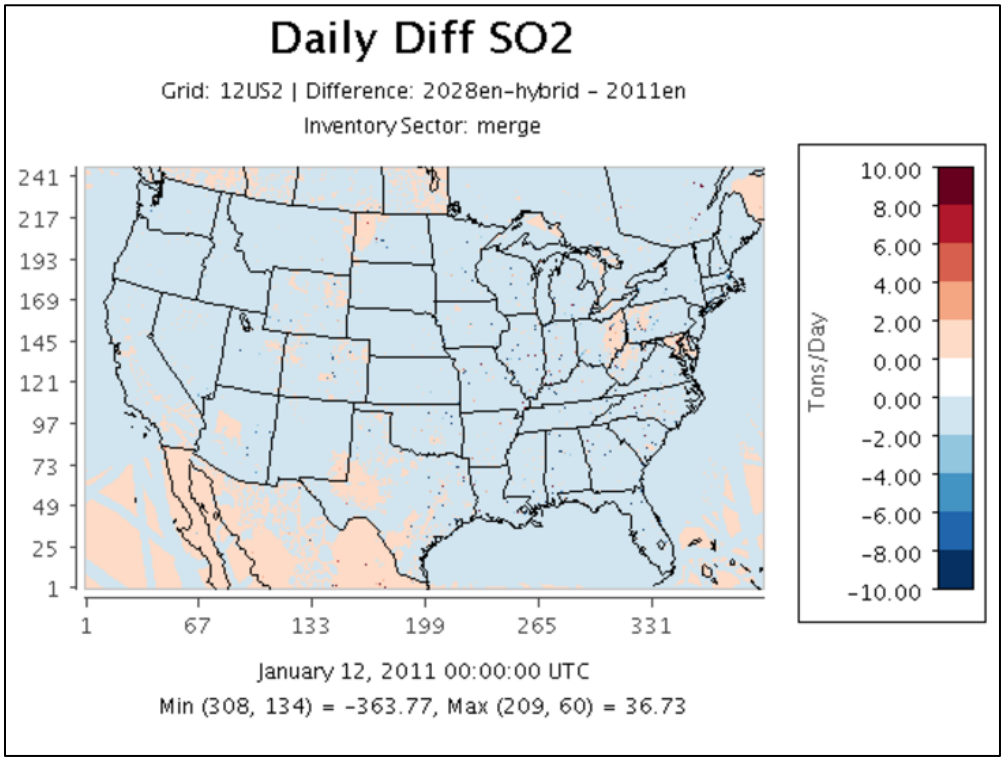


Figure 4-6. Difference (2028-2011) in daily total gridded SO_2 emissions for an example weekday (tons/day)

Table 4-4. 2028_{2011} annual emissions totals

State	Group	2028 Emissions (tons/year)				
		NH_3	NOX	$PM_{2.5}$	SO_2	VOC
Illinois	Biogenics		35,836			440,546
	Fires	1,041	1,004	5,561	519	14,966
	NonPoint	5,119	45,490	14,169	3,298	138,366
	Nonroad	163	63,084	3,543	206	43,917
	Onroad	2,830	56,628	2,493	451	23,773
	Point	1,783	90,542	16,388	163,566	43,460
Indiana	Biogenics		21,016			286,402
	Fires	423	445	2,306	225	6,107
	NonPoint	1,959	17,369	16,877	2,313	94,942
	Nonroad	85	31,734	1,858	88	24,757
	Onroad	2,175	38,877	1,812	324	20,251
	Point	1,263	137,364	20,674	193,066	36,077
Michigan	Biogenics		14,351			576,931
	Fires	511	442	2,695	239	7,342
	NonPoint	4,991	33,902	45,334	2,374	139,194
	Nonroad	116	36,261	2,915	209	67,993
	Onroad	2,478	42,030	1,840	316	27,716
	Point	1,567	83,975	9,374	86,135	22,412
Minnesota	Biogenics		26,137			516,225
	Fires	13,111	10,924	70,357	6,177	190,325
	NonPoint	3,205	24,489	41,397	3,083	110,379
	Nonroad	92	34,984	2,162	108	38,569
	Onroad	1,614	27,406	1,420	238	18,409
	Point	1,988	64,143	16,160	32,847	20,053
Ohio	Biogenics		17,952			340,817
	Fires	163	165	876	84	2,343
	NonPoint	4,198	41,237	32,166	4,357	139,121
	Nonroad	116	44,708	3,019	130	42,407
	Onroad	2,844	49,229	2,322	418	29,479
	Point	4,181	101,354	32,153	190,445	29,857
Wisconsin	Biogenics		15,078			480,085
	Fires	596	566	3,179	294	8,571
	NonPoint	2,796	22,581	37,050	2,478	106,033
	Nonroad	77	26,907	1,835	87	38,878
	Onroad	1,659	33,157	1,416	246	18,531
	Point	1,106	47,852	8,634	47,128	21,787
Grand Total		64,250	1,339,217	401,986	741,448	4,167,021

Table 4-5. Base and future year annual emissions percent change (2028-2011)

State	Group	Percent Change 2011 to 2028				
		NH_3	NOX	$PM_{2.5}$	SO_2	VOC
Illinois	Biogenics		0.0%			0.0%
	Fires	0.0%	0.0%	0.0%	0.0%	0.0%
	NonPoint	-1.3%	4.6%	-10.2%	-35.4%	-4.6%
	Nonroad	27.1%	-53.4%	-60.9%	-85.2%	-39.0%
	Onroad	-17.2%	-68.0%	-59.6%	-58.0%	-64.7%
	Point	3.9%	-39.6%	-13.7%	-41.5%	-40.2%
Indiana	Biogenics		0.0%			0.0%
	Fires	0.0%	0.0%	0.0%	0.0%	0.0%
	NonPoint	-6.1%	0.5%	-9.9%	-5.7%	-8.9%
	Nonroad	28.3%	-53.3%	-60.5%	-75.0%	-41.4%
	Onroad	-34.8%	-77.3%	-66.5%	-60.4%	-75.7%
	Point	9.8%	-26.3%	-7.5%	-54.2%	-25.5%
Michigan	Biogenics		0.0%			0.0%
	Fires	0.0%	0.0%	0.0%	0.0%	0.0%
	NonPoint	-3.8%	3.6%	-5.9%	-37.6%	-11.4%
	Nonroad	25.5%	-46.0%	-54.3%	-91.9%	-45.0%
	Onroad	-39.6%	-78.4%	-70.3%	-66.8%	-73.9%
	Point	50.0%	-43.7%	-9.6%	-67.6%	-60.0%
Minnesota	Biogenics		0.0%			0.0%
	Fires	0.0%	0.0%	0.0%	0.0%	0.0%
	NonPoint	-1.1%	-2.3%	-0.2%	-47.7%	-6.6%
	Nonroad	20.6%	-52.6%	-63.1%	-83.3%	-49.9%
	Onroad	-34.0%	-77.8%	-67.6%	-59.5%	-73.1%
	Point	36.1%	-22.7%	-9.0%	-42.7%	-3.2%
Ohio	Biogenics		0.0%			0.0%
	Fires	0.0%	0.0%	0.0%	0.0%	0.0%
	NonPoint	-3.2%	6.7%	-6.0%	-9.4%	-5.4%
	Nonroad	21.2%	-53.0%	-54.8%	-85.7%	-39.8%
	Onroad	-40.6%	-80.3%	-71.2%	-61.5%	-77.3%
	Point	1.1%	-37.9%	-34.0%	-71.7%	-28.7%
Wisconsin	Biogenics		0.0%			0.0%
	Fires	0.0%	0.0%	0.0%	0.0%	0.0%
	NonPoint	-4.6%	-2.1%	-5.7%	-17.0%	-6.4%
	Nonroad	19.9%	-49.3%	-59.7%	-84.0%	-54.0%
	Onroad	-29.2%	-73.9%	-69.1%	-58.1%	-69.1%
	Point	-34.1%	-26.4%	-1.9%	-67.0%	-0.6%
Grand Total		-9.4%	-49.6%	-16.5%	-60.7%	-15.0%

4.2 2016 Modeling Platform

As described in Section 3.4.2, LADCO based the 2016 and 2028 emissions data for this study on the U.S. EPA 2016fh_16 ("FH") emissions modeling platform (US EPA, 2020). LADCO replaced the EGU emissions in the U.S. EPA FH platform with 2028 EGU forecasts estimated with a modified version of the ERTAC EGU Tool version 16.1 (MARAMA, 2012). Table 3-4 lists the 2016 base year and 2028 future year inventory components that LADCO used to simulate 2016 and 2028 air quality for this application.

The following sections summarize the 2016 and 2028 emissions used by LADCO for simulating regional haze conditions during these years.

4.2.1 2016 Emissions Summary

The tables and figures in this section summarize the emissions used in the LADCO 2016 CAMx simulation. Table 4-6 shows the LADCO state annual 2016 total emissions for all sectors, and Figure 4-7 and Figure 4-8 are tile plots of the 12-km gridded, daily total NOx and SO_2 emissions, respectively, for a winter weekday (Friday, January 15). The NOx plot illustrates that the highest emissions occur in proximity to urban areas and roadways. The SO_2 plot shows that coal EGU point sources and urban areas are the dominant emissions sources for this pollutant. Table 4-7 shows the 2016 annual emissions totals by LADCO member state and major inventory group.

Table 4-6. 2016 annual total emissions by state for all sectors (tons/year)

State	NH_3	NOX	$PM_{2.5}$	SO_2	VOC
Illinois	102,364	387,877	109,474	107,987	800,485
Indiana	86,725	327,142	83,341	129,328	528,217
Michigan	53,366	304,362	66,074	107,265	920,538
Minnesota	208,325	248,879	127,312	35,447	825,120
Ohio	86,354	352,630	106,689	148,912	706,730
Wisconsin	63,286	194,841	68,269	36,468	677,145

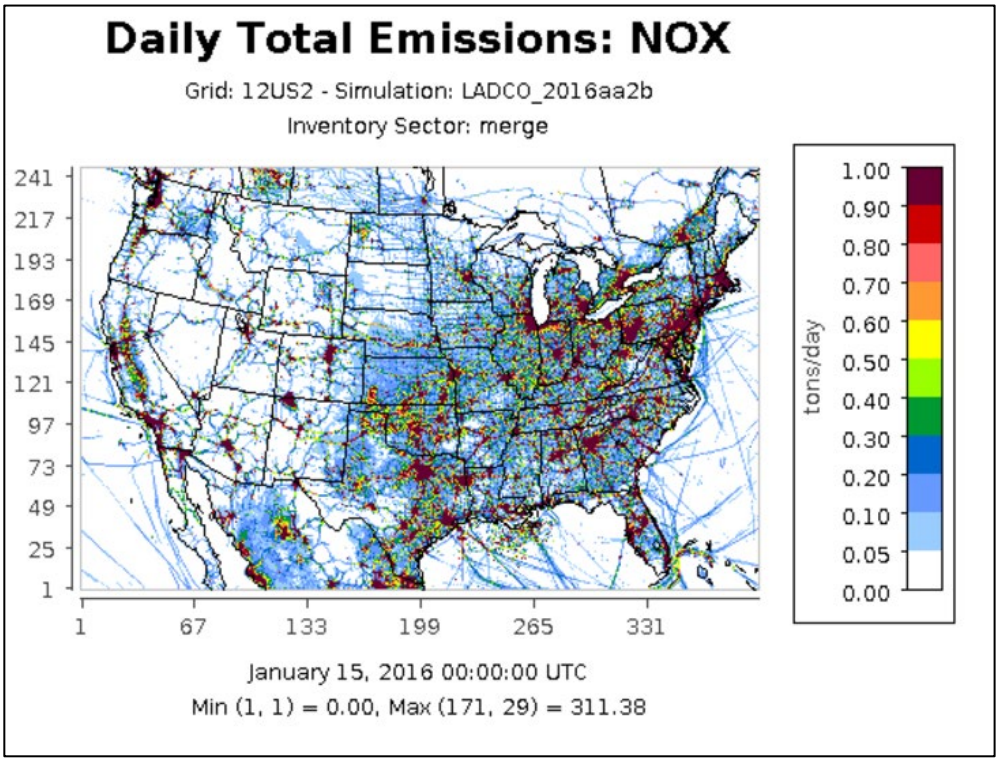


Figure 4-7. Daily total gridded 2016 NOx emissions for an example weekday (tons/day)

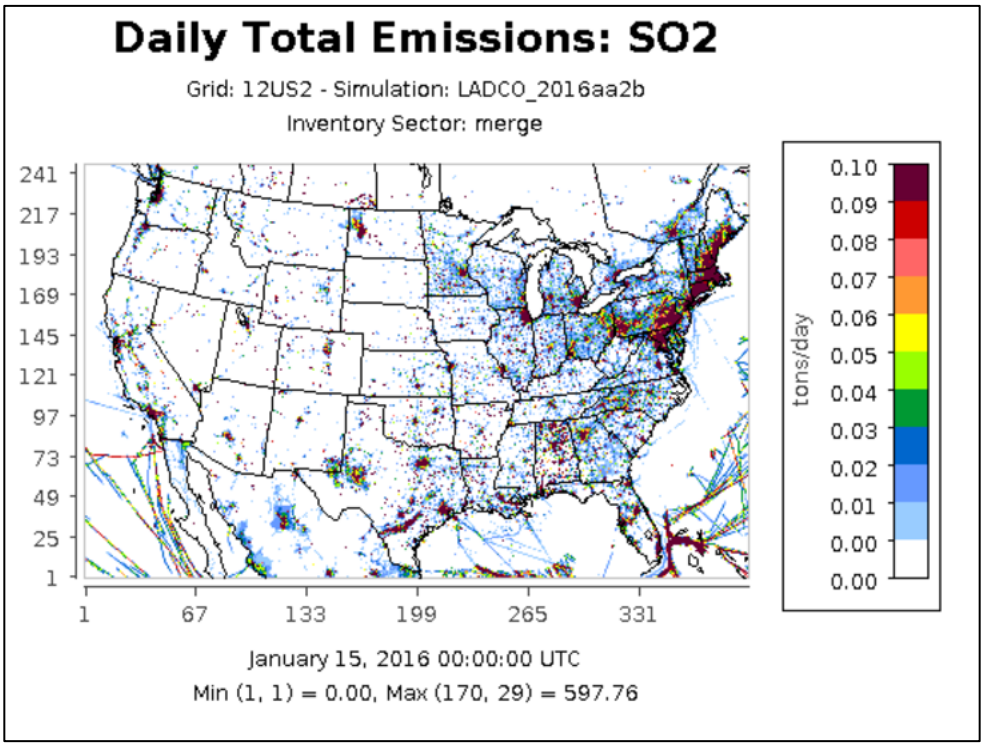


Figure 4-8. Daily total gridded 2016 SO_2 emissions for an example weekday (tons/day)

Table 4-7. 2016 annual emissions totals

State	Group	2016 Emissions (tons/year)				
		NH_3	NOX	$PM_{2.5}$	SO_2	VOC
Illinois	Biogenics		38,921			422,736
	Fires	1,434	1,390	7,662	716	20,607
	NonPoint	96,053	102,399	80,406	5,946	211,921
	Nonroad	79	49,234	4,515	94	38,539
	Onroad	3,300	117,837	4,217	705	65,574
	Point	1,498	78,096	12,674	100,526	41,108
Indiana	Biogenics		21,381			279,976
	Fires	720	697	3,849	359	10,356
	NonPoint	81,708	34,816	46,889	1,142	129,207
	Nonroad	56	36,791	3,208	66	20,407
	Onroad	2,737	103,694	3,385	616	55,049
	Point	1,504	129,763	26,010	127,145	33,222
Michigan	Biogenics		14,572			593,916
	Fires	605	435	3,133	256	8,699
	NonPoint	48,254	66,217	47,856	7,480	174,178
	Nonroad	53	25,644	2,919	67	54,091
	Onroad	3,073	97,879	3,053	695	63,809
	Point	1,381	99,615	9,113	98,767	25,845
Minnesota	Biogenics		28,031			510,385
	Fires	4,931	2,606	24,907	1,807	70,882
	NonPoint	200,203	41,001	83,986	4,404	129,706
	Nonroad	73	43,042	4,192	86	52,838
	Onroad	1,915	66,467	2,195	395	41,382
	Point	1,203	67,732	12,032	28,755	19,927
Ohio	Biogenics		18,120			360,156
	Fires	465	459	2,492	235	6,689
	NonPoint	78,786	64,951	71,145	4,061	192,544
	Nonroad	68	40,429	3,692	82	38,405
	Onroad	3,736	122,966	3,931	852	76,612
	Point	3,299	105,705	25,429	143,682	32,324
Wisconsin	Biogenics		16,095			484,780
	Fires	793	709	4,200	378	11,404
	NonPoint	59,119	33,655	53,366	2,075	81,793
	Nonroad	44	23,906	2,431	54	41,548
	Onroad	1,861	80,086	2,845	413	34,837
	Point	1,469	40,390	5,427	33,548	22,783
Grand Total		**600,422**	**1,815,731**	**561,157**	**565,407**	**4,458,233**

4.2.2 2028_{2016} Emissions Summary

The tables and figures in this section summarize the emissions used in the LADCO 2016-based 2028 CAMx simulation. Table 4-8 shows LADCO state total annual emissions, Figure 4-9 and Figure 4-11 show gridded daily total 2016 NOx and SO_2 emissions for a winter weekday (Friday, January 15). The spatial patterns seen in these figures match with the patterns in the 2016 emissions figures shown previously. Figure 4-10 and Figure 4-12 show the locations where emissions are projected to change in 2028 relative to 2016. The emissions differences indicate widespread changes across the region, with larger emissions changes at locations where there are projected to be EGU shutdowns and new controls applied at specific plants. The largest NOx emissions reductions will occur along roadways and in urban areas; emissions increases are projected in oil and gas development regions, in Mexico, and in Canadian offshore sources in the Great Lakes. SO_2 emissions reductions are projected to occur in urban areas and where power plants are located.

Table 4-8. 2028_{2016} annual total emissions by state for all sectors (tons/year)

State	NH_3	NOX	$PM_{2.5}$	SO_2	VOC
Illinois	110,871	229,820	103,309	52,788	334,078
Indiana	94,931	175,508	76,884	84,814	214,407
Michigan	55,886	190,164	62,566	53,976	269,661
Minnesota	220,374	146,231	121,290	29,319	274,186
Ohio	94,278	211,025	96,585	109,883	298,719
Wisconsin	65,446	128,962	64,876	26,948	158,065

Table 4-9 shows the LADCO state total 2028_{2016} annual emissions tons for the haze species. Table 4-10 compares 2028 and 2016 annual haze emissions by inventory group for each LADCO state. Negative numbers in these tables indicate percent emissions reductions in 2028 relative to 2016. Comparisons of the EGU and industrial point source emissions changes between 2016 and 2028 is confounded by the different methods used by the U.S EPA and ERTAC EGU projection models for distinguishing EGU from non-EGU industrial point sources. ERTAC only models sources with CEM data while EPA does economic projections of all units that sell power to the grid including facilities with co-generation units like paper mills and aluminum foundries. For the LADCO modeling that used ERTAC to project power plant emissions, we used the EPA 2028 inventory projections for those sources that generate power but do not have CEMs.

LADCO projects that overall both the NOX and SO_2 emissions will decrease in 2028 relative to 2016 in all of the LADCO states. The NOx reductions for the anthropogenic sectors (i.e., excluding biogenics and wildfires) range from 28 to 42%, driven primarily by reductions in onroad and offroad mobile source emissions. We project that the SO_2 emissions reductions will be significant, at around 18 to 51% in each of the LADCO states. These reductions are the result of changes to the power sector, primarily coal-fired EGU shutdowns.

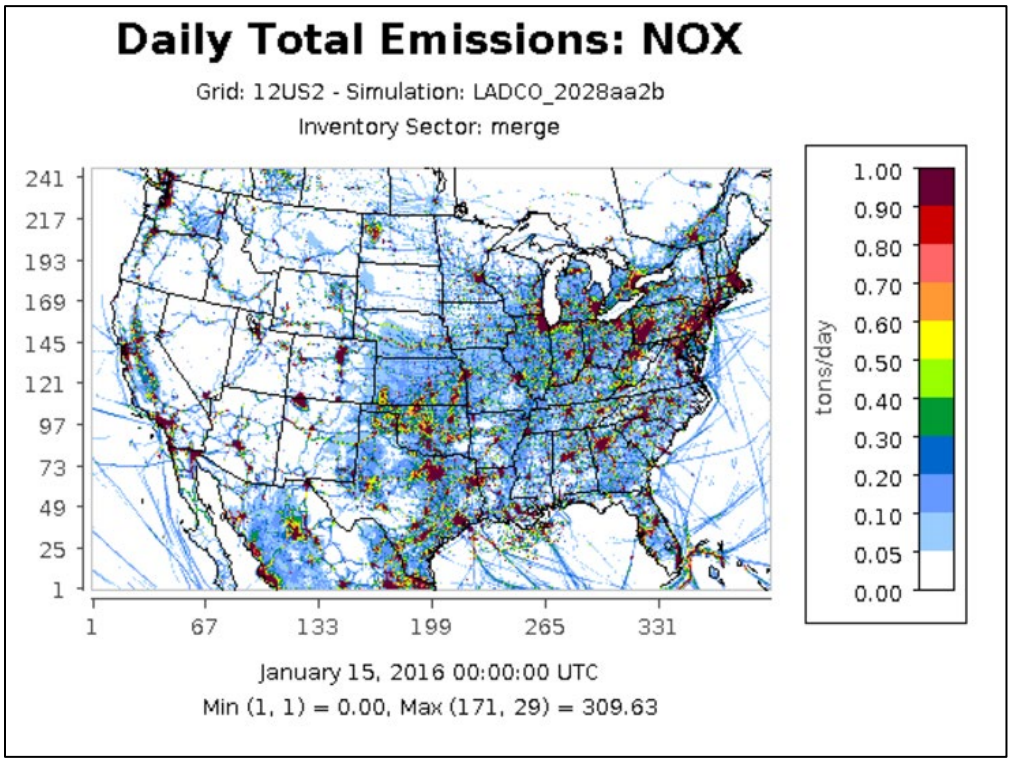


Figure 4-9. Daily total gridded 2028_{2016} NOx emissions for an example weekday (tons/day)

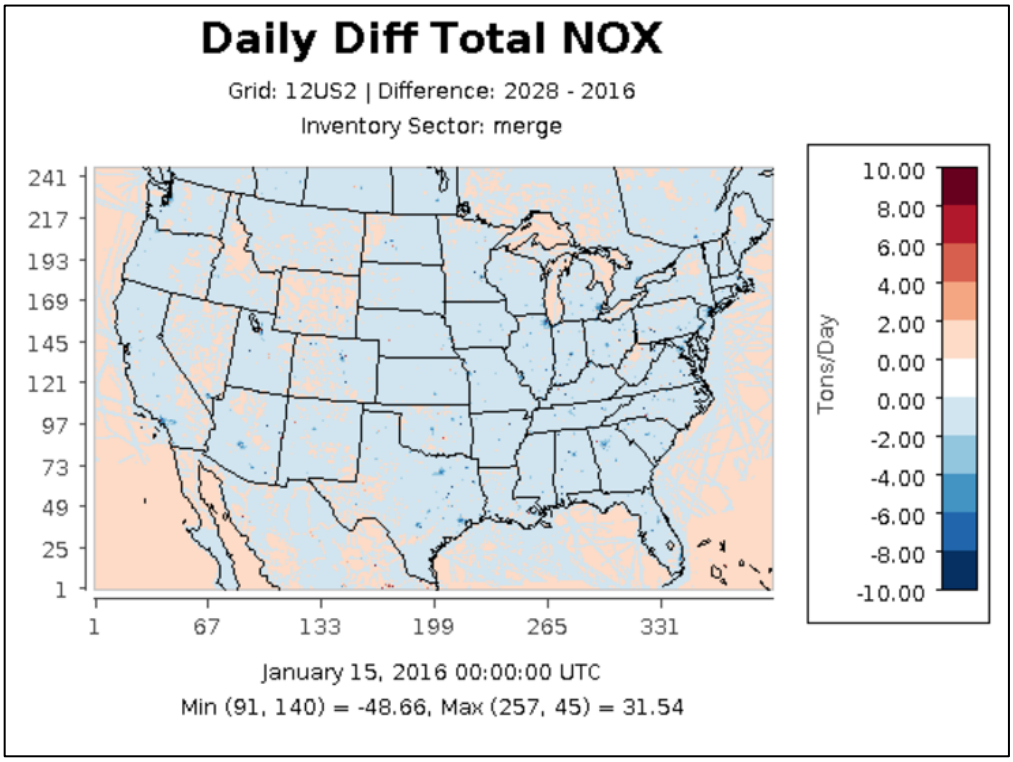


Figure 4-10. Difference (2028-2016) in daily total gridded NOx emissions for an example weekday (tons/day)

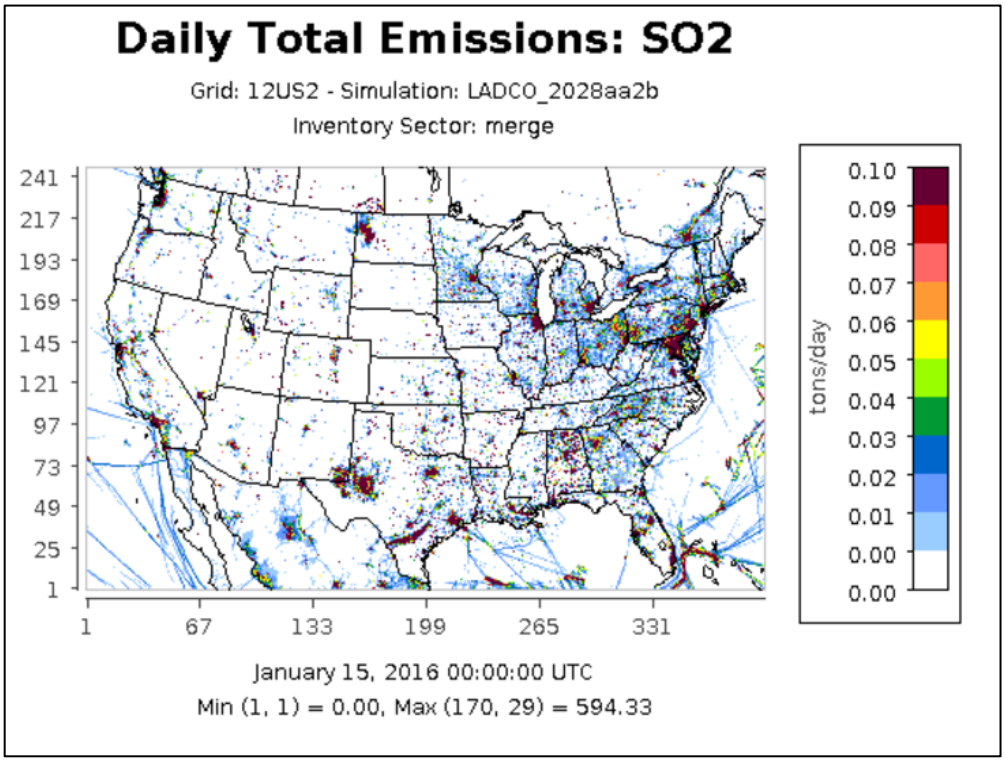


Figure 4-11. Daily total gridded 2028_{2016} SO_2 emissions for an example weekday (tons/day)

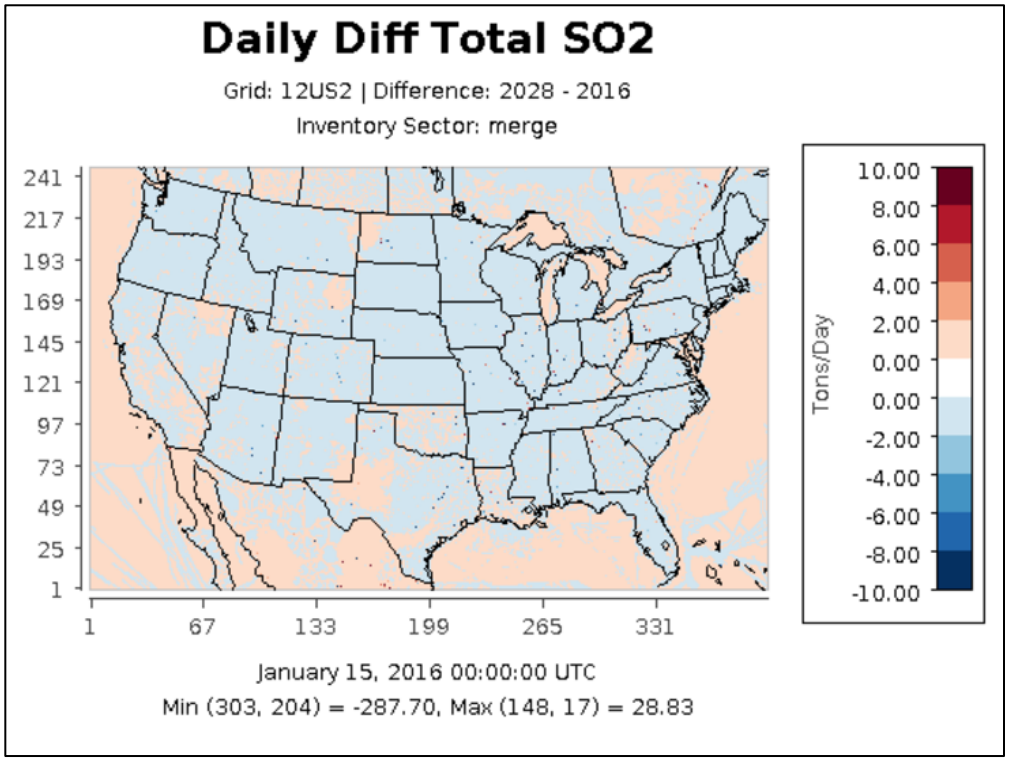


Figure 4-12. Difference (2028-2016) in daily total gridded SO_2 emissions for an example weekday (tons/day)

Table 4-9. 2028_{2016} annual emissions totals

State	Group	2028 Emissions (tons/year)				
		NH_3	NOX	$PM_{2.5}$	SO_2	VOC
Illinois	Biogenics		38,921			422,736
	fires	1,434	1,390	7,662	716	20,607
	nonpoint	104,358	88,663	78,804	6,002	212,101
	nonroad	87	25,289	2,281	68	28,404
	onroad	2,845	41,417	1,987	402	29,271
	point	2,147	73,061	12,575	45,600	43,695
Indiana	Biogenics		21,381			279,976
	fires	720	697	3,849	359	10,356
	nonpoint	89,324	30,049	46,254	1,097	130,268
	nonroad	65	18,170	1,518	54	15,928
	onroad	2,292	36,034	1,588	321	23,806
	point	2,530	90,558	23,675	82,983	34,049
Michigan	Biogenics		14,572			593,916
	fires	605	435	3,133	256	8,699
	nonpoint	50,722	60,755	47,159	7,098	171,926
	nonroad	57	16,675	1,667	41	34,236
	onroad	2,606	31,924	1,544	295	28,268
	point	1,896	80,375	9,063	46,286	26,532
Minnesota	Biogenics		28,031			510,385
	fires	4,931	2,606	24,907	1,807	70,882
	nonpoint	212,377	36,904	81,747	4,208	130,097
	nonroad	79	23,742	2,055	60	33,624
	onroad	1,629	22,024	984	192	19,091
	point	1,358	60,955	11,597	23,052	20,492
Ohio	Biogenics		18,120			360,156
	fires	465	459	2,492	235	6,689
	nonpoint	85,161	57,923	70,496	4,361	197,290
	nonroad	77	22,287	1,940	60	27,314
	onroad	3,155	40,015	1,948	378	34,097
	point	5,420	90,341	19,709	104,849	33,329
Wisconsin	Biogenics		16,095			484,780
	fires	793	709	4,200	378	11,404
	nonpoint	60,146	30,053	53,158	2,046	82,126
	nonroad	49	13,894	1,250	36	25,025
	onroad	1,687	25,272	1,025	229	16,538
	point	2,771	59,034	5,243	24,259	22,972
Grand Total		**641,787**	**1,218,830**	**525,512**	**357,727**	**4,201,065**

Table 4-109. 2016 modeling platform annual emissions percent change (2016-2028)

State	Group	Percent Change 2016 to 2028				
		NH_3	NOX	$PM_{2.5}$	SO_2	VOC
Illinois	Biogenics		0.00%			0.00%
	Fires	0.00%	0.00%	0.00%	0.00%	0.00%
	NonPoint	8.65%	-13.41%	-1.99%	0.93%	0.08%
	Nonroad	9.53%	-48.64%	-49.47%	-27.73%	-26.30%
	Onroad	-13.78%	-64.85%	-52.88%	-43.07%	-55.36%
	Point	43.35%	-6.45%	-0.78%	-54.64%	6.29%
Indiana	Biogenics		0.00%			0.00%
	Fires	0.00%	0.00%	0.00%	0.00%	0.00%
	NonPoint	9.32%	-13.69%	-1.36%	-3.94%	0.82%
	Nonroad	15.23%	-50.61%	-52.68%	-18.34%	-21.95%
	Onroad	-16.26%	-65.25%	-53.08%	-47.88%	-56.75%
	Point	68.25%	-30.21%	-8.98%	-34.73%	2.49%
Michigan	Biogenics		0.00%			0.00%
	Fires	0.00%	0.00%	0.00%	0.00%	0.00%
	NonPoint	5.12%	-8.25%	-1.46%	-5.11%	-1.29%
	Nonroad	7.83%	-34.97%	-42.89%	-38.35%	-36.71%
	Onroad	-15.19%	-67.38%	-49.43%	-57.51%	-55.70%
	Point	37.25%	-19.31%	-0.55%	-53.14%	2.66%
Minnesota	Biogenics		0.00%			0.00%
	Fires	0.00%	0.00%	0.00%	0.00%	0.00%
	NonPoint	6.08%	-9.99%	-2.67%	-4.45%	0.30%
	Nonroad	8.30%	-44.84%	-50.98%	-30.31%	-36.36%
	Onroad	-14.94%	-66.86%	-55.16%	-51.31%	-53.86%
	Point	12.85%	-10.00%	-3.61%	-19.83%	2.83%
Ohio	Biogenics		0.00%			0.00%
	Fires	0.00%	0.00%	0.00%	0.00%	0.00%
	NonPoint	8.09%	-10.82%	-0.91%	7.40%	2.46%
	Nonroad	13.21%	-44.87%	-47.45%	-27.56%	-28.88%
	Onroad	-15.55%	-67.46%	-50.43%	-55.60%	-55.49%
	Point	64.29%	-14.53%	-22.49%	-27.03%	3.11%
Wisconsin	Biogenics		0.00%			0.00%
	Fires	0.00%	0.00%	0.00%	0.00%	0.00%
	NonPoint	1.74%	-10.70%	-0.39%	-1.38%	0.41%
	Nonroad	10.22%	-41.88%	-48.58%	-33.78%	-39.77%
	Onroad	-9.38%	-68.44%	-63.97%	-44.56%	-52.53%
	Point	88.67%	46.16%	-3.38%	-27.69%	0.83%
Average		**6.89%**	**-32.87%**	**-6.35%**	**-36.73%**	**-5.77%**

4.2.3 Typical Year Emissions Platform

Emissions estimates used in modeling can provide a faithful match to real-world base year activity, called an "actual" inventory. Actual inventories are used for model validation to confirm that the model can reproduce the initial pollutant concentrations. In LADCO's point source actual inventories, which are based on hourly CEM data, we modeled extended point source facility shutdowns in the base year for some large facilities. These shutdowns may have occurred for maintenance or due to malfunctions at the facility.

We also build "typical" inventories to be used as the basis for a future year projection. For some point source facilities in Minnesota that did not operate in 2016, we included zero emissions in the actual emissions scenarios. If the plants operated in subsequent contemporary years, we reviewed the historical record for those plants and found that for three sources in Minnesota the 2017 emissions were representative of typical emissions activity.

LADCO worked with staff from the state of Minnesota to include hourly data and alternate base and future year estimates for some facilities that were not operating in 2016 because of maintenance or other operational issues. For these facilities, we used 2017 emissions numbers in the 2016 typical year modeling inventory and projected 2028 emissions from these numbers. We did this because the alternative approach of using actual (zero) 2016 emissions and a 2028 projected inventory in which the plants were operating at expected levels would simulate increases in future year emissions that were not representative of the base period. These unrepresentative increases would incorrectly impact the relative reduction factors used to project future haze conditions in the region.

LADCO used actual 2016 emissions inventories for a model performance evaluation run and typical inventories as the basis for future year projections. All the emissions summary tables in this TSD use typical emissions from the impacted facilities. Emissions for most inventory sectors were identical between the two types of emissions platforms. The facilities that had significant emissions differences between the actual and typical inventories are shown in Table 3-3.

4.3 Comparison of 2011 and 2016 Emissions Platforms

LADCO's 2016 modeling platform differs from the 2011 platform in several important ways. For EGU sources we used the ERTAC model. The ERTAC model is designed to use base year CEM data to define emissions patterns. These patterns define both base and future year regional and plant level behaviors. Our projections to 2028 used the corresponding base year CEM data for both 2011 and 2016. Since the 2011-based projections to 2028 were developed in 2017, we did not include any new EGU shutdowns or controls announced between 2017 and mid-2020 in the simulation.

The ERTAC EGU runs in 2017 that were used for our 2011-based modeling had 54 unit shutdowns between 2017 and 2028. The ERTAC 16.1 runs done in late 2020, which we used for our 2016-based modeling, included 46 additional shutdowns above the ones included in the 2011 simulation. Further, LADCO included an additional 62 unit shutdowns in our 2028_{2016} simulation based on information from our member states on new shutdowns as of September 2020. The final LADCO 2028_{2016} CAMx simulation excluded emissions from a total of 162 units because of announced shutdowns.

LADCO staff worked with the Coordinating Research Council (CRC) to build national emissions modeling inputs that became the county-specific national defaults for several onroad mobile inputs and resulted in improved emissions in the 2016 modeling platform. This work included CRC project A-115, which decoded all the vehicle identification numbers (VIN) in the country to produce updated vehicle fleet age distributions. CRC, LADCO, and a group of states evaluated the methods and data used to set default age distributions and found that older vehicles were being over-counted in the national default data because they were not being removed from the vehicle count database when they left the in-use fleet of vehicles. Figure 4-13 shows the impact on vehicle counts in one state when these older vehicles are removed from the data. We were able to show that because these vehicles are the oldest and highest emitting vehicles in the fleet, a small difference in their population had a significant impact on emissions. Telemetry data for vehicle speed and a second Telemetry project for data on time of hour/weekday/month activity were also included in new national defaults in the 2016 modeling platform.

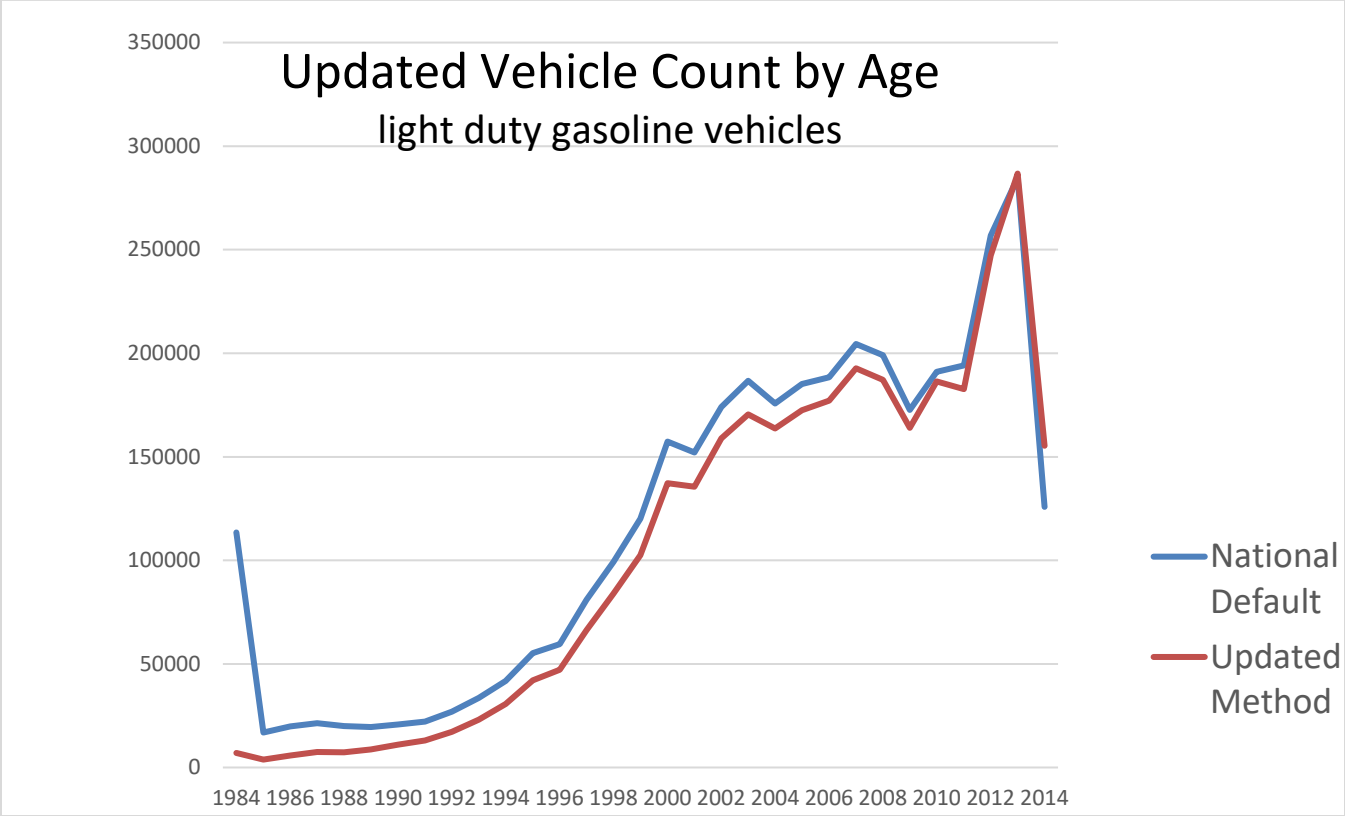


Figure 4-13 Change in vehicle age counts based on updated methodologies to decode VINs.

Several emissions sectors use day-specific temperature and activity data as the basis of their emissions estimates. As the different base years have different meteorology and activity data, the base and future year emissions are changed with the different base year conditions. These sectors include biogenics, wind-blown dust, wildfire, prescribed fire, and onroad motor vehicles.

In the 2011 emissions inventory there were limited emissions estimates from livestock and fertilizer operations. In the 2016 emissions inventory, EPA included agricultural ammonia emissions as a dedicated emissions sector. In most of the LADCO states this change resulted in an order of magnitude increase in estimated NH_3 emissions.

The marine vessels inventory also improved between the 2011 and 2016, when EPA included national 4-minute interval location data of individual ships to define speed, power, and location. This improvement led to hourly vessel-specific estimates of fuel use and emissions.

Oil and gas inventories were also improved as fracking became more prevalent and emissions increased in parts of the country where new fuel reserves were developed, including in Ohio. EPA and states built new national databases of site-specific oil and gas emissions as well as nonpoint inventories at the county level for smaller operations. For Ohio, the 2011 annual NOx emissions were 319 tons, while the 2016 emissions were 13,114 tons. These changes were partially improvements in inventory methods and partially due to increases in oil field development and operation.

5 Class I Area Q/d Analysis

This section describes the data and methods used by LADCO to aid our members in screening emissions source impacts on Class I areas for the second regional haze implementation period. The surrogate analysis of tons/year emissions (Q) divided by distance in kilometers (d) from the Class I areas, known as Q/d, is used to screen emissions source impacts at downwind receptors in lieu of air quality modeling results. LADCO created Q/d results for industrial point sources using preliminary 2016 emissions inventory data. LADCO completed the Q/d calculations in January 2019 using the best available inventories at that time

LADCO did not make any decisions about how the data that we generated would be applied by our member states in their four factor analysis process. We provided stationary sources emissions data and Q/d information at different Q/d threshold for different combinations of haze precursors to aid our member states in decision making for their four factor analyses. This section describes the data that LADCO collected and generated to support these decisions.

5.1 Inventory Sources

Starting in March 2018, LADCO produced a series of Q/d analyses for use by the LADCO member states for regional haze planning. The LADCO Regional Haze workgroup and Project Team provided guidance to LADCO on which sources to include in the Q/d analysis. These groups decided early in the second Regional Haze implementation period to focus the Q/d analysis on point sources of NOx and SO_2. LADCO followed this guidance to produce Q/d results for different inventory years.

The first Q/d versions used 2011-based emissions inventories and included 2011, 2018, and 2028 data. LADCO also computed Q/d values for point sources from different versions of inventories for Canada and Mexico. As LADCO and the LADCO member states learned of new EGU shutdown announcements that were made since the release of the 2011 inventories, the LADCO members requested that the Q/d analyses be redone with newer data.

In January 2019, state and federal participants in the LADCO Regional Haze Technical Workgroup agreed to use the latest available 2016 inventory for a new Q/d analysis by LADCO. The National Emissions Inventory Collaborative 2016 alpha inventory represented the best estimate of 2016 point emissions at

the time[18]. Table 5-1 shows the point source components of the 2016 alpha inventory that LADCO used for the Q/d analysis.

Table 5-1. Point source inventory components used for the 2016 alpha Q/d analysis

Sector	Filename	Description
Electricity Generating Unit (EGU) point	ptegu_2016NEIv2_composite.csv	2016 emissions from the National Emissions Inventory (NEI) integrated with CEM (continuous emissions monitoring) hourly data.
Non-EGU industrial point	ptnonipm_2016alpha_POINT_ 03apr2018_nf_v3.csv	2016 emissions of non-EGU industrial point sources.
Point oil and gas	2028el_marama_pt_oilgas_2011neiv2_ point_20140913_02dec2016_v1.csv	2028 emissions for oil and gas sources. In April of 2018 no 2016 oil and gas inventory was available. We chose to use MARAMA's 2011-based projected 2028 oil and gas inventory that included many new oil and gas fields and sites**.**
Non-US point	canada_mexico.ff10.csv	2013 and 2025 point inventories from Environment and Climate Change Canada were interpolated to year 2016. 2008 inventories for Mexico were projected to the years 2014 and 2018, and then those emissions were interpolated to the year 2016.

5.2 Q/d Analysis Spreadsheets

LADCO developed a utility in R (QD_2028_V2.1.R) to extract the inventory data, calculate Q/d for each facility, and format the data for Microsoft Excel. Because a four factor analysis requires a list of sources at the process (Source Classification Code) level, LADCO developed the Q/d utility to generate a list of all facilities that contribute to 80% of the cumulative Q/d values for each Class 1 area. From those top 80% facilities, the utility further filters out those processes with emissions less than 1 ton/year.

LADCO originally used a cumulative Q/d threshold of 80% to select sources to be consistent with U.S. EPA's 2016 proposed regional haze rule guidance (U.S. EPA, 2016d). Although U.S. EPA ultimately did not

[18]https://www.epa.gov/air-emissions-modeling/2016v71-alpha-platform

recommend any specific threshold in their 2019 regional haze guidance (U.S. EPA, 2019a), the LADCO Regional Haze Workgroup explored the impacts of using different thresholds for selecting sources. LADCO used an 80% threshold for our final Q/d analyses. The workgroup felt that this threshold produced a sufficient list of sources for the LADCO member states to consider for further analysis, including for the four- factor analysis.

Table 5-2 presents Q/d threshold groups for sources in the LADCO region. This table shows the cumulative Q/d and emissions contributions from point sources in the LADCO region for different Q/d values. For example, an analysis that uses a Q/d of 4 would include 95 facilities across the LADCO region that are associated with 75.4% of the regional total Q/d, and emit 79.6% and 60.2% of the regional total point source NOx and SO_2, respectively.

Table 5-2. Q/D threshold groups for sources in the LADCO region

	Q/D threshold Group		
Description	**Q/d=1**	**Q/d=4**	**Q/d=10**
Total facilities In Group	175	95	47
Sum of Q/d	3,898	3,263	2,421
% of Q/d	90.1%	75.4%	57.1%
Sum of emissions (SO_2, NOx, $PM_{2.5}$, NH_3; tons/yr)	892,320	713,332	496,748
% of total emissions captured	86.4%	69.1%	48.1%
Sum of SO_2 emissions (tons/yr)	488,799	414,771	302,882
% of SO_2 emissions	93.9%	79.6%	58.2%
Sum of NOx emissions (tons/yr)	363,188	270,729	176,513
% of NOx emissions	80.7%	60.2%	39.2%

LADCO created an Excel spreadsheet for our member states to use in their Q/d analyses. We tagged the facility processes with four-factor analysis group codes, which are based on NAICS codes. We worked with the LADCO member states and stakeholders to generate a list of facilities that belong to seven NAICS-code categories. These categories include the sources across the LADCO region in specific NAICS code groups with Q/d values greater than 1.0. We calculated this Q/d threshold using the sum of NOX, SO_2, $PM_{2.5}$, NH_3, and VOC emissions at each facility (Q)[19] and for the Class 1 area closest to the facility (d).

[19] The Q/d support data developed by LADCO and shown here used the National Emissions Collaborative 2016v1 inventory.

Table 5-3 shows the NAICS codes and the four factor groups for sources in the LADCO region with Q/d values greater than 1. We provided this list of facilities organized by four factor analysis groups to the LADCO member states to refine based on alternative selection criteria, such as different Q/d thresholds. The sources included in the seven groups in Table 5-3 represent 94.7% of the total Q/d in the region[20].

Table 5-3. Four factor groups used for the LADCO Q/d analysis (Q/d > 1)

4-factor group ID	NAICS	NAICS name	# of Facilities	# of Units	Facility Total Q/d	% of Total Q/d
1	221112	Fossil Fuel Electric Power Generation	81	210	2690	69.0
2	212210	Iron Ore Mining	9	58	374	9.6
3	322121	Paper (except Newsprint) Mills	16	36	182	4.7
3	311221	Wet Corn Milling	5	13	45	1.2
3	311313	Beet Sugar Manufacturing	3	6	14	0.4
3	322110	Pulp Mills	2	4	9	0.2
3	322130	Paperboard Mills	3	3	7	0.2
4	327310	Cement Manufacturing	10	28	104	2.7
4	327410	Lime Manufacturing	8	13	45	1.2
5	331110	Iron and Steel Mills and Ferroalloy Manufacturing	9	33	77	2.0
6	486210	Pipeline Transportation of Natural Gas	16	40	77	2.0
6	221210	Natural Gas Distribution	2	2	4	0.1
7	324199	All Other Petroleum and Coal Products Manufacturing	6	12	47	1.2
7	324110	Petroleum Refineries	5	6	9	0.2

LADCO developed the spreadsheet QoverD_V5.7_2016_scc.xlsx (see the Electronic Docket) to investigate how different inventory years base years, future years, and source inventories impact the Q/d calculation results. We developed this spreadsheet as a tool for our member states to evaluate different Q/d calculation methods and values. In addition to sources in all states, Canada, and Mexico, the spreadsheet includes all facilities with emissions greater than 1 ton/year of any pollutant, and the distances from each facility to every class 1 area in the country.

[20] The LADCO regional haze workgroup concurred on a process to exclude very small sources or sources that had negligible Q/d values from this analysis. The Total Q/d number for the region only includes those sources with non-negligible Q/d impacts.

The spreadsheets and emissions data files used by the LADCO states for the Q/d analysis during the second regional haze implementation period are available in the electronic docket to this TSD.

6 CAMx Model Performance Evaluation Results

This section summarizes the operational evaluation of the LADCO CAMx simulations for the two modeling platforms used for the second regional haze implementation period. As described in Section 3.6, LADCO compared particulate matter (PM) surface layer concentrations from 2011 and 2016 annual base year CAMx simulations to ambient surface monitoring data to evaluate the skill of the model at reproducing the observations. The LADCO model performance evaluation (MPE) results for each of the modeling years are compared to model performance benchmarks and to MPE results from U.S. EPA modeling of similar data. Additional MPE results and discussion for the LADCO 2011 and 2016 CAMx simulations are in the Supplemental Materials Section S5.

We emphasize the nitrate and sulfate model performance during the winter (January, February, and December) and spring (March, April, and May) months as these are species and periods that experience the most anthropogenic impairment to visibility at the Class I areas in the LADCO region. Figure 6-1 shows the distribution of most impaired days in each month across all of the LADCO region Class I areas during the period 2014-2018. The winter and spring months account for over 70% of the most impaired days in the Great Lakes region. The PM species contribution plot for Voyageurs National Park in Figure 6-2 shows that nitrate and sulfate aerosol contributed 79% of the light extinction on the most impaired days during the period 2014-2018. The PM species contributions for the other LADCO region Class I areas are similar to Voyageurs[21].

[21] Source: Federal Land Manager Environmental Database; http://views.cira.colostate.edu/fed/

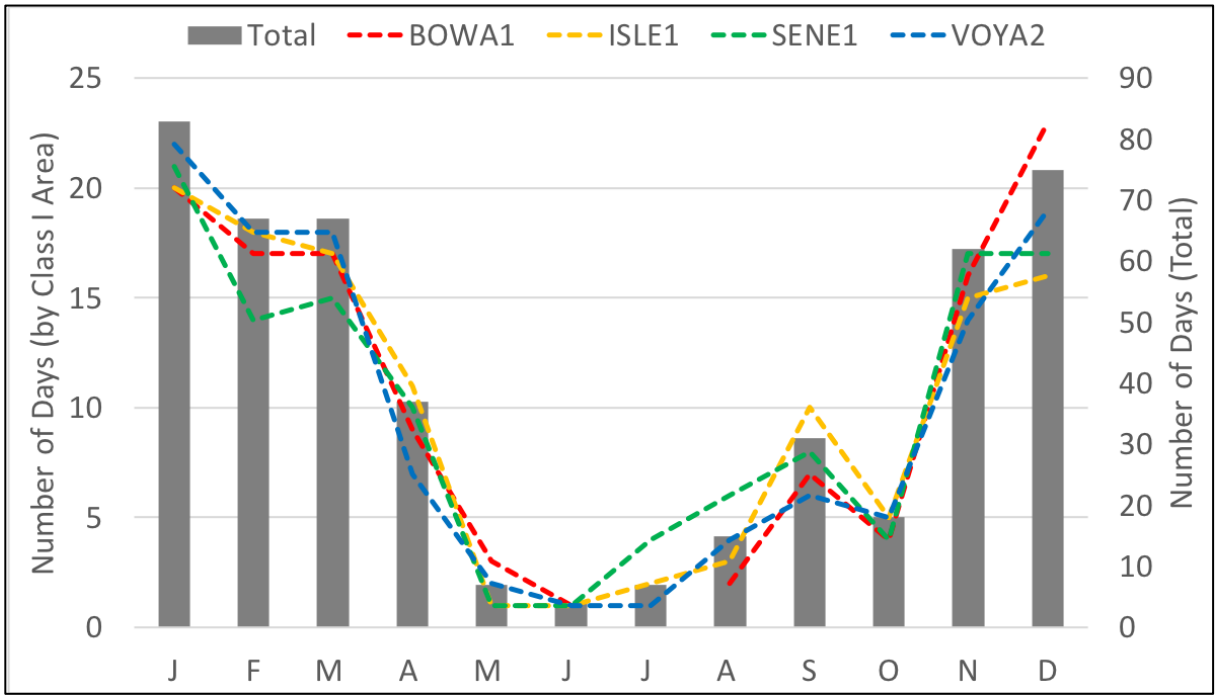


Figure 6-1. Monthly distribution of most impaired days for the LADCO region Class I areas during the period 2014-2018.

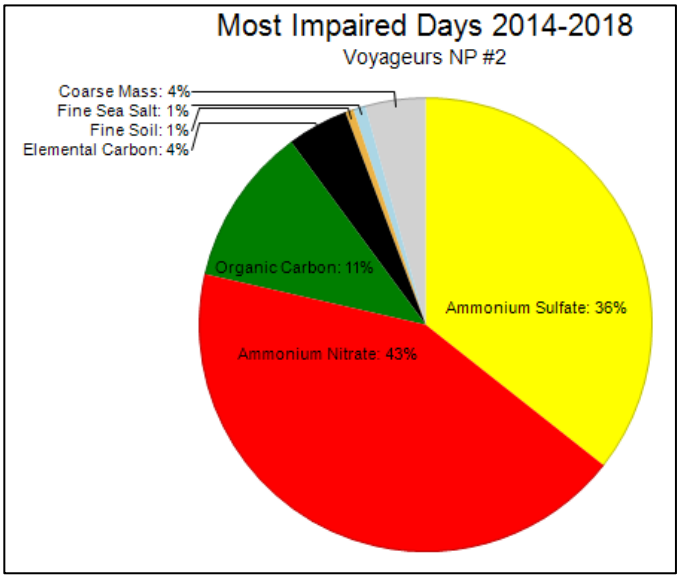


Figure 6-2. Average PM species composition at Voyageurs National Park, MN on the most impaired days during the period 2014-2018.

6.1 2011 CAMx Model Performance Evaluation Results

A summary of the CAMx MPE results for 2011 are presented in this section. The summary first presents annual and regional average MPE statistics for all CSN and IMPROVE monitoring locations in the LADCO region to provide an overview of the CAMx model's skill at simulating $PM_{2.5}$. Supplemental Materials Section S5 includes seasonal and regional MPE metrics to identify how well the model can estimate PM concentrations during different times of the year. Section S5 includes model performance information for different $PM_{2.5}$ components (total $PM_{2.5}$, sulfate, nitrate, and total carbonaceous aerosols[22]) to quantify how well the model can simulate the key light scattering species that most contribute to visibility impairment.

6.1.1 Annual PM Model Performance

Table 6-1 presents annual and regional average model performance statistics for the CSN and IMPROVE monitors in the LADCO region. Relative to the performance goals (which are more stringent) and criteria (which are less stringent) in Table 3-7, the LADCO 2011 CAMx simulation had acceptable performance for annual average total $PM_{2.5}$, sulfate, and nitrate for both the CSN and IMPROVE networks. The model performance statistics for all three of these species were near or within the more restrictive performance goals for NMB, NME, and correlation. While Emery et al. (2017) did not provide performance benchmarks for total carbonaceous (TC = organic aerosol + elemental carbon) $PM_{2.5}$, the goals and criteria for EC and OC are close to each other and can be used to evaluate the modeled TC concentrations. The 2011 CAMx estimates of TC at the IMPROVE locations in the LADCO region were within the performance benchmarks. The notable LADCO 2011 CAMx simulation performance issue on an annual and regional basis is with TC at the CSN monitors. The CAMx simulation overestimates of the observed TC concentrations (NMB = +68.5%) are outside of the performance criteria (40-50%) for carbonaceous aerosols.

[22] Ammonium ion (NH_4^+) evaluation is not reported here because the ammonium ion species reported by the monitoring networks is not a true measurement and thus is not readily comparable to the CAMx modeled species. Soil and sea salt are not included in this evaluation because they are a small component of the measured visibility at the LADCO class I areas on the most impaired days;

Annual average statistics for all of the 2011 simulation $PM_{2.5}$ species at the IMPROVE monitors in the LADCO region are within the NMB performance goals and the NME performance criteria. The LADCO 2011 CAMx simulation performance meets the performance criteria for nitrate at the IMPROVE monitors for both NMB and NME.

Table 6-1. LADCO 2011 CAMx annual average PM modeling performance summary

Species	Obs ($\mu g/m^3$)	CAMx ($\mu g/m^3$)	NMB (%)	NME (%)	r
CSN $PM_{2.5}$	10.89	11.63	9.95	35.83	0.76
IMPROVE $PM_{2.5}$	6.63	6.89	7.41	40.52	0.75
CSN SO_4	2.20	1.86	-12.96	36.29	0.76
IMPROVE SO_4	1.83	1.53	-7.58	38.20	0.76
CSN NO_3	1.83	1.83	2.47	51.01	0.73
IMPROVE NO_3	0.93	1.13	25.93	70.66	0.72
CSN TC	2.92	4.63	68.46	80.93	0.70
IMPROVE TC	2.38	2.69	19.20	53.21	0.68
Key:	Met MPE Goal		Met MPE Criteria		

6.1.2 Seasonal PM Model Performance

Supplemental Materials Section S5.1.5 includes 2011 seasonal CAMx model performance statistics tables for the CSN and IMPROVE monitors in each LADCO state. The seasonal and site average statistics in these tables include observed and modeled concentrations, NMB, NME, and correlation

The skill of the LADCO 2011 CAMx simulation at simulating observed $PM_{2.5}$ species at CSN and IMPROVE monitors in the region was mixed. The LADCO CAMx 2011 modeling results are comparable to the U.S. EPA 2011 modeling platform used for preliminary regional haze modeling (U.S. EPA, 2017a), as expected since the two modeling platforms were nearly identical. Intercomparing the LADCO and U.S. EPA 2011 CAMx simulations is complicated by the use of different regions to calculate performance statistics. The six-state LADCO region used here for calculating performance statistics overlaps with but is not completely inclusive of the states in the Ohio Valley and Upper Midwest regions used by U.S. EPA.

While the LADCO 2011 CAMx simulation of total $PM_{2.5}$ had an overprediction bias through most of the year, it achieved the MPE benchmarks for the spring and winter months at most of the CSN and IMPROVE

monitors in the LADCO region. The LADCO 2011 CAMx simulation had regional average spring and winter NMBs for total $PM_{2.5}$ at the IMPROVE monitors of +8.6% and +29%, respectively.

Figure 6-3 summarizes the winter and spring 2011 CAMx model performance at the IMPROVE monitors in the LADCO region. These plots compare the observed (left stacked bar) and CAMx simulated (right stacked bar) $PM_{2.5}$ species averaged across all IMPROVE monitors in the LADCO region for each season. The spring season CAMx overprediction bias across the region is driven by excess nitrate and organic aerosol in the model. The $PM_{2.5}$ species "Other" in this plot represents fine crustal and seasalt particles, and it is also overpredicted by CAMx. The winter season CAMx overprediction bias is driven primarily by excess organic aerosol in the model, and to a lesser extent excess Other PM.

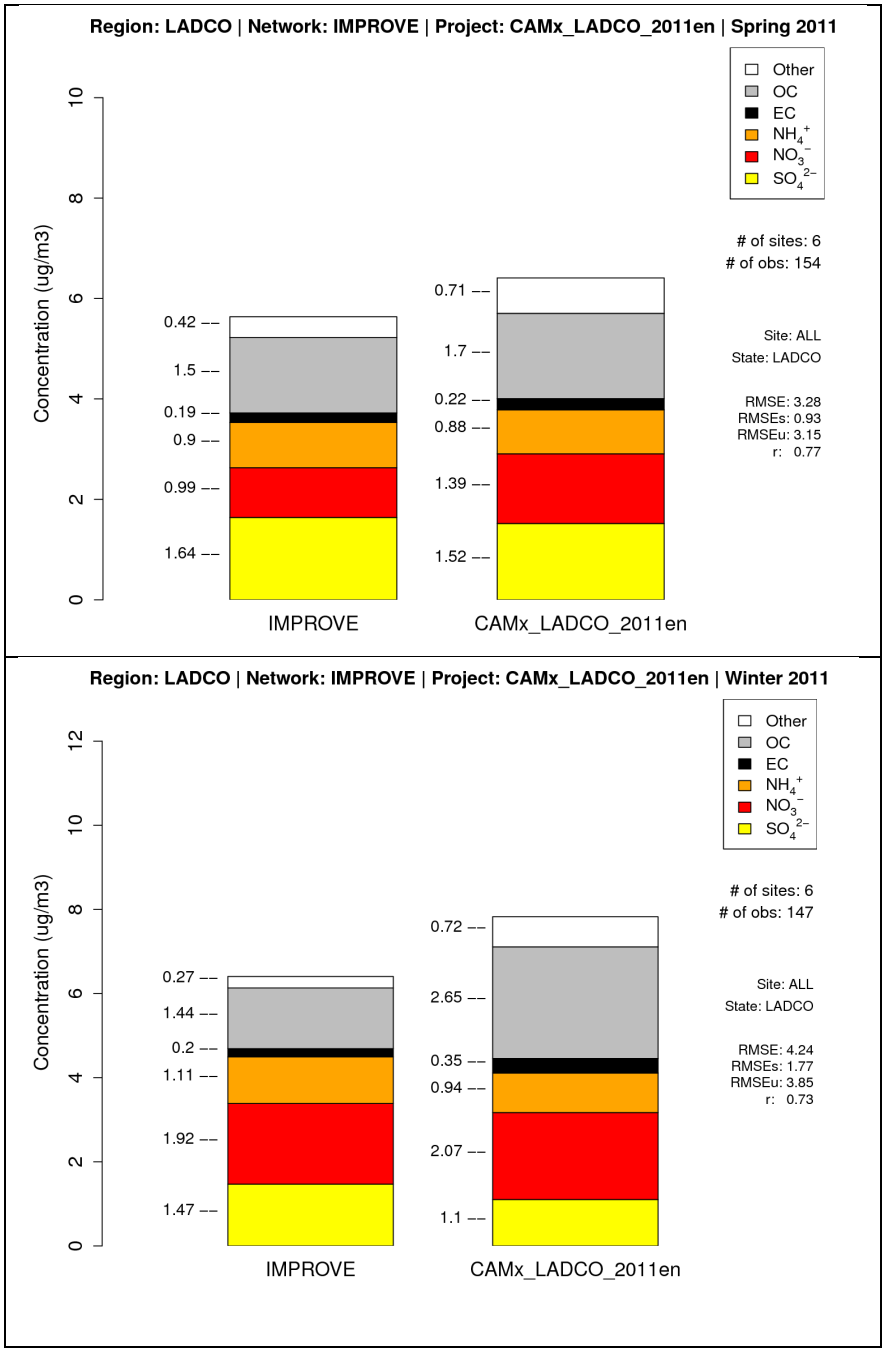


Figure 6-3. Stacked bar plot of spring (top) and winter (bottom) season $PM_{2.5}$ species averaged across all IMPROVE monitors in the LADCO region.

6.1.3 Comparison of LADCO and U.S. EPA 2011 PM Model Performance

The U.S. EPA 2011 CAMx simulation had regional average NMBs (average of the Ohio Valley and Upper Midwest regions) at the IMPROVE monitors in the spring and winter of +13.7%, and +19%, respectively.

The significant wintertime overprediction bias for total $PM_{2.5}$ at the Minnesota IMPROVE sites (NMB > +52%) noted in Supplemental Materials Section S5.1.1 is also present in the U.S. EPA results (Figure 26 in U.S. EPA, 2017a).

Both the LADCO and U.S. EPA CAMx 2011 simulations of spring season sulfate show the stark spatial gradient from overprediction to underprediction (i.e., positive to negative NMBs) along the southern part of the LADCO region. Both simulations also underpredicted wintertime sulfate throughout most of the LADCO region, and produced lower biases (i.e., good simulations) for the northern Class I area IMPROVE monitors.

The U.S. EPA CAMx 2011 simulation overpredicted nitrate in the spring and underpredicted nitrate in the winter, similar to the LADCO simulation. The two simulations both generally captured the monthly variability in observed nitrate concentrations at both the IMPROVE and CSN monitors with concentrations peaking in the winter months (e.g., Figure S 5-11). As with the LADCO CAMx simulation, the U.S. EPA simulation also had a large wintertime nitrate overprediction bias at the northern Class I area IMPROVE monitors (NMB > +40%).

The U.S. EPA (2017a) reported MPE results for elemental and organic carbon aerosols. While LADCO reports total carbonaceous aerosols here, the winter and spring season overpredictions are evident in the results from both simulations.

6.2 2016 CAMx Model Performance Evaluation Results

A summary of the CAMx MPE results for 2016 are presented in this section. The summary presents annual average MPE statistics for all CSN and IMPROVE monitoring locations in the LADCO region to provide an overview of the CAMx model's skill in simulating $PM_{2.5}$. Supplemental Materials Section S5 includes seasonal and regional MPE metrics that are used to identify how well the model can estimate PM concentrations during different times of the year. As with the 2011 simulation, Section S5 also includes model performance information for different $PM_{2.5}$ components (total $PM_{2.5}$, sulfate, nitrate, and total carbonaceous aerosols) to quantify how well the model can simulate the key light scattering species that most contribute to visibility impairment.

6.2.1 Annual PM Model Performance

Table 6-2 presents annual and regional average model performance statistics for the CSN and IMPROVE monitors in the LADCO region. Relative to the performance goals and criteria in Table 3-7, CAMx shows marginally acceptable performance for average total $PM_{2.5}$, sulfate, and nitrate. CAMx meets the more restrictive NMB performance goal only for nitrate at the IMPROVE sites. CAMx achieved the NMB model performance criteria for total $PM_{2.5}$ and sulfate at both networks, and CSN nitrate. The CAMx 2016 simulation had a severe overprediction bias for the carbonaceous aerosols.

Table 6-2. LADCO 2016 CAMx PM modeling performance summary

Species	Obs ($\mu g/m^3$)	CAMx ($\mu g/m^3$)	NMB (%)	NME (%)	r
CSN $PM_{2.5}$	8.19	10.37	30.47	44.68	0.71
IMPROVE $PM_{2.5}$	4.75	5.63	22.82	42.61	0.66
CSN SO_4	1.13	1.42	33.68	48.60	0.70
IMPROVE SO_4	0.99	1.07	16.50	39.53	0.71
CSN NO_3	1.26	1.42	40.19	78.38	0.52
IMPROVE NO_3	0.72	0.64	11.89	75.46	0.50
CSN TC	2.18	4.46	116.93	121.80	0.66
IMPROVE TC	1.89	2.72	56.44	69.95	0.64
Key:	Met MPE Goal		Met MPE Criteria		

6.2.2 Seasonal PM Model Performance

Supplemental Materials Section S5.2.6 includes seasonal CAMx model performance tables for the CSN and IMPROVE monitors in each LADCO state. The seasonal and site average statistics in these tables include observed and modeled concentrations, NMB, NME, and correlation

The LADCO 2016 CAMx simulation performance in simulating observed $PM_{2.5}$ species at CSN and IMPROVE monitors in the region was mixed. As with the 2011 CAMx modeling platform, the LADCO 2016 CAMx simulation exhibited better skill with the inorganic aerosol species than with the carbonaceous aerosols. The CAMx 2016 simulation had particularly poor performance in estimating organic aerosols.

Figure 6-4 summarizes the winter and spring CAMx model performance at the IMPROVE monitors in the LADCO region. These plots compare the observed (left stacked bar) and CAMx simulated (right stacked bar) $PM_{2.5}$ species averaged across all IMPROVE monitors in the LADCO region for each season. The spring season CAMx overprediction bias across the region is driven by excess organic aerosol and $PM_{2.5}$ "Other", which includes fine crustal and seasalt particles. On a seasonal, regionwide basis the LADCO 2016 CAMx simulation compares well to the springtime IMPROVE observations for sulfate, nitrate, ammonium, and elemental carbon. The winter season CAMx overprediction bias at the LADCO IMPROVE sites is also driven primarily by excess organic aerosol in the model, and to a lesser extent excess $PM_{2.5}$ Other. The total $PM_{2.5}$ overprediction is attenuated by underpredictions of wintertime nitrate and ammonium.

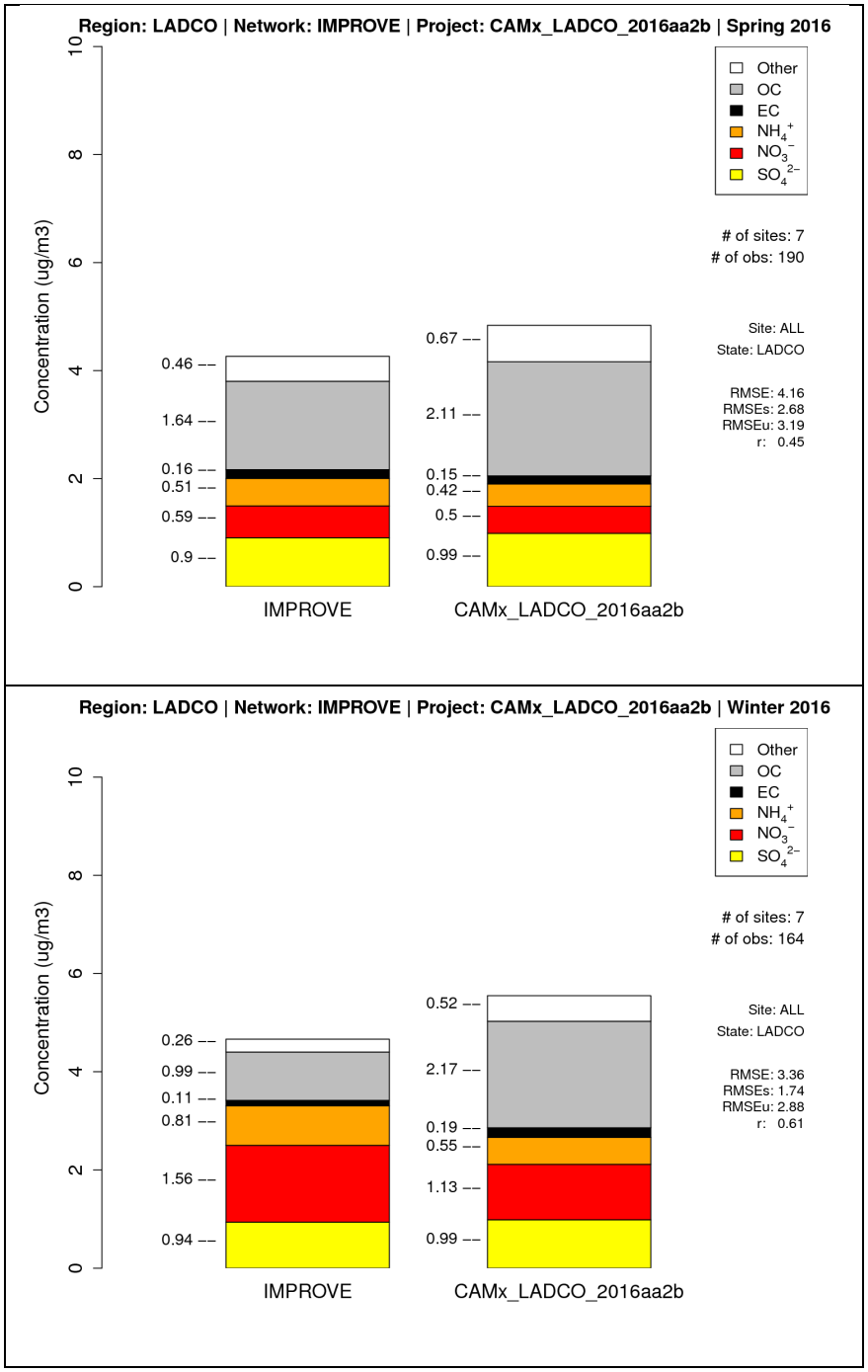


Figure 6-4. Stacked bar plot of 2016 spring (top) and winter (bottom) season $PM_{2.5}$ species averaged across all IMPROVE monitors in the LADCO region.

6.2.3 Comparison of LADCO and U.S. EPA 2016 PM Model Performance

The LADCO CAMx 2016 modeling results are comparable to the U.S. EPA 2016 modeling platform used for their preliminary regional haze modeling (U.S. EPA, 2019b), as expected since the two modeling

platforms were nearly identical. As with the 2011 modeling platform, intercomparing the LADCO and U.S. EPA 2016 CAMx simulations is complicated by the use of different regions to calculate performance statistics.

While the LADCO 2016 CAMx simulation of total $PM_{2.5}$ had an overprediction bias through most of the year, it achieved the model performance benchmarks for the spring and winter months at most of the CSN and IMPROVE monitors in the LADCO region. The LADCO 2016 CAMx simulation had regional average spring and winter NMBs for total $PM_{2.5}$ at the IMPROVE monitors of +15.5% and +29.2%, respectively. The U.S. EPA 2016 CAMx simulation of total $PM_{2.5}$ had regional average NMBs (average of the Ohio Valley and Upper Midwest regions) at the IMPROVE monitors in the spring and winter of +16.3% and +31%, respectively. The LADCO 2016 CAMx simulation had regional average spring and winter NMBs for total $PM_{2.5}$ at the CSN monitors of +23.3% and +34%, respectively. In comparison, the U.S. EPA 2016 CAMx simulation had regional average NMBs at the CSN monitors in the spring and winter of +12% and +17%, respectively.

Both the LADCO and U.S. EPA CAMx 2016 simulations overpredicted sulfate throughout the year in most of the LADCO region. Both simulations better predicted (i.e., lower NMBs) sulfate in the winter months than in the spring. The LADCO 2016 CAMx simulation had regional average spring and winter NMBs for sulfate at the IMPROVE monitors of +7.2% and +9.4%, respectively. The U.S. EPA 2016 CAMx simulation had regional average NMBs at the IMPROVE monitors in the spring and winter of +11% and +7.2%, respectively.

The U.S. EPA 2016 CAMx simulation overpredicted nitrate in the spring and underpredicted nitrate in the winter, similar to the LADCO 2016 simulation. The two simulations both generally captured the monthly variability in observed nitrate concentrations at both the IMPROVE and CSN monitors with concentrations peaking in the winter months. As with the LADCO CAMx simulation, the U.S. EPA 2016 simulation also produced a large underprediction bias at the northern Class I area IMPROVE monitors in the winter (NMB > +40%).

The U.S. EPA (2019b) reported MPE results for elemental and organic carbon aerosols. While LADCO reports total carbonaceous aerosols here, the severe winter and spring season overpredictions are evident in the results from both simulations.

6.3 Model Performance Discussion

In the preceding sections and in Supplemental Materials Section S5 we present MPE results for the PM species components of regional haze estimated by the LADCO 2011 and 2016 CAMx simulations. To narrow the scope of the evaluation for this TSD, we focused on the CAMx performance in simulating spring and winter season nitrate and sulfate. We chose to focus our evaluation on these periods and species because they are associated with the most anthropogenically impaired conditions at the Class I areas in the LADCO region.

Table 6-3 compares the LADCO 2011 CAMx and 2016 CAMx simulation model performance for the spring and winter seasons by monitoring network and PM species. The table shows the average CAMx NMB and NME values across the CSN and IMPROVE monitor locations in the six-state LADCO region for the spring and winter seasons. This table presents a more comprehensive view of the model species than in the preceding sections because it includes the carbonaceous aerosol species and ammonium ion in addition to sulfate and nitrate. Dark green shading indicates if the simulation achieved the performance goal for the model species; light green shading indicates that the model achieved the less stringent performance criteria (Emery et al., 2017).

Looking across all of the MPE benchmarks in Table 6-3, both of the LADCO CAMx simulations achieved either the model performance goals or criteria for most of the species in the two seasons. The LADCO 2011 CAMx simulation of spring season PM species at the IMPROVE sites had the best model performance with most of the species achieving the more stringent MPE goals for both NMB and NME. While not as strong as the 2011 simulation, the spring season 2016 CAMx simulation of PM at the IMPROVE monitors achieved at least the NMB and NME criteria for most of the species. In both years, the CAMx simulations generally better estimated PM at the more rural IMPROVE sites compared to the CSN sites (i.e., lower NMB and NME at IMPROVE vs CSN).

A comparison of the CAMx model performance across the two base years shows fairly comparable results. CAMx did not simulate well the carbonaceous aerosols, and organic aerosol in particular, in either of the base years. The model overestimated these species in both the spring and winter seasons and at both of the networks shown in Table 6-3. The CAMx 2011 simulation of nitrate at the CSN monitor locations is slightly better than the 2016 simulation, but both simulation years achieved the MPE goals

for winter season nitrate. Where the 2011 simulation overpredicted nitrate at the IMPROVE monitors in both seasons, the 2016 simulation underpredicted nitrate and had slightly lower absolute NMB and NME values. The 2011 and 2016 simulations of sulfate at the IMPROVE monitors were comparable. Where the 2011 simulation unpredicted sulfate on average across the IMPROVE sites, the 2016 simulation overpredicted spring and winter season sulfate. Notable deficiencies in the LADCO CAMx simulation performance are winter 2011 (NMB = -38%) and spring 2016 (NMB = +31%) sulfate at the CSN monitors, and organic aerosols in both years at the CSN monitors.

The LADCO CAMx simulations performed relatively well in estimating spring and winter season nitrate and sulfate at the IMPROVE monitors in both years. This result is significant because these two species are the biggest contributors to haze in the LADCO region Class I areas on the most impaired days. The PM model performance for both the 2011 and 2016 LADCO simulations are very similar to the models used by U.S. EPA for their recent regional haze assessments (U.S. EPA, 2017a; U.S. EPA, 2019b). We cannot infer the impacts of the CAMx biases and errors on how the model responds to emissions changes with the information that we have here. Namely, we cannot quantify the impacts of the CAMx biases on the relative response factors (RRFs) and derived future year PM design values and derived haze projections because we don't know how much each of the model processes (e.g., emissions, chemistry, deposition) contribute to the total bias and error in the model.

Table 6-3. NMB (%) and NME (%) summary statistics for LADCO 2011 and 2016 CAMx simulations[23]

Species	2011				2016			
	Spring		Winter		Spring		Winter	
Statistic	NMB	NME	NMB	NME	NMB	NME	NMB	NME
CSN								
EC	42.80	64.11	88.27	97.86	-4.86	43.05	45.92	63.25
NH_4	17.77	39.36	-16.40	39.21	120.26	130.69	31.46	63.74
NO_3	30.79	63.58	-11.49	35.06	20.08	67.29	-10.27	48.21
OA	56.91	66.65	111.73	117.23	61.15	71.74	129.51	132.40
$PM_{2.5}$	19.60	37.73	8.43	30.43	18.81	37.85	25.82	41.74
SO_4	1.49	37.18	-38.15	46.23	31.17	45.60	10.05	38.68
TC	53.84	64.50	107.62	113.43	35.08	54.74	105.17	108.63
IMPROVE								
EC	16.46	47.23	82.02	83.93	0.41	43.60	90.36	94.67
NH_4	-8.12	35.64	-6.05	40.57	-14.65	37.01	-32.62	42.88
NO_3	18.50	61.85	29.65	61.57	-8.40	59.04	-25.11	61.56
OA	12.19	44.58	88.07	89.42	41.97	69.76	126.35	126.85
$PM_{2.5}$	11.48	35.26	36.81	49.06	21.18	47.91	30.78	54.23
SO_4	-0.69	32.37	-17.72	49.80	17.08	36.72	11.78	39.36
TC	12.53	43.78	87.39	88.53	38.52	66.78	122.76	123.28
Key:	Met MPE Goal		Met MPE Criteria					

[23] Dark green shading indicates if the simulation achieved the performance goal for the model species; light green shading indicates that the model achieved the less stringent performance criteria (Emery et al., 2017).

7 Future Year Haze Projections

The air quality modeling that LADCO completed to support regional haze SIPs for the second implementation period culminated in estimating 2028 regional haze conditions in U.S. Class I areas. The future year haze projections described in this section will be available to the LADCO member states to use as weight of evidence to support their demonstration of progress towards natural visibility conditions in 2064. This section presents the methods that LADCO used to forecast 2028 haze conditions, examples of the analysis products from our work, and instructions for how to access our forecasted visibility data for all of the nation's Class I areas.

7.1 Methods

LADCO followed the U.S. EPA Modeling Guidance for Demonstrating Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze (US EPA, 2018) for estimating the 2028 future year visibility condition. Hereafter, the EPA's modeling guidance is referred to as "the SIP Modeling Guidance". The SIP Modeling Guidance describes the recommended modeling analyses to track RHR reasonable progress goals (RPGs). The RPGs reflect the states' long-term strategy for meeting the requirements of the RHR. LADCO completed two set of CAMx modeling runs for forecasting haze in 2028, one is based on 2011 base year and another one is based on 2016 base year. Using these modeling outputs and IMPROVE visibility data, LADCO estimated 2028 visibility conditions.

As required by the RHR, a state's RPGs must produce an improvement in visibility for the 20 percent most anthropogenically impaired days and ensure no degradation in visibility for the 20 percent clearest days, relative to baseline visibility conditions. The baseline for each Class I area is the average visibility (in deciviews) for the years 2000 through 2004. The visibility conditions in these years are the benchmarks for the requirements to improve or not degrade visibility on different types of days. In addition, states are required to determine the rate of improvement in visibility needed to reach natural conditions by 2064 for the 20 percent most anthropogenically impaired days.

The LADCO visibility projections followed the procedures in Section 5 of the SIP Modeling Guidance. Future year modeled visibility is forecast relative to a 5-year period centered around the base modeling year. LADCO estimated the 2028 visibility from the 2011 and 2016 base years using ambient IMPROVE

data for the 2009-2012 and the 2014-2018 periods, respectively. LADCO estimated base and future year visibility with the "revised" IMPROVE equation (Pitchford, 2007). The revised IMPROVE equation "reconstructs light extinction" from modeled and measured PM species concentrations and relative humidity data. The IMPROVE equation calculates visibility impairment or beta extinction (b_{ext}) in units of inverse megameters (Mm^{-1}) as follows:

$$b_{ext} = 2.2 \times fs(RH) \times [\text{Small Sulfate}] + 4.8 \times fL(RH) \times [\text{Large Sulfate}]$$

$$+ 2.4 \times fs(RH) \times [\text{Small Nitrate}] + 5.1 \times fL(RH) \times [\text{Large Nitrate}]$$

$$+ 2.8 \times \{\text{Small Organic Mass}] + 6.1 \times [\text{Large Organic Mass}]$$

The total sulfate, nitrate, and organic mass concentrations are each split into two fractions, representing small and large size distributions of those components. Site-specific Rayleigh scattering is calculated based on the elevation and annual average temperature of each IMPROVE monitoring site.

LADCO used the U.S. EPA Software for Model Attainment Test- Community Edition (SMAT-CE) Version 1.6 (SMAT-CE)[24] tool to calculate 2028 deciview (dv) values on the 20% most anthropogenically impaired and 20% clearest days at each of the IMPROVE monitors in Class I Areas. We used SMAT-CE to estimate the 2028 future year visibility on the 20% most anthropogenically impaired days and 20% clearest days at each Class I area using the observed IMPROVE data (2009-2013 and 2014-2018) and the relative percent change in modeled PM species between 2016 and 2028; and between 2011 and 2028. The SMAT-CE tool outputs individual year and 5-year average base year and future year dv values on the 20% most impaired days and 20% clearest days. Additional SMAT-CE output variables include the results of intermediate calculations, such as PM species light extinction values (both base and future year) and species-specific RRFs (on the 20% most impaired and clearest days).

The process for calculating future year visibility conditions with SMAT-CE is described in the following six steps (see the SIP Modeling Guidance for a more detailed description and examples). LADCO applied this process to data from each Class I area (i.e., each IMPROVE monitoring site).

[24] https://www.epa.gov/scram/photochemical-modeling-tools

1. Estimate anthropogenic impairment (in Mm^{-1}) on each day using observed speciated $PM_{2.5}$ and PM_{10} data for each of the 5 years comprising the base period and rank the days based on impairment. This ranking is used to determine the 20 percent most anthropogenically impaired days. For each Class I area, also rank observed visibility (in dv) on each day using the same speciated data. This ranking will determine the 20 % clearest days.
2. Calculate the mean dv for the 20 percent most anthropogenically impaired days and 20 percent clearest days for each of the 5 years comprising the base period and the 5-year mean dv for the most impaired and clearest days.
3. Use the CAMx model to simulate air quality with base (2011 and 2016) and future year (2028) emissions. We applied SMAT-CE to the model results to develop site-specific relative response factors (RRFs) for each component of PM identified in the "revised" IMPROVE equation. The RRFs are an average percent change in species concentrations based on the measured 20% most impaired and 20% clearest days from 2011 or 2016.
4. Multiply the species-specific RRFs by the measured daily species concentration data during the 2009-2013 and 2014-2018 base periods for each day in the measured 20% most impaired day set and each day in the 20% clearest day set. This results in daily future year 2028 PM species concentration data.
5. Using the results in Step 4 and the IMPROVE algorithm, calculate the future daily extinction coefficients for the previously identified 20% most impaired days and 20% clearest days in each of the five base years.
6. Calculate daily dv values (from total daily extinction) and then compute the future year (2028) average mean dv values for the 20% most impaired days and 20% clearest days for each year. Average the five years together to get the final future mean dv values for the 20% most impaired days and 20% clearest days.

Table 7-1 details the settings used by LADCO for the SMAT-CE runs to estimate the 2028 future year dv value.

Table 7-1. SMAT-CE software configuration settings for 2028 visibility calculations

SMAT Option	Settings/file used for the 2011-based 2028 visibility calculation	Settings/file used for the 2016-based 2028 visibility calculation
IMPROVE algorithm	Use new version	Use new version
Grid cells at monitor or Class I area centroid?	Use grid cells at monitor	Use grid cells at monitor
IMPROVE data file	ClassIareas_NEWIMPROVEALG_2000to2018_2020_may5_IMPAIRMENT.csv[25]	ClassIareas_NEWIMPROVEALG_2000to2018_2020_may5_IMPAIRMENT.csv
Start monitor year	2009	2014
End monitor year	2013	2018
Temporal adjustment at monitor	3x3	3x3
Minimum years required for a valid monitor	1	1
Baseline model file	mats.PM.12US2.bulk.LADCO_2011en.csv	mats.PM.12US2.bulk.2016_ladco_v1b.cb6r4.csv
Forecast model file	mats.PM.12US2.bulk.LADCO_2028HAZE.csv	mats.PM.12US2.bulk.2028_ladco_v1b.cb6r4.csv

7.2 LADCO 2028 Haze Projections

The base and future year dv values on the 20% clearest and most impaired days at Class I areas within LADCO states for the 2011 and 2016 base model periods and 2028 future year are shown in Table 7-2 and Table 7-3, respectively. The last column of each table shows the predicted dv change at each Class I area on the 20% most impaired days. The visibility conditions at the Class I areas in the LADCO region

[25] The IMPROVE ambient data file has the 20% most impaired days identified as "group 90" days and 20% clearest days identified as "group 10" days. The definition of the most impaired days uses the EPA recommended methodology from Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program. Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program | Visibility and Regional Haze | US EPA. The IMPROVE data file used for this analysis included patched and/or substituted data.

were predicted to improve on average by about 2 dv by 2028 as compared to the 2011 base year, and to have about a 0.8 dv improvement relative to the 2016 base year.

Table 7-2. Base and future year deciview values on the 20% clearest and 20% most impaired days at Class I area within LADCO region for the base model period (2009-2013) and future year (2028)

	20% Clearest Days (dv)			20% Most Impaired Days (dv)		
IMPROVE Site ID	Base Period	Future Year	Change (2028-2011)	Base Period	Future Year	Change (2028 -2011)
BOWA1	4.83	4.79	-0.04	16.42	14.43	-1.99
ISLE1	5.40	5.29	-0.11	17.63	15.48	-2.15
SENE1	5.50	5.35	-0.15	19.92	17.34	-2.58
VOYA2	5.68	5.60	-0.08	17.12	15.08	-2.04

Table 7-3. Base and future year deciview values on the 20% clearest and 20% most impaired days at Class I area within LADCO region for the base model period (2014-2018) and future year (2028)

	20% Clearest Days (dv)			20% Most Impaired Days (dv)		
IMPROVE Site ID	Base Period	Future Year	Change (2028 -2016)	Base Period	Future Year	Change (2028 -2016)
BOWA1	4.48	4.30	-0.07	13.96	13.17	-0.79
ISLE1	5.30	5.23	-0.07	15.54	14.83	-0.71
SENE1	5.27	5.17	-0.10	17.57	16.67	-0.90
VOYA2	5.31	5.25	-0.06	14.18	13.36	-0.82

Figure 7-1 shows the visibility glidepath at the Boundary Waters Canoe Area (BOWA) in Minnesota for the 20% most impaired days based on the 2011- and 2016-based 2028 CAMx simulations. The glidepath represents a linear rate of progress and shows the amount of visibility improvement needed in each implementation period to achieve natural visibility conditions in the Class I area by 2064. The figure compares the glidepath with the observed visibility conditions (yellow dots) for 2000-2018[26], baseline visibility condition (observed condition in 2000-2004 period)[27], base year visibility condition (green dot at 2011 or 2016), as well as the predicted 2028 visibility condition (red dot at 2028), and the 2064 target

[26] Dataset was obtained from EPA in June 2020; Filename: ClassIareas_NEWIMPROVEALG_2000to2018_2020_may5_IMPAIRMENT.csv

[27]Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (8/2019) https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period; Natural and Baseline Visibility Condition Values from https://www.epa.gov/sites/production/files/2020-06/documents/memo_data_for_regional_haze_technical_addendum.pdf

of natural conditions[27] for a particular Class I area. In addition, a dashed blue line drawn between the visibility condition in baseline period (2000-2004) and natural condition in 2064 shows a uniform rate of progress (URP) and/or called "glidepath" line between these two points. The glidepath represents a linear or uniform rate of progress and is the amount of visibility improvement needed in each implementation period to achieve natural visibility conditions in the Class I area by 2064.

The RHR allows states to optionally propose adjustments at the end point of the glidepath (URP) to exclude uncontrollable haze contributions, such as contributions from international anthropogenic emissions and certain prescribed fires. The proposed adjustments for each Class I area must be developed using scientifically valid data and methods. U.S. EPA demonstrated in their preliminary (U.S. EPA, 2017a) and updated (U.S. EPA, 2019b) regional haze modeling efforts how the glidepath endpoints could be adjusted. LADCO used the same approaches demonstrated by U.S. EPA to adjust the glidepath endpoints for our 2011 and 2016-based visibility projections.

The figures below also show the adjusted glidepath. The adjusted glidepath for the 2011-based 2028 visibility prediction accounts for contributions from Mexico and Canada anthropogenic emissions. In addition to the Canadian and Mexico sources inside the modeling domain, the adjustment to the glidepath for the 2016-based 2028 visibility predictions also considered international anthropogenic sources outside of the modeling domain, including non-U.S. Class 3 commercial marine emissions (U.S. EPA, 2019b). The glidepath adjustments for the 2011-based modeling are smaller than the 2016-based modeling because they are calculated using fewer haze precursor sources.

Figure 7-1 through Figure 7-4 show the 2011-based and 2016-based LADCO 2028 visibility predictions relative to the URP glidepath for the Boundary Waters Canoe Area (BOWA), Isle Royale National Park (ISLE), Seney National Wildlife Refuge (SENE), and Voyageurs National Park (VOYA) Class I areas, respectively.

LADCO's CAMx visibility forecasts for Class I areas outside of the LADCO region are available in an electronic docket to this TSD in the following spreadsheets:

LADCO 2011-based 2028 Class I Area Visibility Forecasts (6.6 Mb XLSX file)

LADCO 2016-based 2028 Class I Area Visibility Forecasts (6.4 Mb XLSX file)

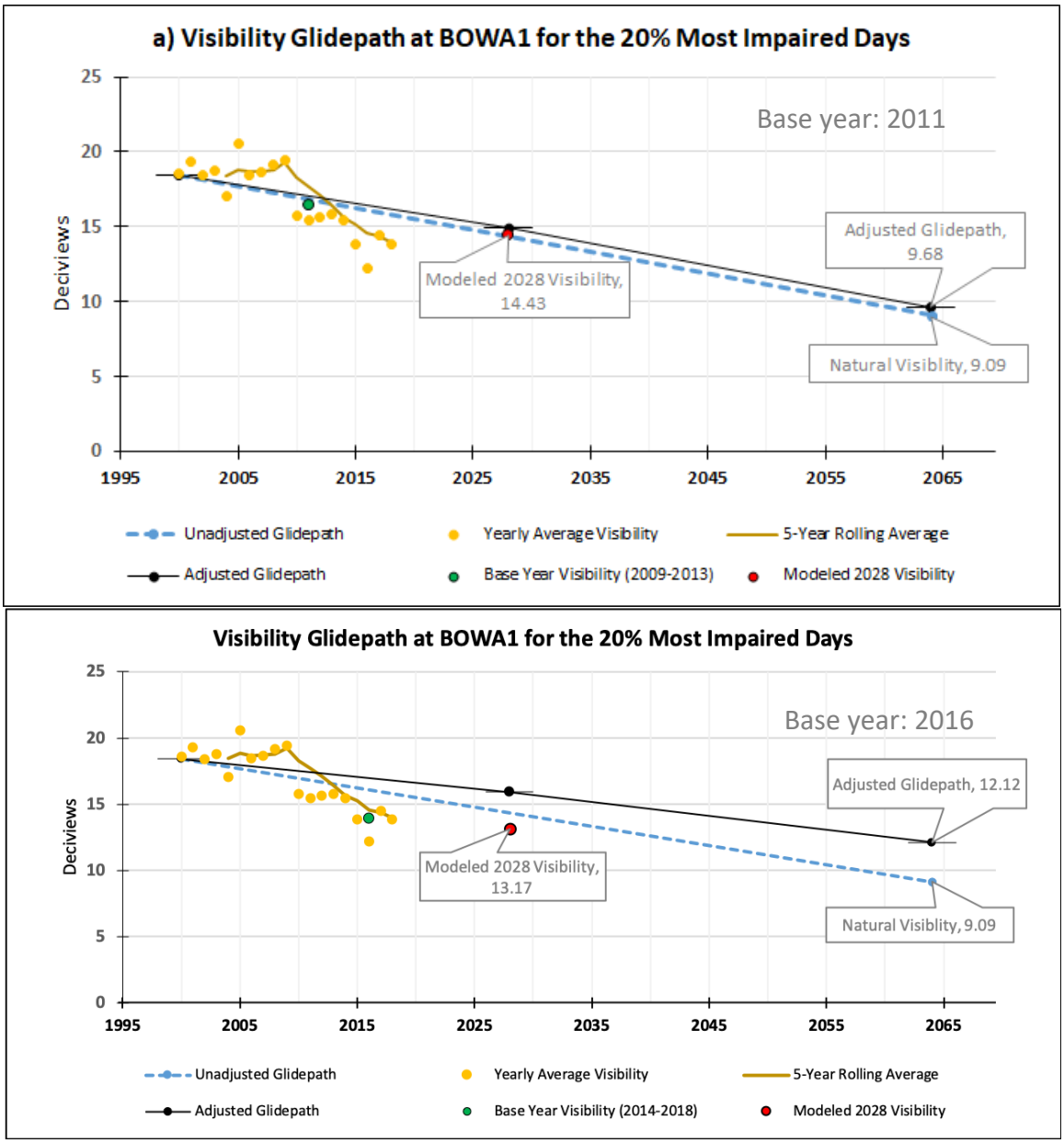


Figure 7-1. Visibility glidepath at BOWA1 IMPROVE site for the 20% most impaired days based on the (a) 2011 based 2028 prediction and (b) the 2016 based 2028 prediction[28].

[28] Note that the adjusted glidepath for the 2011 based prediction is accounted only the contribution from Mexico & Canada anthropogenic emissions, while the adjusted glidepath for 2016 based prediction was accounted for contributions from Mexico & Canada anthropogenic, Non-US C3 commercial marine, international boundary condition and wildland prescribed fire emissions.

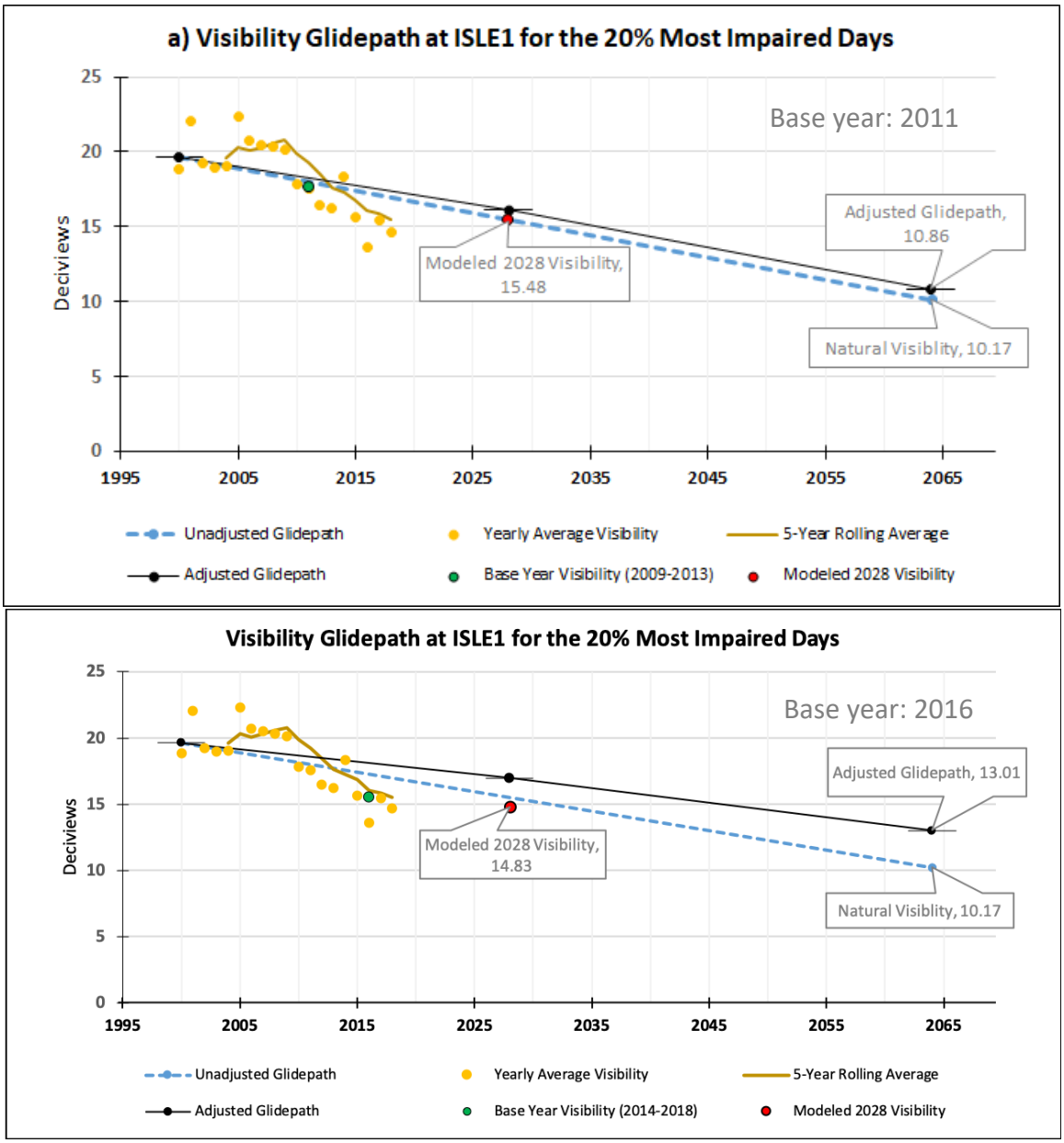


Figure 7-2. Visibility glidepath at ISLE1 IMPROVE site for the 20% most impaired days based on the (a) 2011 based 2028 prediction and (b) the 2016 based 2028 prediction.

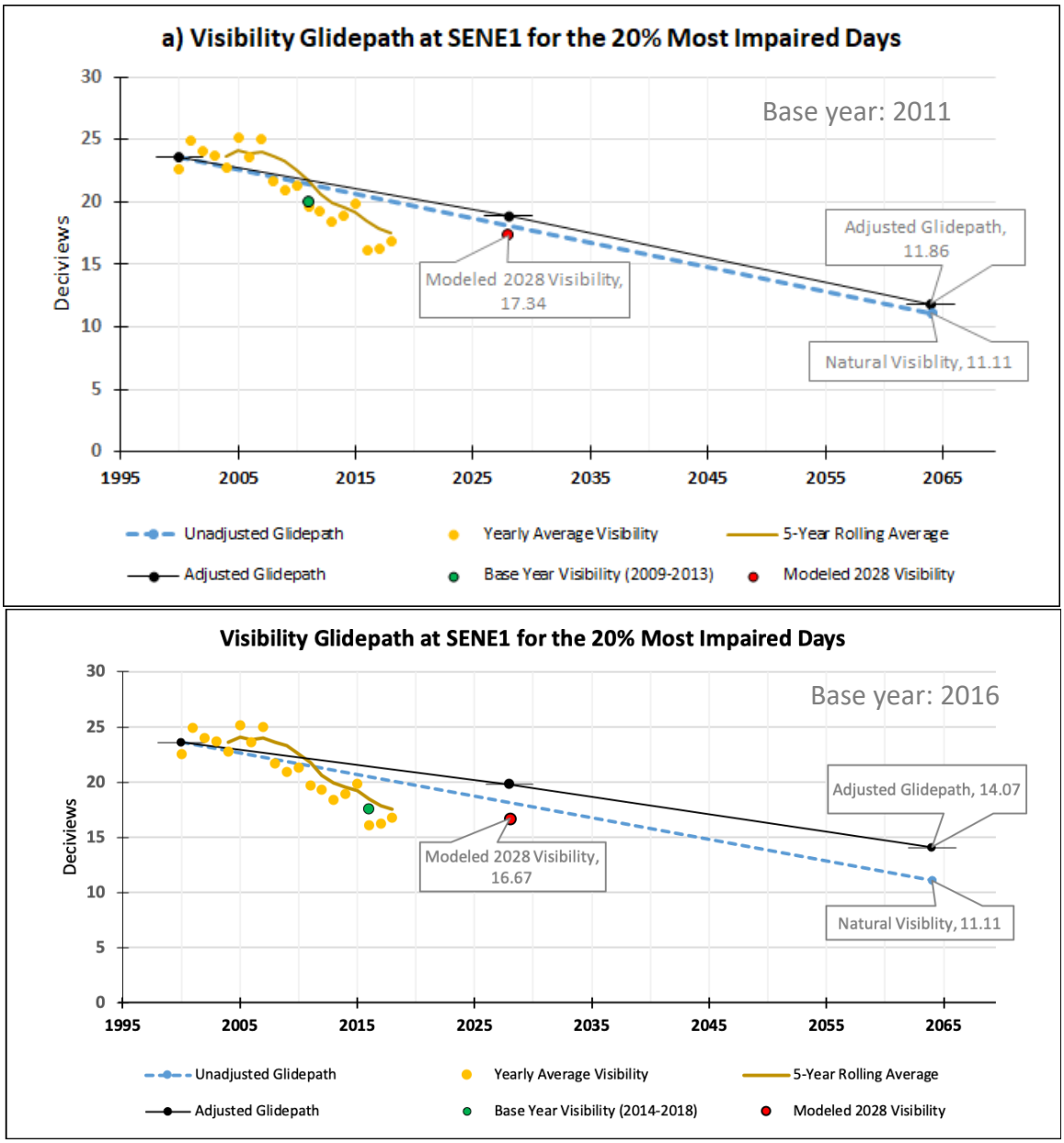


Figure 7-3. Visibility glidepath at SENE1 IMPROVE site for the 20% most impaired days based on the (a) 2011 based 2028 prediction and (b) the 2016 based 2028 prediction.

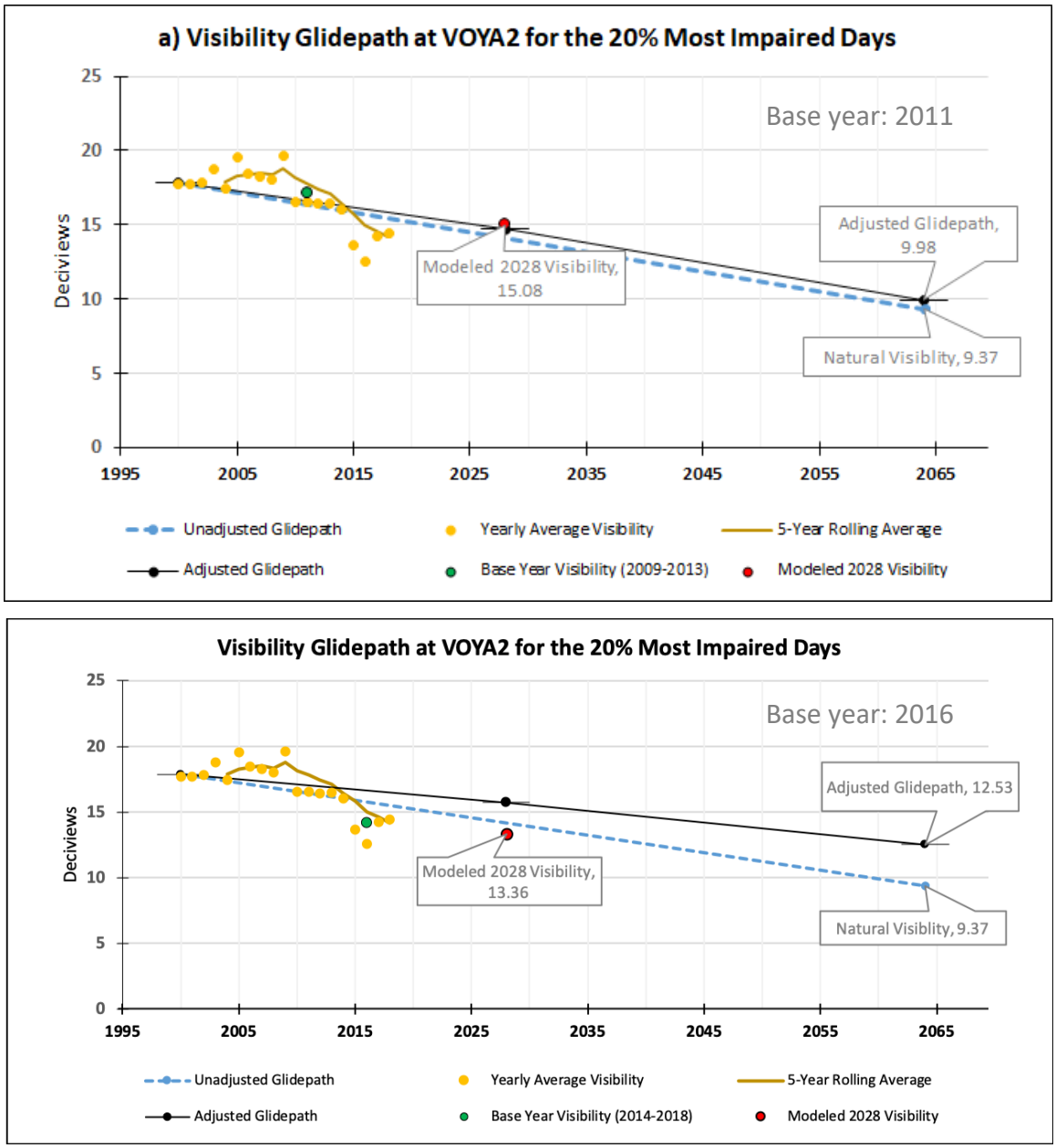


Figure 7-4. Visibility glidepath at VOYA2 IMPROVE site for the 20% most impaired days based on the (a) 2011 based 2028 prediction and (b) the 2016 based 2028 prediction.

The information in these figures is tabulated in Table 7-4 and Table 7-6. The glidepath plots show that the yearly average dv values at the IMPROVE monitors in the LADCO region are decreasing from year to year. One notable trend in these plots is the reduction in the base year visibility (green dot) in the 2016 base year relative to 2011. The 2016 base year visibility conditions are all well below the glidepath. Predicted 2028 visibility conditions based on the 2016 modeling platform shows that the visibility in the

Class I areas in Minnesota and Michigan is about 1.4 dv below the unadjusted glidepath line (i.e., URP). Accounting for the adjustment due to the international contribution, LADCO estimated 2028 visibility on the 20% most impaired days to be about 2.6 dv below the URP line. Table 7-5 and Table 7-7 show the baseline and predicted visibility on the 20% clearest days for the 2011 and 2016-based LADCO modeling.

Table 7-4. Comparison of observed and projected visibility on the 20% most impaired days at Class I areas within LADCO region (2011 base year)

IMPROVE Site ID	Visibility on 20% Most Impaired Days for the 2011 base year (dv)					Impact of Glidepath Adjustment (2028) (B-A)
	Observed Baseline (2000-2004)	Observed Base Years (2009-2013)	Projected Year (2028) (A)	Unadjusted Glidepath Value (2028) (B)	Natural Conditions (2064)	
BOWA1	18.43	16.42	14.43	14.69	9.09	-0.26
VOYA2	17.88	17.12	15.08	14.48	9.37	0.60
ISLE1	19.63	17.63	15.48	15.85	10.17	-0.37
SENE1	23.58	19.92	17.34	18.59	11.11	-1.25

Table 7-5. Comparison of observed and projected visibility on the 20% clearest days at Class I areas within LADCO region (2011 base year)

IMPROVE Site ID	Visibility on 20% Clearest Days for the 2011 base year (dv)			
	Observed Baseline (2000-2004)	Observed Base Years (2009-2013)	Projected Year (2028)	Natural Conditions (2064)
BOWA1	6.50	4.83	4.79	3.48
VOYA2	7.15	5.68	5.60	4.27
ISLE1	6.77	5.40	5.29	3.72
SENE1	7.14	5.50	5.35	3.74

Table 7-6. Comparison of observed and projected visibility on the 20% most impaired days at Class I areas within LADCO region (2016 base year)

IMPROVE Site ID	Visibility on 20% Most Impaired Days for the 2016 base year (dv)					Impact of Glidepath Adjustment (2028) (B-A)
	Observed Baseline (2000-2004)	Observed Base Years (2014-2018)	Projected Year (2028) (A)	Unadjusted Glidepath Value (2028) (B)	Natural Conditions (2064)	
BOWA1	18.43	13.96	13.17	14.69	9.09	-1.52
VOYA2	17.88	14.18	13.36	14.48	9.37	-1.12
ISLE1	19.63	15.54	14.83	15.85	10.17	-1.02
SENE1	23.58	17.57	16.67	18.59	11.11	-1.92

Table 7-7. Comparison of observed and projected visibility on the 20% clearest days at Class I areas within LADCO region (2016 base year)

IMPROVE Site ID	Visibility on 20% Clearest Days for the 2016 base year (dv)			
	Observed Baseline (2000-2004)	Observed Base Years (2014-2018)	Projected Year (2028)	Natural Conditions (2064)
BOWA1	6.50	4.48	4.41	3.48
VOYA2	7.15	5.31	5.25	4.27
ISLE1	6.77	5.30	5.23	3.72
SENE1	7.14	5.27	5.17	3.74

8 PSAT Source Apportionment Results

LADCO conducted source apportionment modeling with CAMx to quantify source-receptor relationships for PM and haze in 2028. The PSAT results show the extent to which emission from different source regions impair visibility in downwind Class I areas. In particular, the techniques used by LADCO to process the PSAT results provide information on the sources that contribute to haze on both the most impaired and clearest days at Class I areas.

In Section 3.5, we discussed the Particulate Matter Source Apportionment Technique (PSAT) configurations for the LADCO 2011-based and 2016-based CAMx simulation. The configuration descriptions included the PSAT emission source or sector tags for quantifying the contributions of upwind states, regions, and inventory sectors at downwind Class I areas. For the 2011-based 2028 PSAT run, LADCO tagged the 2028 emissions by individual LADCO states and neighboring regions (Table 8-1).

CAMx PSAT uses multiple tracer families to track the fate of both primary and secondary PM species, including sulfate (PSO4), particulate nitrate (PNO3), ammonium (PNH4), primary elemental carbon (PEC), primary organic aerosol (POA), secondary organic aerosol (SOA), and primary fine and coarse particles. In addition, PSAT can track contributions from the initial and boundary conditions to the model.

For the 2011-based simulation, LADCO used all of the PSAT tracer families to quantify the haze contributions at Class I areas. Based on those results, we refined the PSAT configuration for the 2016-based simulation to exclude the SOA tracer because it is both computationally expensive to simulate and anthropogenic sources are small contributors to SOA in the LADCO-region Class I areas.

Table 8-1. Source Tag Descriptions for CAMx PSAT runs for 2028_{2011} and 2028_{2016} simulations

Tag #	2028_{2011} Tag Description	2028_{2016} Tag Description
1	Biogenic	Other
2	IL	IL
3	WI	WI
4	IN	IN
5	OH	OH
6	MI	MI
7	MN	MN
8	IA	IA
9	MO	MO
10	AR	TX
11	LA	LA, OK, KS, NE, AR
12	TX	ME, NH, VT, MA, RI, CT, NY, NJ, PA, DE, MD, DC
13	OK	WV, KY, VA, NC, SC, TN, GA, AL, MI, FL
14	KS	NM, AZ, CO, UT, WY, MT, ID, WA, OR, CA, NV, ND, SD
15	NE	Canada/Mexico
16	ND	Commercial Marine (C1/C2/C3)
17	SD	Fires
18	WV	Rockport EGU (IN)
19	KY	Gibson EGU (IN)
20	ME, NH, VT, MA, RI, CT, NY, NJ, PA, DE, MD, DC	All other IN EGUs
21	VA, NC, SC, TN, GA, AL, MI, FL	IN Cement Manufacturing
22	NM, AZ, CO, UT, WY, MT, ID, WA, OR, CA, NV	IN Iron and Steel
23	Canada/Mexico	IN Plastics and Resin
24	Fire	IN Aluminum Production
25	Offshore	All other IN point sources
26	Tribes	IC
27	IC	BC
28	BC	

8.1 PSAT Post-processing for Source Contribution Estimates

LADCO post-processed the CAMx PSAT tagged species model outputs to create SMAT-CE input files. This process involved operations on both the 2028 "bulk outputs" and the source sector specific (or "tagged") source apportionment outputs. The "bulk outputs" are the total PM species concentrations (e.g. sulfate, nitrate, etc.) that are identical to the total species concentrations from the non-source apportionment model run for 2028. However, the source apportionment tracking of PM species uses slightly different variables names for the tagged outputs. The SMAT-CE input variable names and matching CAMx species names for the 2028 bulk and 2028 tagged outputs are tabulated in Table 8-2.

Table 8-2. SMAT input variables and their matching species names for CAMx "bulk" and "PSAT" source output files

SMAT-CE species	SMAT-CE species name	"Combine file" output species	CAMx species in "bulk output"	CAMx species in "tag output"
SO4	Sulfate	PM25_SO4	PSO4	PS4
NO3	Nitrate	PM25_NO3	PNO3	PN3
NH4[29]	Ammonium	PM25_NH4	PNH4	PN4
EC	Elemental carbon	PM25_EC	PEC	PEC
OC[30]	Organic carbon	PM25_OM	POA+SOA1+SOA2+SOPA+SOA3+SOA4+SOPB	POA+PO1+PO2+PPPA+O3+PO4+PPB
CRUSTAL[31]	Crustal	PM25_CRUSTRAL	FPRM+FCRS	PFN+PFC
CM	Coarse PM	PMC_TOT	CCRS+CPRM	PCS+PCC
PM25[32]	Total $PM_{2.5}$	PM25_TOT	PSO4+PNO3+PNH4+PEC+NA+PCL+FPRM+FCRS+SOA1+SOA2+SOPA+SOA3+SOA4+SOPB+POA	PS4+PN3+PN4+POA+PEC+PO1+PO2+PO3+PO4+PPA+PPB+PFN+ PFC

[29] Modeled ammonium concentrations are not used in the post-processing of the 2028 visibility values because the IMPROVE network does not measure ammonium. The IMPROVE equation assumes that sulfate and nitrate is fully neutralized by ammonia.

[30] LADCO's 2028_{2016} CAMx PSAT simulation did not include the organic carbon tracers

[31] LADCO's 2028_{2011} CAMx PSAT simulation was run without writing individual crustal fine particles, thus, the crustal amount was estimated by the sum of fine crustal particles (FCRS) and other fine particles (FPRM).

[32] Total PM2.5 concentration data is needed as a SMAT input variable, however, it is not used in the visibility calculations for regional haze. Visibility calculations only use the species specific model outputs.

The model attainment test software SMAT-CE processes daily total and speciated PM concentrations from the base and future year model (bulk and PSAT) runs from a 3 grid cell x 3 grid cell matrix surrounding each IMPROVE monitor location in the CAMx modeling domain. LADCO used the following steps to prepare the SMAT-CE input files and to run the software to calculate future year visibility at the Class I areas:

1. Combine hourly CAMx "bulk output" into hourly total and speciated PM concentrations (File A) using the species shown in Table 8-2.
2. Generate hourly pseudo total and speciated PM concentration outputs (File X') for each source tag by subtracting the tagged source apportionment output (File X) from File A.
3. Generate daily average total (File $\bar{A}$) and speciated PM (File $\overline{X'}$) concentration files from File A and File X', respectively
4. Extract the results in File $\bar{A}$ and File $\overline{X'}$ from 3x3 grid cells surrounding each IMPROVE monitor location in the modeling domain. LADCO then converted the extracted netCDF data to comma-delimited (CSV) files in the SMAT-CE input file format; the CSV outputs for File $\overline{A2}$ and File $\overline{X2'}$ were then ready for SMAT-CE.
5. Run SMAT-CE version 1.6 using the File $\overline{A2}$ and File $\overline{X2'}$ with observed IMPROVE data as inputs and with the settings in Table 7-1. In this SMAT-CE run, LADCO used the advanced option "Create forecast IMPROVE visibility file" to output the future year (2028) daily species extinction values at each IMPROVE monitor for each of the 20% best and the 20% most impaired days. With this configuration, SMAT-CE generated a "Forecast IMPROVE Daily Data.csv" file, which we used in the next step for calculating the visibility contributions for each PSAT tag.
6. We then used R to prepare the raw SMAT-CE for easy import to a spreadsheet for plotting and tabulation of the results.

LADCO created a comprehensive spreadsheet for each 2028 simulation that included dynamic plotting features with information on natural conditions, baseline visibility, base year and projected year visibility conditions at the Class I areas. We combined this information with the glidepath results described in the previous section.

LADCO's CAMx PSAT visibility forecasts are available in an electronic docket to this TSD in the following spreadsheets:

LADCO 2011-based 2028 Class I Area Visibility Forecasts (6.6 Mb XLSX file)

LADCO 2016-based 2028 Class I Area Visibility Forecasts (2.2 Mb XLSX file)

8.2 2011 Platform PSAT Results

This section presents the results from the LADCO CAMx 2011-based 2028 PSAT configuration that are included in the spreadsheets described in the previous section.

8.2.1 Source Region Tracer Results

The LADCO CAMx 2028_{2011} PSAT modeling estimated the state, biogenic, initial and boundary condition (ICBC), and international (Canada and Mexico) anthropogenic emissions source contributions to visibility in the U.S. Class I areas (Table 8-3 and Figure 8-1). CAMx estimated the average light extinction in 2028 across all of the LADCO region Class I areas to be about 50 Mm^{-1}. CAMx estimated that about 24% of the extinction is due to Rayleigh scattering, 20% from ICBC (mostly from boundary condition), 7-14% from the residing state, about 6% from biogenic emissions, and about 3% from the international anthropogenic emissions, mostly from Canada. The remainder of the extinction comes from other states. Figure 8-1 illustrates the results in Table 8-3 as a stacked bar plot. An aggregation of the PSAT source region tags to regional planning organization (RPO) area for the LADCO's Class I areas is shown in Figure 8-2. Natural sources such as Rayleigh, sea salt, biogenic and fire emissions are projected to contribute 28-36 % of the light extinction coefficients in the LADCO's Class I areas, while the LADCO and CenSARA RPOs are projected to contribute 23-24% and 8-13% of the extinction, respectively.

Table 8-3. 2028_{2011} tracer contributions to b_{ext} on the most impaired days at the LADCO Class I areas

Source region tags	Source contributions to 2028 visibility at IMPROVE Sites (Mm^{-1})					Percent source contributions to 2028 visibility at IMPROVE Sites (%)			
IMPROVE Sites	ISLE1	SENE1	BOWA1	VOYA2		ISLE1	SENE1	BOWA1	VOYA2
Total Bext	50.5	60.7	45.3	47.7					
Rayleigh	12.0	12.0	11.0	12.0		24%	20%	24%	25%
Sea salt (SS)	0.2	0.2	0.1	0.2		0%	0%	0%	1%
Biogenic	3.2	3.7	2.9	3.0		6%	6%	7%	6%
ICBC	10.0	11.1	8.9	8.9		20%	18%	20%	19%
Fire	1.5	1.1	1.6	2.5		3%	2%	3%	5%
Int'l anthropogenic	2.0	2.4	1.5	1.6		4%	4%	3%	3%
Tribal	0.0	0.0	0.0	0.0		0%	0%	0%	0%
Offshore	0.1	0.1	0.0	0.0		0%	0%	0%	0%
West	0.6	0.8	0.8	0.7		1%	1%	2%	1%
Northeast	0.4	1.2	0.2	0.2		1%	2%	0%	0%
Southeast	0.2	0.5	0.1	0.1		0%	1%	0%	0%
IL	2.3	3.4	0.8	1.0		5%	6%	2%	2%
WI	3.5	4.5	2.2	1.7		7%	7%	5%	4%
IN	1.2	2.9	0.5	0.6		2%	5%	1%	1%
OH	0.6	1.5	0.4	0.5		1%	3%	1%	1%
MN	2.4	1.7	6.2	6.5		5%	3%	14%	14%
MI	3.3	6.5	0.8	0.7		7%	11%	2%	2%
IA	1.3	1.3	1.8	1.7		3%	2%	4%	4%
MO	1.4	1.3	0.8	0.9		3%	2%	2%	2%
AR	0.3	0.4	0.2	0.3		1%	1%	1%	1%
LA	0.1	0.1	0.1	0.0		0%	0%	0%	0%
TX	1.3	0.5	1.2	1.0		3%	1%	3%	2%
OK	0.4	0.2	0.6	0.6		1%	0%	1%	1%
KS	0.3	0.4	0.5	0.5		1%	1%	1%	1%
NE	0.9	0.8	0.9	1.0		2%	1%	2%	2%
ND	0.7	0.7	0.8	0.9		1%	1%	2%	2%
SD	0.2	0.2	0.3	0.3		0%	0%	1%	1%
WV	0.1	0.3	0.1	0.1		0%	1%	0%	0%
KY	0.3	0.8	0.1	0.2		1%	1%	0%	0%
Aggregated by RPO									
Natural	4.7	4.9	4.5	5.5		9%	8%	10%	11%
LADCO	13.2	20.6	10.9	11.1		26%	34%	24%	23%
WRAP	1.5	0.8	1.9	1.9		2%	2%	5%	5%
CenSARA	6.0	5.0	6.0	6.0		12%	8%	13%	13%
VISTAS	0.6	1.7	0.3	0.4		1%	3%	1%	1%

Note: Natural (Sea Salt, Fire, Biogenic); LADCO (MN, MI, WI, IL, IN, OH); WRAP (ND, SD, West); CenSARA (IA, MO, AR, LA, TX, OK, KS, Northeast); VISTAS (WY, KY, Southeast)

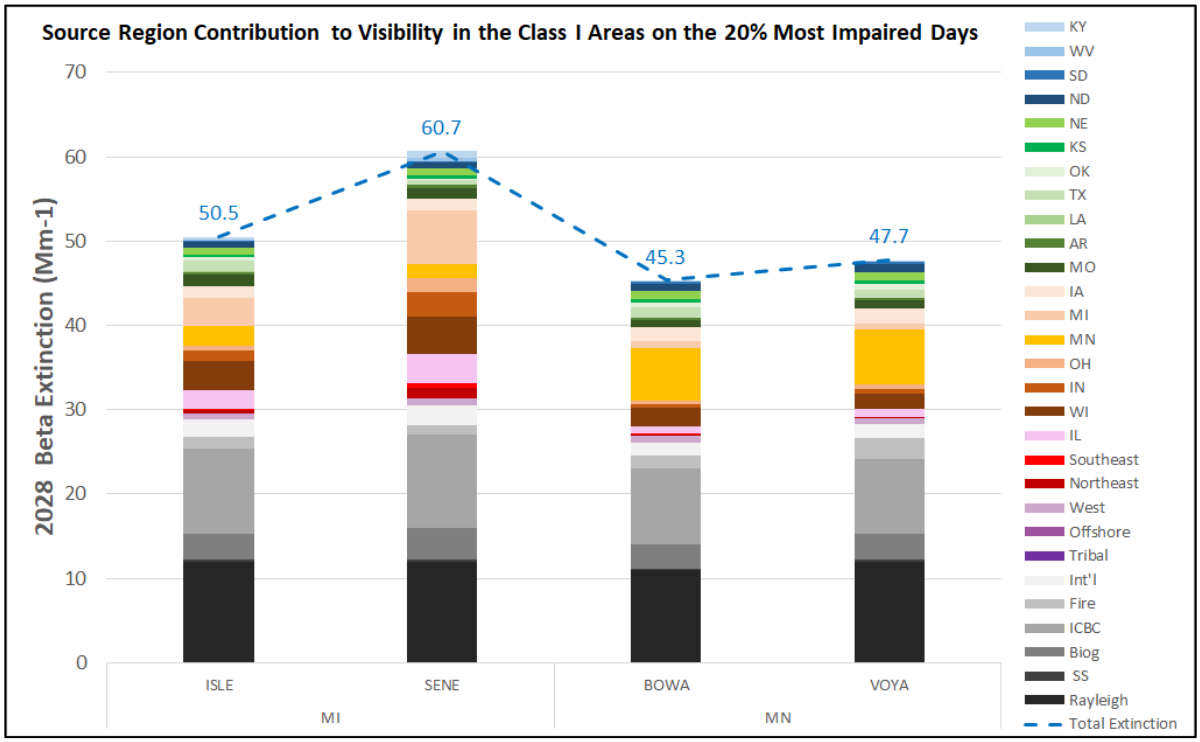


Figure 8-1. State and regional 2028_{2011} tracer contributions to b_{ext} on the 20% most impaired days at the LADCO region class I areas

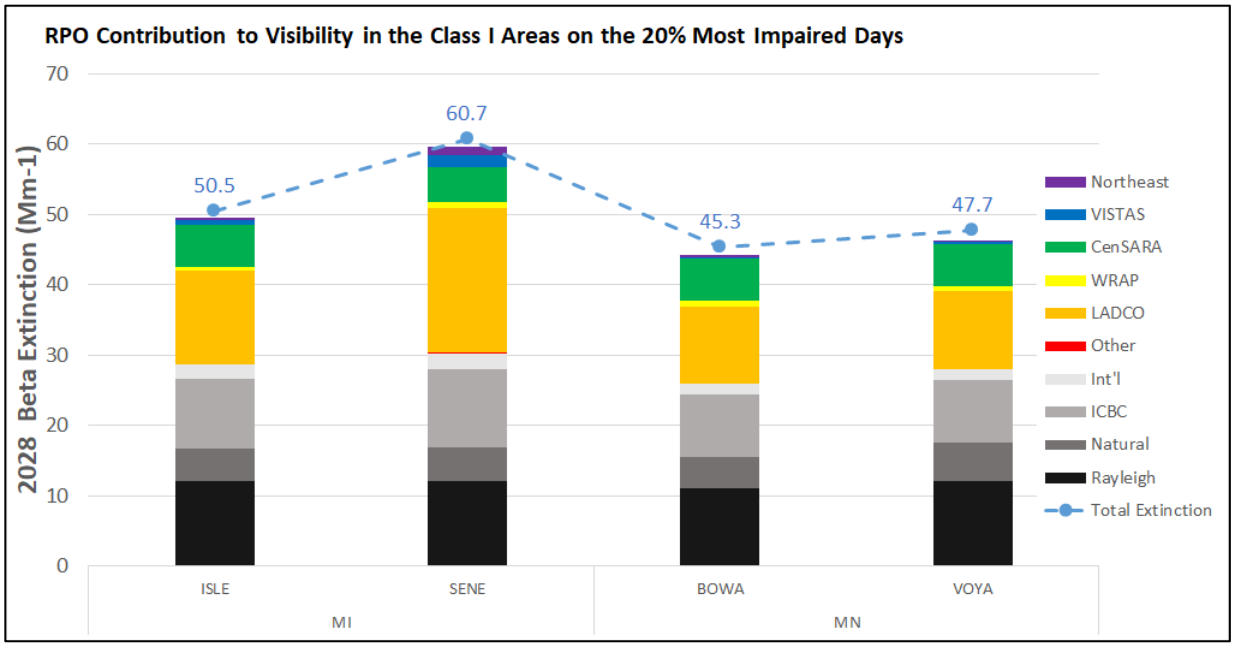


Figure 8-2. RPO 2028_{2011} tracer contributions to b_{ext} on the 20% most impaired days at the LADCO region class I areas

8.2.2 Speciated PM Tracer Results

In addition to quantifying the total contribution from each tracer at receptor areas in the model, the PSAT results can be used to quantify how much each PM species contributes to visibility conditions at the receptors. Figure 8-3 through Figure 8-14 are examples of PSAT tracer footprint plots. These plots show the maximum gridded concentrations of particulate nitrate and sulfate tracers on the 20% most impaired days at different Class I areas in the LADCO. The purpose of the footprint plot is to give a qualitative picture of the spatial signature of sources that contribute to haze impairment at Class I areas. In other words, these plots shows the maximum area of impact of each source region on sulfate and nitrate concentrations during the 20% most impaired days at the different Class I areas. Although PM concentrations do not linearly correspond with visibility impairment, they are a good qualitative surrogate for examining the linkages between emissions sources and downwind visibility impairment.

Figure 8-5 and Figure 8-6 show the maximum nitrate and sulfate tracer forecast (2028_{2011}) concentrations from sources in Minnesota during the 20% most impaired days at the Boundary Waters Canoe Area (BOWA). LADCO estimated that on the 20% most impaired days at BOWA[33], about 2-4 ug/m^3 nitrate and about 1-2 ug/m^3 sulfate concentrations originated from emissions sources in Minnesota. Figure 8-7 and Figure 8-8 show that the LADCO CAMx simulation estimated that a similar amount of nitrate and sulfate originate from the model boundary conditions.

The U.S. EPA's updated 2028 regional haze modeling study (U.S. EPA. 2019b) discussed that the impacts from both nitrate and sulfate are relatively large in the northern states. Based on the U.S. EPA's discussion on Canadian wintertime nitrate and sulfate impacts in the northern states, the modeled concentrations at the Class I areas in the LADCO region could have a minimum of 30-50% contributions from Canada anthropogenic emissions. Figure 8-3 and Figure 8-4 show that the LADCO 2028_{2011} predicted fairly small tracer impacts (<1 μg/m^3) at BOWA from Canadian sources of nitrate and sulfate.

Figure 8-5 through Figure 8-14 show home state maximum particulate nitrate and sulfate tracer concentrations on the 20% most impaired days at Voyageurs National Park, Isle Royale National Park

[33] The tracer footprint plots use the 20% most impaired days from the base year from which the modeling is projected (i.e., 2011 or 2016)

and Seney National Wildlife area, respectively. These figures show sulfate and nitrate contributions on the order of 1-1.5 μg/m^3 from emissions in the home state to each monitor.

LADCO generated footprint plots for all of the Class I areas in and around the LADCO region from our 2011-based 2028 CAMx simulation. The plots are available as an electronic docket to this TSD and can be found on the LADCO website through the following link:

LADCO 2011-based 2028 PM tracer footprint plots

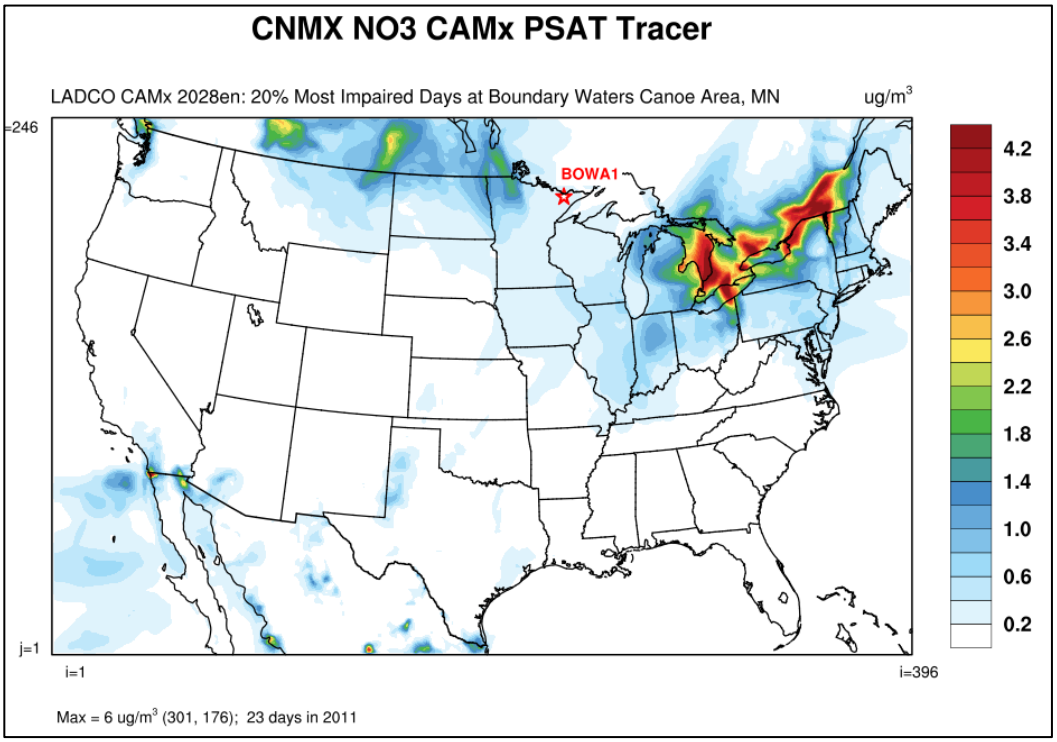


Figure 8-3. Maximum 2028_{2011} nitrate tracer concentration from Canada and Mexico sources on the 20% most impaired days at Boundary Waters, MN

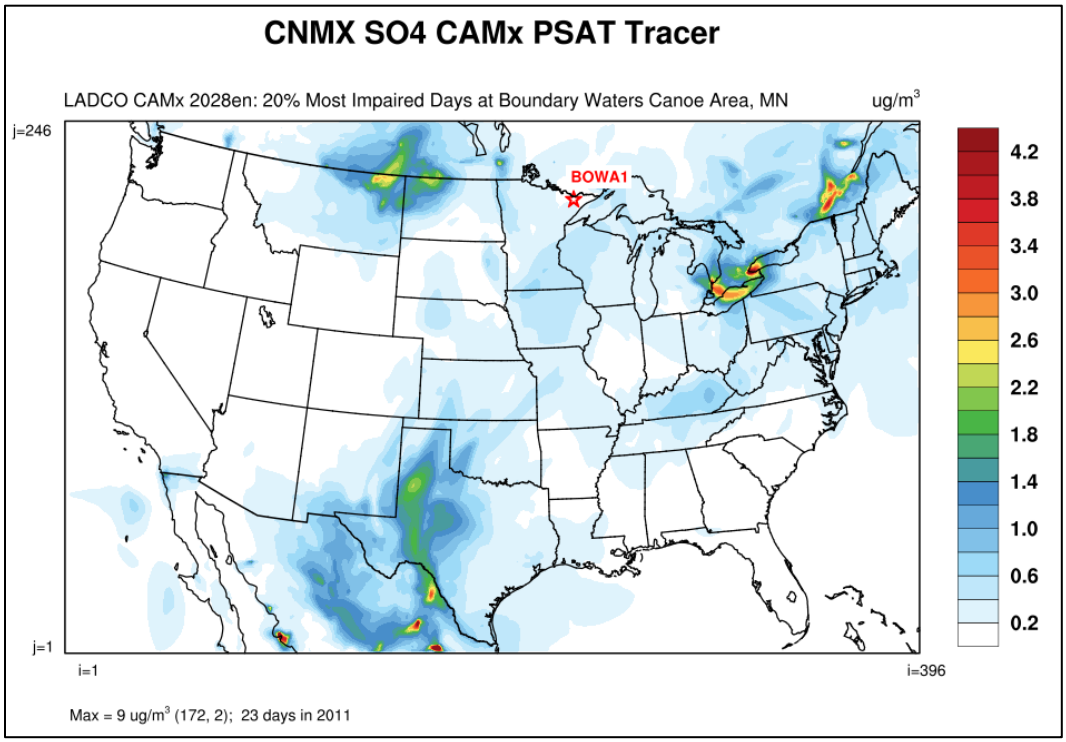


Figure 8-4. Maximum 2028_{2011} sulfate tracer concentration from Canada and Mexico sources on the 20% most impaired days at Boundary Waters, MN

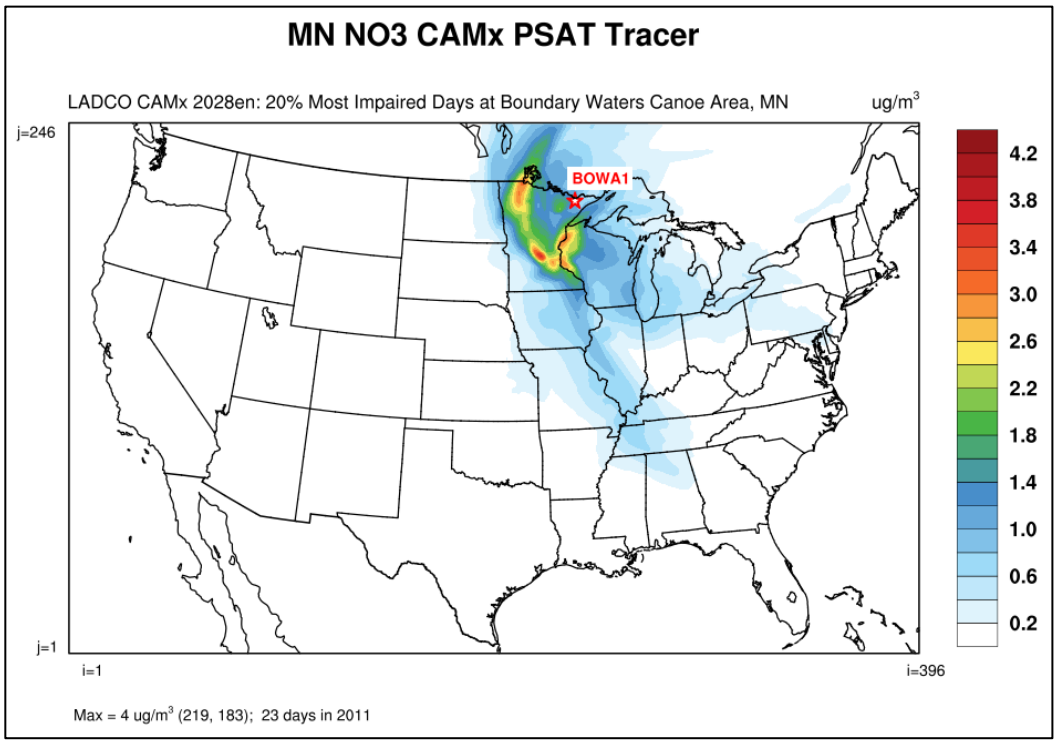


Figure 8-5. Maximum 2028_{2011} nitrate tracer concentration from MN sources on the 20% most impaired days at Boundary Waters, MN

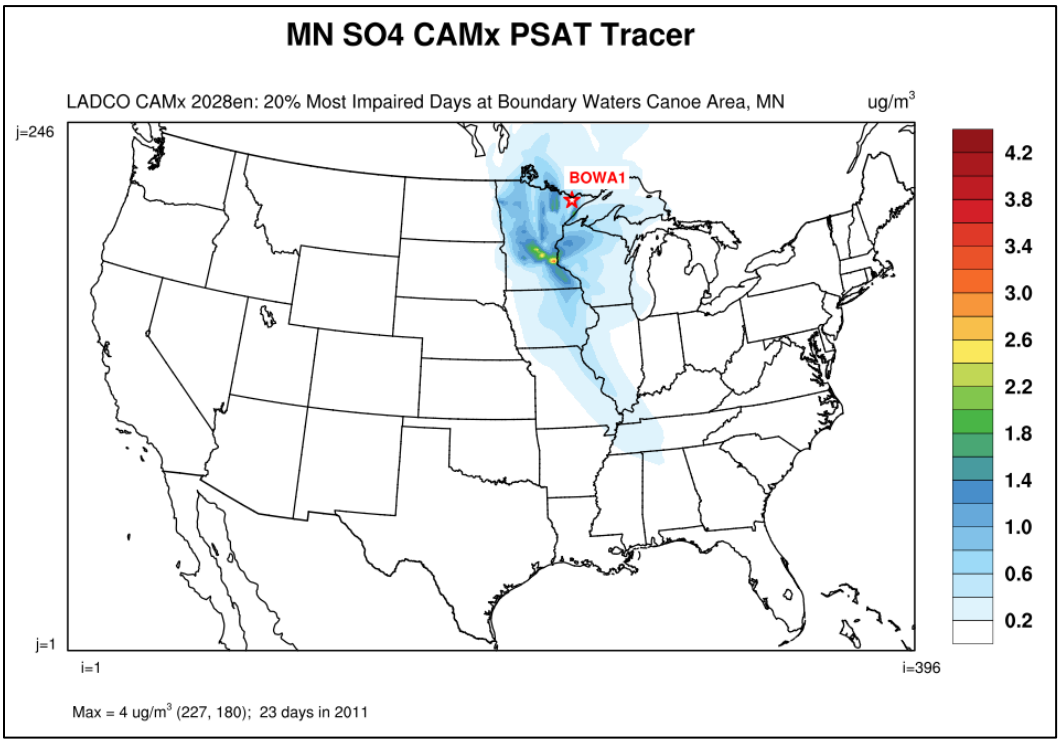


Figure 8-6. Maximum 2028_{2011} sulfate tracer concentration from MN sources on the 20% most impaired days at Boundary Waters, MN

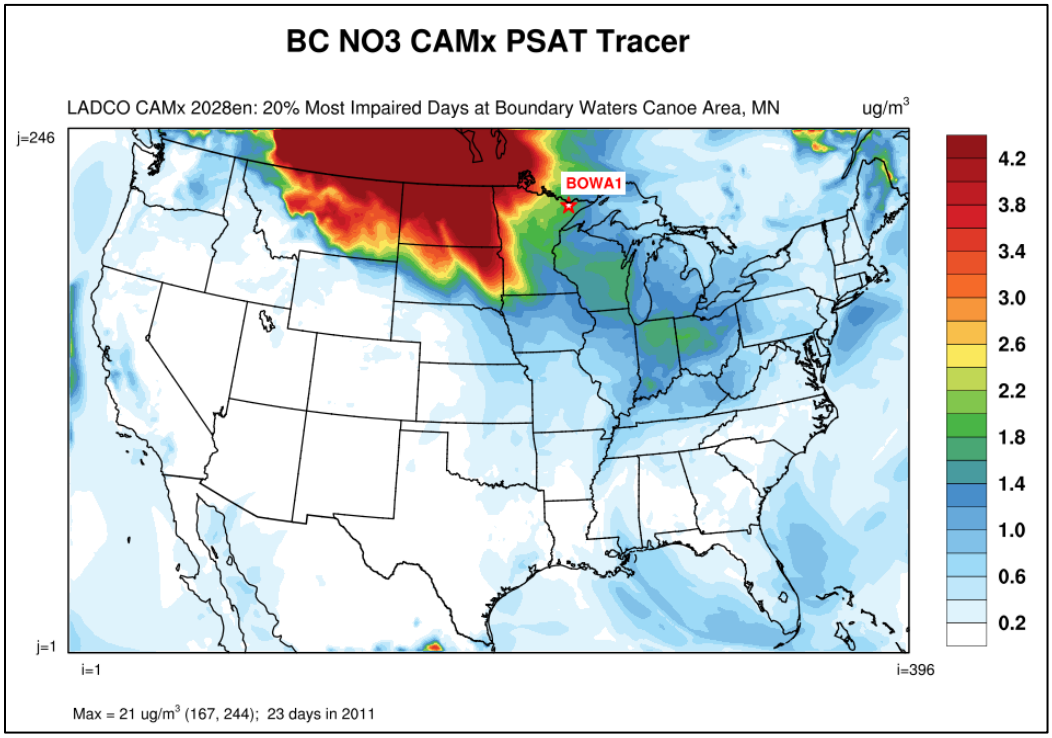


Figure 8-7. Maximum 2028_{2011} nitrate tracer concentration from boundary condition on the 20% most impaired days at Boundary Waters, MN

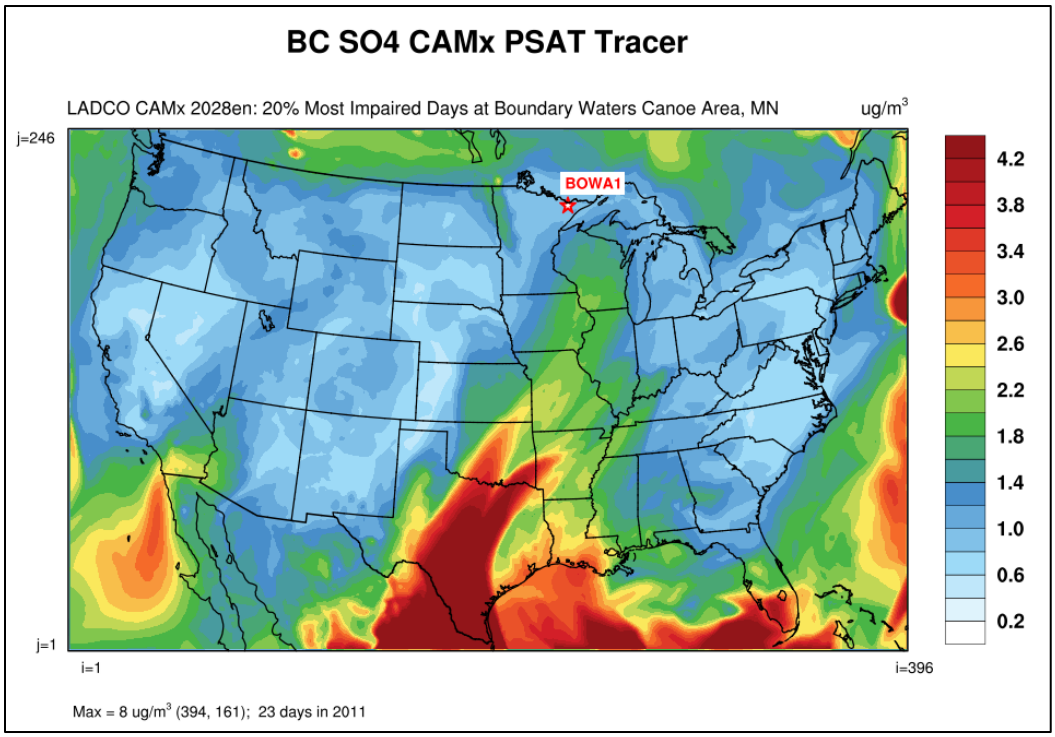


Figure 8-8. Maximum 2028_{2011} sulfate tracer concentration from boundary condition on the 20% most impaired days at Boundary Waters, MN

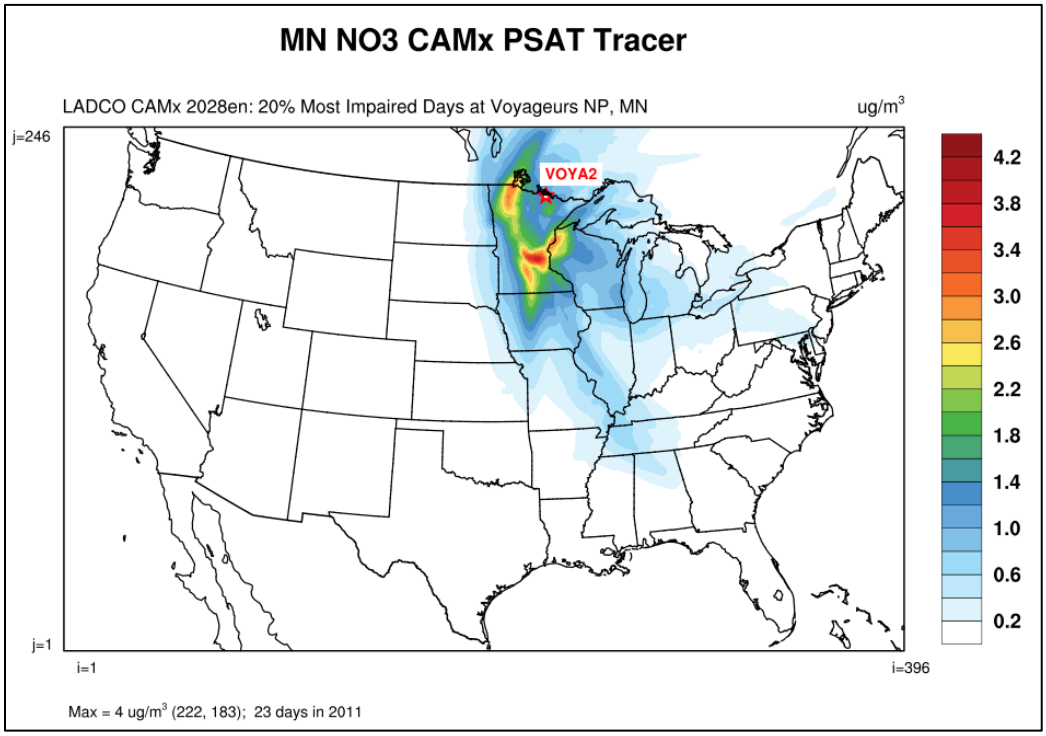


Figure 8-9. Maximum 2028_{2011} nitrate tracer concentration from MN sources on the 20% most impaired days at Voyageurs NP, MN

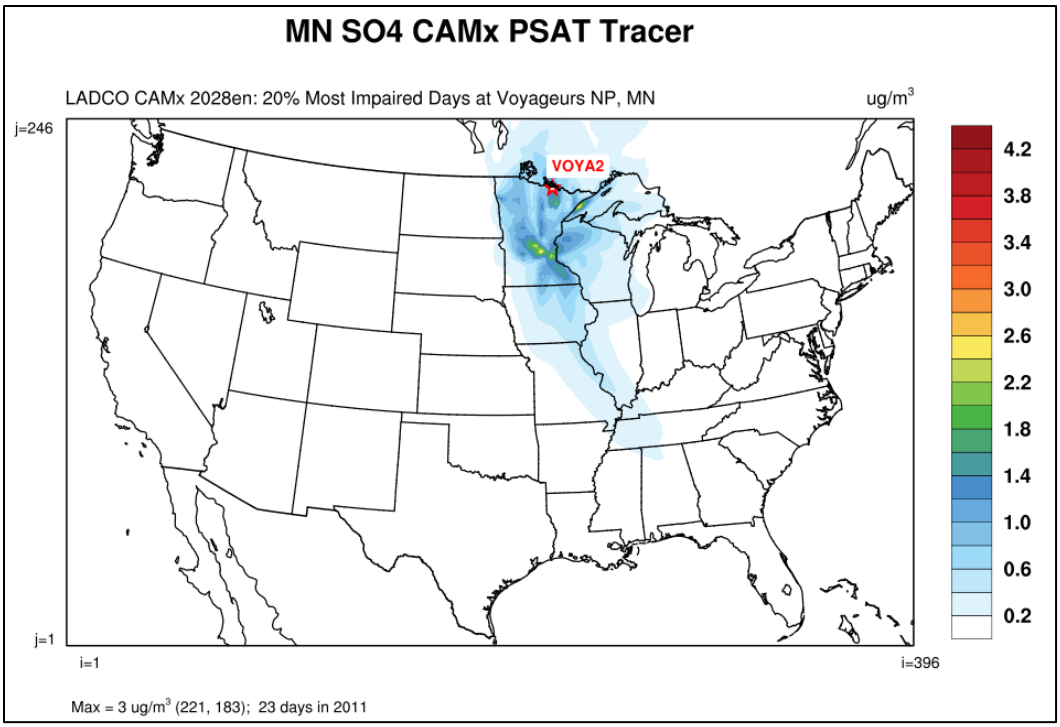


Figure 8-10. Maximum 2028_{2011} sulfate tracer concentration from MN sources on the 20% most impaired days at Voyageurs NP, MN

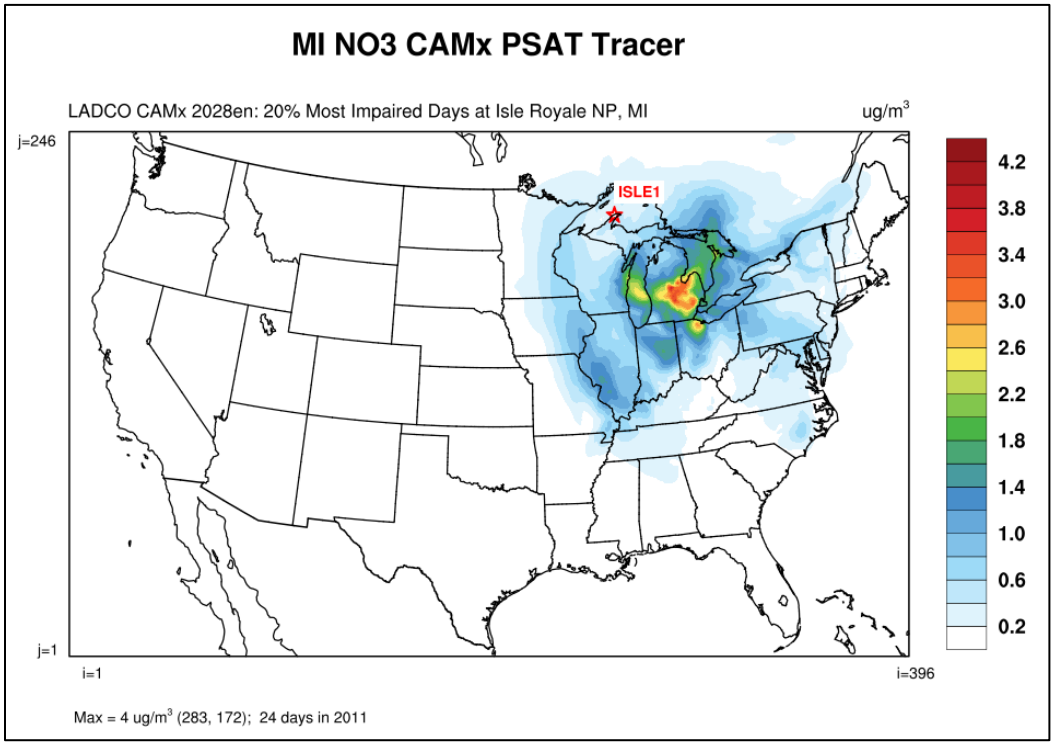


Figure 8-11. Maximum 2028_{2011} nitrate tracer concentration from MI sources on the 20% most impaired days at Isle Royale NP, MI

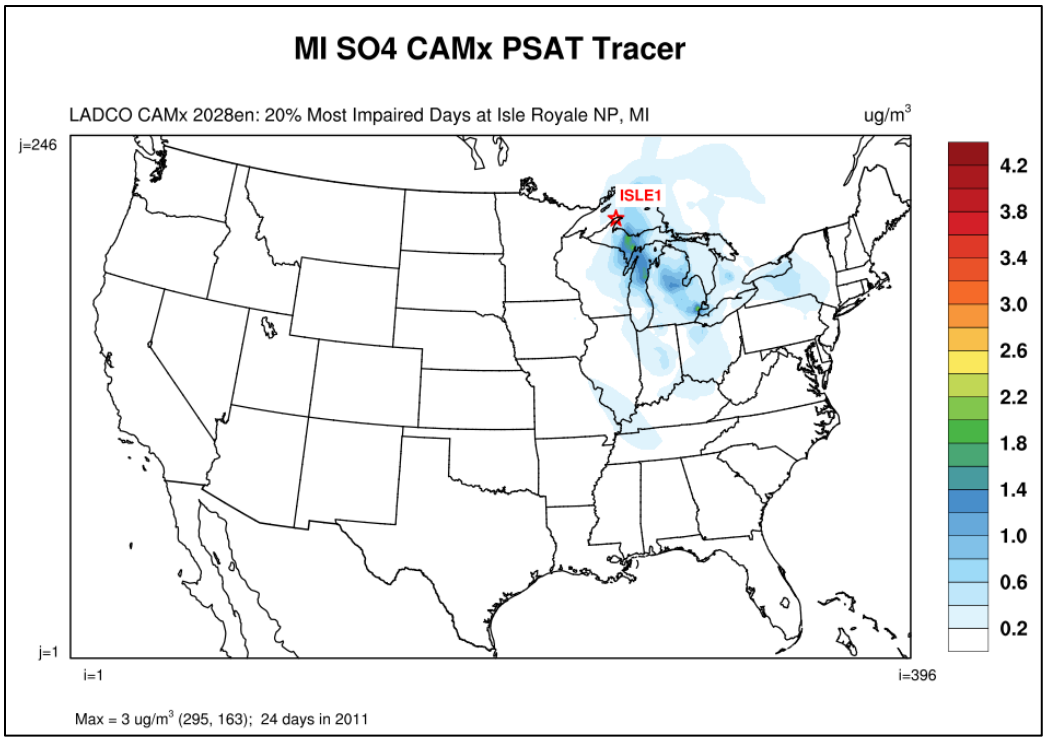


Figure 8-12. Maximum 2028_{2011} sulfate tracer concentration from MI sources on the 20% most impaired days at Isle Royale NP, MI

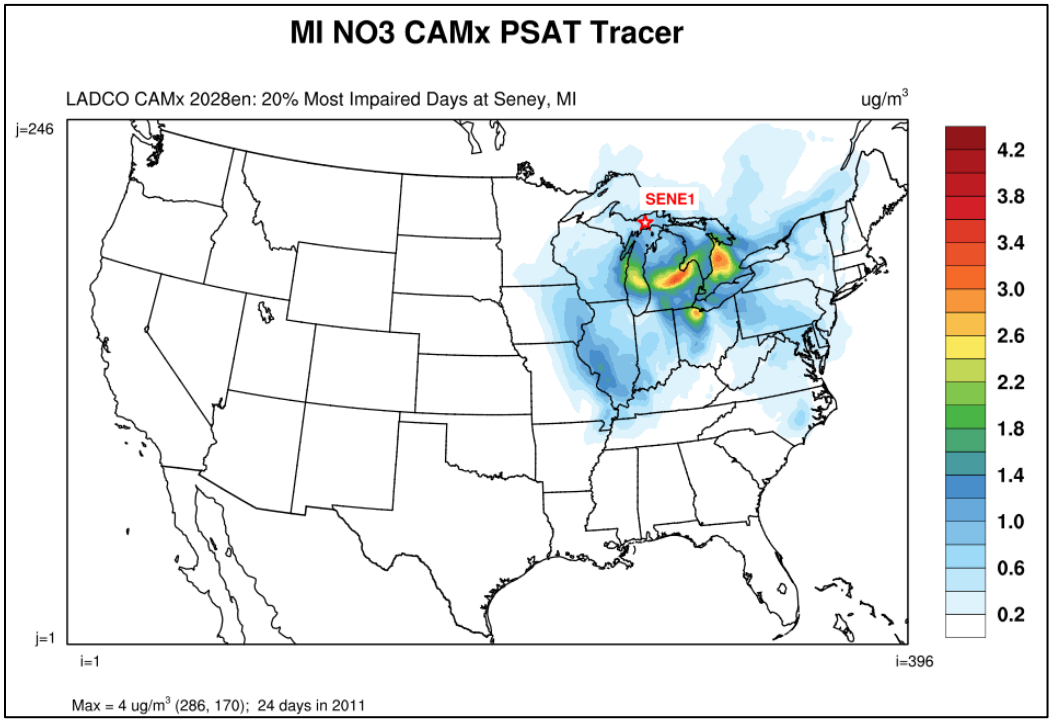


Figure 8-13. Maximum 2028_{2011} nitrate tracer concentration from MI sources on the 20% most impaired days at Seney, MI

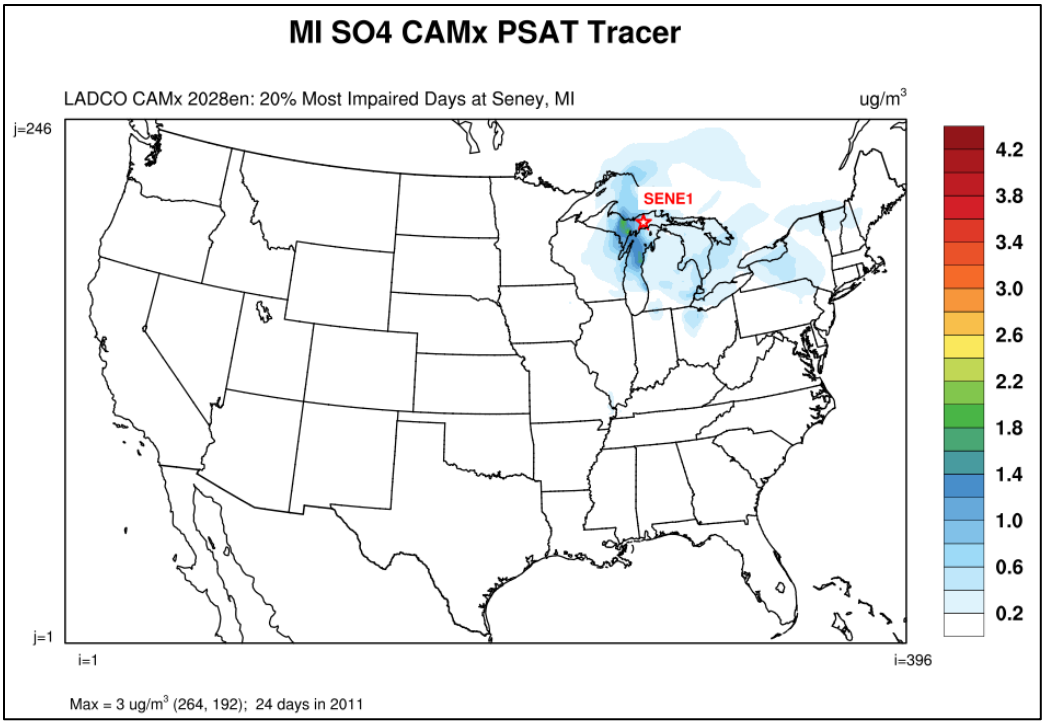


Figure 8-14. Maximum 2028_{2011} sulfate tracer concentration from MN sources on the 20% most impaired days at Seney, MI

The CAMx PSAT results can also be used to quantify the light extinction at the Class I areas by $PM_{2.5}$ composition. LADCO post-processed our CAMx 2028_{2011} modeling results to estimate individual $PM_{2.5}$ species contributions to total light extinction on the 20% most impaired days at the Class I areas. The speciated tracer result for the LADCO region Class I areas are shown in Table 8-4 and in Figure 8-15.

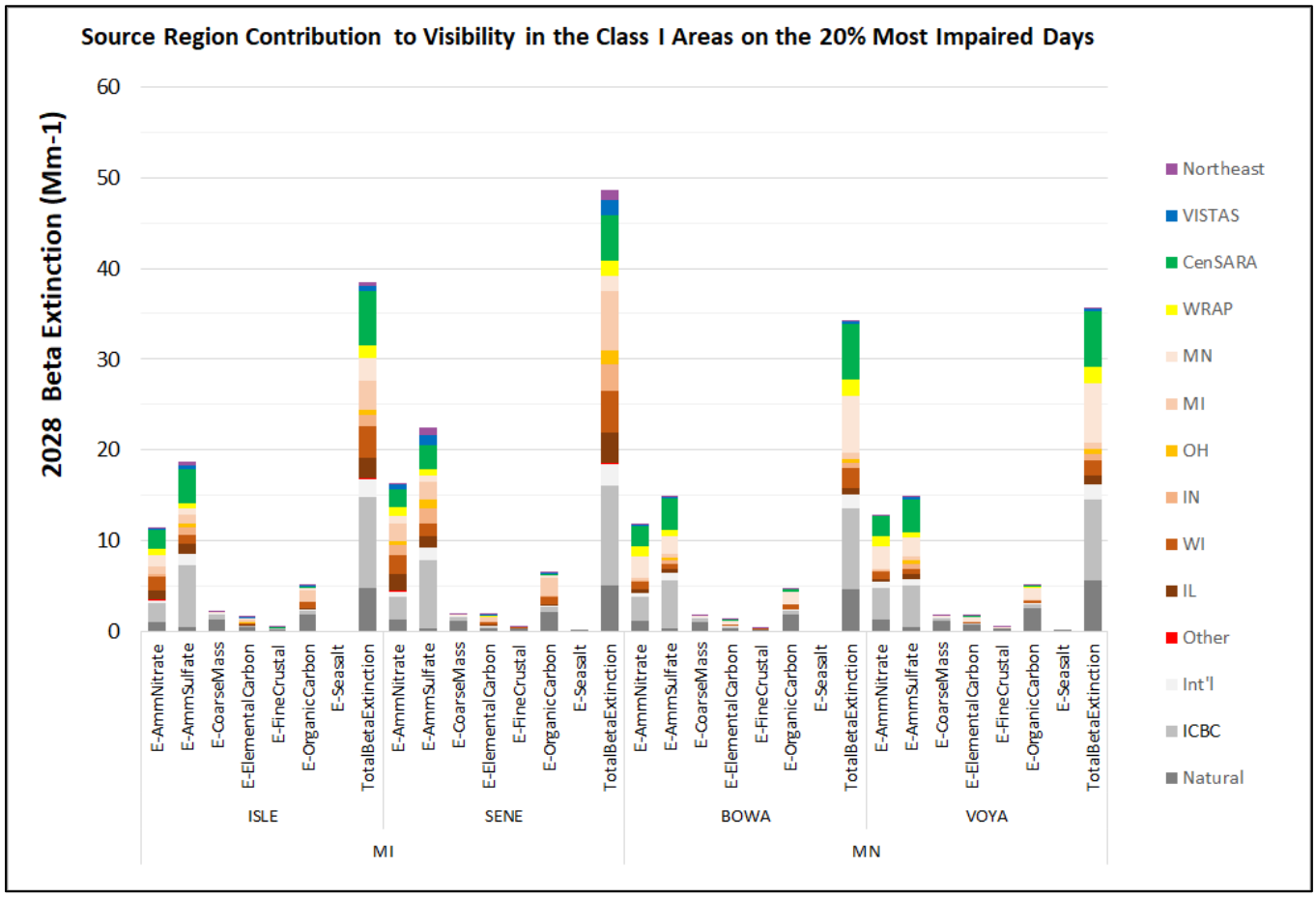


Figure 8-15. PM species tracer contributions to b_{ext} on the 20% most impaired days at the LADCO Class I areas (CAMx 2028_{2011})

Table 8-4. Speciated 2028_{2011} tracer contributions on the 20% most impaired days at the LADCO-region Class I areas

Area	Tracer	Natural	ICBC	Int'l	Other	IL	WI	IN	OH	MI	MN	WRAP	CenSARA	SE	NE	Total
ISLE	Total beta Ext	4.8	10.0	2.0	0.1	2.3	3.5	1.2	0.6	3.3	2.4	1.5	6.0	0.6	0.4	38.5
	NO_3	1.1	2.0	0.4	0.1	1.1	1.5	0.3	0.1	0.7	1.3	0.8	2.0	0.1	0.0	11.3
	SO_4	0.4	6.9	1.3	0.0	1.0	1.0	0.8	0.5	1.0	0.7	0.6	3.7	0.5	0.4	18.7
	CM	1.4	0.5	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2
	EC	0.5	0.1	0.1	0.0	0.1	0.2	0.0	0.0	0.3	0.1	0.0	0.1	0.0	0.0	1.6
	FCRS	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
	OC	1.9	0.4	0.1	0.0	0.1	0.7	0.0	0.0	1.2	0.3	0.0	0.1	0.0	0.0	5.1
	SS	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
SENE	Total beta Ext	5.1	11.1	2.4	0.1	3.4	4.5	2.9	1.5	6.5	1.7	1.7	5.0	1.7	1.2	48.7
	NO_3	1.3	2.5	0.6	0.1	1.8	2.1	1.1	0.4	2.0	0.8	0.9	1.9	0.5	0.2	16.4
	SO_4	0.4	7.5	1.3	0.0	1.3	1.3	1.7	1.0	2.0	0.6	0.7	2.8	1.0	0.9	22.5
	CM	1.3	0.3	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9
	EC	0.4	0.1	0.1	0.0	0.1	0.2	0.1	0.0	0.5	0.1	0.0	0.1	0.0	0.0	1.9
	FCRS	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
	OC	2.2	0.5	0.2	0.0	0.1	0.8	0.1	0.1	1.9	0.2	0.1	0.2	0.1	0.1	6.5
	SS	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
BOWA	Total beta Ext	4.6	8.9	1.5	0.0	0.8	2.2	0.5	0.4	0.8	6.2	1.8	6.0	0.3	0.2	34.3
	NO_3	1.2	2.6	0.4	0.0	0.4	0.9	0.1	0.0	0.3	2.3	1.1	2.3	0.0	0.0	11.7
	SO_4	0.4	5.3	0.8	0.0	0.3	0.7	0.4	0.3	0.4	1.9	0.6	3.5	0.2	0.2	15.0
	CM	1.1	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	1.7
	EC	0.4	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.5	0.0	0.1	0.0	0.0	1.4
	FCRS	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.4
	OC	1.9	0.4	0.1	0.0	0.0	0.5	0.0	0.0	0.1	1.3	0.1	0.2	0.0	0.0	4.6
	SS	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
VOYA	Total beta Ext	5.7	8.9	1.6	0.0	1.0	1.7	0.6	0.5	0.7	6.5	1.8	6.0	0.4	0.2	35.7
	NO_3	1.3	3.5	0.6	0.0	0.4	0.8	0.1	0.0	0.2	2.4	1.2	2.2	0.0	0.0	12.8
	SO_4	0.5	4.6	0.7	0.0	0.5	0.5	0.5	0.4	0.4	2.1	0.6	3.6	0.3	0.2	15.0
	CM	1.2	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	1.8
	EC	0.8	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.5	0.0	0.1	0.0	0.0	1.7
	FCRS	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.6
	OC	2.7	0.3	0.1	0.0	0.0	0.3	0.0	0.0	0.1	1.3	0.1	0.2	0.0	0.0	5.1
	SS	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

8.3 2016 Platform Results

This section presents the results from the LADCO CAMx 2016-based 2028 PSAT configuration that are included in the spreadsheets described in the previous section.

8.3.1 Source Region Tracer Results

The LADCO CAMx 2028_{2016} PSAT modeling estimated the state, Indiana point source, biogenic, initial and boundary condition (ICBC), and international (Canada and Mexico) anthropogenic emissions source contributions to visibility in the U.S. Class I areas (Table 8-5 and Figure 8-16). LADCO redefined the tracers for the 2028_{2016} simulation to support analyses requested by our member states, and to eliminate tracers that had a small (<1 Mm^{-1}) estimated impact on visibility in the 2028_{2011} simulation. In particular, the 2016-based simulation excluded tracers for some of the states surrounding the LADCO region, and included tracers for specific point sources and sectors in Indiana. The 2028_{2016} simulation results include an estimated OC contribution to beta light extinction because the 2028_{2016} did not include the CAMx organic aerosol tracer. LADCO calculated the species "OC estimated" as the difference of total beta extinction from the core CAMx model and the sum of all of the PSAT tracers (including Rayleigh).

CAMx estimated the average light extinction in 2028 across all of the LADCO region Class I areas to be about 47 Mm^{-1}. CAMx estimated that about 25.5% of the extinction is due to Rayleigh scattering, 22% from ICBC (almost entirely from the model boundary conditions), 3.5-10.5% from the residing state, and about 4.6% from the international anthropogenic emissions, mostly from Canada. The average biogenic contribution of 3% does not include the contribution from organic carbon aerosols as these species were not explicitly tracked in this simulation. The relative contribution from biogenics to light extinction at the LADCO Class I areas is at least double the 2028_{2016} estimate as biogenic emissions are the primary source of organic aerosols. The majority of the remainder of the light extinction contribution comes from other states.

Figure 8-16 illustrates the results in Table 8-5 as a stacked bar plot. An aggregation of the PSAT source region tags to regional planning organization (RPO) area for the LADCO Class I areas is shown in Figure 8-17.

Table 8-5. 2028_{2016} tracer contributions to b_{ext} on the most impaired days at the LADCO Class I areas

Source region tags	Source contributions to 2028 visibility at IMPROVE Sites (Mm^{-1})					Percent source contributions to 2028 visibility at IMPROVE Sites (%)			
IMPROVE Sites	ISLE1	SENE1	BOWA1	VOYA2		ISLE1	SENE1	BOWA1	VOYA2
Total Bext	48.6	57.4	40.5	41.0					
Rayleigh	12.0	12.0	11.0	12.0		24.7%	20.9%	27.2%	29.2%
Sea salt (SS)	0.3	0.2	0.2	0.3		0.5%	0.4%	0.5%	0.7%
Biogenic	1.4	1.8	1.2	1.3		2.9%	3.1%	2.9%	3.1%
ICBC	10.5	9.9	9.7	10.0		21.5%	17.2%	23.9%	24.4%
OC Estimated	4.2	5.1	3.6	3.5		8.6%	8.9%	8.9%	8.6%
Fire	0.9	0.9	0.9	0.4		1.9%	1.5%	2.1%	0.9%
Int'l anthropogenic	1.7	2.7	1.7	2.3		3.5%	4.8%	4.3%	5.7%
Offshore	0.2	0.2	0.1	0.1		0.5%	0.4%	0.1%	0.1%
West	1.6	1.9	1.9	1.8		3.4%	3.2%	4.6%	4.4%
Northeast	0.1	0.3	0.1	0.1		0.2%	0.5%	0.2%	0.2%
Southeast	0.4	1.3	0.2	0.2		0.8%	2.2%	0.6%	0.5%
CenSARA Other	2.4	1.8	1.9	1.5		4.9%	3.2%	4.6%	3.6%
IA	1.4	1.5	0.9	0.9		2.9%	2.6%	2.3%	2.1%
MO	1.4	1.7	0.8	0.6		3.0%	3.0%	2.1%	1.6%
TX	0.6	0.3	0.3	0.3		1.1%	0.6%	0.8%	0.7%
IL	2.0	3.6	0.6	0.4		4.0%	6.3%	1.6%	1.0%
WI	2.3	3.5	0.9	0.4		4.8%	6.2%	2.3%	1.0%
MI	1.7	3.4	0.1	0.2		3.5%	6.0%	0.3%	0.5%
OH	0.2	1.2	0.2	0.2		0.4%	2.0%	0.4%	0.5%
MN	2.4	1.7	3.9	4.4		5.0%	3.0%	9.6%	10.6%
IN (Total)	0.9	2.3	0.2	0.2		1.9%	4.0%	0.6%	0.5%
IN (Nonpoint)	0.3	0.7	0.1	0.1		0.6%	1.2%	0.2%	0.2%
IN (Rockport EGU)	0.0	0.1	0.0	0.0		0.1%	0.1%	0.0%	0.0%
IN (Gibson EGU)	0.0	0.1	0.0	0.0		0.1%	0.1%	0.0%	0.0%
IN (other EGU)	0.2	0.5	0.0	0.0		0.4%	0.8%	0.1%	0.1%
IN (Cement)	0.0	0.0	0.0	0.0		0.0%	0.1%	0.0%	0.0%
IN (Iron & Steel)	0.3	0.7	0.0	0.1		0.6%	1.2%	0.1%	0.1%
IN (Plastics & Resins)	0.0	0.0	0.0	0.0		0.0%	0.1%	0.0%	0.0%
IN (Aluminum)	0.0	0.0	0.0	0.0		0.0%	0.0%	0.0%	0.0%
IN (Other Point)	0.1	0.2	0.0	0.0		0.2%	0.4%	0.1%	0.0%
Other Anthro	0.0	0.0	0.0	0.0		0.0%	0.0%	0.0%	0.0%
Aggregated by RPO									
Natural	2.3	2.7	2.0	1.6		5%	5%	5%	4%
LADCO	9.6	15.7	6.0	5.8		20%	27%	15%	14%
WRAP	1.6	1.9	1.9	1.8		3%	3%	5%	4%
CenSARA	5.8	5.4	4.0	3.3		12%	9%	10%	8%
VISTAS	0.4	1.3	0.2	0.2		1%	2%	1%	0%

Note: Natural (Sea Salt, Fire, Biogenic); LADCO (MN, MI, WI, IL, IN, OH); WRAP (ND, SD, West); CenSARA (IA, MO, AR, LA, TX, OK, KS, Northeast); VISTAS (WY, KY, Southeast)

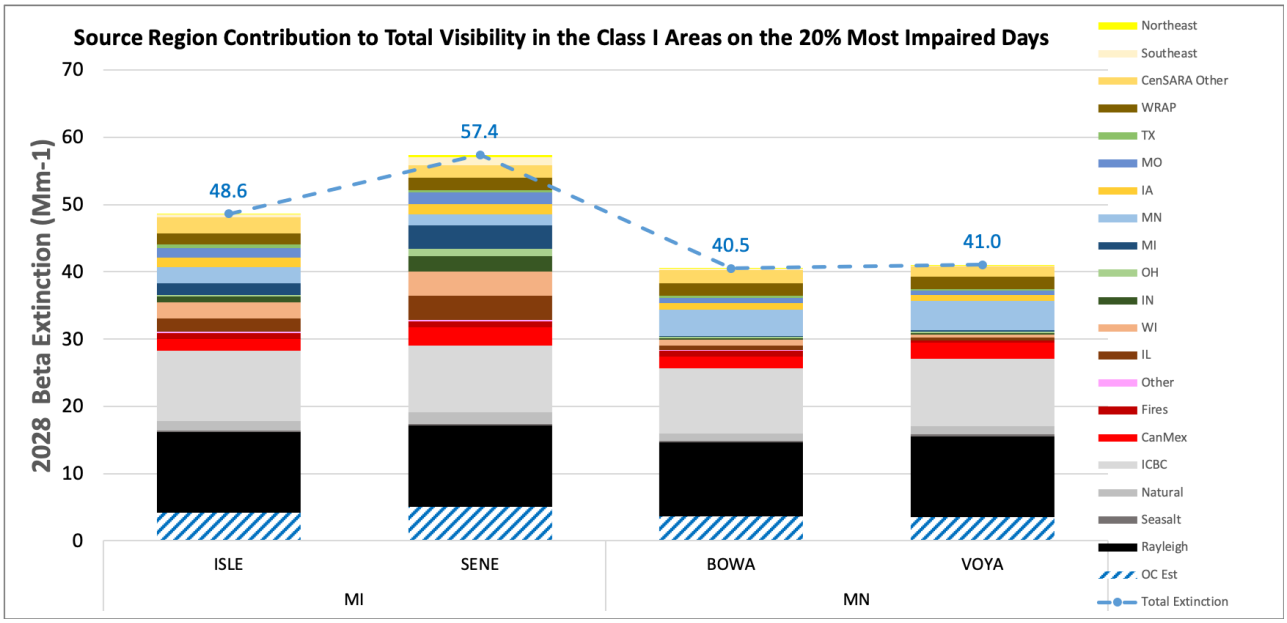


Figure 8-16. State and regional 2028$_{2016}$ tracer contributions to b_{ext} on the 20% most impaired days at the LADCO region class I areas

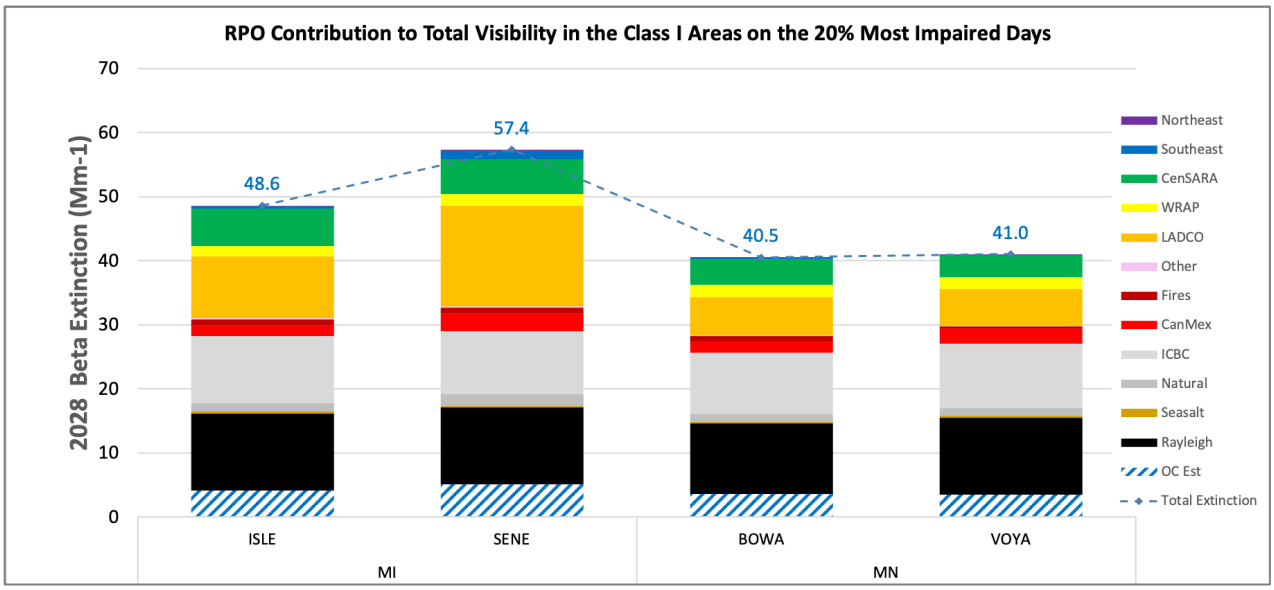


Figure 8-17. RPO 2028$_{2016}$ tracer contributions to b_{ext} on the 20% most impaired days at the LADCO region class I areas

8.3.2 Speciated PM Tracer Results

The PSAT results can also be used to quantify how much each PM species contributes to visibility conditions at the receptors. Figure 8-18 through Figure 8-21 are examples of PSAT tracer footprint plots from LADCO CAMx 2028_{2016}. These plots show the maximum gridded concentrations of particulate nitrate and sulfate tracers on the 20% most impaired days at different Class I areas in the LADCO. These plots shows the maximum area of impact of each source region on sulfate and nitrate concentrations during the 20% most impaired days at the different Class I areas. Although PM concentrations do not linearly correspond with visibility impairment, they are a good qualitative surrogate for examining the linkages between emissions sources and downwind visibility impairment.

Figure 8-20 and Figure 8-21 show the maximum nitrate and sulfate tracer forecast (2028_{2016}) concentrations from sources in Minnesota during the 20% most impaired days at the Boundary Waters Canoe Area (BOWA). LADCO estimated that on the 20% most impaired days at BOWA[34] in 2028, about 0.5-1.5 ug/m^3 nitrate and about 0.5-1.0 ug/m^3 sulfate concentrations will be attributed from emissions sources in Minnesota. Figure 8-18 and Figure 8-19 show that the LADCO 2028_{2016} CAMx simulation estimated that a similar amount of nitrate and sulfate at BOWA originate from Canadian sources as Minnesota sources.

As with the 2011-based 2028 modeling, LADCO generated footprint plots for all of the Class I areas in and around the LADCO region from our 2016-based 2028 CAMx simulation. The plots are available as an electronic docket to this TSD and can be found on the LADCO website through the following link:

LADCO 2016-based 2028 PM tracer footprint plots

[34] The tracer footprint plots use the 20% most impaired days from the base year from which the modeling is projected (i.e., 2011 or 2016)

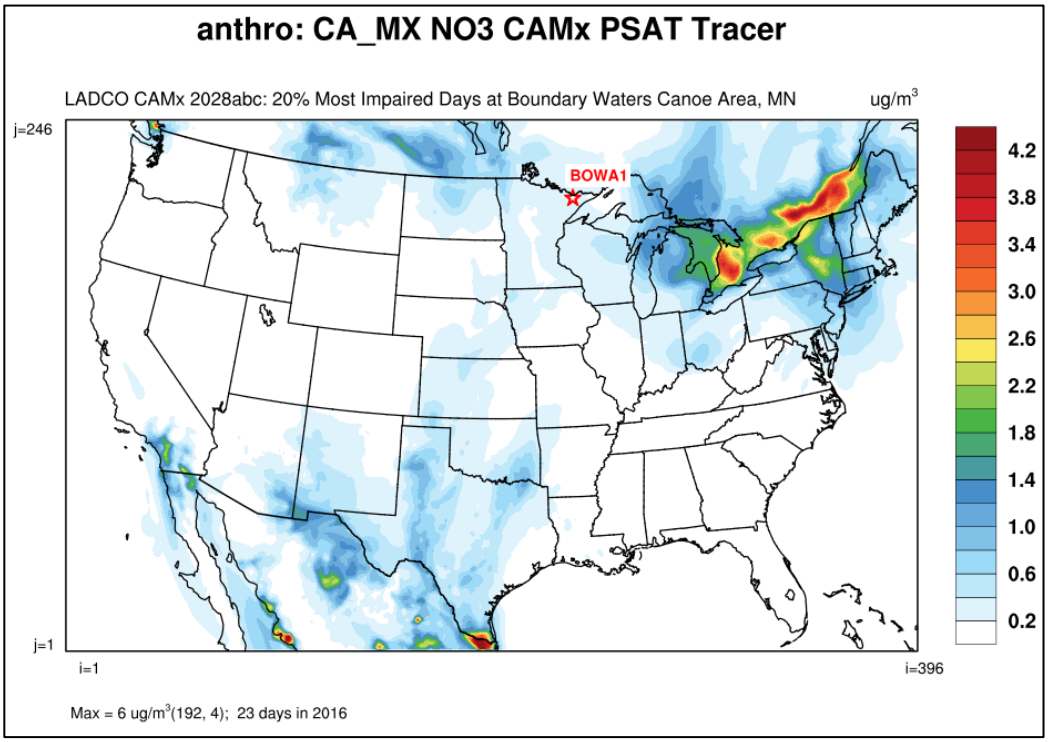


Figure 8-18. Maximum 2028_{2016} nitrate tracer concentration from Canada and Mexico sources on the 20% most impaired days at Boundary Waters, MN

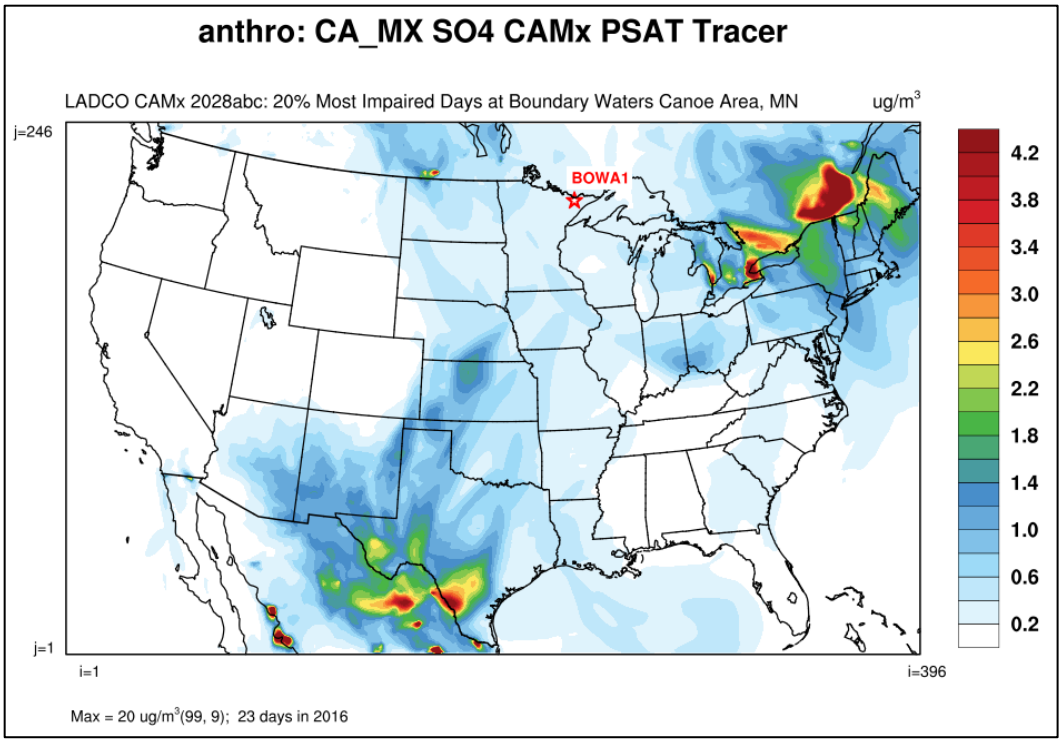


Figure 8-19. Maximum 2028_{2016} sulfate tracer concentration from Canada and Mexico sources on the 20% most impaired days at Boundary Waters, MN

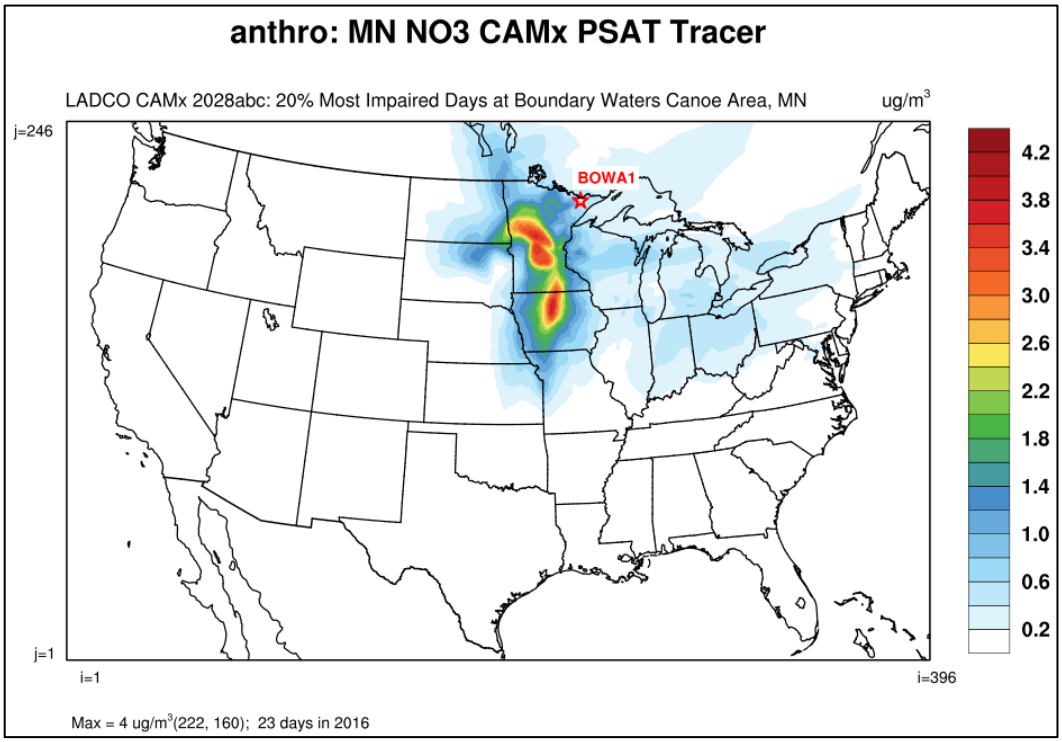


Figure 8-20. Maximum 2028_{2016} nitrate tracer concentration from MN sources on the 20% most impaired days at Boundary Waters, MN

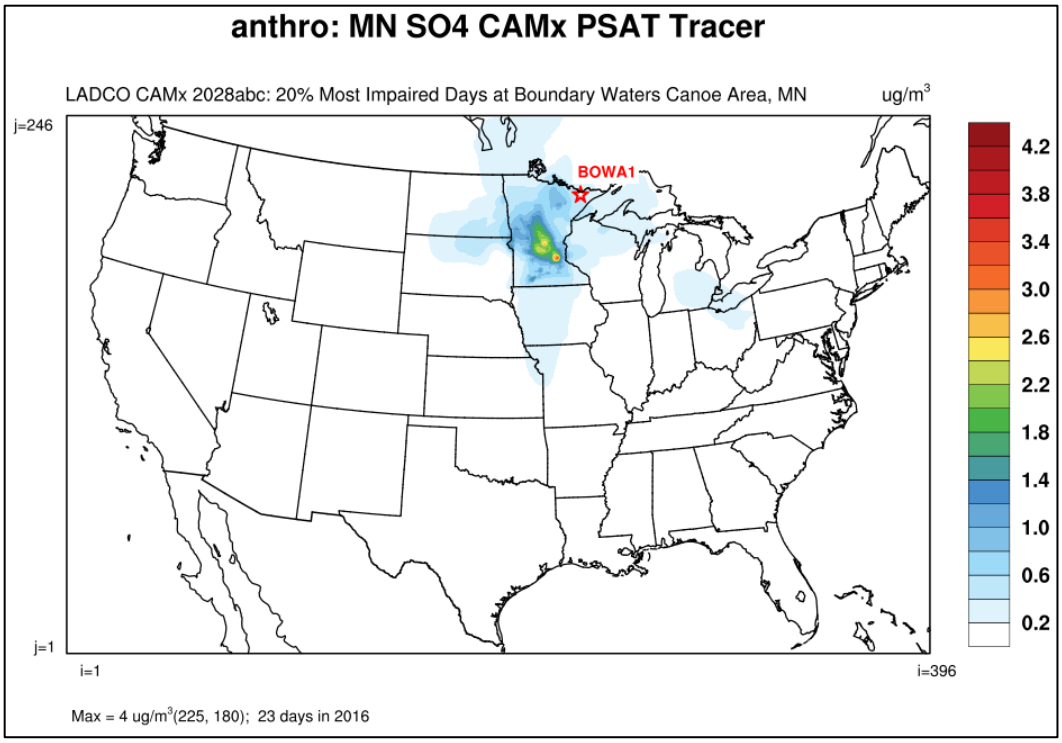


Figure 8-21. Maximum 2028_{2016} sulfate tracer concentration from MN sources on the 20% most impaired days at Boundary Waters, MN

LADCO also used the CAMx PSAT results to quantify the light extinction at Class I areas by $PM_{2.5}$ composition in 2028. LADCO post-processed our CAMx 2028_{2016} modeling results to estimate individual $PM_{2.5}$ species contributions to total light extinction on the 20% most impaired days at the Class I areas. The speciated tracer result for the LADCO region Class I areas are shown in Table 8-6 and in Figure 8-15.

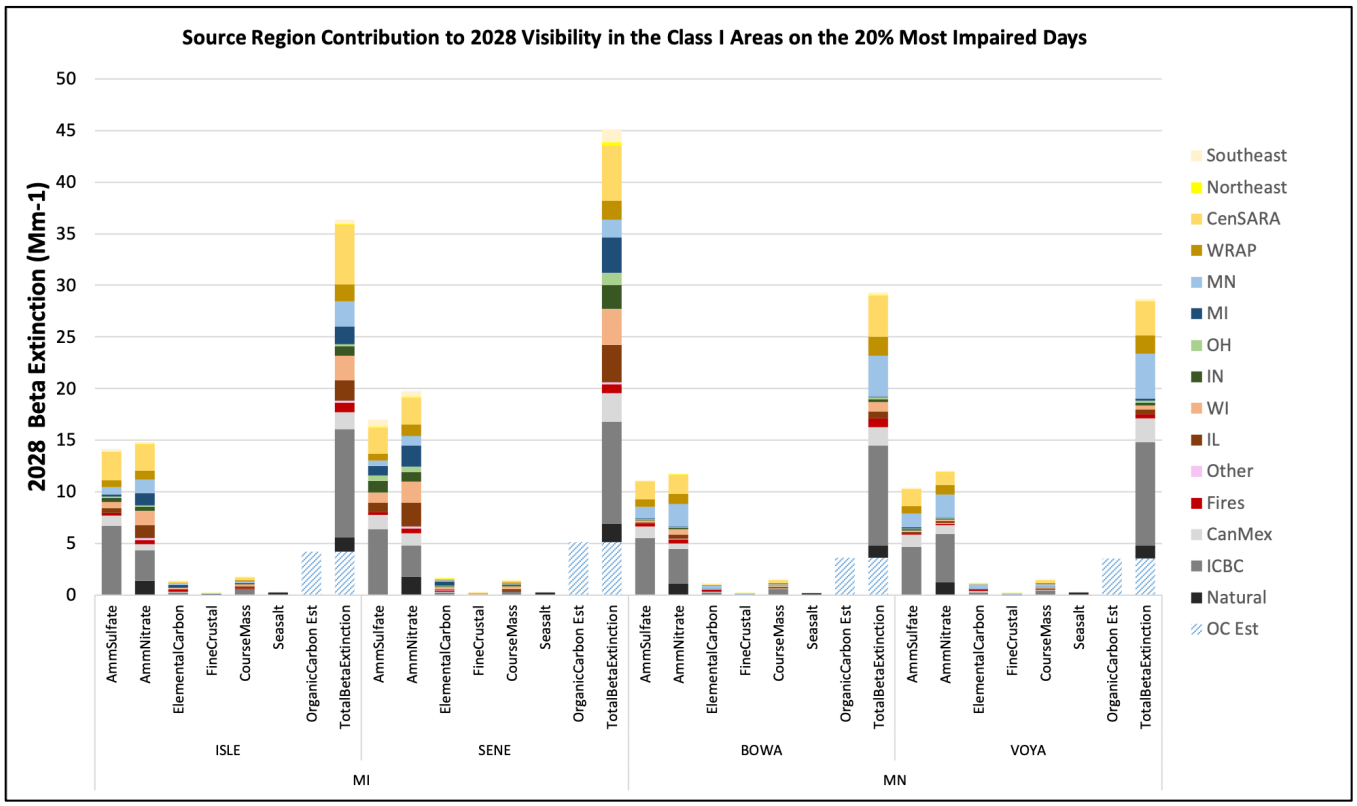


Figure 8-22. PM species tracer contributions to b_{ext} on the 20% most impaired days in 2028 at the LADCO Class I areas (CAMx 2028_{2016})

Table 8-6. Speciated 2028_{2016} tracer contributions on the 20% most impaired days at the LADCO-region Class I areas

Area	Tracer	OC_{est}	Natural	ICBC	Int'l	Fires	Other	IL	WI	IN	OH	MI	MN	WRAP	Cen	SE	NE	Total
ISLE	Total beta Ext	4.2	1.4	10.5	1.7	0.9	0.2	2.0	2.3	0.9	0.2	1.7	2.4	1.6	5.8	0.4	0.1	36.4
	NO_3	0.0	1.4	3.0	0.6	0.4	0.2	1.3	1.3	0.4	0.1	1.2	1.4	0.8	2.6	0.1	0.1	14.8
	SO_4	0.0	0.0	6.7	1.0	0.3	0.0	0.4	0.6	0.4	0.1	0.2	0.7	0.6	2.8	0.2	0.0	14.1
	CM	0.0	0.0	0.6	0.1	0.0	0.0	0.2	0.2	0.0	0.0	0.1	0.1	0.1	0.3	0.0	0.0	1.7
	EC	0.0	0.0	0.3	0.1	0.2	0.0	0.1	0.1	0.0	0.0	0.2	0.2	0.0	0.1	0.0	0.0	1.3
	FCRS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
	OC	4.2	0.0	0.0	0.0	0.0	0.0			0.0					0.0	0.0	0.0	4.2
	SS		0.3															0.3
SENE	Total beta Ext	5.1	1.8	9.9	2.7	0.9	0.2	3.6	3.5	2.3	1.2	3.4	1.7	1.9	5.4	1.3	0.3	45.1
	NO_3	0.0	1.8	3.0	1.2	0.4	0.2	2.3	2.1	1.0	0.5	2.0	1.0	1.1	2.6	0.5	0.2	19.8
	SO_4	0.0	0.0	6.3	1.4	0.2	0.0	0.9	1.0	1.1	0.5	0.9	0.5	0.7	2.5	0.7	0.1	17.0
	CM	0.0	0.0	0.3	0.0	0.0	0.0	0.2	0.2	0.1	0.1	0.1	0.0	0.1	0.2	0.0	0.0	1.4
	EC	0.0	0.0	0.2	0.1	0.2	0.0	0.1	0.2	0.1	0.0	0.4	0.1	0.0	0.1	0.0	0.0	1.6
	FCRS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
	OC	5.1	0.0	0.0	0.0	0.0	0.0			0.0					0.0	0.0	0.0	5.1
	SS		0.2															0.2
BOWA	Total beta Ext	3.6	1.2	9.7	1.7	0.9	0.1	0.6	0.9	0.2	0.2	0.1	3.9	1.9	4.0	0.2	0.1	29.3
	NO_3	0.0	1.1	3.3	0.5	0.4	0.1	0.4	0.5	0.1	0.1	0.1	2.2	1.0	1.9	0.1	0.0	11.8
	SO_4	0.0	0.0	5.5	1.1	0.3	0.0	0.1	0.2	0.1	0.1	0.0	1.1	0.7	1.7	0.1	0.0	11.2
	CM	0.0	0.0	0.6	0.1	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.2	0.1	0.3	0.0	0.0	1.5
	EC	0.0	0.0	0.3	0.1	0.2	0.0	0.0	0.1	0.0	0.0	0.0	0.3	0.0	0.1	0.0	0.0	1.1
	FCRS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.2
	OC	3.6	0.0	0.0	0.0	0.0	0.0			0.0					0.0	0.0	0.0	3.6
	SS		0.2															0.2
VOYA	Total beta Ext	3.5	1.3	10.0	2.3	0.4	0.1	0.4	0.4	0.2	0.2	0.2	4.4	1.8	3.3	0.2	0.1	28.7
	NO_3	0.0	1.2	4.7	0.9	0.1	0.0	0.2	0.2	0.1	0.1	0.1	2.2	0.9	1.3	0.1	0.0	12.0
	SO_4	0.0	0.0	4.6	1.2	0.1	0.0	0.1	0.1	0.1	0.1	0.1	1.3	0.7	1.6	0.1	0.0	10.4
	CM	0.0	0.0	0.4	0.1	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.3	0.1	0.3	0.0	0.0	1.4
	EC	0.0	0.0	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.1	0.0	0.0	1.1
	FCRS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.2
	OC	3.5	0.0	0.0	0.0	0.0	0.0			0.0					0.0	0.0	0.0	3.5
	SS		0.3															0.3

9 Conclusions and Significant Findings

LADCO presents in this TSD the results from two regional air quality modeling platforms for quantifying and evaluating future year haze conditions pursuant to tracking progress during the second planning period for the Regional Haze Rule.

Significant findings in this report include:

Trends in PM Concentrations and Regional Haze (Section 2)

- $PM_{2.5}$ design values at all monitors in the LADCO region are currently below the levels of both $PM_{2.5}$ NAAQS. In particular, the 2019 24-hour DVs are at least five $\mu g/m^3$ below the level of the NAAQS. The highest concentrations in the LADCO region are in the urban areas, and the lowest concentrations are in the far northern parts of the region, including near LADCO's Class I areas.
- Both the annual and 24-hour $PM_{2.5}$ design values for the LADCO states decreased by 33% to 51% between 2002 and 2019.
- Concentrations of all of the measured $PM_{2.5}$ species have decreased at the regional surface monitors since 2001, with the largest reductions (70%) from ammonium sulfate aerosols and the smallest reductions (7%) from organic carbon.
- From 2000 to 2018, visibility on the most impaired days at the LADCO region Class I areas improved by 18% to 26%. Visibility improvements were even greater on the clearest days, with improvements of 26% to 34%.
- Concentrations of ammonium sulfate have undergone particularly large reductions over the past two decades. As a result, ammonium nitrate and organic carbon have become relatively more important contributors to fine particulate matter and haze in the LADCO region.

Air Quality Modeling (Section 3)

- LADCO used 2011 and 2016 as modeling base years from which to project visibility conditions in 2028. LADCO selected these modeling years because they were available as modeling platforms that included projections to 2028 during the current regional haze implementation period.

Air Quality Modeling Performance Evaluation (Section 6)

- The LADCO CAMx 2011 and 2016 modeling results are comparable to the U.S. EPA 2011 and 2016 modeling platforms that the Agency used for regional haze modeling
- Both of the LADCO base year CAMx simulations achieved either the model performance goals or criteria for most of the $PM_{2.5}$ species in the winter and spring seasons
- The LADCO CAMx simulations generally better estimated $PM_{2.5}$ at the more rural IMPROVE sites compared to the CSN sites (i.e., lower NMB and NME at IMPROVE vs CSN).
- CAMx did not simulate the carbonaceous or organic aerosol well in either of the base years.
- The LADCO CAMx simulations performed relatively well in estimating spring and winter season nitrate and sulfate at the IMPROVE monitors in both 2011 and 2016.

Future Year Haze Projections (Section 7)

- The visibility conditions at the Class I areas in the LADCO region were predicted to improve on average by about 2 dv in 2028 as compared to the 2011 base year, and about 0.8 dv improvement relative to the 2016 base year.
- Predicted 2028 visibility conditions based on the 2016 modeling platform shows that the visibility in the Class I areas in Minnesota and Michigan is about 1.4 dv below the unadjusted glidepath line (i.e., URP). Accounting for the adjustment due to the international contribution, LADCO estimated 2028 visibility on the 20% most impaired days to be about 2.6 dv below the URP line.

2028 Source-Receptor Modeling Results (Section 8)

- LADCO's 2011-based 2028 projection modeling estimated that natural sources such as Rayleigh, sea salt, biogenic and fire emissions will contribute 28-33 % of the light extinction coefficients in the LADCO's Class I areas, while the LADCO and CenSARA RPOs will contribute 23-24% and 8-13% of the extinction, respectively.
- LADCO's 2016-based 2028 projection modeling estimated that natural sources such as Rayleigh, sea salt, biogenic and fire emissions will contribute 28-36 % of the light extinction coefficients in the LADCO's Class I areas, while the LADCO and CenSARA RPOs will contribute 14-27% and 8-13% of the extinction, respectively.

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APPENDIX C: Consultation with Arkansas DEQ

ARKANSAS
ENERGY & ENVIRONMENT

February 4, 2020

Rory Davis
Air Quality Planning
Illinois EPA

Sent Via Electronic Mail

Dear Mr. Davis:

The Arkansas Department of Energy and Environment, Division of Environmental Quality (DEQ), seeks consultation with Illinois EPA (IEPA) to develop a coordinated emission management strategy for Regional Haze State Implementation Plan (SIP) Revisions due on July 31, 2021 as required under 40 CFR 51.308(f)(2)(ii) for Upper Buffalo wilderness area.

The key pollutants from anthropogenic sources impairing visibility at Upper Buffalo are ammonium sulfate and ammonium nitrate.[1] Ammonium sulfate is formed by chemical reactions between ammonia and sulfur dioxide (SO_2) in the atmosphere. Ammonium nitrate is formed by chemical reactions between ammonia and nitrogen oxides (NOx) in the atmosphere. Environmental Protection Agency (EPA) modeling projects that these two pollutants will continue to be the key pollutants contributing to visibility impairment at Arkansas Class I areas in 2028.[2]

The states in the Central States Air Resources Agencies (CENSARA) organization, which includes Arkansas, contracted with Ramboll US Corporation (Ramboll) to produce a study examining the impact of stationary sources of NOx and SO_2 on each Class I area in the central region of the United States. For each Class I area, the study took into account light extinction-weighted wind trajectory residence times, 2016 sulfur dioxide and nitrogen oxides facility emissions, and distance from sources of nitrogen oxides and sulfur dioxide to Class I Areas. The study produced an area of influence (AOI) for each Class I area, which shows the geographic areas with a high probability of contributing to anthropogenic visibility impairment.

Based on the results of the AOI study, DEQ has identified the following source in your state as reasonably anticipated to impact visibility conditions at Upper Buffalo: Prairie Generating Station

Therefore, DEQ requests that IEPA consider whether performing a four-factor analysis is appropriate for the listed source in accordance with 40 CFR 51.308(f)(2)(i) and, if so, whether any

[1] http://vista.cira.colostate.edu/Improve/improve-data/
[2] https://www.epa.gov/visibility/visibility-guidance-documents

control measures for sulfur dioxide or nitrogen oxides are necessary to make reasonable progress towards natural visibility at Upper Buffalo during the 2021–2028 planning period.

We look forward to working with you on this important effort. We request that you share with DEQ the results of your analysis, including any technical supporting documentation, and provide an opportunity for consultation on the analysis and your state's long-term strategy early enough in the process for DEQ to provide feedback to IEPA and for DEQ to incorporate emission reductions anticipated from IEPA's long-term strategy affecting Upper Buffalo into DEQ's reasonable progress goals for Upper Buffalo.

Should you have any questions, please contact Tricia Treece at 501-682-0055 (treecep@adeq.state.ar.us) or David Clark at 501-682-0070 (clarkd@adeq.state.ar.us).

Sincerely,

William K. Montgomery
Interim Associate Director
Office of Air Quality

ARKANSAS
ENERGY & ENVIRONMENT

March 1, 2021

Rory Davis
Air Quality Planning
Illinois EPA

Sent via electronic mail

Re: Notification of Opportunity for Consultation; Arkansas Regional Haze State Implementation Plan (SIP) for Planning Period II

Dear Mr. Davis:

This letter serves to notify you that the Arkansas Department of Energy and Environment's Division of Environmental Quality (DEQ) has prepared two pre-proposal draft revisions to the Arkansas Regional Haze State Implementation Plan (SIP) to address requirements for Planning Period II. The first addresses Regional Haze Rule Requirements for Planning Period II with the exception of the control strategy for Entergy's Independence facility. The second addresses the control strategy for Independence.

This notification is intended to provide your agency with an opportunity for a sixty-day consultation period on this SIP revision in accordance with 40 C.F.R. § 51.308(i). This consultation will give you the opportunity to discuss your assessment of the impact of the proposed revisions on federal Class I areas in a manner consistent with 40 C.F.R. § 51.308(i).

The pre-proposal draft of the SIP revision can be accessed at https://1drv.ms/f/s!AtaMFQw8GYddgWVKkz-quTL2xT6f. Please note that all documents are draft working documents and are subject to change prior to finalization for proposal. If changes are made between the date of this letter and proposal, DEQ will notify you of the changes.

DEQ requests that any comments on the pre-proposal copy of the SIP revision be provided to DEQ by no later than Friday April 30, 2021.

Should you wish to schedule a meeting or have any questions, please contact Tricia Treece at treecep@adeq.state.ar.us. We request that written comments be submitted electronically by emailing treecep@adeq.state.ar.us. You may also mail comments to Tricia Treece, Office of Air Quality, Division of Environmental Quality, Department of Energy and Environment, 5301 Northshore Drive, North Little Rock, AR 72118.

Sincerely,



William K. Montgomery
Associate Director, Office of Air Quality
Division of Environmental Quality
5301 Northshore Drive, North Little Rock, AR 72118

APPENDIX D: Consultation with MANE-VU

Members
Connecticut
Delaware
District of Columbia
Maine
Maryland
Massachusetts
New Hampshire
New Jersey
New York
Pennsylvania
Penobscot Indian Nation
Rhode Island
St. Regis Mohawk Tribe
Vermont

Nonvoting Members
U.S. Environmental Protection Agency
National Park Service
U.S. FIsh and Wildlife Service
U.S. Forest Service

MANE-VU Class I Areas

ACADIA NATIONAL PARK ME

BRIGANTINE WILDERNESS NJ

GREAT GULF WILDERNESS NH

LYE BROOK WILDERNESS VT

MOOSEHORN WILDERNESS ME

PRESIDENTIAL RANGE DRY RIVER WILDERNESS NH

ROOSEVELT CAMPOBELLO INTERNATIONAL PARK ME/NB, CANADA

Mid-Atlantic/Northeast Visibility Union

MANE-VU

Reducing Regional Haze for Improved Visibility and Health

STATEMENT OF THE MID-ATLANTIC/NORTHEAST VISIBILITY UNION (MANE-VU) STATES CONCERNING A COURSE OF ACTION IN CONTRIBUTING STATES LOCATED UPWIND OF MANE-VU TOWARD ASSURING REASONABLE PROGRESS FOR THE SECOND REGIONAL HAZE IMPLEMENTATION PERIOD (2018-2028)

The federal Clean Air Act (CAA) and Regional Haze rule require States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment within the national parks and wilderness areas designated as mandatory Class I Federal areas. Most pollutants that affect visibility also contribute to ozone, fine particulate and sulfur dioxide (SO_2) air pollution. In order to assure protection of public health and the environment, any additional air pollutant emission reduction measures necessary to meet the 2028 reasonable progress goal for regional haze should be implemented as soon as practicable but no later than 2028.

According to the federal Regional Haze rule (40 CFR 51.308 (f)(2)(i) through (iv)), all states must consider, in their Regional Haze SIPs, the emission reduction measures identified by Class I States as being necessary to make reasonable progress in any Class I area. These emission reduction measures are referred to as "Asks." If any State cannot agree with or complete a Class I State's "Asks," the State must describe the actions taken to resolve the disagreement in their Regional Haze SIP. This Ask by the MANE-VU Class I states, was developed through a collaborative process with all of the MANE-VU states. It is designed to identify reasonable emission reduction strategies which must be addressed by the states and tribal nations through their regional haze SIP updates. This Ask has been developed and presented at this time so that SIPs may be developed and submitted between July of 2018 and July of 2021.

444 North Capitol Street, NW ~ Suite 322 ~ Washington, DC 20001
202.508.3840 p ~ 202.508.3841 f

The following states identified by MANE-VU as contributing to visibility impairment at MANE-VU Class I areas should address this "Ask" in their regional haze SIP updates in addition to any other Class I area state "Ask"; Alabama, Florida, Illinois, Indiana, Kentucky, Louisiana, Michigan, Missouri, North Carolina, Ohio, Tennessee, Texas, Virginia, and West Virginia. There is a separate "Ask" to address visibility impairing emissions from MANE-VU states. Contributing state methodology is documented in a MANE-VU report; "Selection of States for MANE-VU Regional Haze Consultation (2018)", using actual 2015 emissions for EGUs and 2011 for other emission sources.

In addressing the emission reduction strategies in the Ask, states will need to harmonize any activity on the strategies in the Ask with other federal or state requirements that affect the sources and pollutants covered by the Ask. These federal and state requirements include, but are not limited to:

- The 2010 SO_2 standard,
- The Regional Greenhouse Gas Initiative (RGGI), if applicable,
- The Mercury and Air Toxics Standards (MATS), and
- The new 2015 ozone standard.

Because of this need for cross-program harmonization and because of the formal public process required by the federal CAA and state rulemaking processes, it is expected that there will be opportunities for stakeholders and the public to comment on how states intend to address the measures in the Ask.

To address the impact on mandatory Class I Federal areas within the MANE-VU region, the Mid-Atlantic and Northeast States will pursue a coordinated course of action designed to assure reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal areas and to leverage the multi-pollutant benefits that such measures may provide for the protection of public health and the environment. Per the Regional Haze rule, being on or below the uniform rate of progress for a given Class I area is not a factor in deciding if a State needs to undertake reasonable measures.

Therefore, the course of action for pursuing the adoption and implementation of measures necessary to meet the 2028 reasonable progress goal for regional haze include the following "emission management" strategies:

1. Electric Generating Units (EGUs) with a nameplate capacity larger than or equal to 25MW with already installed NOx and/or SO_2 controls - ensure the most effective use of control technologies on a year-round basis to consistently minimize emissions of haze precursors, or obtain equivalent alternative emission reductions;

2. Emission sources modeled by MANE-VU that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area, as identified by MANE-VU contribution analyses (see attached listing) - perform a four-factor analysis for reasonable installation or upgrade to emission controls;

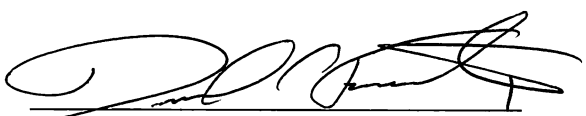
3. States should pursue an ultra-low sulfur fuel oil standard similar to the one adopted by MANE-VU states in 2007 as expeditiously as possible and before 2028, depending on supply availability, where the standards are as follows:
    a. distillate oil to 0.0015% sulfur by weight (15 ppm),
    b. #4 residual oil to 0.5% sulfur by weight,
    c. #6 residual oil to 0.5% sulfur by weight.

4. EGUs and other large point emission sources larger than 250 MMBTU per hour heat input that have switched operations to lower emitting fuels – pursue updating permits, enforceable agreements, and/or rules to lock-in lower emission rates for SO_2, NOx and PM. The permit, enforcement agreement, and/or rule can allow for suspension of the lower emission rate during natural gas curtailment;

5. Each State should consider and report in their SIP measures or programs to: a) decrease energy demand through the use of energy efficiency, and b) increase the use within their state of Combined Heat and Power (CHP) and other clean Distributed Generation technologies including fuel cells, wind, and solar.

This long-term strategy to reduce and prevent regional haze will allow each state up to 10 years to pursue adoption and implementation of reasonable and cost-effective NOx and SO_2 control measures.

Signed on behalf of the MANE-VU states and tribal nations:



David Foerter, Executive Director
MANE-VU/OTC

August 25, 2017

Listing of emission units that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area using actual 2015 emissions for EGUs and 2011 for other emission sources). The complete contribution analyses report is available at http://www.otcair.org/manevu.

State	Facility Name	Facility/ ORIS ID	Unit IDs	Max Extinction
IN	Rockport	6166	MB1,MB2	3.8
KY	Big Sandy	1353	BSU1,BSU2	3.5
MI	Belle River		2	4.0
MI	Belle River		1	3.7
MI	St. Clair	1743	1,2,3,4,...6	3.1
NC	KapStone Kraft Paper Corporation	8048011	ST-1,2	6.0
OH	Avon Lake Power Plant	2836	12	9.2
OH	Gen J M Gavin	8102	1	3.3
OH	Gen J M Gavin	8102	2	3.1
OH	Muskingum River	2872	5	7.7
OH	Muskingum River	2872	1,2,3,4	4.4
VA	Yorktown Power Station	3809	3	10.9
VA	Yorktown Power Station	3809	1,2	7.0
WV	Harrison Power Station		1 (25%) 2 (20%)	7.0
WV	Kammer	3947	1,2,3	3.2

APPENDIX E: Illinois Ambient Air Monitoring 2023 Network Plan

State of Illinois

Ambient Air Monitoring

2023 Network Plan

Illinois Environmental Protection Agency

Bureau of Air

June 2022

Introduction

In 1970, Congress enacted the Clean Air Act (CAA), empowering the United States Environmental Protection Agency (USEPA) to develop and implement National Ambient Air Quality Standards (NAAQS) for pollutants shown to threaten human health.

NAAQS exist for six criteria pollutants – carbon monoxide (CO), ozone (O_3), lead (Pb), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and particulate matter (PM). Particulate matter is measured both with a diameter less than or equal to 10 micrometers (PM_{10}) and a diameter less than or equal to 2.5 micrometers ($PM_{2.5}$). There are primary and secondary NAAQS. Primary standards protect public health, whereas secondary standards protect public welfare including the environment.

The Illinois operates an air monitoring network that includes monitors for the six criteria pollutants: CO, O_3, Pb, NO_2, SO_2, and PM. The Illinois air monitoring network meets or, in most cases, exceeds the applicable minimum network requirements.

A predominant goal of the air monitors within Illinois' network is to collect data with which to assess compliance with the NAAQS. A listing of these NAAQS can be found at https://www.epa.gov/criteria-air-pollutants/naaqs-table.

Illinois has designed its ambient air monitoring network to accomplish more than this primary goal, including to provide timely air pollution data to the public, support compliance with ambient air quality standards and emissions strategy development, and support air pollution research studies. Data gathered from the Illinois EPA's monitoring network is used to produce a daily Air Quality Index (AQI) report, compile daily air quality forecast reports, support short- and long-term health risk assessments, identify localized health concerns, and track long-term trends in air quality that could potentially threaten Illinois citizen's quality of life.

Monitor siting takes into consideration: peak (the highest concentration of pollution in a given area), population (presence of pollutants in areas with high population densities), sources (pollution resulting from significant sources or source categories), background (general pollutant levels), and transport (extent of regional pollutant transport between populated areas). Federal regulations prescribe requirements for monitor and probe siting to ensure that the ambient air quality data is accurately representative. The criteria for the placement and operation of each monitor and probe vary. Site surveys ensure that each requirement is satisfied.

Federal regulations require each State to submit to USEPA an air monitoring network plan annually for the prospective year. Additionally, a five-year network assessment must be completed by USEPA Region 5 monitoring organizations. The last five-year network assessment was completed in 2020 and found the criteria pollutant monitoring network was adequate in meeting USEPA's minimum criteria. The next network assessment will be completed in 2025. The annual network plans take into consideration findings of these assessments. The annual network plan provides a description of the monitoring network for each

criteria pollutant including proposed changes. The air monitoring network plan is subject to public review and comment prior to its submission to the USEPA.

Monitoring Designations

The following designations describe the various types of monitors at the sites within Illinois' air monitoring network:

- **NCore** - National Core multi-pollutant monitoring station. Illinois is required by federal regulations to operate one NCore site, which includes monitors for CO, nitric oxide/reactive nitrogen (NO/NO_y), SO_2, O_3, PM_{10}, speciated $PM_{2.5}$, $PM_{2.5}$, $PM_{10\text{-}2.5}$, wind speed, wind direction, relative humidity, and ambient temperature. Illinois operates an NCore site in Northbrook and provides support for the federal rural NCore site located in Bondville measuring $PM_{2.5}$.
- **Near-road** - Placed near busy roadways, near-road sites measure hourly concentrations of NO_2 and sometimes CO or $PM_{2.5}$ in urban areas. Illinois EPA operates two near-road locations, one in Chicago and one in Lansing. The Lansing near-road location began operating off the Kingery Expressway on March 1, 2019. The Chicago near-road location, along the Kennedy Expressway, began operating July 26, 2019.
- **PAMS** - Photochemical Assessment Monitoring Station. In addition to monitoring of criteria pollutants, Illinois also participates in a regional Photochemical Assessment Monitoring Station (PAMS) network in the Chicago area that is part of the USEPA approved "Alternate Plan for the Regional Lake Michigan PAMS Network." This regional PAMS network focuses on both the Milwaukee and Chicago areas that are classified as ozone nonattainment areas. These sites are dedicated to obtaining more information about ozone and its precursors. The Illinois sites participating in the 2023 regional PAMS network will include enhanced monitoring in Schiller Park as well as regulatorily-required monitoring in Northbrook. Illinois' regional PAMS sites will collect and monitor some or all of the following: speciated volatile organic compounds (VOCs), carbonyls, NO_2, NO/NO_y, O_3, CO, and meteorological data in order to monitor potential threats of nonattainment. Required PAMS meteorological data that are not part of the NCORE requirements are: atmospheric pressure, precipitation, solar radiation, and ultra-violet radiation.
- **SLAMS** - State or Local Ambient Monitoring Station. SLAMS monitoring is for comparison to the NAAQS.
- **SPM** - Special Purpose Monitor. The monitors in this category are included in the Agency network but do not apply toward the determination of area NAAQS compliance.

Siting and operation, including collocation requirements, of each monitor meets the requirements of Part 58 Appendices A, B, C, D, and E.

Monitoring Objectives

Monitoring objectives describe the various purposes of the monitors within Illinois' air monitoring network:

- **General Concentration (Background)** - These sites are positioned to measure the general background concentration of pollutants in an area.
- **Highest Concentration (Highest Conc.)-** These sites are located to determine the expected peak concentrations of pollutants in an area.
- **Population** - Located in areas categorized by high population density, these sites are used to determine the typical pollutant concentrations in a specific area.
- **Regional Transport (Transport)** - These sites are located to monitor the level of regional pollution transport from one area to the next.
- **Source-Oriented Source (Source)** - As certain sources contribute to pollution more significantly than others, source-oriented monitors are placed in order to identify the impact of these sources.

Spatial Scale Designations

Sites are not only characterized by type and by the objective, but also according to spatial scale. These scales are used to categorize siting areas and link them with the specific monitoring objectives. Spatial scales as outlined by the USEPA include:

- **Micro** - Concentrations in air volumes associated with area dimensions ranging from several meters up to about 100 meters.
- **Middle** - Concentrations typical of areas up to several city blocks in size with dimensions ranging from about 100 meters to 0.5 kilometer.
- **Neighborhood** - Concentrations within some extended area of the city that has relatively uniform land use with dimensions in the 0.5 to 4.0 kilometers range.
- **Urban** - Overall, citywide conditions with dimensions on the order of four to 50 kilometers.
- **Regional** - A rural area of reasonably homogenous geography without large sources, extending from tens to hundreds of kilometers.

Sampling Methodology

Every ambient air monitor can be classified by a specific method number which identifies sample collection and analysis methods. A comprehensive list of these numbers can be found at: https://www.epa.gov/aqs/aqs-code-list.

Federal regulations specify that monitoring methods used for comparison to the NAAQS must be Federal Reference or Equivalent Methods (FRM or FEM). Almost all monitors listed in Illinois' network plan use either FRM or FEM with only a few exceptions. Locations hosting continuous $PM_{2.5}$ samplers solely for AQI purposes are not operated as FRM or FEM. The long term goal, as resources permit, is to phase out these solely AQI PM2.5 samplers in favor of FEM samplers capable of both meeting NAAQS and AQI status.

Quality Assurance

Guidance, policies, and federal regulations establish quality system requirements for data submitted to USEPA. Currently, there are two Primary Quality Assurance Organizations under

this network plan – the Illinois EPA and the Cook County Department of Environment and Sustainability (CCDES).

Proposed Network for 2023

Ozone

Illinois is required to operate a minimum of 14 O_3 monitoring sites across the state to meet SLAMS O_3 requirements. NCore requires the operation of one of these O_3 monitors year-round. Additionally, 19 other O_3 monitors are operated for purposes of supporting the basic monitoring objectives of public data reporting, air quality mapping, compliance, enhanced monitoring, and supporting air pollution research studies. In 2022, Illinois operated 33 O_3 monitors. Additionally, USEPA operated three ozone monitors as part of the Clean Air Status and Trends Network (CASTNET). The number of ozone monitors will not change in 2023.

After the end of the 2021 ozone season, Illinois EPA purchased 17 new Teledyne T400 ozone monitors (USEPA method 087). These monitors are replacing older ozone monitors beginning with the 2022 ozone season.

Site access was lost at the Maryville ozone monitoring location in 2022. A replacement site was found nearby with very little data loss from the relocation. Given the short distance between the previous and new monitoring locations, Illinois EPA is requesting monitoring data from the two sites be combined under the same airshed. Figure 1 and Figure 2 show the previous and new Maryville monitoring locations respectively. The details of the sites are as follows:

Previous site: Maryville
Address: 200 West Division Street, Maryville
Coordinates: +38.726573, -89.959963
Parameter: Ozone
Air Quality System Identifier: 17-119-1009
Agency Operator: Illinois Environmental Protection Agency

The proposed new location is as follows:

New Site: Maryville
Address: 8B Schiber Court, Maryville
Coordinates: +38.730263, -89.950053
Parameter: Ozone
Air Quality System Identifier: 17-119-0122
Agency Operator: Illinois Environmental Protection Agency

Figure 1: Maryville Previous and New Monitoring Locations

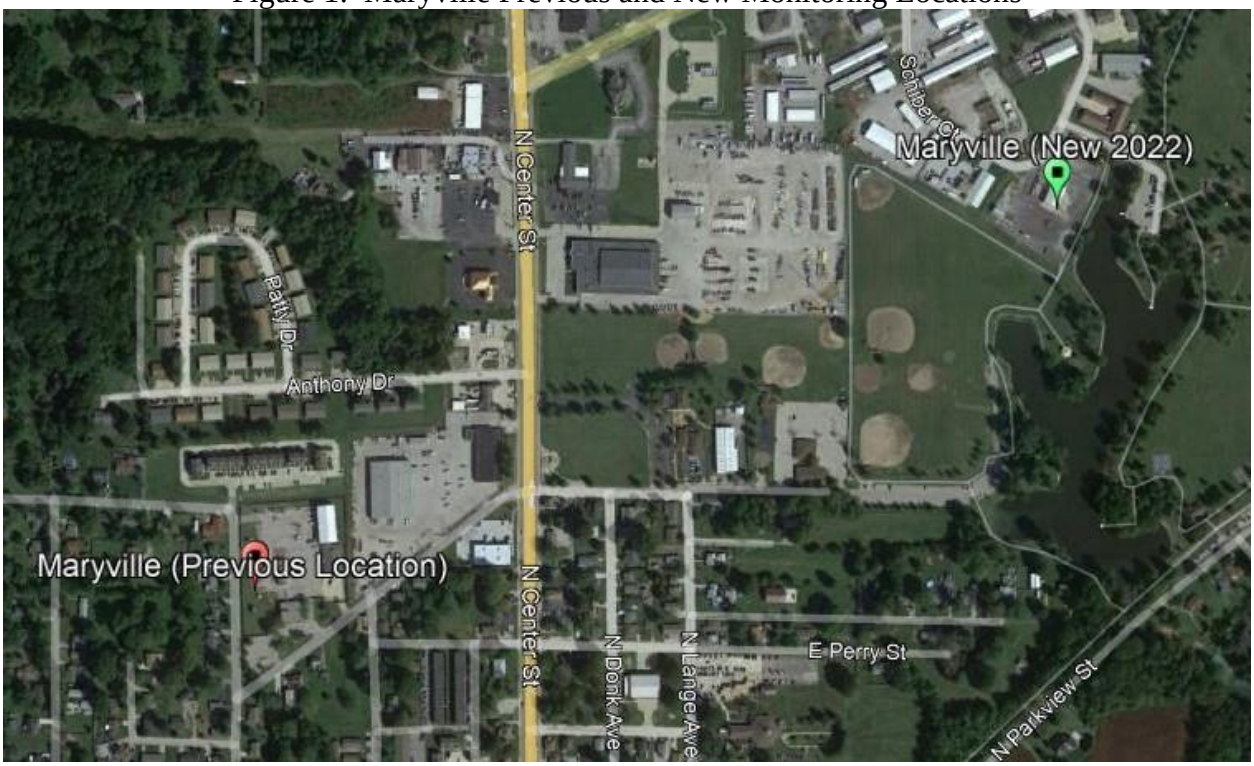


Figure 2: Maryville New Monitoring Location



Fine Particulate Matter ($PM_{2.5}$)

Illinois is required to operate a minimum of 13 FRM or FEM $PM_{2.5}$ monitors. NCore requires one continuous and one filter based $PM_{2.5}$ monitor. One near-road monitoring site with one FRM or FEM $PM_{2.5}$ monitor is also required. Illinois must operate at least one FRM or FEM $PM_{2.5}$ site monitoring regional background and at least one FRM or FEM $PM_{2.5}$ site to monitor regional transport. Additionally, 18 other $PM_{2.5}$ monitoring sites are operated for purposes of supporting the basic monitoring objectives of public data reporting, air quality mapping, compliance, and supporting air pollution research studies. In 2022, 34 $PM_{2.5}$ sites were operating in Illinois. In 2023, the number of $PM_{2.5}$ sites will not change.

USEPA will be providing funding to convert the remaining FRM $PM_{2.5}$ monitors in the network to continuous FEM monitors. This funding will also help convert FRM $PM_{2.5}$ monitors operated by Cook County Department of Environment and Sustainability to continuous FEM monitors. The sites that currently are planned to have FEM monitors between 2022 and 2023 are listed in Table 3. At the following locations a Teledyne T640 may replace filter-based FRMs: Alsip, Alton, Aurora, Champaign, Chicago - Springfield Pumping Station, Cicero, Elgin, Granite City – Gateway Medical, Lawndale (ComEd), Mayfair, Schiller Park, Summit, and Wood River. At the following locations a Teledyne T640x may replace filter-based FRMs: Chicago – George Washington High School, Lyons Township, Northbrook, and Granite City - 23rd & Madison.

Sulfur Dioxide

Illinois is required to operate six SO_2 monitors. One SO_2 monitor is required at each of the Northbrook and Bondville NCore sites to fulfill NCore requirements (The Illinois State Water Survey operates the Bondville SO_2 monitor). Additionally, four SO_2 monitoring sites are operated in Illinois' network supporting the basic monitoring objectives of public data reporting, air quality mapping, compliance, and supporting air pollution research studies. SO_2 data requirements established by USEPA require either modeling or monitoring to characterize current air quality in areas with large sources of SO_2 (40 CFR 51 Subpart BB). Tate & Lyle is contracting with Environmental Resources Management, Inc. operating two SO_2 monitors under this rule. A total of 12 SO_2 monitors were operated in Illinois in 2022. In 2023, the number of SO_2 sites will remain at twelve.

Nitrogen Dioxide

Illinois is required to operate two near-road NO_2 monitors. In addition to area-wide monitors, federal regulations require the Regional Administrator to collaborate with each State in determining the need for additional NO_2 monitoring requirements beyond the minimum, with a primary focus on siting monitors in locations to protect susceptible and vulnerable populations. In Illinois, two NO_2 monitoring sites are designated, East St. Louis and ComEd, as susceptible and vulnerable population monitoring sites. Illinois operates one NO/NO_y monitor in Northbrook. Additionally, the Illinois State Water Survey operates an NO/NO_y monitor at the rural NCore site in Bondville.

In 2022, the monitoring network consisted of eight NO_2 monitoring sites. Two NO/NO_y monitors will continue to be operated by Illinois EPA and the State Water Survey. In 2023, the number of NO_2 sites will remain at eight.

Carbon Monoxide

Illinois must operate one CO monitor in conjunction with one near-road NO_2 monitor. In addition, it must operate one CO monitor at each NCore site, Northbrook and Bondville. (The Illinois State Water Survey operates the Bondville CO monitor at the rural NCore site.) In 2022, three CO monitors were in operation. The number of CO monitors will not change in 2023.

Particulate Matter (PM_{10})

Illinois must operate three PM_{10} monitors to satisfy MSA requirements. One PM_{10} monitor must also be operated for NCore purposes. Additionally, Illinois operates one $PM_{10-2.5}$ (PM coarse) monitor at the Northbrook location to fulfill NCore requirements. The National Park Service operates one PM_{10} monitor at the Bondville NCore location. In 2022, Illinois EPA operated a total of four PM_{10} monitoring sites. In 2023, Illinois EPA will continue to operate four PM_{10} monitoring sites and one $PM_{10-2.5}$ monitoring site. As discussed in the $PM_{2.5}$ section, due to funding provided by USEPA, filter or tape-based PM_{10} monitors may be replaced with

continuous FEM T640x monitors. The location of T640x monitors would include: Chicago – George Washington High School, Lyons Township, Northbrook (for $PM_{10-2.5}$), and Granite City - 23rd & Madison.

Lead

Illinois is required to operate source-oriented monitors near facilities emitting 0.5 tons/year of lead that also have maximum lead concentrations in ambient air in excess of 50 percent of the NAAQS unless a waiver for that site has been approved. Lead monitoring waivers are currently in place with USEPA for Kincaid Generation Power Plant, Keystone Steel & Wire Corporation, Sterling Steel Corporation, Gateway Energy and Coke Company, and Gunite Corporation. The waivers were approved by USEPA in 2017 for Kincaid, in 2018 for Keystone Steel, Sterling Steel, and Gunite, and in 2020 for Gateway Energy and Coke Company. Waivers must be renewed every five years. Modeling and/or monitoring results for these facilities demonstrated that they do not have the potential to contribute to a maximum lead concentration greater than 50 percent of the NAAQS.

In 2021, Olin Corporation began operating a special purpose lead monitor in Alton measuring lead concentrations at its facility for a period of one year, ending May 29, 2022. The data supports monitor discontinuation. In 2023, Illinois EPA will operate three lead monitors - one located in Granite City and two in Chicago (Perez Elementary School and George Washington High School).

Lead Waiver – Kincaid Generation Power Plant

As noted above, Illinois EPA currently has a lead monitoring waiver in place with USEPA for the Kincaid Generation Power Plant in Kincaid, Illinois. USEPA approved the waiver for this facility in 2017, with renewal required every five years. Illinois is requesting that USEPA renew the existing waiver for Kincaid, as lead emissions from the facility remain sufficiently low such that they do not contribute to lead concentrations in excess of 50 percent of the NAAQS.

The Kincaid facility is located in Christian County and has a single lead emission source. Boiler Units 1 and 2 emit to a single stack, which is located near the southern edge of the property boundary. Previous lead modeling demonstrations also included a separate auxiliary boiler as a second lead emission source. However, revisions to the Kincaid facility's Clean Air Act Permit Program (CAAPP) permit (ID: 95090078) eliminates a second, oil-firing mode capable of generating lead emissions solely authorizing the auxiliary boiler operations using natural gas.

The Air Quality Planning Section (AQPS) of Illinois EPA used its 2017 lead modeling demonstration for Kincaid as a baseline for its 2022 demonstration. AQPS retained the same building configurations and receptor grid in both modeling demonstrations. AQPS also continued to use surface data collected from the Abraham Lincoln Capital Airport in Springfield, Illinois, and upper air data collected at the National Weather Service Office in Lincoln, Illinois.

However, AQPS did update its meteorology files to align with the most recent five-year data set (2017 through 2021).

Like the 2017 demonstration, AQPS assigned a 1 tpy emission rate to Boiler Units 1 and 2. In both cases, the use of a 1 tpy emission rate is conservative.[1] Unlike the 2017 demonstration, the 2022 modeling effort does not include the auxiliary boiler, since this boiler is no longer a source of lead emissions, as noted above.

As anticipated, the 2022 modeling demonstration yielded lead concentrations below those reported in the previous demonstration. Updated modeling results indicate that the maximum three-month rolling average concentration is 0.000107 µg/m^3 and occurred over the span of June, July, and August 2017. The 0.000107 µg/m^3 value is well below the standard of 0.15 µg/m^3. According to 40 CFR Part 58 Appendix D 4.5(ii), if a "State…agency can demonstrate the Pb source will not contribute to a maximum Pb concentration in ambient air in excess of 50 percent of the NAAQS (based on historical monitoring data, modeling, or other means," then the Regional Administrator may waive the requirement to monitor a Pb source emitting greater than or equal to 0.5 tons per year. Because the modeled maximum rolling three-month average concentration for Kincaid is less than 50 percent of the lead NAAQS, a monitoring waiver for this facility remains appropriate.

Photochemical Assessment Monitoring

Illinois was required to collect and report additional PAMS measurements at the Northbrook monitoring location by June 1, 2021. Existing year round NCore monitoring at Northbrook that also meets PAMS requirements include hourly O3, NO/NOy, ambient temperature, relative humidity, atmospheric pressure, vector wind speed, and vector wind direction In 2021, Illinois added to the existing NCore/PAMS measurements the following items:

Three eight-hour carbonyls samples on a one-in-three day schedule, true nitrogen dioxide (NO2), hourly precipitation, solar radiation, ultraviolet radiation, averaged mixing height and hourly average speciated volatile organic compounds (gas chromatograph) This additional PAMS monitoring is expected to continue to be operational for the PAMS 2023 season. Illinois will run these additional items during the months of June, July, and August.

[1] Kincaid reported its highest annual lead emissions in 2008. Since this time, AER data indicates that annual emissions have not exceeded the 0.93 tpy of lead reported in 2008.

Table 1: Illinois Monitoring Network by Criteria Pollutant

AQS ID	County	City	Address	Site Description	Owner	CO	NO_2	NOy	SO_2	O_3	PM_{10} / Coarse	$PM_{2.5}$	Pb
17-001-0007	Adams	Quincy	1301 S. 48th St	John Wood Community College	IEPA					X			
17-019-0006	Champaign	Champaign	904 N. Walnut	Ameren Substation Platform	IEPA							X	
17-019-0007	Champaign	Thomasboro	North Thomas St.	Resident's Building	IEPA					X			
17-019-1001	Champaign	Bondville	Twp. Rd. 500 E.	State Water Survey Climate Station	SWS	X		X	X				
17-019-1001	Champaign	Bondville	Twp. Rd. 500 E.	State Water Survey Climate Station	IEPA							X	
17-019-1001	Champaign	Bondville	Twp. Rd. 500 E.	CASTNET Station	USEPA					X			
17-019-1001	Champaign	Bondville	Twp. Rd. 500 E.	IMPROVE Station	NPS						PM_{10} / Coarse		
17-031-0001	Cook	Alsip	4500 W. 123rd St.	Village Garage	CCDES					X		X	
17-031-0022	Cook	Chicago	3535 E. 114th St	Washington High School	CCDES						X***	X***	X
17-031-0032	Cook	Chicago	3300 E. Cheltenham Pl.	South Water Filtration Plant	CCDES					X			
17-031-0052	Cook	Chicago	4850 Wilson Ave.	Mayfair Pump Station	CCDES							X	
17-031-0057	Cook	Chicago	1745 N. Springfield Ave.	Springfield Pump Station	CCDES							X	
17-031-0076	Cook	Chicago	7801 Lawndale	Com Ed Maintenance Bldg. Trailer	CCDES		X		X	X		X	
17-031-0110	Cook	Chicago	1241 19th St.	Perez Elementary School	CCDES								X
17-031-1003	Cook	Chicago	6545 W. Hurlbut St.	Taft High School	CCDES					X			
17-031-0119	Cook	Lansing	Kingery Expy & Torrence Ave.	Kingery Near-road #1	IEPA	X	X					X	
17-031-0219	Cook	Chicago	Kennedy Expy & W. Webster Ave.	Kennedy Near-road #2	IEPA		X						
17-031-1016	Cook	Lyons Township	50th St. & Glencoe	Village Hall	IEPA						X	X	

AQS ID	County	City	Address	Site Description	Owner	CO	NO_2	NOy	SO_2	O_3	PM_{10} / Coarse	$PM_{2.5}$	Pb
17-031-1601	Cook	Lemont	729 Houston	Lemont Trailer	CCDES				X	X			
17-031-3103	Cook	Schiller Park	4743 Mannheim Rd.	Schiller Park Trailer	IEPA		X			X		X	
17-031-3301	Cook	Summit	60th St. & 74th Ave.	Graves Elementary School	CCDES							X	
17-031-4002	Cook	Cicero	1820 S. 51st Ave.	Cicero Trailer	CCDES		X			X			
17-031-4007	Cook	Des Plaines	9511 W. Harrison St.	Regional Office Bldg.	IEPA					X		X	
17-031-4201	Cook	Northbrook	750 Dundee Rd.	Northbrook Water Plant	IEPA	X	X	X	X	X	Coarse	X	
17-031-6005	Cook	Cicero	13th St. & 50th Ave.	Liberty School	CCDES							X	
17-031-7002	Cook	Evanston	531 E. Lincoln	Evanston Water Plant	IEPA					X			
17-043-4002	DuPage	Naperville	400 S. Eagle St.	City Hall	IEPA							X	
17-043-6001	DuPage	Lisle	Route 53	Morton Arboretum	IEPA					X			
17-049-1001	Effingham	Effingham	10421 N. US Hwy. 45	Central Grade School	IEPA					X			
17-065-0002	Hamilton	Knight Prairie Twp	Route 14	Knight Prairie Trailer	IEPA					X		X	
17-083-0117	Jersey	Jerseyville	21965 Maple Summit Rd.	Jerseyville Trailer	IEPA					X		X	
17-085-9991	Jo Daviess	Stockton	10952 E. Parker Rd.	CASTNET Station	USEPA					X			
17-089-0003	Kane	Elgin	258 Lovell St.	McKinley School	IEPA							X	
17-089-0005	Kane	Elgin	665 Dundee Rd.	Larsen Junior High School	IEPA					X			
17-089-0007	Kane	Aurora	1240 N. Highland	Health Department	IEPA							X	
17-097-1007	Lake	Zion	Illinois Beach State Park	Zion Trailer	IEPA					X			
17-099-0007	La Salle	Oglesby	308 Portland Ave.	Oglesby Trailer	IEPA				X				

AQS ID	County	City	Address	Site Description	Owner	CO	NO_2	NOy	SO_2	O_3	PM_{10} / Coarse	$PM_{2.5}$	Pb
17-111-0001	McHenry	Cary	First St. & Three Oaks Rd.	Cary Grove High School	IEPA					X		X	
17-113-2003	McLean	Normal	Main & Gregory	Normal-ISU Physical Plant Trailer	IEPA					X		X	
17-115-0013	Macon	Decatur	2200 N. 22nd St.	Decatur Trailer	IEPA				X	X		X	
17-115-0217	Macon	Decatur	Folk & E. Marietta Sts.	Tate & Lyle Northwest	ERM Inc.				X				
17-115-0317	Macon	Decatur	El Dorado St.	Tate & Lyle Southeast	ERM Inc.				X				
17-117-0002	Macoupin	Nilwood	Heaton & Dubois	Nilwood Trailer	IEPA		X		X	X			
17-119-0120	Madison	Alton	2708 Edwards St.	Horace Mann School	IEPA					X		X	
17-119-0121*	Madison	Alton	Powder Mill Rd.	Olin Corporation	IEPA								X*
17-119-0010	Madison	Granite City	15th & Madison	Air Products	IEPA								X
17-119-0024	Madison	Granite City	2100 Madison	Gateway Medical Center	IEPA							X	
17-119-1007	Madison	Granite City	23rd. & Madison	Fire Station # 1	IEPA						X	X	
17-119-0122**	Madison	Maryville	8B Schiber Court	Village of Maryville	IEPA					X**			
17-119-1009*	Madison	Maryville	200 W. Division	Maryville Trailer	IEPA					X*			
17-119-3007	Madison	Wood River	54 N. Walcott	Wood River Water Treatment Plant	IEPA				X	X		X	
17-119-9991	Madison	Highland	5403 State Rd. 160	CASTNET Station	USEPA					X			
17-143-0024	Peoria	Peoria	Hurlburt & MacArthur	Fire Station #8	IEPA					X			
17-143-0037	Peoria	Peoria	613 N.E. Jefferson	City Office Bldg.	IEPA							X	
17-143-1001	Peoria	Peoria Heights	508 E. Glen Ave.	Peoria Heights High School	IEPA					X			
17-157-0001	Randolph	Houston	Hickory Grove & Fallview	Houston Trailer	IEPA					X		X	

AQS ID	County	City	Address	Site Description	Owner	CO	NO_2	NOy	SO_2	O_3	PM_{10} / Coarse	$PM_{2.5}$	Pb
17-161-3002	Rock Island	Rock Island	32 Rodman Ave.	Rock Island Arsenal	IEPA					X		X	
17-163-0010	St. Clair	East St. Louis	13th & Tudor	ESTL Trailer	IEPA		X		X	X		X	
17-167-0012	Sangamon	Springfield	State Fair Grounds	Agriculture Bldg.	IEPA							X	
17-167-0014	Sangamon	Springfield	Illinois Building	State Fairgrounds Shelter	IEPA					X			
17-179-0004	Tazewell	Pekin	272 Derby	Pekin Fire Station #3	IEPA				X				
17-197-1002	Will	Joliet	Midland & Campbell Sts.	Pershing Elementary School	IEPA							X	
17-197-1011	Will	Braidwood	36400 S. Essex Rd.	Com Ed Training Ctr. Trailer	IEPA					X		X	
17-201-0118	Winnebago	Rockford	204 South 1st St.	Fire Department Admin. Bldg.	IEPA							X	
17-201-2001	Winnebago	Loves Park	1405 Maple Ave.	Maple Elementary School	IEPA					X			
					IEPA	2	6	1	7	27	4	27	1
					CCDES	0	2	0	2	6	0	7	2
					NPS/SWS	1	0	1	1	0	1	0	0
					ERM Inc.	0	0	0	2	0	0	0	0
					USEPA	0	0	0	0	3	0	0	0
					Total	3	8	2	12	36	5	34	3

* Indicates monitor/site proposed for removal or has been removed.

** Indicates monitor/site proposed for installation or has been installed.

*** Indicates continuous PM10 monitor run by Illinois EPA at a CCDES site with PM2.5 FRM run by CCDES. Once the PM10 BAM 1020 is upgraded to a T640x, this monitor run by Illinois EPA will also meet PM2.5 FRM/FEM requirements for the site.

Table 2: Ozone Sites

AQS ID	POC	Site	Latitude Longitude	Area Represented	Primary Objective	Secondary Objective	Spatial Scale	Station Type	Monitor Type	Sampling Schedule
17-001-0007	1	Quincy	+39.91540937 -91.33586832	Quincy, IL-MO	Population	Highest Conc.	Urban	SLAMS	T400	Hourly/S
17-019-0007	1	Thomasboro	+40.244913 -88.188519	Champaign-Urbana, IL	Population	N/A	Urban	SLAMS	T400	Hourly/S
17-019-1001	1	Bondville	+40.052780 -88.372510	Champaign-Urbana, IL	Highest Conc.	N/A	Regional	NCORE	49i	Hourly/Y
17-031-0001	1	Alsip	+41.6709919 -87.7324569	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	SLAMS	Ecotech 187	Hourly/S
17-031-0032	1	South Water Filtration Plant	+41.75583241 -87.54534967	Chicago-Naperville-Michigan City, IL-IN-WI	Highest Conc.	Population	Neighborhood	SLAMS	T400	Hourly/S
17-031-0076	1	Com Ed.	+41.75139998 -87.71348815	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	SLAMS	Ecotech 187	Hourly/S
17-031-1003	2	Taft High School	+41.98433233 -87.7920017	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	SLAMS	Ecotech 187	Hourly/S
17-031-1601	1	Lemont	+41.66812034 -87.99056969	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	SLAMS	Ecotech 187	Hourly/S
17-031-3103	2	Schiller Park	+41.96519348 -87.87626473	Chicago-Naperville-Michigan City, IL-IN-WI	Population	Source	Neighborhood	PAMS/SLAMS	T400	Hourly/S
17-031-4002	1	Cicero	+41.85524313 -87.7524697	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Neighborhood	SLAMS	Ecotech 187	Hourly/S
17-031-4007	1	Des Plaines	+42.06028469 -87.86322543	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	SLAMS	T400	Hourly/S
17-031-4201	1	Northbrook	+42.13999619 -87.79922692	Chicago-Naperville-Michigan City, IL-IN-WI	Population	NA	Urban	PAMS/NCORE	T400	Hourly/Y
17-031-7002	1	Evanston	+42.062053 -87.675254	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Neighborhood	SLAMS	T400	Hourly/S
17-043-6001	1	Lisle	+41.81304939 -88.0728269	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	SLAMS	T400	Hourly/S
17-049-1001	2	Effingham	+39.06715932 -88.54893401	Effingham, IL	Population	N/A	Regional	SLAMS	T400	Hourly/S
17-065-0002	1	Knight Prairie	+38.08215516 -88.6249434	Mt Vernon, IL	Background	N/A	Regional	SLAMS	T400	Hourly/S
17-083-0117	1	Jerseyville	+39.101439 -90.344494	St Louis, IL-MO	Transport	Population	Urban	SLAMS	T400	Hourly/S
17-085-9991	1	Stockton	+42.2869 -89.9997	Stockton, IL	Highest Conc.	N/A	Regional	SLAMS	49i	Hourly/S

AQS ID	POC	Site	Latitude Longitude	Area Represented	Primary Objective	Secondary Objective	Spatial Scale	Station Type	Monitor Type	Sampling Schedule
17-089-0005	1	Elgin	+42.04914776 -88.27302929	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	SLAMS	T400	Hourly/S
17-097-1007	1	Zion	+42.4675733 -87.81004705	Chicago-Naperville-Michigan City, IL-IN-WI	Highest Conc.	Transport	Urban	SLAMS	T400	Hourly/S
17-111-0001	1	Cary	+42.22144166 -88.24220734	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	SLAMS	T400	Hourly/S
17-113-2003	1	Normal	+40.51873537 -88.99689571	Bloomington-Normal, IL	Population	Highest Conc.	Urban	SLAMS	T400	Hourly/S
17-115-0013	1	Decatur	+39.866933 -88.925452	Decatur, IL	Population	Highest Conc.	Urban	SLAMS	49i	Hourly/S
17-117-0002	1	Nilwood	+39.39607533 -89.80973892	St Louis, IL-MO	Transport	Population	Regional	SLAMS	49i	Hourly/S
17-119-0122**	1	Maryville	+38.730263 -89.950053	St Louis, IL-MO	Population	N/A	Urban	SLAMS	T400	Hourly/S
17-119-1009*	1	Maryville	+38.72657262 -89.95996251	St Louis, IL-MO	Population	N/A	Urban	SLAMS	T400	Hourly/S
17-119-0120	1	Alton	+38.901316 -90.146211	St Louis, IL-MO	Highest Conc.	Population	Urban	SLAMS	T400	Hourly/S
17-119-3007	1	Wood River	+38.86066947 -90.10585111	St Louis, IL-MO	Population	N/A	Urban	SLAMS	49i	Hourly/S
17-119-9991	1	Highland	+38.8690 -89.6228	St Louis, IL-MO	Highest Conc.	N/A	Regional	SLAMS	49i	Hourly/S
17-143-0024	1	Peoria	+40.68742038 -89.60694277	Peoria, IL	Population	N/A	Neighborhood	SLAMS	T400	Hourly/S
17-143-1001	1	Peoria Heights	+40.74550393 -89.58586902	Peoria, IL	Highest Conc.	Population	Urban	SLAMS	T400	Hourly/S
17-157-0001	1	Houston	+38.17627761 -89.78845862	N/A	Background	N/A	Regional	SLAMS	T400	Hourly/S
17-161-3002	1	Rock Island	+41.51472697 -90.51735026	Davenport-Moline-Rock Island, IA-IL	Population	Highest Conc.	Neighborhood	SLAMS	T400	Hourly/S
17-163-0010	2	East St. Louis	+38.61203448 -90.16047663	St Louis, IL-MO	Population	N/A	Neighborhood	SLAMS	T400	Hourly/S
17-167-0014	1	Springfield	+39.831522 -89.640926	Springfield, IL	Population	Highest Conc.	Urban	SLAMS	T400	Hourly/S
17-197-1011	1	Braidwood	+41.22153707 -88.19096718	Chicago-Naperville-Michigan City, IL-IN-WI	Background	N/A	Regional	SLAMS	T400	Hourly/S
17-201-2001	1	Loves Park	+42.33498222 -89.0377748	Rockford, IL	Highest Conc.	Population	Urban	SLAMS	T400	Hourly/S

T400 – Teledyne (method 087); 49i – ThermoScientific (method 047); Ecotech 187 – Ecotech Serinus 10 (method 187)

Ozone parameter code – 44201

S = Seasonal – March through October ozone monitoring season

Y = Year-round monitoring

* indicates monitor proposed for removal or has been removed

** indicates monitor proposed for installation or has been installed

Figure 3a: Ozone Sites – Illinois

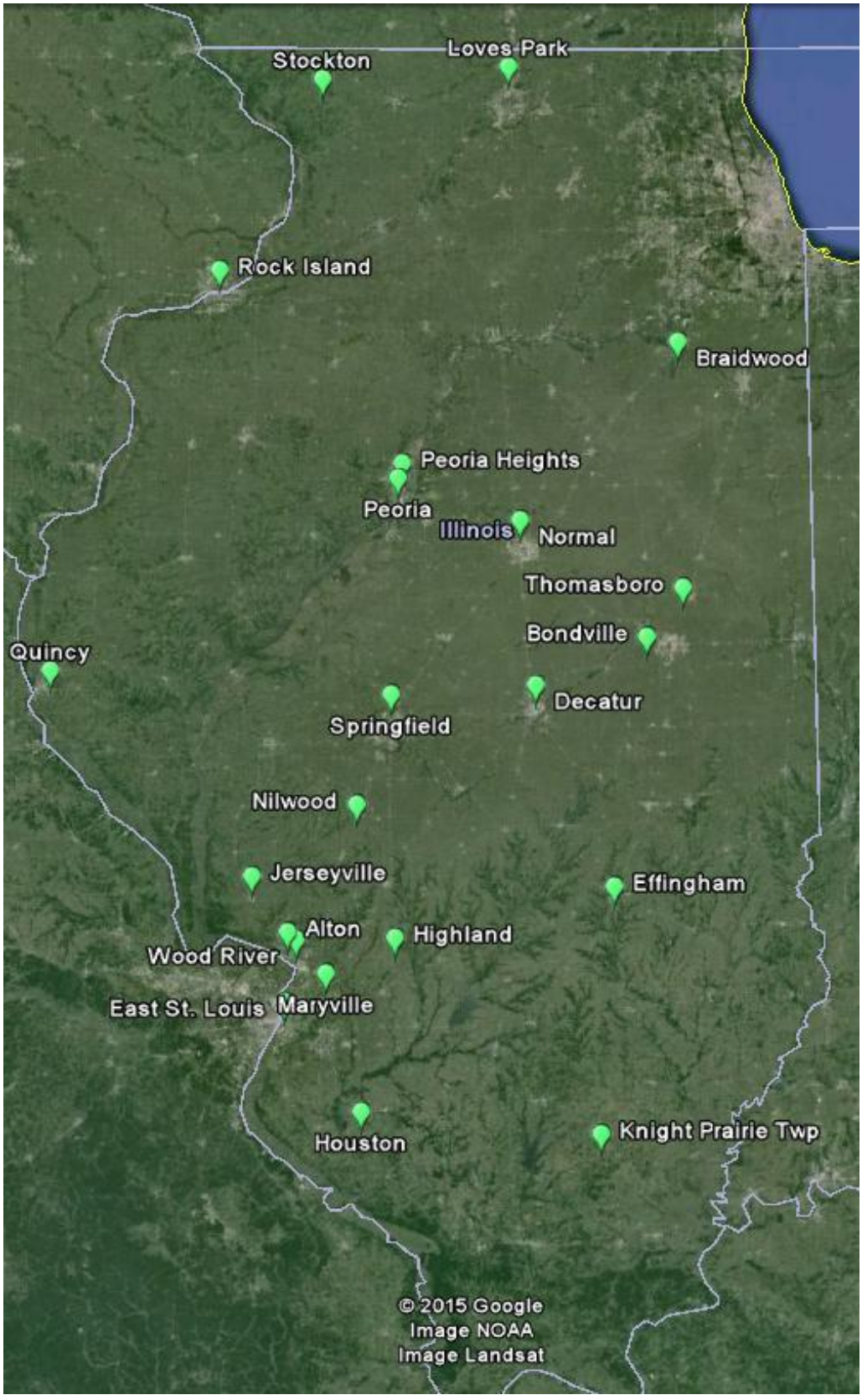


Figure 3b: Ozone Sites – Illinois Chicago Area

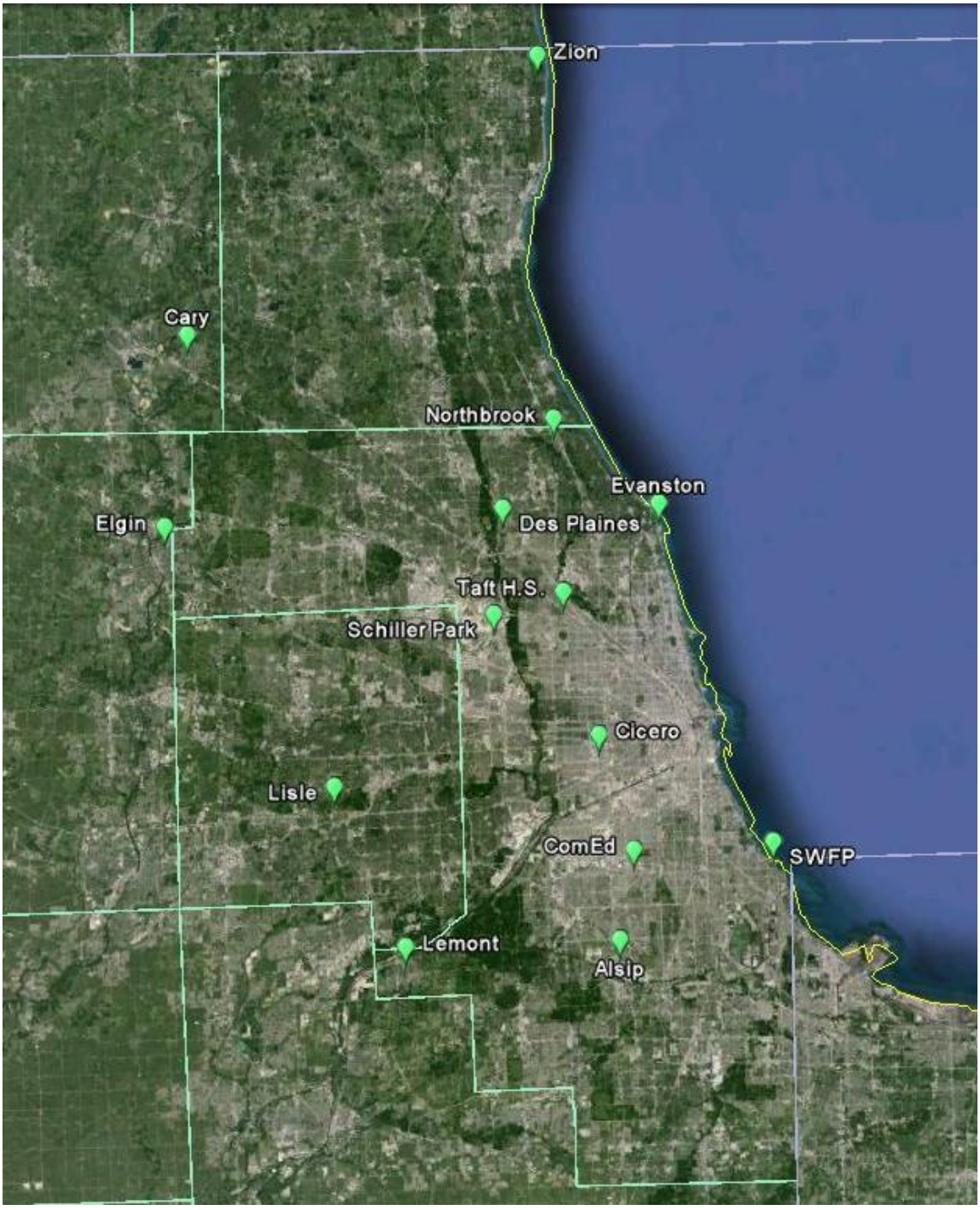


Table 3: $PM_{2.5}$ Sites

AQS ID	POC	Site	Latitude Longitude	Area Represented	Primary Objective	Secondary Objective	Spatial Scale	Standard	Station Type	Monitor Type (Primary)	Sampling Schedule	Collocated	Chemical Speciation	Frequency
17-019-0006	3	Champaign	+40.123883 -88.240550	Champaign-Urbana, IL	Population	N/A	Neighborhood	Annual/24	SLAMS	FEM Teledyne T640	H			
17-019-1001	3, 1	Bondville	+40.052780 -88.372510	Champaign-Urbana, IL	Transport	Population	Regional	Annual/24	RURAL NCORE	FEM Teledyne T640	H	THRM (1/3 day)	YES	1/3
17-031-0001	3	Alsip	+41.6709919 -87.7324569	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Neighborhood	Annual/24	SLAMS, SPM***	FEM Teledyne T640	H			
17-031-0022	3, 9	Washington High School	+41.68716544 -87.53931548	Chicago-Naperville-Michigan City, IL-IN-WI	Population	Source	Neighborhood	Annual/24	SLAMS	FEM Teledyne T640X	H			
17-031-0052	3, 9	Mayfair Pump Station	+41.96548483 -87.74992806	Chicago-Naperville-Michigan City, IL-IN-WI	Highest Conc.	Population	Neighborhood	Annual/24	SLAMS	FEM Teledyne T640	H	Met One (1/12 day)		

AQS ID	POC	Site	Latitude Longitude	Area Represented	Primary Objective	Secondary Objective	Spatial Scale	Standard	Station Type	Monitor Type (Primary)	Sampling Schedule	Collocated	Chemical Speciation	Frequency
17-031-0057	3	Springfield Pump Station	+41.912739 -87.722673	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Neighborhood	Annual/24	SLAMS, SPM***	FEM Teledyne T640	H		YES	1/6
17-031-0076	3	Com Ed	+41.75139998 -87.71348815	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Neighborhood	Annual/24	SLAMS, SPM***	FEM Teledyne T640	H		YES	1/3
17-031-1016	3	Lyons Township	+41.801180 -87.832349	Chicago-Naperville-Michigan City, IL-IN-WI	Source	Population	Middle	24	SLAMS	FEM Teledyne T640X	H			
17-031-3103	3, 9	Schiller Park	+41.96519348 -87.87626473	Chicago-Naperville-Michigan City, IL-IN-WI	Highest Conc.	Population	Middle	Annual/24	SLAMS	FEM Teledyne T640	H	THRM (1/12 day)		
17-031-3301	3	Summit	+41.78276601 -87.80537679	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Neighborhood	Annual/24	SLAMS	FEM Teledyne T640	H			
17-031-4007	3	Des Plaines	+42.06028469 -87.86322543	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	Annual/24	SLAMS	FEM Teledyne T640	H			

AQS ID	POC	Site	Latitude Longitude	Area Represented	Primary Objective	Secondary Objective	Spatial Scale	Standard	Station Type	Monitor Type (Primary)	Sampling Schedule	Collocated	Chemical Speciation	Frequency
17-031-4201	3, 1	Northbrook	+42.140204 -87.798989	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	Annual/24	URBAN NCORE	FEM Teledyne T640X	H	THRM (1/3 day)	YES	1/3
17-031-6005	3	Cicero	+41.86442642 -87.74890238	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Neighborhood	Annual/24	SLAMS, SPM***	FEM Teledyne T640	H			
17-031-0119	3	Lansing Kingery near-road #1	+41.578603 -87.557392	Kingery high traffic near-road segment	Highest Conc.	N/A	Micro	Annual/24	SLAMS	FEM Teledyne T640	H			
17-043-4002	3	Naperville	+41.77107094 -88.15253365	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	Annual/24	SLAMS	FEM Teledyne T640	H			
17-065-0002	3	Knight Prairie	+38.08215516 -88.6249434	Mt Vernon, IL	Background	Population	Regional	Annual/24	SLAMS	FEM Teledyne T640	H			
17-083-0117	3	Jerseyville	+39.101439 -90.344494	St Louis, IL-MO	Population	Transport	Urban	Annual/24	SLAMS	FEM Teledyne T640	H			
17-089-0003	3	Elgin	+42.050403 -88.28001471	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	Annual/24	SLAMS	FEM Teledyne T640	H			
17-089-0007	3	Aurora	+41.78471651 -88.32937361	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	Annual/24	SLAMS	FEM Teledyne T640	H			
17-111-0001	3	Cary	+42.22144166 -88.24220734	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	Annual/24	SLAMS	FEM Teledyne T640	H			

AQS ID	POC	Site	Latitude Longitude	Area Represented	Primary Objective	Secondary Objective	Spatial Scale	Standard	Station Type	Monitor Type (Primary)	Sampling Schedule	Collocated	Chemical Speciation	Frequency
17-113-2003	3, 9	Normal	+40.51873537 -88.99689571	Bloomington-Normal, IL	Population	N/A	Urban	Annual/24	SLAMS	FEM Teledyne T640	H	FEM Teledyne T640 (H)		
17-115-0013	3	Decatur	+39.86683389 -88.92559445	Decatur, IL	Population	Source	Neighborhood	Annual/24	SLAMS	FEM Teledyne T640	H			
17-119-0024	3	Granite City Gateway	+38.7006315 -90.14476267	St Louis, IL-MO	Source	Population	Middle	24	SLAMS	FEM Teledyne T640	H		YES	1/6
17-119-1007	3	Granite City	+38.70453426 -90.13967484	St Louis, IL-MO	Highest Conc.	Population	Neighborhood	Annual/24	SLAMS, SPM***	FEM Teledyne T640X	H			
17-119-0120	3	Alton	+38.901316 -90.146211	St Louis, IL-MO	Population	N/A	Urban	Annual/24	SLAMS	FEM Teledyne T640	H			
17-119-3007	3	Wood River	+38.86066947 -90.10585111	St Louis, IL-MO	Population	N/A	Neighborhood	Annual/24	SLAMS	FEM Teledyne T640	H			
17-143-0037	3	Peoria	+40.697007 -89.58473722	Peoria, IL	Population	N/A	Urban	Annual/24	SLAMS	FEM Teledyne T640	H			
17-157-0001	3	Houston	+38.17627761 -89.78845862	N/A	Background	Population	Regional	Annual/24	SLAMS	FEM Teledyne T640	H			
17-161-3002	3	Rock Island	+41.51472697 -90.51735026	Davenport-Moline-Rock Island, IA-IL	Population	N/A	Urban	Annual/24	SLAMS	FEM Teledyne T640	H			

AQS ID	POC	Site	Latitude Longitude	Area Represented	Primary Objective	Secondary Objective	Spatial Scale	Standard	Station Type	Monitor Type (Primary)	Sampling Schedule	Collocated	Chemical Speciation	Frequency
17-163-0010	3, 9	East St. Louis	+38.61203448 -90.16047663	St Louis, IL-MO	Population	Source	Neighborhood	Annual/24	SLAMS	FEM Teledyne T640	H	FEM Teledyne T640 (H)		
17-167-0012	3	Springfield	+39.83192087 -89.64416359	Springfield, IL	Population	N/A	Urban	Annual/24	SLAMS	FEM Teledyne T640	H			
17-197-1002	3	Joliet	+41.52688509 -88.11647381	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Neighborhood	Annual/24	SLAMS	FEM Teledyne T640	H			
17-197-1011	3	Braidwood	+41.22153707 -88.19096718	Chicago-Naperville-Michigan City, IL-IN-WI	Background	Population	Regional	Annual/24	SLAMS	FEM Teledyne T640	H			
17-201-0118	3	Rockford	+42.2670002 -89.089170	Rockford, IL	Population	N/A	Middle	Annual/24	SLAMS	FEM Teledyne T640	H			

Met One - MetOne sequential (method 545); THRM – ThermoScientific (method 143); FEM Teledyne T640 – Federal Equivalent Method Teledyne T640 Continuous (method 236); FEM Teledyne T640X – Federal Equivalent Method Teledyne T640x Continuous (method 238); H = Hourly.

$PM_{2.5}$ parameter code – 88101 (FRM/FEM), 88502 (non FRM/FEM)

Sites that are part of the Chemical Speciation Network are listed in the Chemical Speciation column.

* indicates monitor proposed for removal

** indicates monitor proposed for installation

***** indicates continuous Special Purpose Monitor currently run as non-regulatory for AQI in conjunction with SLAMS FRM sampler. Plan is to gradually phase in SLAMS FEM continuous monitors listed in the table above that will replace both the SPM monitor and the site FRM sampler.**

Figure 4a: $PM_{2.5}$ Sites – Illinois

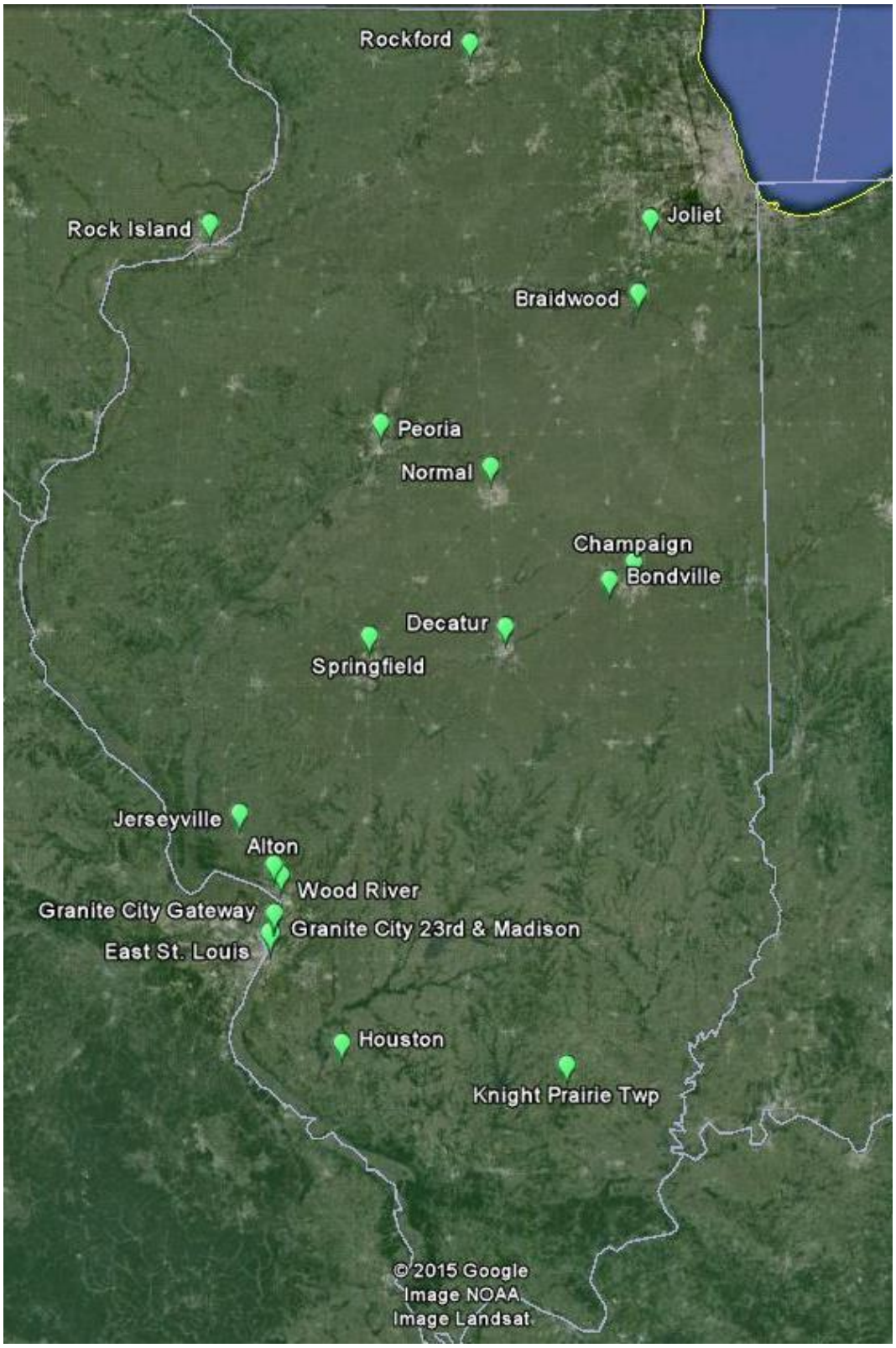


Figure 4b: $PM_{2.5}$ Sites – Illinois Chicago Area

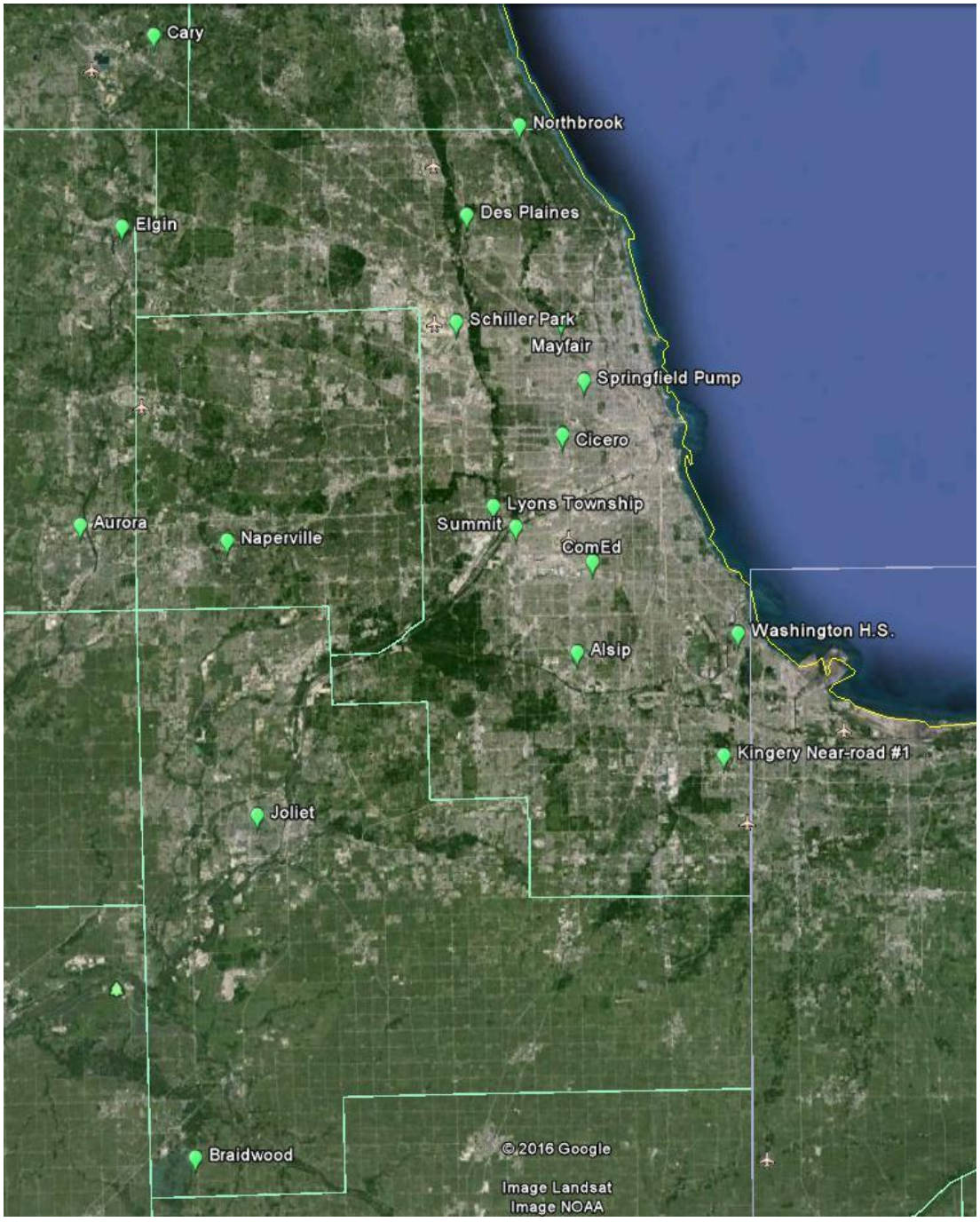


Table 4: SO_2 Sites

AQS ID	POC	Site	Latitude Longitude	Area Represented	Primary Objective	Secondary Objective	Spatial Scale	Station Type	Monitor Type	Sampling Schedule
17-019-1001	2	Bondville	+40.052780 -88.372510	Champaign-Urbana, IL	Regional Transport	Welfare Related	Regional	NCORE	T100U	Hourly
17-031-0076	1	Com Ed	+41.75139998 -87.71348815	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	SLAMS	T100	Hourly
17-031-1601	1	Lemont	+41.66812034 -87.99056969	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Neighborhood	SLAMS	T100	Hourly
17-031-4201	2	Northbrook	+42.13999619 -87.79922692	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	NCORE	T100U	Hourly
17-099-0007	1	Oglesby	+41.29301454 -89.04942498	Ottawa-Streator, IL	Highest Conc.	Source	Neighborhood	SLAMS	T100	Hourly
17-115-0013	1	Decatur	+39.86683389 -88.92559445	Decatur, IL	Population	N/A	Neighborhood	SLAMS	T100	Hourly
17-115-0217	1	Tate & Lyle NW	+39.850712 -88.933635	Tate & Lyle	Source	N/A	Neighborhood	SLAMS	43i	Hourly
17-115-0317	1	Tate & Lyle SE	+39.846856 -88.923323	Tate & Lyle	Source	N/A	Neighborhood	SLAMS	43i	Hourly
17-117-0002	1	Nilwood	+39.39607533 -89.80973892	St Louis, IL-MO	Background	Population	Regional	SLAMS	T100	Hourly
17-119-3007	3	Wood River	+38.86066947 -90.10585111	St Louis, IL-MO	Population	N/A	Neighborhood	SLAMS	T100	Hourly
17-163-0010	3	East St. Louis	+38.61203448 -90.16047663	St Louis, IL-MO	Population	N/A	Neighborhood	SLAMS	T100	Hourly
17-179-0004	2	Pekin	+40.55646017 -89.65402807	Peoria, IL	Highest Conc.	Source	Neighborhood	SLAMS	T100	Hourly

T100 – Teledyne (method 100); T100U – Teledyne Trace Level (method 600); 43i – Thermo Scientific Model 43i (method 060)

SO_2 parameter code – 42401

* indicates monitor proposed for removal

** indicates monitor proposed for installation

Figure 5: SO_2 Sites – Illinois

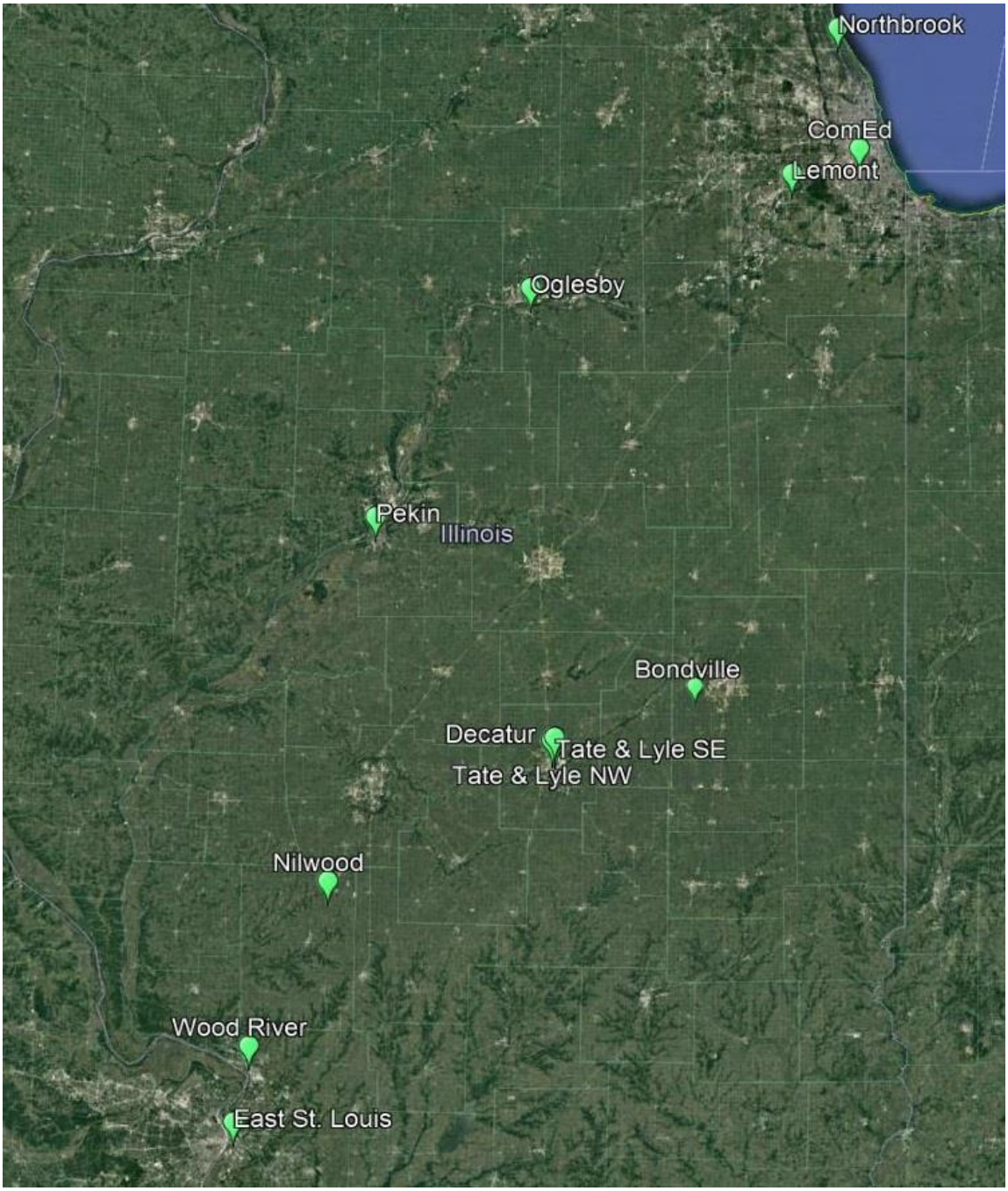


Table 5: NO_2 Sites

AQS ID	POC	Site Description	Latitude Longitude	Area Represented	Monitoring Type	Primary Objective	Secondary Objective	Spatial Scale	Station Type	Monitor Type	Sampling Schedule
17-019-1001	1	Bondville	+40.052780 -88.372510	Champaign-Urbana, IL	Area-wide	Regional Transport	Welfare Related	Regional	NCORE	T200EU/ 501Y	Hourly
17-031-0076	1	Com Ed	+41.75139998 -87.71348815	Chicago-Naperville-Michigan City, IL-IN-WI	Susceptible Population	Population	N/A	Neighborhood	SLAMS	TE 42i	Hourly
17-031-3103	1	Schiller Park	+41.96519348 -87.87626473	Chicago-Naperville-Michigan City, IL-IN-WI	Area-wide	Highest Conc.	Source	Middle	PAMS/SLAMS	T500U	Hourly
17-031-4002	1	Cicero	+41.85524313 -87.7524697	Chicago-Naperville-Michigan City, IL-IN-WI	Area-wide	Population	Highest Conc.	Neighborhood	SLAMS	T200	Hourly
17-031-4201	1	Northbrook	+42.13999619 -87.79922692	Chicago-Naperville-Michigan City, IL-IN-WI	Area-wide	Population	N/A	Urban	PAMS/NCORE	T500U	Hourly
17-031-4201	1	Northbrook (NOy)	+42.13999619 -87.79922692	Chicago-Naperville-Michigan City, IL-IN-WI	Area-wide	Population	N/A	Urban	PAMS/NCORE	42i-y	Hourly
17-031-0119	1	Lansing Kingery near-road #1	+41.578603 -87.557392	Kingery high traffic road segment	Near-road	Highest Conc.	Source	Micro	SLAMS	T500U	Hourly
17-031-0219	1	Chicago Kennedy near-road #2	+41.920681 -87.674425	Kennedy high traffic road segment	Near-road	Highest Conc.	Source	Micro	SLAMS	T500U	Hourly
17-117-0002	1	Nilwood	+39.39607533 -89.80973892	St Louis, IL-MO	Area-wide	Background	Population	Regional	SPM	T500U	Hourly
17-163-0010	2	East St. Louis	+38.61203448 -90.16047663	St Louis, IL-MO	Susceptible Population	Population	N/A	Neighborhood	SLAMS	T500U	Hourly

T200 – Teledyne (method 099); TE 42i – ThermoScientific (method 074); T500U – Teledyne (method 212); 42i-y – ThermoScientific (NOy method 674)

NO_2 parameter code – 42602
NO_y parameter code - 42600

* indicates monitor proposed for removal
** indicates monitor proposed for installation

Figure 6: NO_2 Sites – Illinois

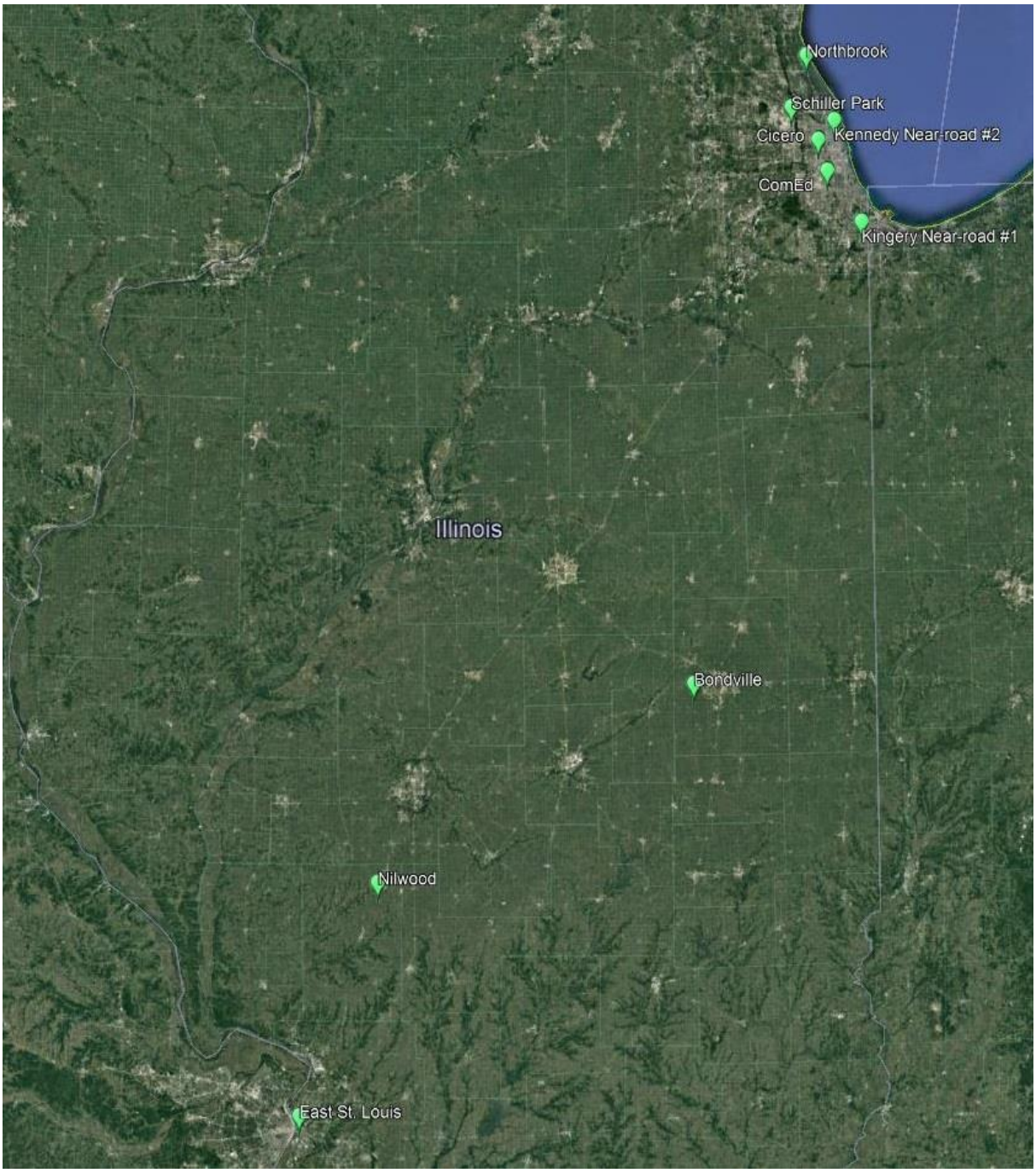


Table 6: CO Sites

AQS ID	POC	Site Description	Latitude Longitude	Area Represented	Primary Objective	Secondary Objective	Spatial Scale	Station Type	Monitor Type	Sampling Schedule
17-019-1001	1	Bondville	+40.052780 -88.372510	Champaign-Urbana, IL	Regional Transport	Welfare Related	Regional	NCORE	API 300EU	Hourly
17-031-4201	1	Northbrook	+42.13999619 -87.79922692	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Neighborhood	PAMS/NCORE	48iTLE	Hourly
17-031-0119	1	Lansing Kingery near-road #1	+41.578603 -87.557392	Kingery high traffic road segment	Highest Conc.	Source	Micro	SLAMS	API 300	Hourly

48iTLE – ThermoScientific Trace Level (method 554); API 300EU – Teledyne Trace Level (method 593) API 300 – Teledyne/API non-trace level (method 093)

CO parameter code – 42101

* indicates monitor proposed for removal

** indicates monitor proposed for installation

Figure 7: CO Sites – Illinois

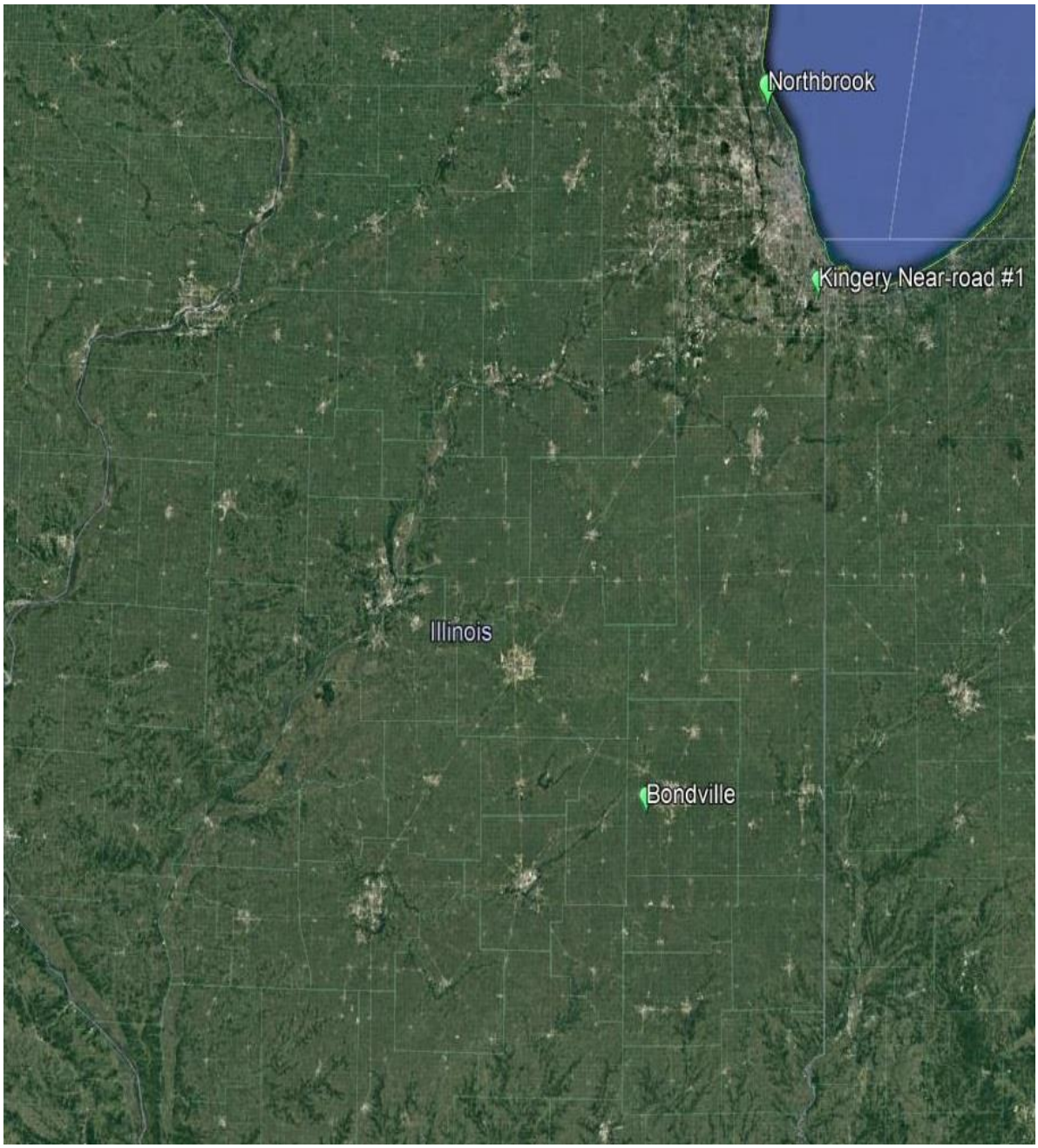


Table 7: PM_{10} and $PM_{10-2.5}$ Sites

AQS ID	POC	Site Description	Latitude Longitude	Area Represented	Primary Objective	Secondary Objective	Spatial Scale	Station Type	Monitor Type (Primary)	Sampling Schedule	Collocated
17-031-0022	4	Washington High School (PM10)	+41.68716544 -87.53931548	Chicago-Naperville-Michigan City, IL-IN-WI	Highest Conc.	Source	Neighborhood	SLAMS	Teledyne T640x	Hourly	
17-031-1016	4	Lyons Township (PM10)	+41.801180 -87.832349	Chicago-Naperville-Michigan City, IL-IN-WI	Highest Conc.	Source	Middle	SLAMS	Teledyne T640x	Hourly	
17-031-4201	1, 9	Northbrook (PM10)	+42.13999619 -87.79922692	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	NCORE	SA/GMW	1/6	YES (1/12 day)
17-031-4201	1	Northbrook (PM coarse)	+42.13999619 -87.79922692	Chicago-Naperville-Michigan City, IL-IN-WI	Population	N/A	Urban	NCORE	Teledyne T640X	Hourly	
17-119-1007	1	Granite City (PM10)	+38.70453426 -90.13967484	St Louis, IL-MO	Highest Conc.	Source	Neighborhood	SLAMS	Teledyne T640X	Hourly	

Teledyne T640x – Federal Equivalent Method Teledyne T640x Continuous (method 239 for PM10 and method 240 for PM10-2.5/course);
SA/GMW - Sierra Anderson/General Metal Works Hi-Volume Sampler, Standard Conditions (method 063);
The National Park Service operates an additional PM_{10} monitor in Bondville as part of the IMPROVE network.

PM_{10} parameter code – 81102
PM coarse parameter code – 86101

* indicates monitor proposed for removal
** indicates monitor proposed for installation

Figure 8: PM_{10} Sites – Illinois

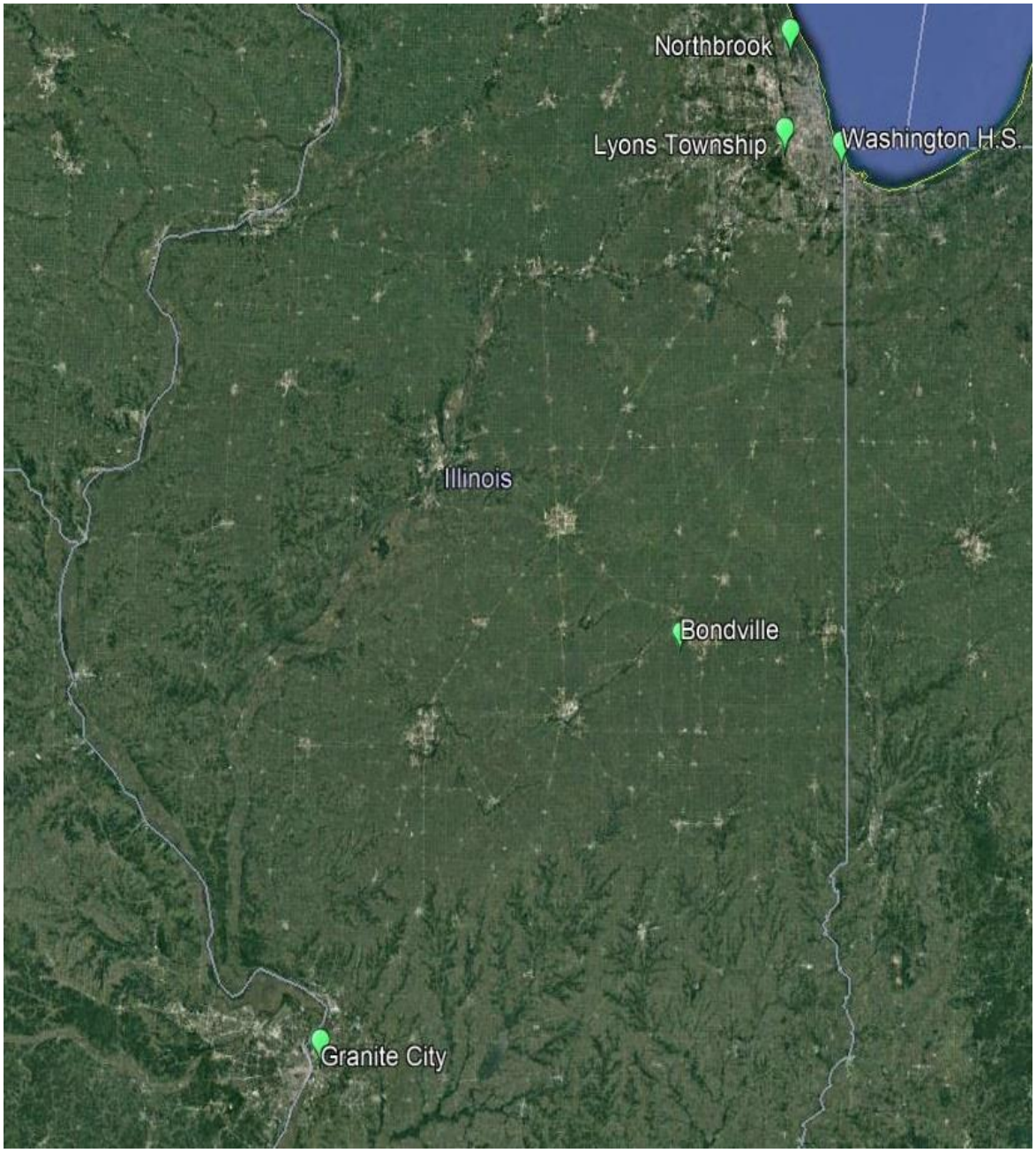


Table 8: Lead Sites

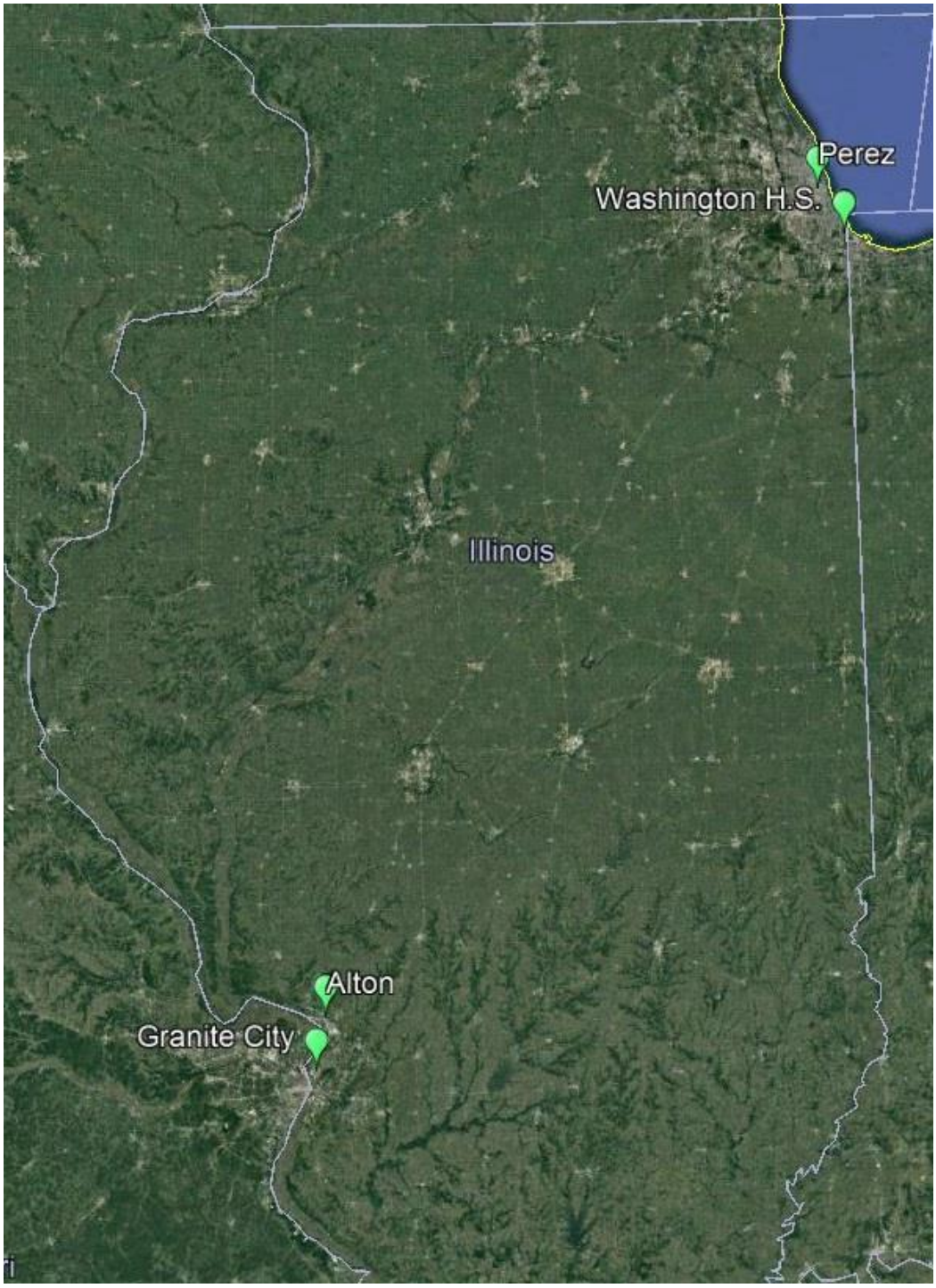
AQS ID	POC	Site Description	Latitude Longitude	Area Represented	Primary Objective	Secondary Objective	Spatial Scale	Station Type	Monitor Type (Primary)	Frequency	Collocated
17-031-0022	2	Washington High School	+41.68716544 -87.53931548	Chicago-Naperville-Michigan City, IL-IN-WI	Highest Conc.	N/A	Neighborhood	SLAMS	Tisch 5170	1/6	
17-031-0110	1, 9	Perez	+41.855917 -87.658419	H. Kramer	Source	N/A	Middle	SLAMS	Tisch 5170	1/6	YES (1/12 day)
17-119-0010	1, 9	Granite City	+38.69443831 -90.15395426	Mayco / US Steel	Highest Conc.	Source	Middle	SLAMS	Hi-Vol(1)	1/6	YES (1/12 day)
17-119-0121*	1	Alton	+38.888373 -90.107592	Olin Corporation	Source	N/A	Micro	SPM	HI-Vol(2)	1/6	

Hi-Vol (1) - Environmental Products Hi-Volume Sampler, Local Conditions (laboratory method 045);
Hi-Vol (2) – Thermo Hi-Volume Sampler, Local Conditions (laboratory method 192);
Tisch 5170 – Tisch Model 5170-D Hi-Volume Sampler, Local Conditions (laboratory method 045)

Lead parameter code – 14129

* indicates monitor proposed for removal or has been removed
** indicates monitor proposed for installation or has been installed

Figure 9: Lead Sites – Illinois



Appendix A

Data Requirements Rule SO_2 Emissions Assessment for Illinois Areas Modeled to be in Attainment with the 2010 1-hour SO_2 NAAQS

Background

Pursuant to Section 51.1205(b) of the Data Requirements Rule (DRR) (40 CFR 51 Subpart BB), Illinois EPA is required to submit an annual report to the Regional Administrator that documents the annual SO_2 emissions of each applicable source in each area previously modeled to be attaining the 2010 1-hour SO_2 NAAQS. Applicable sources refer to stationary sources that are not located in designated nonattainment areas. These sources either have actual annual SO_2 emissions data of 2,000 tons or more or are such that either an air agency or the EPA Regional Administrator has identified these sources as requiring further air quality characterization. This report is to be submitted to the Regional Administrator by July 1 of each year and must provide an assessment of the cause of any emissions increases from the previous year and a recommendation regarding the need for additional modeling to determine if the areas are still meeting the 1-hour SO_2 NAAQS.

Multiple areas in Illinois have been designated by USEPA as attaining the 1-hour SO_2 NAAQS, based upon a technical analysis by USEPA that considered, in part, modeling results submitted by Illinois EPA pursuant to the DRR or the 2015 SO_2 Consent Decree. Six of the attainment areas have both active applicable DRR sources and model design values greater than 50% of the 1-hour SO_2 NAAQS (see Table A-1). These six areas are still subject to the ongoing data requirements listed under Section 51.1205(b).

Table A-1: SO_2 Attainment/Unclassifiable Areas in Illinois Subject to Ongoing Data Requirements Pursuant to Section 51.1205(b)

Attainment/Unclassifiable Area	Applicable Source(s)	Modeled Period	Model Design Value	Percent of 1-hour SO_2 NAAQS*
Jasper County	Newton Power Station	2012-2014	138.89 ug/m^3	70.75%
Massac County	Joppa Power Station	2012-2014	168.29 ug/m^3	85.72%
Crawford County	Rain CII Carbon	2015-2017	118.2 ug/m^3	60.21%
Lake County	Midwest Generation LLC -Waukegan	2013-2015	98.91 ug/m^3	50.38%
Granite City Area	U.S. Steel-Granite City Works; Gateway Energy & Coke Company	2013-2015	190.93 ug/m^3	97.25%
Williamson County	Southern Illinois Power Coop	2013-2015	194.92 ug/m^3	99.29%

*Based on 1-hour SO_2 NAAQS value of 196.32 ug/m^3

2015-2021 SO_2 Emission Trends Data and Recommendations

Table A-2 presents the annual SO_2 emissions data for the applicable attainment/unclassifiable areas for the period 2015 through 2021. Annual SO_2 emissions are listed for the applicable DRR source in each area, along with all the background sources that were included in the DRR and SO_2 Consent Decree modeling.

USEPA's implementation of the primary SO_2 NAAQS occurred in phases and continues with ongoing annual emissions assessment requirements. As a result, progressively more recent years of emissions data have been used in modeling demonstrations. These modeling demonstrations have been the basis of some area designations and in verification modeling.

Within the three-year modeling runs that Illinois EPA conducted for each of the six areas listed in Table A-1, the agency identified the year with the maximum annual emissions and defined the emission total associated with that year as the maximum modeled annual SO_2 emissions total.. Each year, Illinois EPA compares maximum modeled annual SO_2 totals with area emission totals for the most recent year. Illinois EPA uses these comparisons to identify whether there is a need to update existing modeling, or whether existing modeling is sufficient to account for annual emissions within each area.

Appendix A describes comparisons between the emissions used in the latest three-year modeled period for each area and the emissions that applicable sources in each area reported in 2021.[2] Illinois EPA then compared this data with USEPA's recommended guidelines for additional modeling presented in the Preamble to the DRR (80 FR 51052). Emissions data for 2012-2014 were used in the SO_2 Consent Decree modeling, whereas emissions data for 2013-2015 were used in the DRR modeling. The Crawford County area modeling was updated using emissions data for 2015-2017 due to the 2017 emissions increase at the Rain CII Carbon facility. The Granite City area modeling was updated using emissions data for 2016-2018 due to the 2018 emissions increase at Gateway Energy & Coke.[3] The results of these analyses are presented below:

Jasper County – This area includes a single source in Jasper County, IL (FIPS Code: 17079). The highest modeled annual SO_2 emissions total for the Jasper County attainment/unclassifiable area was 16,533.83 tons, which occurred in 2012. Associated modeling results yielded a design value that was roughly 70.75% of the 1-hour SO_2 NAAQS (Table A-1). Emissions from the Newton Power Station (ID: 079808AAA), the only applicable SO_2 source for this area, have since decreased to 6,453.10 tons in 2021 (-61.0%). Given that emissions have continued to decrease since the last time Illinois EPA modeled Jasper County, Illinois EPA would not expect new modeling to generate higher impacts than what was originally modeled. Likewise, Illinois

[2] Please note that highest modeled annual SO_2 emissions totals listed correlate with the modeled period described in Table A-1 for each area. The only exception to this is the Granite City Area, for which the highest modeled annual SO_2 emissions occurred in 2018. Both footnote 3 below and the Granite City Area discussion on pages 40 and 41 of Appendix A provide more information about this exception.

[3] Because the 2018 emissions increase is attributable to a now-complete project that was undertaken at Gateway Energy & Coke as part of a consent decree, Illinois compared its 2021 emission inventory against the 2014 emissions inventory, rather than the 2018 emissions inventory based on instructions from USEPA.

EPA recommends no additional modeling for the Jasper County attainment/unclassifiable area at this time.

Massac County – This area includes five sources in Massac County, IL (FIPS Code: 17127) and a sixth source in McCracken County, KY (FIPS Code: 21145). The highest modeled annual SO_2 emissions total for the Massac County attainment/unclassifiable area was 48,599.45 tons, which occurred in 2014. Associated modeling results yielded a design value that was roughly 85.72% of the 1-hour SO_2 NAAQS (Table A-1). Emissions from SO_2 sources in the area have since decreased to 28,236.20 tons in 2021 (-41.9%). Given that emissions have continued to decrease since the last time Illinois EPA modeled Massac County, Illinois EPA would not expect new modeling to generate higher impacts than what was originally modeled. Likewise, Illinois EPA recommends no additional modeling for the Massac County attainment/unclassifiable area at this time.

Crawford County – This area includes two sources in Crawford County, IL (FIPS Code: 17033) and a third source in Sullivan County, IN (FIPS Code: 18153). The highest modeled annual SO_2 emissions total for the Crawford County attainment/unclassifiable area was 9,625.37 tons, which occurred in 2017. Associated modeling results yielded a design value that was roughly 60.21% of the 1-hour SO_2 NAAQS (Table A-1). Emissions from SO_2 sources in the area have since decreased to 5,797.23 tons in 2021 (-39.8%). Given that emissions have continued to decrease since the last time Illinois EPA modeled Crawford County, Illinois EPA would not expect new modeling to generate higher impacts than what was originally modeled. Likewise, Illinois EPA recommends no additional modeling for the Crawford County attainment/unclassifiable area at this time.

Lake County – This area includes eight sources in Lake County, IL (FIPS Code: 17097), one of which is no longer operating. Originally, this area also included Pleasant Prairie Generating Station, located in Kenosha County, WI (FIPS Code: 55059). However, this facility is no longer operational. The highest modeled annual SO_2 emissions total for the Lake County attainment/unclassifiable area was 9,205.90 tons, which occurred in 2013. Associated modeling results yielded a design value that was roughly 50.38% of the 1-hour SO_2 NAAQS (Table A-1) and included impacts from two facilities that have since shutdown. Emissions from SO_2 sources in the area have since decreased to 1,412.98 tons in 2021 (-84.7%). Given that emissions have continued to decrease since the last time Illinois EPA modeled Lake County, Illinois EPA would not expect new modeling to generate higher impacts than what was originally modeled. Likewise, Illinois EPA recommends no additional modeling for the Lake County attainment/unclassifiable area at this time.

Granite City Area – This area includes five sources in Madison County, IL (FIPS Code: 17119) and two sources in St. Clair County, IL (FIPS Code: 17163). The highest modeled annual SO_2 emissions total for the Granite City attainment/unclassifiable area was 2,995.99 tons, which occurred in 2018, and is associated with the 2016 through 2018 modeling demonstration. Although 2018 was the last year of emissions modeled, based on USEPA guidance, Illinois is comparing 2021 emissions to the 2014 emissions inventory instead of the 2018 emissions inventory to determine if additional analysis is required for the Granite City area. This 2014 inventory is associated with the 2013 through 2015 modeling presented in Table A-1.

The 2018 emissions in the Granite City area were unusually high because of maintenance activities that were associated with the "redundant [heat recovery steam generator] HRSG tie-in project required under the consent decree ("Consent Decree") filed on June 26, 2013, in the United States District Court for the Southern District of Illinois, East St. Louis Division (Civil Action No. 3:13-cv-00616-DRH-SCW)." The latest Granite City area modeling results (2016 through 2018) indicated that the largest annual contribution to the design value from 2017 occurred during the same time as a spray dryer/fabric filter (SD/FF) maintenance outage. This outage was associated with the redundant HRSG tie-in project. The largest annual contribution to the design value from 2018 occurred at the same time as an additional outage associated with the redundant HRSG tie-in project.

The HRSG was fully operational as of June 9, 2019. Company-provided data from 2019 and early 2020 indicates that, following project completion, the number of hours dedicated to HRSG and SD/FF maintenance and malfunctions has decreased. This finding suggests that 2018 modeled emissions are not representative of the Granite City attainment/unclassifiable area. Consequently, USEPA recommended that Illinois use the 2014 emissions inventory as a point of comparison, to determine if there are any SO_2 issues in the future.

In 2014, the maximum modeled concentration for the Granite City area was 2,345.30 tons. Emissions from SO_2 sources in the area decreased to 1,468.47 tons in 2021 (-37.4%). Given that the emissions increase in 2017 was associated with a now-completed project and emissions in the Granite City Area attainment/unclassifiable area have continued to decrease in recent years, Illinois EPA recommends no additional modeling at this time

Williamson County – This area includes two sources in Williamson County, IL (FIPS Code: 17199) The highest modeled annual SO_2 emissions total for the Williamson County attainment/unclassifiable area was 8,651.62 tons, which occurred in 2014. Associated modeling results yielded a design value that was roughly 99.29% of the 1-hour SO_2 NAAQS (Table A-1). Emissions from SO_2 sources in the area have since decreased to 1,657.91 tons in 2021 (-80.8%). Given that emissions have continued to decrease since the last time Illinois EPA modeled Williamson County, Illinois EPA would not expect new modeling to generate higher impacts than what was originally modeled. Likewise, Illinois EPA recommends no additional modeling for the Williamson County attainment/unclassifiable area at this time.

Table A-2: Annual SO_2 Emissions Data for Attainment/Unclassifiable Areas

ID Number	Facility Name	2015 Emissions	2016 Emissions	2017 Emissions	2018 Emissions	2019 Emissions	2020 Emissions	2021 Emissions	Modeled Maximum	2021 Total Area Emissions
079808AAA	Newton Power Station	12,805.40	7,742.70	4,873.20	4,638.60	5,000.30	4,632.20	6,453.10	16,533.83	6,453.10
127855AAC	Joppa Power Station	13,230.00	7,634.00	10,310.20	11,968.40	10,436.10	8,243.00	13,230.90	37,939.13	28,236.20
127855AAA	Holcim US Inc.	259.42	698.18	409.31	332.38	208.59	268.70	308.50		
127899AAA	Midwest Electric Power Inc. (MEPI)	0.01	0.01	0.02	0.01	0.03	0.10	0.29		
127855AAB	Trunkline Gas Company	0.60	0.20	0.12	0.12	0.18	0.10	0.11		
127854AAD	Honeywell International Inc.	147.30	148.89	100.60	0.04	0.00	0.00	0.00		
2114500006	TVA – Shawnee Power Plant	24,301.80	*23,807.80*	*20,494.00*	*15,149.50*	*16,345.70*	*9,024.40*	*14,696.40*		
033025AAJ	Rain CII Carbon	2,161.40	3,836.20	6,810.10	4,162.60	5,451.60	4,067.00	1,759.90	9,625.37	5,797.23
033808AAB	Marathon Petroleum	213.40	262.22	177.17	114.07	146.16	138.78	170.53		
1815300005	Merom Generating Station	2,579.40	*3,143.80*	*2,638.10*	*3,802.70*	*2,897.90*	*1,587.90*	*3,866.80*		
097190AAC	Midwest Generation LLC – Waukegan	2,339.30	2,733.95	1,705.94	1,173.77	754.15	416.40	1,264.35	9,205.90	1,412.98
097190AAP	New NGC Inc.	8.70	7.72	0.13	0.12	0.13	0.13	0.14		
097025AAR	Countryside Genco LLC	41.50	19.43	41.85	50.73	51.76	43.00	0.00		
097806AAG	Countryside Landfill	14.50	30.90	21.80	17.20	16.20	37.50	63.40		
097809AAD	Abbott Laboratories	0.20	0.32	0.31	0.31	0.31	0.31	0.31		
097125AAA	AbbVie Inc.	6.60	12.35	1.50	1.57	0.40	0.36	0.39		
097200AAV	ADS Zion Landfill Inc.	26.70	23.40	32.87	47.80	81.83	98.09	84.39		
097200ABC	Bio Energy (Illinois) LLC	22.30	15.10	21.60	25.30	32.54	16.89	*Shutdown*		
230006260	Pleasant Prairie Generating Station	1,335.50	*1,087.00*	*931.00*	*258.30*	*Shutdown*	*Shutdown*	*Shutdown*		
119813AAI	U.S. Steel – Granite City Works	828.30	9.94	12.10	350.30	418.67	375.25	260.54	2,345.30	1,468.47
119040ATN	Gateway Energy & Coke	1,187.70	1,190.74	1,470.37	2,542.82	1,171.37	976.71	1,118.61		
119465AAG	Green Plains Madison LLC	7.80	3.10	1.96	1.72	0.96	0.60	0.33		
119040AAC	Amsted Rail Co. Inc.	5.90	4.00	3.50	5.10	4.00	1.00	1.10		
163121AAB	Afton Chemicals	98.00	72.97	73.78	71.18	73.40	58.02	57.95		
163050AAD	Milam Recycling & Disposal	17.50	7.35	15.98	24.10	32.87	31.85	29.35		
119801AAK	Chain of Rocks Recycling & Disposal	4.80	4.81	4.66	0.77	0.80	0.76	0.59		
199856AAC	Southern Illinois Power Coop	4,233.60	3,699.20	3,830.80	5,112.70	5,843.70	2,927.40	1,657.90	8,651.62	1,657.91
199862AAD	United States Penitentiary	0.01	0.02	0.02	0.02	0.02	0.02	0.01		

Source: Illinois EPA Annual Emissions Reports, except for those values listed in *red italics*, which were obtained from USEPA's Clean Air Markets database. Although Pleasant Prairie Generating Station and Bio Energy (Illinois) LLC are no longer operating, Illinois EPA continues to include them in Table A-2 as modeling demonstrations described above conservatively account for these sources' impacts.

Appendix B

Ozone and PM2.5 Required Monitoring Site Tables

Minimum O_3 Monitoring Sites Requirement (CFR 40 Part 58):

MSA population[1, 2]	Most recent 3-year design value concentrations ≥85% of any O_3 NAAQS[3]	Most recent 3-year design value concentrations <85% of any O_3 NAAQS[3, 4]
>10 million	4	2
4-10 million	3	1
350,000-<4 million	2	1
50,000-<350,000[5]	1	0

[1] Minimum monitoring requirements apply to the Metropolitan statistical area (MSA).
[2] Population based on latest available census figures.
[3] The ozone (O_3) National Ambient Air Quality Standards (NAAQS) levels and forms are defined in 40 CFR part 50.
[4] These minimum monitoring requirements apply in the absence of a design value.
[5] Metropolitan statistical areas (MSA) must contain an urbanized area of 50,000 or more population.

Illinois O3 Sites by MSA:

MSA/(μSA) Name	Populations	Maximum 2019-2021 8-Hour DV as % of Standard (70 ppb)	Minimum Required Sites	IL Sites in MSA
Chicago-Naperville-Elgin, IL-IN-WI	9,458,539	104%*	3	15**
St. Louis, MO-IL	2,803,228	97%	2	7**
Peoria, IL	400,561	93%	2	2
Davenport-Moline-Rock Island, IA-IL	379,172	93%*	2	1**
Rockford, IL	336,116	94%	1	1
Champaign-Urbana, IL	226,033	93%	1	2
Springfield, IL	206,868	89%	1	1
Bloomington, IL	171,517	93%	1	1
Ottawa, IL	147,036	-	0	0
Carbondale-Marion, IL	135,764	-	0	0
Kankakee, IL	109,862	-	0	0
Decatur, IL	104,009	91%	1	1
Quincy, IL-MO (μSA)	75,211	90%	0	1
Effingham, IL (μSA)	34,008	91%	0	1
Sites outside of a MSA/(μSA)	N/A	93%	0	3

*Out of state monitors not included in calculation.
**Required sites met or further exceeded by monitors run outside of Illinois boundaries, but within MSA/μSA.

Minimum PM2.5 Monitoring Sites Requirement (CFR 40 Part 58):

MSA population[1, 2]	**Most recent 3-year design value concentrations ≥85% of any $PM_{2.5}$ NAAQS[3]**	**Most recent 3-year design value concentrations <85% of any $PM_{2.5}$ NAAQS[3, 4]**
>1 million	3	2
500,000-1,000,000	2	1
50,000-<500,000[5]	1	0

[1] Minimum monitoring requirements apply to the Metropolitan statistical area (MSA).
[2] Population based on latest available census figures.
[3] The $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS) levels and forms are defined in 40 CFR part 50.
[4] These minimum monitoring requirements apply in the absence of a design value.
[5] Metropolitan statistical areas (MSA) must contain an urbanized area of 50,000 or more population.

Illinois PM2.5 Sites by MSA:

MSA Name	Populations	Maximum 2021 Annual DV as % of Standard (12 µg/m³)	Maximum 2021 Daily DV as % of Standard (35 µg/m³)	Minimum Required Sites	IL Sites in MSA
Chicago-Naperville-Elgin, IL-IN-WI	9,458,539	90%*	73%*	3	18**
St. Louis, MO-IL	2,803,228	85%*	67%*	3	6***
Peoria, IL	400,561	73%	57%	0	1
Davenport-Moline-Rock Island, IA-IL	379,172	73%*	58%*	0	1
Rockford, IL	336,116	81%	65%	0	1
Champaign-Urbana, IL	226,033	65%	55%	0	2
Springfield, IL	206,868	68%	54%	0	1
Bloomington, IL	171,517	75%	58%	0	1
Ottawa, IL	147,036	-	-	0	0
Carbondale-Marion, IL	135,764	-	-	0	0
Kankakee, IL	109,862	-	-	0	0
Decatur, IL	104,009	79%	58%	0	1
Sites outside MSA or Background	N/A	74%	51%	1	2

*Out of state monitors not included in calculation.

**Addition PM2.5 NCore site requirement met at Northbrook and addition PM2.5 Near-Road requirement met at Kingery site and included in this total.

***Additional PM2.5 Near-Road required met at Missouri operated Near-Road site for St. Louis MSA.

APPENDIX F: Illinois Smoke Management Plan

ILLINOIS SMOKE MANAGEMENT PLAN

AQPSTR 08-05

May 8, 2009

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 NORTH GRAND AVENUE EAST

P.O. BOX 19276

SPRINGFIELD, ILLINOIS 62794-9276

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List of Acronyms

AQI	**Air Quality Index**
CAA	**Clean Air Act**
CAAA	**Clean Air Act Amendments**
FOFEM	**First Order Fire Effects Model**
IDNR	**Illinois Department of Natural Resources**
Illinois EPA	**Illinois Environmental Protection Agency**
IPCB	**Illinois Pollution Control Board**
ISWS	**Illinois State Water Survey**
MOA	**Memorandum of Agreement**
NWS	**National Weather Service**
NO_X	**Nitrogen Oxides**
NAAQS	**National Ambient Air Quality Standards**
PM	**Particulate Matter**
SASEM	**Simple Approach Smoke Estimation Model**
SMP	**Smoke Management Plan**
SIP	**State Implementation Plan**
TNC	**The Nature Conservancy**
USEPA	**United States Environmental Protection Agency**
USFS	**United States Forest Service**
USFWS	**United States Fish and Wildlife Service**
USNPS	**United States National Park Service**
VOC	**Volatile Organic Compounds**

Executive Summary

Prescribed fire and managed wildfire have been used in Illinois for many years to improve and maintain natural resources. Reasons for burning include hazardous vegetative fuel reduction, site preparation, seed production, wildlife habitat improvement and maintenance, range/pasture improvement and maintenance, disease and insect control (forest health), ecosystem management, restoration and maintenance of biological diversity, restoration of fire as a natural process, research, and training.

This Smoke Management Plan (SMP) is based on Section VI "Smoke Management Programs" of the U.S. Environmental Protection Agency's (U.S.EPA) "Interim Air Quality Policy on Wildland and Prescribed Fires" (April 23, 1998). According to this policy, the purpose of a SMP is to mitigate the nuisance and public safety hazards posed by smoke intrusions into populated areas (including on roadways and at airports); prevent deterioration of air quality and National Ambient Air Quality Standards (NAAQS) violations; and address visibility impacts in mandatory Federal Class I Areas.

The impetus for developing a SMP for Illinois is the anticipated increase in the use of prescribed fire in Illinois, the need to mitigate nuisance hazards, and the goal to utilize a voluntary program to prevent particulate matter (PM) NAAQS violations related to emissions from prescribed fires and wildland fires managed for resource benefits in Illinois. With the projected increasing need for prescribed burning in Illinois, particularly in the prairies and grasslands near Chicago and northeastern Illinois, it is prudent to set in place a voluntary SMP so that emissions from prescribed burning do not contribute to exceedances of the NAAQS in nonattainment areas (NAAs).

The planning process for this SMP began early in 2004 with preliminary discussions between the Illinois EPA, U.S.EPA, and the Illinois Department of Natural Resources (IDNR), U.S. Fish & Wildlife Service (USFWS), U.S. National Park Service and the U.S. Forest Service (USFS). In 2007, the Illinois Smoke Management Committee was assembled to undertake the effort. Participants include representatives from the Illinois EPA, IDNR, USFS, The Nature Conservancy (TNC), Lake County Forest Preserve and the Forest Preserve District of Cook County. This document is the product of this Smoke Management Committee. It is anticipated that future prescribed fires in Illinois will be conducted in accordance with this SMP. Environmental laws, including the Illinois Environmental Protection Act (Illinois Act) and the Clean Air Act (CAA) that implement the NAAQS address both regional haze and criteria pollutants. The Illinois EPA and Illinois Pollution Control Board (Board) have the authority to adopt regulations that implement and enforce federal air quality standards.

For the purposes of the SMP, prescribed burn plans must include the following elements:

- Location and description of the area to be burned
- Personnel responsible for managing the fire
- Type of vegetation to be burned
- Area (acres) to be burned
- Amount of fuel to be consumed (tons/acre)
- Fire prescription, including smoke management components and dispersion index
- Criteria concerning smoke management that the fire manager will consider when making

burn/no burn decisions
- Safety and contingency plans

While government entities involved in prescribed burning have utilized elements of this SMP for prescribed burns in the past, not all of the elements above would necessarily have been included in previous burn plans. Specifically, two of the above-delineated elements, the inclusion of fuel loads and the desired dispersion index for proposed prescribed burns, will be new to some government entities. Methods for deriving these elements are discussed in this document. In addition, as a result of this SMP, the NWS will include ventilation indices on their daily fire weather forecasts for regions of the State. Open burning permits for prairie and ecological management may be obtained from the Illinois EPA, Division of Air Pollution Control, Permit Section. Applications are available on the internet at **www.epa.state.il.us/air/permits/openburn/index.html**.

To evaluate the effectiveness of the SMP, the Illinois EPA will annually collect and review information on acres burned with prescribed fire and/or wildland fire use. Reports of nuisance complaints or smoke intrusions will be noted. The Illinois EPA and the Illinois Smoke Management Committee will use this information to measure the effectiveness of this SMP and make recommendations for future revisions of the SMP.

Every attempt has been made in this document to use terminology that is easy to understand. The reader should refer to the "Glossary" in Section 5.0 of this document if unfamiliar terms are encountered.

1.0 Introduction

Historically, wildland fires in Illinois' ecosystems have been an important process in the ecology of natural communities, such as forests, woodlands, savannas, prairies, and wetlands, located within the state. While wildland fire is an integral part of ecosystem management and is essential in maintaining functional ecosystems, air pollutants emitted from these fires can be harmful to human health and welfare. Because of public and governmental concerns about the possible risk of wildland fire smoke to public health and safety, as well as nuisance, visibility, and regional haze impacts, smoke management plans (SMPs) and air quality policies are being developed and implemented with support from research and land management agency programs.

2.0 Background

The Clean Air Act (CAA) requires each state to submit a State Implementation Plan (SIP) that provides for attainment with air quality standards established by the United States Environmental Protection Agency (U.S.EPA). The SIP must detail the emissions-reducing measures that the State will implement in the affected area in order to meet and maintain the National Ambient Air Quality Standards (NAAQS) for a particular pollutant.

Regarding wildland fires, the U.S.EPA has created guiding principles for States to consider in developing and implementing SIPs:

- Air quality and visibility impacts from fires managed for resource benefits should be treated equitably with other source impacts;
- States should promote land and vegetation management practices that are best for wildland ecosystems, yet protect public health and avoid visibility impairment;
- States/tribes should foster collaborative relationships among wildland owners/managers, air quality managers and the public in developing and implementing SMPs;
- States/tribes should be allowed the flexibility (prior to measuring violations of the $PM_{2.5}$ or PM_{10} NAAQS attributable to fires managed for resource benefits) to decide when a SMP is needed and how the program will be designed to prevent adverse air quality impacts;
- The SMP does not preclude wildland owners/managers from including smoke management components in burn plans for fires they conduct in the absence of an applicable State/tribal program;
- All parties (wildland owners/managers, air quality managers and the public) are expected to act in good faith and will be held accountable for implementing their respective parts of fire and smoke managements plans.

2.1 Climate Factors

According to the Illinois State Water Survey (ISWS), the climate in Illinois has five major controlling influences: the latitude and solar input; weather systems caused by the large scale circulation of the atmosphere; topography; Lake Michigan; and cultural effects. The sun's energy is higher in the southern part of the state than in the north, contributing to a gradient in temperatures throughout Illinois with the south generally warmer than the north. Weather systems have a noticeable effect on precipitation, clouds, and winds during the fall, winter and spring when the jet stream is often located over or near Illinois.

The other controlling factors affect climate on a more local scale. In the Shawnee Hills across southern Illinois, elevation or topographic changes influence precipitation, while Lake Michigan provides a moderating influence which produces cooler summers and warmer winters near the lake compared to inland locations. Finally, urban areas tend to be warmer than the surrounding countryside and contribute to precipitation downwind of the city due to the urban "heat island" effect.

The above climatic factors result in different temperatures, precipitation, and types of severe weather in northern Illinois compared to southern Illinois. Annual temperatures average 48ºF in the north and 58ºF in the south. Summer temperatures are consistent across the state with lows in the 60s and highs

in the 80s. During other seasons, there is an approximately 10ºF difference between the north and south, with the north cooler on average than the south. Precipitation also varies north to south. The north receives 32 inches of precipitation on average and the south receives 48 inches. The north receives considerably more snowfall, while the south has more days with an inch or more of precipitation. Overall, May and June are the wettest months and January and February are the driest.

2.2 Use of Fire as a Land Management Tool

Prescribed fire is a tool used by natural resource land managers to accomplish natural resource restoration and management objectives which include:

- Controlling invasive species.
- Increasing moisture filtration into the soil.
- Opening the dense vegetation to allow light penetration to the soil for plant growth.
- Enhancing habitat diversity by increasing plant quality/vigor and increasing the quantity of wildlife and plants.
- Increasing nutrient cycling by fixing nitrogen in the soil from burn debris.
- Reducing thatch build-up that can lead to dangerous fires.
- Helping to maintain and protect listed species and dedicated Illinois Nature Preserves and Land and Water Reserves. The State of Illinois has statutorily mandated the IDNR to protect these species and State designated natural areas.

As noted above, prescribed burning generates emissions that can negatively impact public health and safety; however, if prescribed burns are implemented correctly, such impact will be negligible. Several reasons listed below account for this and will be highlighted in the SMP.

1. Prescribed fires are implemented when fuels are dry, limiting greater emissions.
2. Prescribed fires are implemented when Pollution Action Days are unlikely to occur.
3. Prescribed fires are implemented on days when smoke dispersal conditions are optimal.
4. Prescribed fires are implemented under specific weather conditions to reduce emissions.
5. Prescribed fires prevent fuel build-up which can lead to unplanned wildland fires occurring during inappropriate times.
6. Prescribed fires promote vigorous herbaceous plant growth, which stores atmospheric carbon in the roots and soil of these habitat areas, thereby offsetting carbon dioxide emissions.

Properly implemented, prescribed fire will provide excellent benefits to the natural ecosystem while reducing potential health and safety issues. The resulting improvement to the natural ecosystems found within the State of Illinois will increase the quantity and aerial coverage of native plants. These native plants are excellent filters of pollutants from the air while storing vast amounts of atmospheric carbon in the extensive roots systems.

Implementation of the SMP will assure that land managers in Illinois will be conducting prescribed burns in a manner that minimizes impacts to air quality, while allowing the appropriate use of an important management tool.

2.3 Reasons for Having a Smoke Management Plan

The SMP is intended to provide a basic framework of procedures and requirements for managing smoke from prescribed fires. The SMP is typically developed by States/tribes with cooperation and participation by wildland owners/managers. The purpose of the SMP is to mitigate the nuisance and public safety hazards posed by smoke intrusions into populated areas (e.g. on roadways and at airports); to prevent impacts to human health due to deterioration of air quality; to prevent NAAQS violations; and to address visibility impacts in mandatory federal Class I areas (U.S.EPA 1998). The NAAQS referred to here are for particulate matter less than 2.5 microns ($PM_{2.5}$) and particulate matter less than 10 microns (PM_{10}).

U.S.EPA encourages the use of SMPs to minimize impacts of burning activities on air quality and visibility impairment, without prohibiting the use of fire for land management. U.S.EPA supports and is willing to partner with Federal, State, Tribal and private land managers to ensure equitable and appropriate use of fire while meeting air quality goals and standards.

According to the U.S.EPA's "Interim Air Quality Policy on Wildland and Prescribed Fires" (Interim Policy, April 1998), "strong indications" that a SMP is necessary are:

1. Citizens increasingly complain of smoke intrusions;
2. The trend of monitored air quality values is increasing (approaching the 24-hour or annual NAAQS for $PM_{2.5}$ or PM_{10}) because of significant contributions from fires managed for resource benefits;
3. Fires cause or significantly contribute to monitored air quality that is already greater than 85 percent of the daily or annual NAAQS for $PM_{2.5}$ or PM_{10}; or
4. Fires in the area significantly contribute to visibility impairment in mandatory Federal Class I Areas.

There are two areas in Illinois, the Chicago metropolitan area and the Metro-East area of St. Louis, which are currently designated as nonattainment for the $PM_{2.5}$ NAAQS. Illinois does not have a federal Class I area. To date there is no evidence that fire emissions are significantly contributing to $PM_{2.5}$ violations; however fire emission can be measured as a component of particulate levels in these areas.

Two primary reasons exist for developing a SMP for Illinois. First, a significant increase in the use of prescribed fire is anticipated in Illinois. There is a nationwide trend among federal and state and local land managers to increase the use of prescribed fire on the landscape in order to improve habitat for plant and animal communities, increase biodiversity and productivity, and reduce fuel loads that are largely due to a long history of fire suppression in wildlands. Public agencies and non-governmental organizations in Illinois anticipate a continued increase of acres treated using prescribed burning. These agencies/organizations anticipate an increasing trend in the next five years.

Second, the goal of the Illinois SMP is to utilize a voluntary program to prevent future PM NAAQS violations related to emissions from prescribed fire management for resource benefit. Implementation of the SMP by land management agencies as well as the private sector should reduce potential emissions and smoke impacts from prescribed fires so that emissions do not cause or

contribute to NAAQS violations. As explained in the U.S.EPA interim policy document, states that implement U.S.EPA-certified SMPs and have exceedances of the PM_{10} or $PM_{2.5}$ standards will not have areas designated as "nonattainment" as a result of those exceedances, if it is demonstrated that prescribed fires significantly contributed to the air concentrations of pollutants that exceeded the standards. This policy provided by U.S.EPA for implementation of a SMP can be very important if an area of a state were to have exceedances of the air quality standards due to smoke from prescribed burning. (Under U.S.EPA's "Natural Events Policy," smoke from wildland fire is not counted against an area when determining attainment of the NAAQS.). This policy is outlined in U.S.EPA's Exceptional Events Rule dated March 22, 2007 (72 FR 13560).

According to the National Fire and Aviation Executive Board, prescribed fire is defined as any fire ignited by management actions to meet specific resource management objectives. Prescribed fire qualifies as an exceptional event if it meets the following criteria:

- Unlikely to recur at the same location and not reasonably controllable or preventable; and
- Where the State certifies that a smoke management program or that basic smoke management practices were in place.

States are provided flexibility regarding the structure of the SMP; thus, a SMP can be extensive and detailed, or simply identify the basic smoke management practices for minimizing emissions and controlling impacts from prescribed fire (burn plan practices).

If an area of a state has been designated as a nonattainment area for the $PM_{2.5}$ or PM_{10} NAAQS, the CAA requires the state to prepare a SIP that is submitted to U.S.EPA for approval. The SIP sets forth measures that the state will undertake to reduce emissions of designated pollutants and attain and maintain the NAAQS. Air monitors for $PM_{2.5}$ and PM_{10} collect air samples that are analyzed to measure emissions of specified pollutants. Monitoring is also used to improve air pollution models. Air modeling is done to determine the sources of the pollutants and the effect of emission reductions on the concentrations of those pollutants. The SIP requirements can include restrictions on the construction of new sources of emissions, or emissions reductions for existing sources whose emissions contributed to the violations.

2.4 Planning Process and Participants

The planning process for this document began in early 2004. Over the course of the next two years, discussions were held with U.S.EPA, multiple states, the U.S. Department of Agriculture, USFS, and IDNR staff regarding SMP requirements and framework development. A meeting was held on October 17, 2007 to facilitate efforts to develop a SMP for the State of Illinois. Following this meeting, a multi-agency committee was formed to develop a state-wide SMP. Committee participants include: representatives from the USFS, IDNR, Illinois EPA, TNC, Lake County Forest Preserve and the Forest Preserve District of Cook County. This document is the product of this committee.

3.0 Compliance and Responsibilities

The U.S.EPA does not directly regulate the use of fire within a State. The U.S.EPA's authority is to enforce the requirements of the CAA. The CAA requires States and tribes to attain and maintain the NAAQS adopted to protect public health and welfare.

3.1 Environmental Laws and Regulations

Prior to 1990 the CAA did not directly address prescribed burning. However, the 1990 Clean Air Act Amendments (CAAA) contains a number of provisions that may result in both direct and indirect regulatory controls. As a result of the CAAA, regulatory rules referenced as, Regional Haze Regulations (64 FR 35714) were developed to address impairment of visibility and emission reductions.

3.1.1 The Clean Air Act and Visibility

Regulatory requirements regarding visibility and regional haze date from 1977 when Congress addressed sources and air pollutants which "...may reasonably be anticipated to cause or contribute significantly to impairment of visibility." In 1980, USEPA established rules addressing "reasonably attributable" sources of visibility impairment, which is to say, individual sources or groups of sources whose emission "plumes" could be observed to affect visibility in federal Class I areas.

In 1990, Congress amended the CAA adding requirements addressing regional haze. In 1999, the U.S.EPA published final rules that required SIP submittals by all states and implementation of "reasonable progress goals" for all federal Class I areas. (The regional haze rules and related information can be found at this U.S.EPA website: http://www.epa.gov/ttn/oarpg/). The regional haze SIP will include emission reductions necessary to meet a goal of showing continuous improvement in visibility in the Federal Class I Areas on the 20 percent "worst" days, and no degradation of visibility on the 20 percent "best" days, as determined by IMPROVE monitoring data. The national goal is to achieve "natural background" visibility in all federal Class I areas by 2064. Emission reductions are to be achieved from all sources in the state, including prescribed burning. Although it is not required, the present SMP may be submitted to the U.S.EPA as part of the regional haze SIP. The first regional haze SIP was due in December 2007 with review every 5 years and revision every 10 years.

3.1.2 Visibility Emissions from Fire

Both the scattering of light and the absorption of light by particles in the atmosphere reduce visibility. Light transmission is inversely related to the concentration of small particles in the air. Because of this correlation, measured levels of $PM_{2.5}$ can be used to calculate visibility impairment. IMPROVE monitors measure different chemical species of $PM_{2.5}$ (and PM_{10}) in air samples so that the effect of different pollutants on visibility can be determined.

Vegetative burning produces various chemical compounds. These compounds include nitrogen oxides (NOx), organic compounds, carbon monoxide, and PM. The pollutants that affect visibility that derive from vegetative burning are PM_{10}, $PM_{2.5}$, nitrates, ozone, organic carbon, and elemental carbon. Ozone, which can form "smog" or haze, is not directly produced by fires, but from chemical reactions in the atmosphere of precursor pollutants (primarily NOx and volatile organic compounds,

VOCs). Air quality tests indicate that 90 percent of smoke particles from wildland and prescribed fires, depending on organic compounds, are composed of PM_{10} while about 70 percent of PM_{10} is composed of $PM_{2.5}$ (Interim Policy, USEPA 1998).

3.1.3 National Ambient Air Quality Standards

Both PM and ozone are "criteria" pollutants, meaning that there are NAAQS established to limit concentrations of these substances in the air. This means that emissions of these pollutants and their precursors from fire can contribute to exceedances of these air quality standards. There are no national or state air quality standards for organic carbon particles or for elemental carbon. However, these pollutants are measured by the IMPROVE monitors, as are other $PM_{2.5}$ species, so concentrations in air samples will be used to measure long-term improvement in visibility. The modules of an IMPROVE monitor measure sulfates, nitrates, organic carbon, elemental carbon (which are all $PM_{2.5}$) and PM_{10}. The IMPROVE monitors inside or adjacent to the federal Class I areas can be considered "compliance" monitors that measure degradation in regional haze due to air pollutants. The IMPROVE monitoring network is designed for measurement of the composition and concentration of the fine particles that cause light extinction that affects visibility within Federal Class I areas. Any similar monitoring outside of Class I areas does not need to conform to the standards or methods that are set forth in the IMPROVE program. Additional sites, known as IMPROVE Protocol sites, exist in Illinois and are used primarily to expand monitoring coverage and improve the understanding of PM and haze in regions without federal Class I areas.

U.S.EPA has established PM air quality standards that differentiate particulate matter based on the size of individual particles. The PM_{10} NAAQS targets suspended PM that is ten microns or less in aerodynamic diameter. Similarly, $PM_{2.5}$ refers to particulate matter that is less than 2.5 microns in aerodynamic diameter.

U.S.EPA established the PM_{10} NAAQS in 1987. There are two forms of the PM_{10} standards: a 24-hour average concentration and an annual average concentration. U.S.EPA issued a revised standard for PM_{10} that took effect on September 16, 1997. The annual standard was 50 micrograms per cubic meter of air (ug/m^3), calculated as an arithmetic mean of three years of values. The 24-hour standard is 150 ug/m^3 calculated as a three-year average of the 99^{th} percentile of measured samples. In October of 2006, the PM_{10} standard was revised. The effective date for the new standard was December 18, 2006. In this action, U.S.EPA retained the 150 ug/m^3 for 24-hour PM_{10} and revoked the 50 ug/m^3 annual PM_{10} standard.

There are presently 18 PM_{10} monitors operating in Illinois. Illinois is considered attainment for PM_{10}; however, Illinois currently has four PM_{10} maintenance areas where PM_{10} violations have occurred in the past. A maintenance area is defined as any geographic region previously designated nonattainment pursuant to the CAAA and subsequently redesignated to attainment subject to the requirements of Section 175A of the CAAA. Two of the four maintenance areas are located in Cook County, and referenced as the Lyons Township and Lake Calumet (Southeast Chicago) maintenance areas. A third is located in Madison County and is identified as the Granite City and Nameoki Township maintenance areas. The fourth area is located in LaSalle County and is referenced as the Oglesby maintenance area.

In 1997, U.S.EPA established annual and 24-hour NAAQS for $PM_{2.5}$ for the first time. In October 2006, U.S.EPA revised the 24-hour NAAQS for $PM_{2.5}$. The revised standard for $PM_{2.5}$ took effect on December 18, 2006. The NAAQS for $PM_{2.5}$ has both annual and 24-hour average times. The annual standard is 15 ug/m^3, calculated as the arithmetic mean of three years of annual averages. The 24-hour standard was strengthened in 2006, from 65 ug/m^3 to 35 ug/m^3, and is calculated as a three-year average of the 98^{th} percentile of measured daily concentrations.

There are presently 38 $PM_{2.5}$ monitors around the state, with 19 located in the Chicago metropolitan area, three in northern Illinois, four in east central Illinois, three in west central Illinois, eight in the Metro-East St. Louis area and one in southeast Illinois (see Appendix A). In addition to these "mass" monitors that measure total $PM_{2.5}$, Illinois also has $PM_{2.5}$ speciated samplers that are located in populated areas. Speciated samplers measure individual components of $PM_{2.5}$. During the period of 2004 – 2006, Illinois values show an average of 17 violations of the 24-hour standard for total $PM_{2.5}$. The highest values are at monitors in the Chicago metropolitan area.

Ozone (O_3) is a gas composed of three oxygen atoms. It is not usually emitted directly into the air, but is created in the atmosphere by chemical reactions between NOx and VOC in the presence of sunlight.

In 1997, U.S. EPA replaced the previous one-hour ozone standard with an 8-hour standard. The 1997 NAAQS for ozone is 0.08 parts per million (ppm), calculated as an average of three years of the fourth highest 8-hour values.

U.S. EPA recently strengthened the air quality standards for ground-level ozone. On March 12, 2008, U.S. EPA revised the level of the 8-hour ozone standard to 0.075 parts per million (ppm). With regard to the secondary standard for ozone, U.S. EPA is revising the current 8-hour standard by making it identical to the revised primary standard. These changes will improve both public health as well as protect sensitive trees and plants.

There are presently 20 ozone monitors around the state with the majority of the monitors located in the Chicago metropolitan area.

3.2 Agency Authority

According to Illinois' Environmental Protection Act, the Illinois Pollution Control Board has the authority to adopt regulations that protect federal air quality standards. It is the responsibility of the Illinois EPA to develop and propose new regulatory requirements, and then to implement and enforce regulations adopted by the Board. If air monitoring in a state exceeds the NAAQS for a criteria pollutant, then the area that exceeds the standard is designated as a "nonattainment" area, meaning it does not "attain" or meet the standard. Section 110 of the CAA requires states with NAAs to submit a SIP to the U.S.EPA that contains enforceable measures to reduce emissions affecting the area, in order to attain and maintain compliance with the standard. Section 110 requires that each plan include "enforceable emission limitations and other control measures" for facilities and sources that contribute to a violation of the standard. The plan must also regulate the construction and modification of stationary sources within the areas covered by the plan and contain adequate provisions prohibiting any source "or other type of emissions activity within the state from emitting any air pollutant in amounts which will contribute significantly to nonattainment in any

other state."

By implementing the requirements of a SIP that have been approved by the Board and the U.S.EPA, the Illinois EPA ensures compliance with air quality standards in Illinois. There are four regulatory instruments that can be included in a SIP in order for an area to attain and maintain an air quality standard.

1. **Statutory requirements** might be imposed by the state legislature on particular sources that would be enforced by the Illinois EPA, with or without rulemaking by the Agency.

2. **State rulemaking** through the Board might be undertaken to impose emissions reductions on particular pollution sources.

3. **Administrative orders through a court system** might be issued to individual facilities with requirements for compliance with lower emission limits.

4. **The air pollution operating permit** issued to a particular source that limits the amount of pollution that can be emitted to the ambient air might be amended to reduce air emissions that affect regional haze. Violations of permit conditions are subject to enforcement action.

Historically, options 3 and 4 have been used when nonattainment areas are small and relatively few sources contribute to the problem. Violations of statutes, rules, orders, or permit conditions are subject to enforcement action by the state. These same measures might be incorporated into a regional haze SIP in order to implement a statewide program of continuous improvement in visibility.

Existing air quality regulatory programs and the regional haze program are related by the implementation plans developed by the states (i.e., SIPs). As described above, areas within a state are subject to designation by the U.S.EPA as "attainment" or "nonattainment" with the NAAQS. A SIP must be submitted to, and approved by, the U.S.EPA for any areas that do not meet ("attain") any one of the NAAQS. Such a SIP is a separate document from the regional haze SIP.

The regional haze SIP will be prepared by the Illinois EPA to directly address emissions that cause visibility impairment in Federal Class I Areas. A regional haze SIP developed by a state will be a plan that describes all measures the state will implement to reduce regional haze. For this reason, although a NAAQS SIP and the regional haze SIP are two different plans, the haze SIP would also include all measures that have been included in a SIP for a visibility pollutant.

4.0 Elements of the Illinois Smoke Management Program

This section describes the components of Illinois' Smoke Management Program. The following topics are addressed:

- authorization to burn from the Illinois EPA
- ways to address smoke management in the preparation of the prescribed burn plan;
- actions to consider to minimize smoke impacts;
- how to estimate the amount of fuels to be consumed by the prescribed fire;
- identification of smoke sensitive populations and areas;
- public notification and procedures to reduce human exposure;
- monitoring of air quality impacts;
- consideration of weather conditions to ensure maximum dispersion;
- consideration of Air Pollution Action Days and the Air Quality Index;
- public education and awareness;
- surveillance and enforcement;
- program evaluation.

4.1 Authorization to Burn

The Illinois EPA issues permits for open burning in Illinois pursuant to the Illinois Pollution Control Board regulations (part 237). Federal and state agencies are required to comply with state burning regulations (CAA Sec. 118). Open burning permits for prairie and ecological management are obtained from the Illinois EPA, Division of Air Pollution Control, Permit Section. Applications for "open burning" permits are also available on the internet at:
www.epa.state.il.us/air/permits/openburn/index.html

Burn managers will monitor Illinois EPA alerts for areas of "Air Pollution Action" days. In areas of the State with "Air Pollution Action" days, prescribed burners are expected to cease all burning.

4.2 Preparation of the Burn Plan

The prescribed burn manager should take measures to reduce the impact of smoke. To this end, at a minimum, the prescribed burn plan must include the following elements:

- Location and description of the area to be burned.
- Illinois EPA office, local fire department or sheriff's office to be contacted.
- List of occupants to be contacted that may have significant smoke impacts from the prescribed fire.
- Personnel responsible for managing the fire.
- Type of vegetation to be burned.
- Number of acres to be burned.
- Amount of fuel to be consumed (tons/acre).
- Fire prescription, including weather, ignition techniques, personnel and equipment.

- If available, documentation (along with any maps or tables) from atmospheric dispersion models/smoke dispersion prediction models which present information on what impact the smoke may have on any smoke sensitive areas.
- Optimal wind direction for the burn
- Actions needed to stop a burn if weather conditions degrade from the forecast values.
- Smoke management criteria the fire manager will consider when making burn/no burn decisions.
- Safety precautions for personnel on the prescribed fire.
- Areas of concern around the burn unit, i.e. schools, major roadways, etc.

4.3 Actions to Minimize Smoke Impacts

The prescribed fire plan should document the steps taken before, during and after the burn to reduce smoke impacts. Where applicable, use one or more of the following approaches:

- Reduce the size of the burn to achieve the allowed emissions.
- Utilize different firing techniques to accomplish burn objectives and minimize smoke emissions. For example: Use of backing, strip-head, flanking, and dot firing patterns, etc.
- Reduce the fuel loading in the area to be burned by mechanical methods or by using frequent, low-intensity burns to gradually reduce fuels.
- Reduce the amount of fuel consumed by the fire by burning when fuel moistures for the larger fuels and duff moistures are high.
- Record smoke dispersion behavior during the burn rapid and complete mop-up after the burn or mop-up of certain fuels.
- Use alternative techniques to vegetation management, such as herbicides, where appropriate.

4.4 Estimate the Amount of Fuels to be Consumed by the Prescribed Fire

Determining the amount of fuel to be consumed by the prescribed fire is an important part of the smoke analysis. Prescribed burn managers should examine the results of their analysis to determine if the prescribed fire could be divided into smaller units since the prescribed burn at issue may not be the sole burn in the vicinity.

A wide variety of fuel types and conditions are found in Illinois. Table 1 describes those fuel types that are found in greatest quantities on typical prescribed fire sites. In most prescribed fires, "available" tons of fuel will be less than "total" tons of fuel. Due to fuel moisture and other factors, the burn may not consume all the fuel. The prescribed burn manager must provide reasonable estimates of the total amount of available fuels that will be burned by the prescribed fire. The prescribed burn manager may need to consider a higher fuel loading estimate than shown in Table 1 for forests that have never been burned or have been impacted by pests, diseases, storm damage, or other factors.

Fuel models are composed of fuel size classes, which are determined by the length of time it takes for fuels to reach 63 percent of the equilibrium moisture content. The sizes of the dead fuel classes are 1 hour - 0 to 1/4 inch; 10 hour - 1/4 to 1 inch; 100 hour - 1 to 3 inches; 1,000 hour - 3 to 7 inches.

Some fuel models also have a "Live" fuel component that adds to the flaming front as it dries from preheating.

To calculate fuel loading during the prescribed fire planning process, agencies should first use site-specific data if available. Lacking this type of data, other local sources of information should be used, such as the National Wildfire Coordinating Group's "Stereo Photo Series for Quantifying Natural Fuels, Volume 5." Table 1 below contains fuel-loading information from the Anderson fuel model series, which can serve as a third source of fuel loading information.

Table 1 Fuel Loading-Tons per Acre*

Fuel Model	Fuel Type	1 hr	10 hr	100 hr	Live	Total
1	Short grass (1 foot)	.74	0	0	0	.74
2	Timber, grass understory	2.0	1.0	.5	.5	4.0
3	Tall grass (2.5 feet)	3.0	0	0	0	3.0
8	Closed timber litter	1.5	1.0	2.5	0	5.0
9	Hardwood litter or long needle pine litter	2.92	.41	.15	0	3.48
10	Timber (litter & understory)	3.0	2.0	5.0	2.0	12.0
11	Light slash	1.5	4.5	5.5	0	11.5
12	Medium slash	4.0	14.0	16.5	0	34.5
13	Heavy slash	7.0	23.0	28.0	0	58.0

*Fuel models 4, 5, 6 and 7 are not widely used in Illinois. This chart is a general reference guide. For more information on fuel loading, refer to "Aids to Determining Fuel Models for Estimating Fire Behavior" by Hal E. Anderson, General Technical Report INT-122, available from the National Interagency Fire Center in Boise, Idaho.

Once the amount of fuels that will be consumed has been determined, multiply the value times the amount of acres to be burned. For example, if an organization plans to burn 300 acres of hardwood leaf litter (Fuel Model 9 in Table 1); the prescribed fire would be expected to consume 1,044 tons of fuel (3.48 tons/acres X 300 acres).

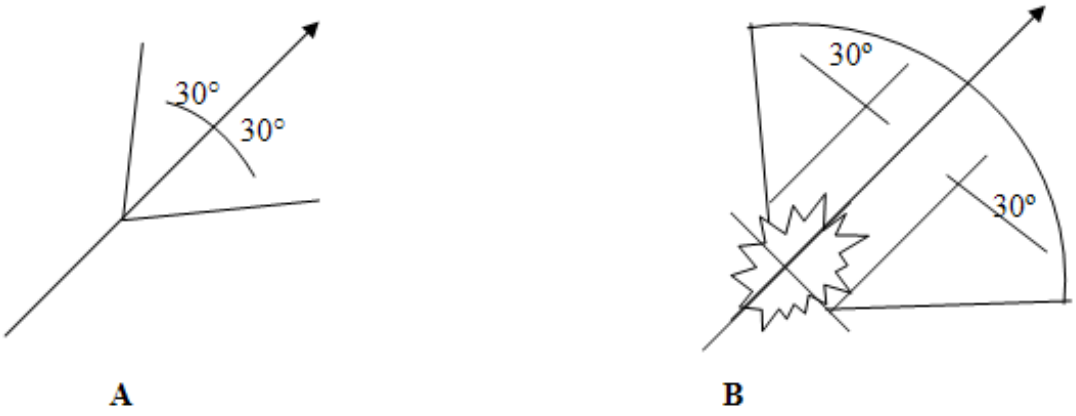
4.5 Identification of Smoke Sensitive Populations and Areas

Prescribed fire plans should identify and evaluate potential smoke impacts on sensitive receptors. The plan should identify the distance and direction from burn site to local sensitive receptor areas where appropriate.

Efforts should be made to keep smoke away from sensitive populations and areas, such as communities, schools, hospitals and nursing homes, airports, four-lane and larger highways, and

industrial areas. Industrial areas may include areas that are already experiencing an air pollution or visibility problem. Smoke-sensitive targets may be determined using the following steps:

1. Locate on a map the prescribed fire and all potential smoke sensitive targets (such as airports, highways, hospitals, schools etc), plus areas known to already have air pollution problems. (consider targets up to 30 miles from the prescribed fire.)
2. Determine the wind direction that will have the least impact on smoke sensitive targets.
3. Draw a line representing the centerline of the path of the smoke plume using the wind direction chosen in the previous step.
4. Determine the distance from the edge of the prescribed fire to the nearest smoke sensitive target.
5. To allow for the horizontal dispersion of the smoke, as well as shifts in wind direction, draw two other lines from the burn at an angle of 30 degrees from the centerline(s). If a prescribed fire is represented as a spot, draw as in Figure A. If larger, draw as shown in Figure B.



Figures A and B

Additionally, the prescribed burn managers should evaluate frequently traveled roads within one mile of the prescribed fire, especially if these roads are down wind or down smoke-drainage of the burn. Residual smoke flows and settles in low areas during the night and early morning and may contribute to heavy fog, which creates hazardous road conditions.

Planning and public notification are recommended when igniting large areas in a short time period, such as with aerial ignition. The heat produced from the prescribed fire may allow the smoke to penetrate above the mixing height where dispersion of the smoke is minimal. Smoke from these prescribed fires may travel long distances before descending to the ground. Therefore, it is important to monitor the smoke column downwind to determine if a problem actually develops.

4.6 Public Notification and Exposure Reduction Procedures

The prescribed fire plan should identify actions that will be taken to notify people and authorities at "smoke-sensitive areas" before the prescribed fire. The prescribed fire plan should identify contingency actions that will be taken during a prescribed fire to reduce the exposure of people at smoke-sensitive areas, if smoke intrusions occur. Appropriate contingency actions may include:

1. Provide information regarding upcoming burning activities on an internet website if available.
2. Post signs at location of the burn(s).
3. Suggesting actions be taken by sensitive persons to minimize their exposure (e.g. remain indoors, leave the area, avoid vigorous activity, avoid exposure to tobacco smoke and other respiratory irritants).
4. Halting ignitions of any additional prescribed burning that could add smoke to the same area.

4.7 Monitor Air Quality

The prescribed fire plan should include monitoring of the smoke from the prescribed fire. The extent of the monitoring should be commensurate with the size of the fire. For small, or short duration fires (such as those in grass or leaf litter), visual monitoring of the direction of the smoke plume and monitoring nuisance complaints by the public may be sufficient. Other monitoring techniques include: posting personnel on vulnerable roadways to look for visibility impairment and to initiate safety measures for motorists; posting personnel at other smoke sensitive areas to look for smoke intrusions; using aircraft to track the progress of smoke plumes; and continued tracking of meteorological conditions during the fire. For prescribed fires in fuels with longer duration burning (such as timber litter or slash), and which are expected to last more than one day, locating real-time PM monitors at smoke-sensitive areas may be warranted to facilitate timely response to smoke problems.

4.8 Consideration of Weather Conditions and Smoke Dispersion

The National Weather Service (NWS) forecast offices that serve Illinois provide a twice-daily fire weather forecast with 12-hour forecast intervals during spring and fall fire seasons for much of the state. The fire weather forecast includes smoke management information and is available by 0600 hours and 1500 hours. The seasonal range is flexible, but will normally run from February 15 – May 1 and October 1 – November 30. The forecast consists of a brief weather discussion and a detailed forecast of weather temperatures, relative humidity, winds and smoke dispersion parameters. Site specific (spot) forecasts are non-routine products issued upon request of users. Prescribed burn managers who intend to ignite burns, should consult their local National Weather Service office or consult their website for their area to determine the anticipated ventilation index (dispersion category) at the time of ignition. Prescribed fire managers who plan ignitions at times other than forecast times, may request ventilation/dispersion criteria as part of the spot weather forecast from the NWS. Fire weather information for Illinois is available at the following websites:

Lincoln - central and southeast Illinois - http://www.crh.noaa.gov/ilx/firewx.php

Chicago - northeast Illinois - http://www.crh.noaa.gov/lot/?n=firewx

Paducah, KY - far southern Illinois - http://www.crh.noaa.gov/pah/?n=firewx

St. Louis, MO - southwest Illinois - http://www.crh.noaa.gov/lsx/?n=firewx

Davenport, IA - northwest Illinois -http://www.crh.noaa.gov/dvn/?n=fireweather (*NOTE: Davenport provides spot forecasts, not routine fire weather forecasts.)*

To ensure optimum dispersal of smoke emissions during prescribed burns, the mixing layer must be deep enough and with sufficient transport wind speed to ensure the dilution and dispersal of emission concentrations. Ventilation is a function of atmospheric stability, mixing height, and transport wind speed. Ventilation information is included as part of the daily fire weather forecast. The fire weather forecast which is issued twice daily, describes the mixing height, transport wind speed, as well as an average ventilation rate (vent rate) for an area in its forecast. Table 2 provides a ventilation index (also known as the Dispersion Index), which is determined by multiplying the mixing height (measured in feet) and transport wind speed (measured in knots). The index describes the ability of the atmosphere to disperse emissions. As the ventilation index increases so will the ability of the atmosphere to disperse smoke in an effective manner (exceptions noted below). Due to the fact that the ventilation index is also reported in meters squared per second (m^2/sec) and miles per hour feet (mph-ft) by different NWS offices, these additional units are provided in Table 2.

Table 2 Ventilation Index

VENTILATION INDEX (m^2/sec)	VENTILATION INDEX (mph-ft)	VENTILATION INDEX (knot-feet)	DISPERSION CATEGORY
> 23,445	> 172,617	> 150,000	Excellent
15,630 – 23,445	115,078 – 172,617	100,000 – 150,000	Very Good
9,378 – 15,630	69,047 – 115,078	60,000 – 100,000	Good
6,252 – 9,378	46,031 – 69,047	40,000 – 60,000	Fair
< 6,252	< 46,031	< 40,000	Poor

NOTE: In using the Ventilation Index, exercise caution with high transport wind and low mixing height or low transport wind and high mixing height which, although they combine to give an acceptable category, can inhibit smoke dispersion, as well as potential control problems!

When utilizing the ventilation index it is important to take into consideration the total fuel load being burned, both in terms of fuel loading (tons of fuel per acre) and total area to be burned (see Table 1). The proximity of downwind smoke sensitive areas to the burn unit should also be considered; prescribed burns may be safely conducted when lower total fuel consumption is expected and when the smoke sensitive area is farther away. Conversely, when higher total fuel consumption is expected and the smoke sensitive area is closer to the prescribed burn unit, conditions should be in higher ventilation categories to safely conduct the burn. In addition, steps taken which reduce the total fuel available for consumption can lower the acceptable dispersion category.

Below are two methods for utilizing the ventilation index to mitigate smoke impacts during burn plan formulation. The first method (Method A), may be used as a general guide to utilizing the ventilation index to screen for downwind smoke sensitive receptors and is recommended for burns with low to moderate potential for smoke impacts. The second method (Method B) is more rigorous and is recommended for complex prescribed burns with a high degree of potential for smoke impacts. Note that these are voluntary guidelines which may vary by the local unit's definition of smoke sensitive receptor and the ability to mitigate potential smoke problems by instituting traffic controls when smoke could impact major roads or by burning under fuel moisture conditions which limit consumption of heavier fuels.

Method A: Recommended for prescribed burns where there is a low – moderate degree of potential for smoke impacts.

1. Use Table 3 below to determine the recommended minimum distance to downwind smoke sensitive areas for your burn(s). On a map, locate any downwind sensitive receptors that could be impacted from your smoke.
2. Determine the general fuel category of the burn area (e.g. grass, leaf litter, timber, slash, piled fuels). Select that category in the table. For burns with multiple fuel categories, utilize the fuel model which best characterizes the majority of the area.
3. In the second column select the acreage to be burned for the single day (daily basis).
4. Select the proper Dispersion Category from Table 2, and look at the corresponding row in Table 3 to determine the recommended minimum distance the burn should take place upwind of a sensitive receptor.

Method B: Recommended for Complex Prescribed Burns where there is a high potential for smoke impacts.

1. Estimate the fuel loading for the area to be burned. This may be done formally, utilizing site-specific survey data if available or by consulting the fuel model information found in Table 1.
2. Determine the acreage to be burned in one day.
3. Estimate the expected fuel consumption using hand calculations or computer models such as First Order Fire Effects Model (FOFEM) or CONSUME. Selection of higher fuel moistures (such as higher 100 and 1,000 hour fuel moisture), which will reduce the fuel available for consumption, should be factored into the calculations.
4. Determine the total PM_{10} and $PM_{2.5}$ emissions per day based on outputs from previous bullet (#3).
5. Locate downwind sensitive receptors that could be impacted from your smoke.
6. Utilize a dispersion computer program such as the Simple Approach Smoke Estimation Model (SASEM) or V-SMOKE to screen for the potential to exceed ambient air quality standards.

Table 3 Minimum Distances to Smoke Sensitive Areas

General Fuel Category	Daily Fire Size (acres)*	Dispersion Category	Minimum Distance to Downwind Smoke Sensitive Areas (miles)
Single large pile or Scattered small piled fuels	NA	POOR	0.25
	NA	FAIR or BETTER	No limitation
Grass or Leaf litter	< 50	POOR	0.25
	< 50	FAIR or BETTER	No limitation
	50 - 150	POOR	No burning
	50 - 150	FAIR or BETTER	No limitation
	150 - 500	POOR	No burning
	150 - 500	FAIR	0.25
	150 - 500	GOOD or BETTER	No limitation
	500+	POOR	No burning
	500+	FAIR	0.75
	500+	GOOD	0.50
	500+	EXCELLENT	0.25
Timber, slash, or piled fuels	< 50	POOR	No burning (See above exception for pile(s))
	< 50	FAIR	0.50
	< 50	GOOD or BETTER	No limitation
	50 -150	POOR	No burning
	50 - 150	FAIR	0.50
	50 - 150	GOOD or BETTER	No limitation
	150 - 500	POOR	No burning
	150 - 500	FAIR	0.75
	150 - 500	GOOD	0.50
	150 - 500	EXCELLENT	0.25
	500+	POOR	No burning
	500+	FAIR	1.0
	500+	GOOD	0.75
	500+	EXCELLENT	0.50

*Assumes no more than one unit within a 5-mile radius.

Note: On Poor Category days no burning is suggested within ¼ mile of any downwind smoke sensitive area and is not recommended in general.

Night Time Burning

Residual night burning requires the same planning as daytime burns; however, predicting visibility and smoke drift is more difficult at night. Winds may lessen or die out completely, and smoke will tend to stay near the ground. Although burning at night or residual night burning may help achieve other objectives, it may aggravate smoke management problems. In general, prescribed burning

should be conducted during day time hours and concluded at sunset. Preferred hours to initiate a prescribed burn are between 8:00 A.M. and 4:00 P.M. Central Standard Time and 9:00 A.M. and 5:00 P.M. when Central Daylight Savings Time is in effect. In the event that residual night burning is required, these special circumstances should be documented and the following recommendations should be considered:

1. Burn in light fuels
2. Use back firing
3. Burn when humidity is 80 percent or less
4. Do not burn if overnight low is within 5 degrees of dew point
5. Burn with surface wind speed of 5 miles per hour or more
6. Obtain a nighttime dispersion index. Monitor down drainage and low areas, especially populated areas, airports or roads near the burn area.

Special Smoke Concerns

The following situations could result in smoke impacting the surface downwind, particularly when there has been a large production of smoke:

1. Transport wind speed exceeds 25 mph and average wind speed is over 20 mph with stronger gusts.
2. Transport wind direction carries smoke over a large lake.
3. A thick layer of smoke from a large burn significantly reduces the heating of the ground.

Transport wind direction moves smoke from a fire on the slope of a ridge toward and over the top of a ridge. Smoke may return to the ground in an eddy that can develop on the lee side of the ridge.

4.9 Air Pollution Action Days and Air Quality Index

The Illinois EPA collects air quality data from a network of air monitoring stations located throughout the state. When data from these monitors indicate conditions are conducive for unhealthful levels of ozone and/or PM, an “Air Pollution Action Day” will be declared. On an “Air Pollution Action Day” the public is advised to avoid ozone and or fine particle-generating activities until the health threat has passed. “Air Pollution Action Day” information is accessible on the internet at http://www.epa.state.il.us/air/aqi/index.html. This website can be checked on a daily basis. Prescribed burn managers should not initiate prescribed fires on “Air Pollution Action Days.”

The Illinois EPA also participates in the development of the Air Quality Index (AQI). The AQI is an index for reporting daily air quality and is an indicator of expected local air quality. The higher the AQI value, the greater the level of air pollution and the greater the health concern. An AQI value of 100 generally corresponds to the NAAQS for the pollutant. An AQI of 0-50 is good, 51 – 100 is moderate, 101 – 150 is unhealthy for sensitive groups, 151 – 200 is unhealthy, 201 – 300 is very unhealthy, and values greater than 300 are hazardous. The U.S. EPA has assigned a specific color to each AQI category. For example, the color orange means that conditions are "unhealthy for sensitive groups," while red means that conditions may be "unhealthy for everyone." Air Pollution Action Days are called when the AQI is forecast to be “unhealthy for sensitive groups,” or considered “code orange” air quality days.

The Air Quality Index (AQI) has recently changed to reflect the new 8-hour ozone NAAQS. AQI categories now reflect the new ozone standard making the upper end of the "moderate" range equal to 0.075 ppm. Other categories have also changed proportionally. Under the revised AQI, ozone levels above 0.075 ppm are considered in the "unhealthy for sensitive groups" category (U.S. EPA, 2008).

4.10 Public Education and Awareness

The Illinois EPA and prescribed fire partners (Federal, State, Local Governmental land management agencies, non-governmental land management agencies, and private individuals) have developed a state-wide prescribed fire council. The agencies and the council will work to explain the importance of prescribed fire in ecosystem management, implications for public health, and the goals for the Illinois SMP. Educational programs include: public presentations, posters, teacher/classroom educational materials, television and radio spots, presentations, as well as the distribution of literature at public events including state and county fairs, and open houses.

4.11 Surveillance and Enforcement

Prescribed burning is conducted under the direct supervision of a certified prescribed burn manager, or burn boss. This prescribed burn manager/boss ensures that the burn is conducted in accordance with the prescribed fire plan. For prescribed fires in nonattainment areas, the burn manager or burn boss should not only be sufficiently trained, but also experienced.

Government entities directly involved in burning activities should have methods and procedures to track and follow up on complaints by the public. The Illinois EPA enforces state air quality laws and regulations and investigates nuisance complaints. Section 9(a) of the Environmental Protection Act is applicable to open burning, i.e. persons affected by such open burning may lodge complaints with the Illinois EPA if the burning is injurious to human, plant or animal life, to health or to property, or unreasonably interferes with the enjoyment of life or property. If it is determined that the actions of any agency burn manager or the burn plan/prescription violates any provision of the guidelines of this SMP, or threatens the public health and safety, he/she will be subject to internal agency review. The Illinois EPA will also notify the identified government entities of such complaint(s) and apprise them of the progress of the investigation. This SMP does not exempt open burning from applicable local restrictions.

4.12 Program Evaluation

Evaluation of the Smoke Management Plan is recommended every 3-5 years and should be reviewed by wildland owners/managers, air quality managers, and the public. This periodic review should include an evaluation of the effectiveness of the program in preventing smoke intrusions. Use of information from nuisance complaints or significant smoke intrusions should be used to the measure the effectiveness of the SMP.

Changes in the SMP should be based on effectiveness and input from all government entities/parties. Information related to acres of fires managed for resource benefits planned for the coming year, acres burned by site location and county, as well as citizen complaints received and resolution of such complaints should be provided to the Illinois EPA in electronic form on an annual basis. Additional

records should be maintained to demonstrate an Exceptional Event, per 40 CFR part 51, Sec. 14 and Part 52, Subpart Y, Treatment of Data Influenced by Exceptional Events; Final Rule. Records should be saved for approximately four years or the duration necessary under U.S.EPA's reporting requirement.

5.0 Glossary

Air Quality Manager -- The regulatory body responsible for managing the air quality protection program for a State, local or tribal government.

Air Quality -- The characteristics of the ambient air (all locations accessible to the general public) as indicated by concentrations of the six air pollutants for which national standards have been established, and by measurement of visibility in mandatory federal Class I areas.

Ambient Air -- That portion of the atmosphere, external to buildings, to which the general public has access.

Attainment Area -- A geographic area in which levels of a criteria air pollutant meet the health-based primary standard (national ambient air quality standard, or NAAQS) for the pollutant. An area may have an acceptable level for one criteria air pollutant, but may have unacceptable levels for others. Thus, an area could be both attainment and nonattainment at the same time. Attainment areas are defined using pollutant limits set by U.S.EPA.

Burn Boss -- Person trained in application of prescribed fire that will be in charge of planning and executing a prescribed burn. Different agencies have different training requirements for burn bosses.

Burn Plan – Commonly used term for the Prescribed Fire Plan

Certified Prescribed Burn Manager -- An individual who successfully completes an approved training program and receives proper certification.

Combustion – Burning -- Many important pollutants, such as sulfur dioxide, nitrogen oxides, and particulates are combustion products, often products of the burning of fuels such as coal, oil, gas and wood

Complexity (Complex) -- A system for rating the potential difficulty of a prescribed burn by analyzing the cumulative elements which may be involved in the burn such as safety, threats to boundaries, fuel types, values to be protected, organization needed, air quality values to be protected, etc. Complexity is usually rated as Low, Moderate and High. Qualifications of prescribed burn practitioners are usually specific to the different complexity levels.

CONSUME Model -- Is a software program which predicts total smoldering fuel consumption during wildfires. Using these predictions, the resource manager can accurately determine when and where to conduct a prescribed burn to achieve desired objectives, while reducing impacts on other resources.

Criteria Pollutants -- A group of common air pollutants regulated by U.S.EPA on the basis of criteria (information on health and/or environmental effects of pollution) and for which NAAQS have been established. In general, criteria pollutants are widely distributed over the country. They are: particulate matter (PM), carbon monoxide (CO), nitrogen oxides (NOx), sulfur dioxide (SO2), ozone (O3), and lead (Pb).

Dispersion Index -- a numerical index developed by Lee Lavdas (Southern Forest Fire Laboratory). This index is an estimate of the atmosphere's capacity to disperse smoke form prescribed burns over a 1,000-square mile area. It is related to the Ventilation Index, but also considers the rate of pollutant dispersion.

Emission -- Release of pollutants into the air from a mobile source (e.g. vehicle), stationary source (e.g. industry), or area source (e.g. gas stations, chimneys, vegetative burning).

Equilibrium Moisture Content (EMC) -- The value that the actual moisture content approaches if the fuel is exposed to constant atmospheric conditions of temperature and relative humidity for an infinite length of time. EMC determines the amount of water vapor that a specific piece of wood can hold.

Federal Class I Area -- An area set aside under the Clean Air Act (CAA) to receive the most stringent protection from air quality degradation. Mandatory federal Class I areas are (1) international parks, (2) national wilderness areas which exceed 5,000 acres in size, (3) national memorial parks which exceed 5,000 acres in size, and (4) national parks which exceed 6,000 acres and were in existence prior to the 1977 CAA Amendments. The extent of a mandatory Federal Class I Area includes subsequent changes in boundaries, such as park expansions. NOTE: There are no federal Class I areas in Illinois.

Federal Land Manager (FLM) -- With respect to any lands in the United States, the Secretary of the Federal department with authority over such lands. Generally, the Secretaries delegate their authority to specific elements within each department.

Fire Dependent Ecosystem -- A community of plants and animals that must experience recurring disturbances by fire in order to sustain its natural plant succession, structure and composition of vegetation, and maintain appropriate fuel loading and nutrient cycling to ensure proper ecosystem function.

First Order Fire Effects Model (FOFEM) – Is a computer program for predicting tree mortality, fuel consumption, smoke production, and soil heating caused by prescribed fire or wildfire.

Fuel -- Includes combustible vegetative matter such as grass, trees, shrubs, limbs, branches, duff, and stumps.

Government Entity-- A subordinated unit of federal, state, or local government created to carry out a governmental function or to implement a statute or statutes.

Haze -- An atmospheric aerosol of sufficient concentration to be visible. The particles are too small to see individually, but reduce visual range by scattering light.

IMPROVE -- Interagency Monitoring of Protected Visual Environments is a program that uses air monitors in federal Class I areas or outside federal Class I areas (IMPROVE protocol) to measure visibility pollutants---sulfates, nitrates, organic and elemental carbon, and PM.

Inversion -- A layer in the atmosphere where the temperature increases with altitude.

Land Use Plan -- A broad scale, long range plan (e.g., forest plan, refuge plan or resource management plan) that identifies the scope of actions and goals for the land and resources administered by a land owner/manager.

Mechanical Methods -- Mechanical site preparation designed to clear unwanted vegetation, move logging slash, or cultivate upper soil layers. Techniques include:

- Bedding: plowing to form cultivated beds with a slightly elevated center.
- Blading: using bulldozer-mounted blades to uproot trees and shrubs.
- Chaining: dragging heavy chains using bulldozers to remove vegetation and scarify soil surface.
- Chopping: using heavy rolling choppers to crush or break apart debris.
- Clearing: using Seppi, Fecon or other horizontal mower mounted on mover apparatus.
- Mowing: using rotary, fail or other type of mower apparatus to reduce height of vegetation.
- Contouring, terracing, leveling: moving soil with bulldozers to change medium-scale topography and drainage.
- Disking: plowing with rollers to incorporate organic material into the mineral soil.
- Ditching: constructing ditches to improve soil drainage within the rooting zone.
- Piling: using bulldozer-mounted blades to push debris into piles or rows (windrows).
- Plowing: dragging a plow by bulldozer to scarify surface soil and mix surface litter.
- Subsoiling: plowing the subsoil to break or puncture an impervious soil layer and improve drainage.
- Shearing: cutting residual trees using a swept-back blade horizontally mounted on a crawler tractor

Mixing Height -- the maximum height that rapid vertical mixing takes place in the atmosphere. In general, the more unstable the atmosphere, the higher the mixing height. It acts as a lid on the height smoke can reach.

Mobile Sources -- Moving objects that release pollution. Mobile sources include cars, trucks, buses, planes, trains, motorcycles and gasoline-powered lawn mowers. Mobile sources are divided into two groups: road vehicles, which include cars, trucks and buses, and non-road vehicles which include trains, planes and lawn mowers.

Monitoring (monitor) -- Measurement of air pollution is referred to as monitoring. U.S. EPA and

state and local agencies measure the types and amounts of pollutants in the ambient air. The CAA requires certain large polluters to perform enhanced monitoring to provide an accurate picture of how much pollution is being released into the air. The 1990 CAA requires states to monitor community air in polluted areas to check on whether the areas are being cleaned up according to schedules set out in the law.

National Ambient Air Quality Standards (NAAQS) -- Standards for maximum acceptable concentrations of "criteria" pollutants in the ambient air to protect public health with an adequate margin of safety (primary standard), and to protect public welfare from any known or anticipated adverse effects of such pollutants (e.g., visibility impairment, soiling, materials damage, etc.) in the ambient air (secondary standard).

Nonattainment Area -- A geographic area in which the level of a criteria air pollutant is higher than the level allowed by the federal standards. It has been estimated that 60 percent of Americans live in nonattainment areas.

Nuisance (Smoke) -- Amounts of smoke in the ambient air that interfere with a right or privilege common to members of the public, including the use or enjoyment of public or private resources.

Ozone -- Ozone (O_3) is a gas composed of three oxygen atoms. It is not usually emitted directly into the air, but at ground-level is created by a chemical reaction between oxides of nitrogen (NOx) and volatile organic compounds (VOC) in the presence of sunlight. Ozone can be "good" or "bad," depending on its location in the atmosphere.

Particulate Matter (PM) -- A mixture of very small particles that are suspended in the atmosphere, except uncombined water, which exists as a solid or liquid at standard conditions (e.g., dust, smoke, mist, fumes, or smog).

PM_{10} -- Particles with an aerodynamic diameter less than or equal to a nominal 10 micrometers (including $PM_{2.5}$). Concentrations in the air are measured as micrograms per cubic meter of air (ug/m^3).

$PM_{2.5}$ -- Particles with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers. Concentrations in the air are measured as micrograms per cubic meter of air (ug/m^3).

Prescription -- Measurable criteria that guide selection of appropriate management response and actions. Prescription criteria may include the meteorological conditions affecting the area under prescription, as well as factors related to the state of the area to be burned such as the fuel moisture condition and other physical parameters. Other criteria which may be considered include safety, economic, public health, environmental, geographic, administrative, social or legal considerations, and ecological and land use objectives.

Prescribed Burn Manager -- Person responsible for managing a prescribed fire from planning to ignition and mop up.

Prescribed Burning -- The planned application of fire to naturally occurring vegetative fuels under specified environmental conditions and following appropriate precautionary measures, which causes the fire to be confined to a predetermined area and accomplish the planned land management

objectives.

Prescribed Fire -- Any fire ignited by management actions to meet specific objectives (i.e., managed to achieve resource benefits).

Prescribed Fire Plan -- A strategic plan that defines a program to manage wildland and prescribed fires, and documents the fire plan to meet management objectives outlined in the approved land use plan. The plan is supplemented by operational procedures such as preparedness plans, burn plans and prevention plans. Also referenced as Fire Plan.

Project Plan -- A strategic plan for accomplishing specific actions and goals (objectives) established in a land use plan. A project may include several activities such as cutting and hauling trees and shrubs, planting trees, building trails, and fire treatment.

Regional Haze -- Generally, concentrations of fine particles in the atmosphere extending hundreds of miles across a region and causing deteriorated visibility conditions or wide-spread visibility impairment, especially in mandatory Federal Class I Areas where visibility is an important value.

Residual Night Burning -- Planned prescribed burns initiated during the daytime hours and are allowed to burn into the night with reduced intensity. Residual night burning generally occurs in the interior of the burn unit and involves creeping ground fires and smoldering woody materials.

Simple Approach Smoke Estimation Model (SASEM) -- This program calculates the consumption of fuel, emission of particles, and dispersion of these pollutants produced by prescribed burning of forest and range vegetation.

Smoke Management – Conducting a prescribed fire under fuel moisture, meteorological conditions, and firing techniques that keep the impact of the smoke on the environment within acceptable limits.

Smoke Sensitive Area -- An area on which, for reasons of visibility, health or human welfare, smoke could have an adverse impact. Examples: Airports, major highways, communities, Federal Class I Areas, recreation areas, schools, hospitals, nursing homes and factories, etc.

Smoke Sensitive Populations -- Those populations for whom smoke may present particular health risks.

Smoke Sensitive Receptors -- Locations where human population tend to concentrate and where smoke could impact the health of those population or significantly impact visibility that may be detrimental to either health or the enjoyment of scenic qualities of the landscape. These may be residential concentrations in the form of towns or cities, or locations where people tend to gather in groups such as parks. Travel routes such as highways may be labeled as sensitive receptor sites where smoke can be a factor in potential motor vehicle accidents. Particular areas along highways or other locations may be more prone to being declared sensitive receptor sites because of topographic and microclimate features.

Smoke Management Plan/Program (SMP) -- Establishes a basic framework of procedures and requirements for managing smoke from fires that are managed for resource benefits. The purposes of

SMPs are to mitigate the nuisance and public safety hazards posed by smoke intrusions into populated areas (e.g., on roadways and at airports); to prevent deterioration of air quality and NAAQS violations; and to address visibility impacts in mandatory Federal Class I Areas in accordance with the regional haze rules.

Source -- Any place or object from which pollutants are released. A source can be a power plant, factory, dry cleaning business, gas station or farm. Cars, trucks and other motor vehicles are sources, and consumer products and machines used in industry. Sources that stay in one place are referred to as stationary sources; sources that move around, such as cars or planes, are referenced as mobile sources.

State Implementation Plan (SIP) -- A detailed description of the programs a state will use to carry out its responsibilities under the CAA. State implementation plans are collections of the regulations and emission reduction measures used by a state to reduce air pollution in order to attain and maintain NAAQS or to meet other requirements of the Act. The CAA requires that USEPA approve each SIP. Members of the public are given opportunities to participate in review and approval of SIPs.

Stationary Source -- A place or object from which pollutants are released and which does not move around. Stationary sources include power plants, gas stations, incinerators, etc.

Suppression -- A management action intended to protect identified values from a fire, extinguish a fire, or alter a fire's direction of spread.

Temperature Inversion -- One of the weather conditions that are often associated with serious smog episodes in some portions of the country. In a temperature inversion, air does not rise because it is trapped near the ground by a layer of warmer air above it. Concentrations of pollutants increase in the lower atmosphere.

Transport Wind – an average of the horizontal wind speed and direction from the surface to the mixing height.

Vent Rate – Average Ventilation rate for a given time. The ventilation rate is defined as the product of the Transport Wind Speed and the Mixing Height and is used to forecast smoke behavior and trajectories.

Volatile Organic Compounds (VOC) -- Any organic compound that participates in atmospheric photochemical reactions. Photochemical reactions of VOC's with oxides of nitrogen and sulfur can produce O_3 and PM.

Wildfire -- An unplanned unwanted wildland fire including unauthorized human-caused fires, escaped wildland fire use events, escaped prescribed fire projects, and all other wildland forest where the objective is to put the fire out.

Wildland Fire -- Any non-structural fire, other than prescribed fire, that occurs in a wildland. Note: Wildland fires include unwanted (wild) fires and naturally ignited fires that are managed within a prescription to achieve resource benefits. Three distinct types of wildland fire have been defined and included wildfire, wildland fire use, and prescribed fire.

Wildland Fire Use -- The application of the appropriate management response to naturally ignited wildland fires to accomplish specific resource management objectives in pre-defined designated areas outlined in Fire Management Plans.

Wildland -- An area where development is generally limited to roads, railroads, power lines, and widely scattered structures. The land is not cultivated (i.e., the soil is disturbed less frequently than once in 10 years), is not fallow, and is not in the United States Department of Agriculture Conservation Reserve Program. The land may be neglected altogether or managed for such purposes as wood or forage production, wildlife, recreation, wetlands or protective plant cover. [The distinction between wildlands, to which the recommendations in this document apply, and agricultural lands are subject to further discussion.] In urban areas of Illinois wildlands may occur amongst developed areas, such as State Parks and Forest Preserve lands.

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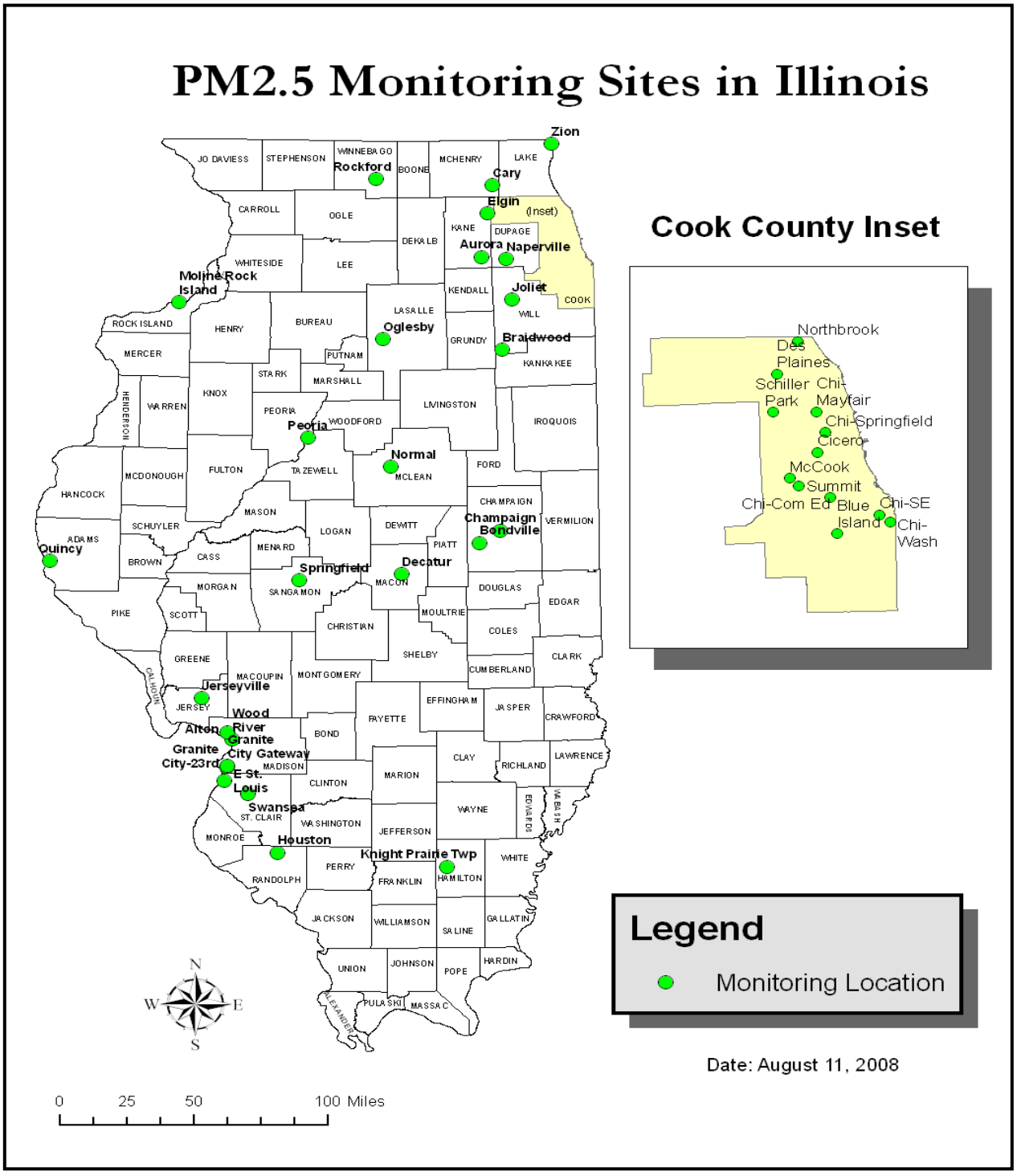
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http://www.epa.gov/ttn/faca/pbdirs/smpdrft4.pdf, Elements of a Smoke Management Program

APPENDIX A


PM2.5 Monitoring Sites in Illinois
Zion
Rockford
Cary
Elgin
(Inset)
Aurora
Naperville
Joliet
Moline
Rock Island
Oglesby
Braidwood
Peoria
Normal
Champaign
Bondville
Springfield
Decatur
Quincy
Jerseyville
Wood River
Alton
Granite City Gateway
Granite City-23rd
E St. Louis
Swansea
Houston
Knight Prairie Twp
JO DAVIESS
STEPHENSON
WINNEBAGO
BOONE
MCHENRY
LAKE
CARROLL
OGLE
DEKALB
KANE
DUPAGE
WHITESIDE
LEE
KENDALL
WILL
COOK
ROCK ISLAND
HENRY
BUREAU
LASALLE
GRUNDY
KANKAKEE
MERCER
PUTNAM
STARK
MARSHALL
KNOX
WARREN
HENDERSON
PEORIA
WOODFORD
LIVINGSTON
IROQUOIS
FULTON
TAZEWELL
MCLEAN
FORD
MCDONOUGH
HANCOCK
MASON
CHAMPAIGN
VERMILION
SCHUYLER
LOGAN
DEWITT
PIATT
ADAMS
BROWN
CASS
MENARD
MACON
DOUGLAS
EDGAR
MORGAN
SANGAMON
PIKE
SCOTT
CHRISTIAN
MOULTRIE
COLES
GREENE
MACOUPIN
MONTGOMERY
SHELBY
CUMBERLAND
CLARK
CALHOUN
JERSEY
EFFINGHAM
JASPER
CRAWFORD
FAYETTE
BOND
CLAY
RICHLAND
LAWRENCE
MADISON
CLINTON
MARION
WAYNE
EDWARDS
WABASH
ST. CLAIR
WASHINGTON
JEFFERSON
MONROE
PERRY
WHITE
RANDOLPH
FRANKLIN
HAMILTON
JACKSON
WILLIAMSON
SALINE
GALLATIN
UNION
JOHNSON
POPE
HARDIN
ALEXANDER
PULASKI
MASSAC
N
W
E
S
0
25
50
100 Miles
Cook County Inset
Northbrook
Des Plaines
Schiller Park
Chi-Maytair
Chi-Springfield
Cicero
McCook
Summit
Chi-Com Ed
Blue Island
Chi-SE
Chi-Wash
Legend
Monitoring Location
Date: August 11, 2008

APPENDIX G: Documentation for Shutdown EGUs

Source Name: Illinois Power Generating Co.

Source ID: 135 803 AAA

Permit No.: Entire Source

02

JAN 15 2020

REVIEWER: SAB

PERMIT WITHDRAWN

Type of Source: CAAPP

Withdraw Request Received: 11-08-2019

Fees Owed: $23,875.35

Ceased Operations Date Entered in Iceman: 01-01-2020

Acknowledgement Letter Sent: 12-31-2019

Comments:

Initials: JAN

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 NORTH GRAND AVENUE EAST, P.O. BOX 19276, SPRINGFIELD, ILLINOIS 62794-9276 · (217) 782-3397

JB PRITZKER, GOVERNOR JOHN J. KIM, DIRECTOR

217/785-1705

WITHDRAWAL ACKNOWLEDGMENT LETTER

IEPA-DIVISION OF RECORDS MANAGEMENT
RELEASABLE

JAN 15 2020

REVIEWER: SAB

December 31, 2019

Luminant
Attn: Dianna Tickner, Director, Decommissioning & Demolition
1500 Eastport Plaza Drive
Collinsville, IL 62234

I.D. No.: 135803AAA
Source: Illinois Power Resources, LLC - Coffeen Power Plant
Date Letter Received: November 8, 2019

Withdrawal Effective: January 1, 2020

The Illinois EPA hereby acknowledges the receipt of your above-referenced letter and confirms the withdrawal of the entire source and all associated permits and pending permit applications, effective as of the beginning of January 1, 2020, in accordance with your request.

Although the source withdrawal has been granted, any outstanding annual CAAPP fee for the source should be paid consistent with the recently-concluded settlement discussions involving the Illinois EPA's Response to Renewed Request For CAAPP Fee Reconsideration, dated December 31, 2019.

If you have not already done so, please pay electronically at https://magic.collectorsolutions.com/magic-ui/Login/illinois-epa or mail your payment to Fiscal Services #2, Illinois Environmental Protection Agency, 1021 North Grand Avenue East, P.O. Box 19276, Springfield, Illinois 62794-9276. Payment by check or money order should be made payable to "Illinois Environmental Protection Agency."

If you have any questions concerning this withdrawal, you may contact Michael Reed at 217/782-4651. For questions concerning fees owed, please contact Fiscal Services at 217/782-3250.

Raymond E. Pilapil MTR 12/31/2019

Raymond E. Pilapil
Manager, Permit Section
Bureau of Air

cc: Charles Koudelka, Plant Closure Director
Jim Ross, Director, Environmental

Luminant

Luminant
6555 Sierra Drive
Irving, TX 75039
o 214.812.4600
m 214.812.4600

11/6/2019

Mr. Raymond Pilapil
Manager, Permit Section
Illinois Environmental Protection Agency
Bureau of Air
1021 North Grand Avenue East
PO Box 19276
Springfield, IL 62794

RECEIVED
STATE OF ILLINOIS
NOV 8 2019
Environmental Protection Agency
BUREAU OF AIR

Re: Illinois Power Generating Company – Coffeen Power Plant
Withdraw of Permits
I.D. No. 135803AAA

Dear Mr. Pilapil:

This letter requests withdraw of all air permits for Coffeen Power Plant effective January 1, 2020. Accordingly, please find enclosed form 285-CAAPP, WITHDRAWAL OF PERMIT OR PERMIT APPLICATION.

If you have any questions regarding this information, please contact Jim Ross 217-753-8903, Jim.Ross@vistraenergy.com.

Sincerely,

Dianna Tickner
Director, Decommissioning & Demolition

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
DIVISION OF AIR POLLUTION CONTROL -- PERMIT SECTION
P.O. BOX 19506
SPRINGFIELD, ILLINOIS 62794-9506

FOR APPLICANT'S USE
Revision #: _____
Date: ____ / ____ / ____
Page _____ of _____
Source Designation: _____

WITHDRAWAL OF PERMIT OR PERMIT APPLICATION
EFFECTIVE 1/1/2020

FOR AGENCY USE ONLY
ID NO.: 135803AAA
PERMIT NO.: Entire Source
DATE: 11-08-2019

SECTION ONE — SOURCE INFORMATION

1) SOURCE NAME: Coffeen Power Plant	2) SOURCE ID NO.: 135803AAA
3) SOURCE ADDRESS: 134 Cips Lane, Coffeen, IL	
4) CONTACT NAME: Jim Ross	5) CONTACT PHONE NO.: 217-753-8903

SECTION TWO — INSTRUCTIONS IN BRIEF

1) COMPLETE THIS FORM IF THE APPLICANT REQUESTS TO WITHDRAW ISSUED PERMITS AND THEIR ASSOCIATED APPLICATIONS OR PENDING PERMIT APPLICATIONS.
2) SECTION THREE, NO. 1 IS USED TO WITHDRAW THE ENTIRE SOURCE, NO. 2 -7 ARE FOR SPECIFIC PERMITS.
3) A WITHDRAWAL AND SUBSEQUENT DELETION FROM THE SYSTEM IS **PERMANENT**.
4) A SHUTDOWN OR TERMINATION OF THE OPERATION IS NOT SUFFICIENT TO WITHDRAW A PERMIT. THE PERMITTEE MUST SPECIFICALLY INSTRUCT THE ILLINOIS EPA, IN WRITING, TO WITHDRAW THE UNDERLYING AUTHORIZING PERMIT(S). SUBMISSION OF THIS FORM CONSTITUTES THAT WRITTEN INSTRUCTION.
5) THE ILLINOIS EPA BILLS ANNUALLY FOR HOLDING AN PERMIT WHETHER OR NOT THE SOURCE IS IN OPERATION. TO STOP BILLING, A PERMIT MUST BE WITHDRAWN BEFORE THE FEE DUE DATE.
6) DATA AND INFORMATION REQUIRED FOR ANNUAL EMISSION REPORTS WILL STILL BE REQUIRED TO BE SUBMITTED FOR THE PORTION OF THE YEAR THAT THE SOURCE HELD A VALID PERMIT.

SECTION THREE — PERMIT(S) TO WITHDRAW

1) DO YOU REQUEST TO WITHDRAW THE ENTIRE SOURCE AND ALL ASSOCIATED PERMITS?
WITHDRAW THE **ENTIRE** SOURCE: ☒ YES ☐ NO, IF "NO" COMPLETE THE FOLLOWING TABLE.
EFFECTIVE 1/1/2020

2) APPLICATION NO.:	5) APPLICATION NO.:
3) APPLICATION NO.:	6) APPLICATION NO.:
4) APPLICATION NO.:	7) APPLICATION NO.:

SECTION FOUR — SIGNATURE BLOCK

AS AUTHORZIZED BY THE BELOW SIGNATORY, THE ABOVE LISTED SOURCE REQUESTS THE WITHDRAWAL OF THE ABOVE LISTED PERMITS AND THEIR ASSOSCIATED APPLICATIONS OR ANY PENDING PERMIT APPLICATIONS.

THE SIGNATORY RECOGNIZES A WITHDRAWAL FROM THE SYSTEM IS PERMANENT.

AUTHORIZED SIGNATURE: EFFECTIVE 1/1/2020

BY:

Dianna Tickner
AUTHORIZED SIGNATURE

Director, Decommissioning + Demolit.
TITLE OF SIGNATORY

Dianna Tickner
TYPED OR PRINTED NAME OF SIGNATORY

11, 04, 2019
DATE

THIS AGENCY IS AUTHORIZED TO REQUIRE THIS INFORMATION UNDER 39.5 OF THE ILLINOIS ENVIRONMENTAL PROTECTION ACT, 415 ILCS 5/39.5. FURTHER DISCLOSURE OF THIS INFORMATION IS REQUIRED UNDER THAT SECTION, MOREOVER AS ALSO PROVIDED IN THAT SECTION, FAILURE TO PROVIDE THIS INFORMATION MAY PREVENT THIS APPLICATION FROM BEING PROCESSED AND COULD RESULT IN THE APPLICATION BEING DENIED.

FOR APPLICANT'S USE
_____

APPLICATION PAGE _____

DYNEGY

1500 Eastport Plaza Drive
Collinsville, IL 62234

UNITED STATES POSTAGE
PITNEY BOWES
02 1P $ 000.50⁰
0001908455 NOV 06 2019
MAILED FROM ZIP CODE 62234

Mr. Raymond Pilapil
Illinois EPA
Bureau of Air
1021 North Grand Ave East
PO Box 19276
Springfield, IL 62794

135803AAA
95090009

Luminant

Luminant
1500 Eastport Plaza Drive
Collinsville, IL 62234

RECEIVED
STATE OF ILLINOIS
NOV 12 2019
Environmental Protection Agency
BUREAU OF AIR

November 6, 2019

Compliance Section
Illinois Environmental Protection Agency
Bureau of Air
1021 North Grand Avenue East
PO Box 19276
Springfield, IL 62794

Re: Change in Responsible Official – Coffeen Power Plant
ID Number: 135803AAA

This letter provides notification of a change in responsible official for Coffeen Power Plant to Dianna Tickner, Director of Decommissioning and Demolition and Charles Koudelka, Plant Closure Director. Please note that Coffeen Power Plant has permanently ceased operation. Attached is the Administrative Amendment Form 273.

If you have questions, please feel free to contact Jim Ross at 217-753-8903, Jim.Ross@vistraenergy.com.

Sincerely,

Dianna Tickner
Director, Decommissioning & Demolition

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
DIVISION OF AIR POLLUTION CONTROL -- PERMIT SECTION
P.O. BOX 19506
SPRINGFIELD, ILLINOIS 62794-9506

FOR APPLICANT'S USE
Revision #: _____
Date: ____ / ____ / ____
Page _____ of _____
Source Designation:
_____

REQUEST FOR ADMINISTRATIVE PERMIT AMENDMENT FOR CAAPP PERMIT	***FOR AGENCY USE ONLY***
	ID NUMBER: 135803AAA
	PERMIT #: 95090009
	DATE: 11-12-19

GENERAL INFORMATION

1) SOURCE NAME:
Coffeen Power Plant

2a) ID NUMBER (IF KNOWN):	b) CAAPP PERMIT NUMBER:
135803AAA	95090009
3) ENVIRONMENTAL CONTACT PERSON:	4) CONTACT PERSON'S TELEPHONE NUMBER:
Jim Ross	217-753-8903

AMENDMENT DATA

5) AN ADMINISTRATIVE PERMIT AMENDMENT SHALL ONLY BE USED FOR ONE OR MORE OF THE FOLLOWING REVISIONS TO A CAAPP PERMIT (PLEASE INDICATE THE TYPE OF AMENDMENT(S)):

☐ A) CORRECTS TYPOGRAPHICAL ERRORS;

☒ B) IDENTIFIES A CHANGE IN THE NAME, ADDRESS, OR PHONE NUMBER OF ANY PERSON IDENTIFIED IN THE PERMIT, OR PROVIDES A SIMILAR MINOR ADMINISTRATIVE CHANGE AT THE SOURCE;

☐ C) REQUIRES MORE FREQUENT MONITORING OR REPORTING BY THE PERMITTEE; OR

☐ D) ALLOWS FOR A CHANGE IN OWNERSHIP OR OPERATIONAL CONTROL OF THE SOURCE WHERE NO OTHER CHANGE IN THE PERMIT IS NECESSARY, PROVIDED THAT A WRITTEN AGREEMENT CONTAINING A SPECIFIC DATE FOR TRANSFER OF PERMIT RESPONSIBILITY, COVERAGE, AND LIABILITY BETWEEN THE CURRENT AND NEW PERMITTEES HAS BEEN SUBMITTED TO THE ILLINOIS EPA.

THIS AGENCY IS AUTHORIZED TO REQUIRE THIS INFORMATION UNDER ILLINOIS REVISED STATUTES, 1991, AS AMENDED 1992, CHAPTER 111 1/2, PAR. 1039.5. DISCLOSURE OF THIS INFORMATION IS REQUIRED UNDER THAT SECTION. FAILURE TO DO SO MAY PREVENT THIS FORM FROM BEING PROCESSED AND COULD RESULT IN THE APPLICATION BEING DENIED. THIS FORM HAS BEEN APPROVED BY THE FORMS MANAGEMENT CENTER.

FOR APPLICANT'S USE
_____

APPLICATION PAGE _____

AMENDMENT DATA (CON'T)

6) DESCRIPTION OF REQUESTED ADMINISTRATIVE PERMIT AMENDMENT:

	CURRENT PERMIT INFORMATION	AMENDED PERMIT INFORMATION
1)	Responsible Official - John Cooley	Responsible Official - Dianna Tickner, Director, Decommissioning & Demolition Charles Koudelka, Plant Closure Director
2)		
3)		
4)		
5)		
6)		
7)		
8)		

7) DOES THE APPLICATION INCLUDE A COPY OF THOSE PARTICULAR PAGES OF THE CAAPP PERMIT WHICH ARE CLEARLY MARKED TO SHOW THE REQUESTED AMENDMENT? ☒ YES ☐ NO

SIGNATURE BLOCK

NOTE: THIS CERTIFICATION MUST BE SIGNED BY A RESPONSIBLE OFFICIAL. APPLICATIONS WITHOUT A SIGNED CERTIFICATION WILL BE RETURNED AS INCOMPLETE.

8) I CERTIFY UNDER PENALTY OF LAW THAT, BASED ON INFORMATION AND BELIEF FORMED AFTER REASONABLE INQUIRY, THE STATEMENTS AND INFORMATION CONTAINED IN THIS APPLICATION ARE TRUE, ACCURATE AND COMPLETE.

AUTHORIZED SIGNATURE:

BY: Dianna Tickner
AUTHORIZED SIGNATURE

Director, Decommissioning & Demolition
TITLE OF SIGNATORY

Dianna Tickner
TYPED OR PRINTED NAME OF SIGNATORY

11 / 06 / 2019
DATE

APPLICATION PAGE _____

Printed on Recycled Paper
273-CAAPP

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 NORTH GRAND AVENUE EAST, P.O. BOX 19276, SPRINGFIELD, ILLINOIS 62794-9276 • (217) 782-3397
BRUCE RAUNER, GOVERNOR ALEC MESSINA, ACTING DIRECTOR

217-785-1705

REOPENING FOR CAUSE
CLEAN AIR ACT PERMIT PROGRAM (CAAPP) PERMIT

PERMITTEE:

Illinois Power Generating Company
Attn: Rick Diericx
1500 Eastport Plaza Drive
Collinsville, Illinois 62234

Application No.: 95090009
I.D. No.: 135803AAA
Date Received: September 01, 1995
Operation of: Coffeen Power Station
Date Issued: September 29, 2005
Initial Effective Date: September 20, 2012
Expiration Date[1]: September 20 2017
Source Location: 134 CIPS Lane, Coffeen, Montgomery County
Responsible Official: ~~Randy O'Keefe, Managing Director Plant Operations,~~ Coffeen Power Station
Dianna Tickner, Director, Decommissioning + Demolition Charles Koudelka, Plant Closure Director

The above-referenced permit was originally issued to the Permittee to OPERATE an electrical power generation station, pursuant to the corresponding permit application, on September 29, 2005. As a result of an automatic stay of the permit during the pendency of an administrative permit appeal, the CAAPP permit did not become effective until September 20, 2012.

Permit Action: Reopening for Cause
Date Issued: January 18, 2017

In accordance with Section 39.5(15)(a)(i) of the Illinois Environmental Protection Act, this permit action addresses all new Clean Air Act (CAA) requirements that have become applicable to the source since September 29, 2005. Affected permit conditions largely reflect the addition of new or revised text to the permit; however, some conditions will also reflect deleted text that has been displaced or made obsolete by newly applicable requirements.

Please note that this cover letter encompasses only permit revision(s) to the attached CAAPP permit from the above-referenced permit reopening, as described in the accompanying Statement of Basis. Other permit revision(s) occurring in parallel with this permit action, while also appearing in the attached permit, are authorized by a different origin of authority and are therefore addressed by separate cover letters. Applicable procedures used in this permit action were the same as for initial permit issuance, 415 ILCS 5/39.5(15)(c).

If you have any questions concerning this permit, please contact the CAAPP Unit at 217/785-1705 (217/782-9143 TDD).

Raymond E. Pilapil
Manager, Permit Section
Division of Air Pollution Control

REP:MTR:MWG:clc
cc: Illinois EPA, FOS, Region 2, USEPA

1 Except as addressed in Condition 8.7 of this permit.

Retired Unit Exemption

For more information, see instructions and refer to 40 CFR 72.8, 97.405, 97.505, 97.605, 97.705, 97.805, and 97.905, or a comparable state regulation, as applicable.

This submission is: ☐ **New** ☒ **Revised**

STEP 1

Identify the unit by plant (source) name, State, plant code and unit ID#.

Plant (Source) Name	State	Plant Code	Unit ID#
Coffeen Power Plant	IL	861	CB-1 CB-2

STEP 2

Indicate the program(s) that the unit is subject to.

- ☒ Acid Rain
- ☒ CSAPR NO_x Annual
- ☒ CSAPR NO_x Ozone Season Group 1
- ☐ CSAPR NO_x Ozone Season Group 2
- ☒ CSAPR SO_2 Group 1
- ☐ CSAPR SO_2 Group 2
- ☐ Texas SO_2

STEP 3

Identify the date on which the unit was (or will be) permanently retired.

November 1 , 2019

STEP 4

If the unit is subject to the Acid Rain Program, identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.8(d).

Calendar year starting January 1, 2020

STEP 5 Read the applicable special provisions.

Acid Rain Program Special Provisions

(1) A unit exempt under 40 CFR 72.8 shall not emit any sulfur dioxide and nitrogen oxides starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with 40 CFR part 73 subpart B.

(2) A unit exempt under 40 CFR 72.8 shall not resume operation unless the designated representative of the source that includes the unit submits a complete Acid Rain permit application under 40 CFR 72.31 for the unit not less than 24 months prior to the date on which the unit is first to resume operation.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 72.8 shall comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) For any period for which a unit is exempt under 40 CFR 72.8, the unit is not an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71 and is not eligible to be an opt-in source under 40 CFR part 74. As an unaffected unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR parts 70 and 71.

(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 72.8 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Administrator or the permitting authority. The owners and operators bear the burden of proof that the unit is permanently retired.

(6) On the earlier of the following dates, a unit exempt under 40 CFR 72.8(b) or (c) shall lose its exemption and become an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71: (i) the date on which the designated representative submits an Acid Rain permit application under paragraph (2); or (ii) the date on which the designated representative is required under paragraph (2) to submit an Acid Rain permit application. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under 40 CFR 72.8 shall be treated as a new unit that commenced commercial operation on the first date on which the unit resumes operation.

CSAPR NO_X Annual Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.405 shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.405 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.405 shall comply with the requirements of the CSAPR NO_X Annual Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.405 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart AAAAA, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_X Ozone Season Group 1 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.505 shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.505 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.505 shall comply with the requirements of the CSAPR NO_X Ozone Season Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.505 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart BBBBB, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_X Ozone Season Group 2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.805 shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.805 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.805 shall comply with the requirements of the CSAPR NO_X Ozone Season Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.805 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart EEEEE, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR SO_2 Group 1 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.605 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.605 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.605 shall comply with the requirements of the CSAPR SO_2 Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.605 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart CCCCC, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR SO_2 Group 2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.705 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.705 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.705 shall comply with the requirements of the CSAPR SO_2 Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.705 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart DDDDD, as a unit that commences commercial operation on the first date on which the unit resumes operation.

Texas SO_2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.905 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.905 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.905 shall comply with the requirements of the Texas SO_2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.905 shall lose its exemption on the first date on which the unit resumes operation. A retired unit that resumes operation will not receive an allowance allocation under 40 CFR 97.911. The unit may receive allowances from the Supplemental Allowance Pool pursuant to 40 CFR 97.912. All other provisions of 40 CFR part 97 subpart FFFFF regarding monitoring, reporting, recordkeeping and compliance will apply on the first date on which the unit resumes operation.

STEP 6 Read the statement of compliance and the applicable certification statements, sign, and date.

Statement of compliance

I certify that the unit identified above at STEP 1 was (or will be) permanently retired on the date identified at STEP 3 and will comply with the applicable Special Provisions listed at STEP 5.

Certification by designated representatives or alternate designated representatives

I am authorized to make this submission on behalf of the owners and operators of the source and unit for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Dianna Tickner	Director Demolition & Decommissioning Title
Owner Company Name Illinois Power Generating Company	
Email dianna.tickner@vistraenergy.com	Phone 618-343-7929
Signature Dianna L Tickner	Date 12/19/2019

Certification by certifying officials of units subject only to the Acid Rain Program for which no designated representative has been authorized

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Title
Owner Company Name	
Email	Phone
Signature	Date

CAAPP Permit Revision Checklist

SECTION 1: ADMINISTRATIVE REVIEW – Completed by Records Unit		
Source Name: Illinois Power Resources-Coffeen		Reviewed By: MTR
ID #: 135803AAA	Permit #: 95090009	Date Received: 11/8/2019

1)	Does the Source have an issued CAAPP Permit? If no, application is not a CAAPP permit revision. Do not use this form.	☒ YES ☐ NO
2)	Did the Source submit a 273-CAAPP form for an Administrative Permit Amendment?	☒ YES ☐ NO
3)	Did the Source submit a 271-CAAPP form and check the Minor Modification box?	☐ YES ☒ NO
4)	Did the Source submit a 271-CAAPP form and check the Significant Modification box?	☐ YES ☒ NO

SECTION 2: CAAPP SPECIALIST REVIEW – Completed by CAAPP Unit Manager	
CAAPP Specialist: Michael T. Reed	Date Completed: 12/31/2019

DETERMINATION OF TYPE OF REVISION
Note that either a 273-CAAPP or 271-CAAPP must be submitted

5)	What type of revision is the application?	☒ Administrative ☐ Minor ☐ Significant
6)	Did the Source submit the proper CAAPP form for this type of application? If no, proceed to question 8	☒ YES ☐ NO
7)	Has a "Responsible Official", as defined in the Act, signed the application?	☒ YES ☐ NO
8)	Has the applicant been contacted to inform them to submit the proper CAAPP form? Date Contacted: Date Form Received:	☐ YES ☐ NO NA

SECTION 3: TECHNICAL REVIEW – Completed by Permit Engineer		
Engineer: Michael T. Reed	Date Completed: 12/31/2019	Due Date: 12/31/2019

ADMINISTRATIVE PERMIT AMENDMENT
Note, formal public or USEPA notice not required

9)	Has permit been revised and final action taken within 60 days?	☒ YES ☐ NO
10)	Has a copy of the revised CAAPP permit been submitted to USEPA?	☐ YES ☒ NO

MINOR PERMIT MODIFICATION
Note, formal public notice other than notifying affected states not required

11)	Has Community Relations been provided a copy of the application to notify the affected states and USEPA within 5 days of a complete application?	☐ YES ☐ NO
12)	Has the 45-day USEPA comment period been completed?	☐ YES ☐ NO
13)	Has the permit been revised and final action taken within 90 days, or 15 days after the USEPA's 45 day review period, whichever is later?	☐ YES ☐ NO

SIGNIFICANT PERMIT MODIFICATION

14)	Has the application gone through the standard CAAPP public notice procedure?	☐ YES ☐ NO
15)	Has the 45-day USEPA comment period been completed?	☐ YES ☐ NO
16)	Has the permit been revised and final action taken within 9 months?	☐ YES ☐ NO

Source Name: Illinois Power Resources Generating LLC

Source ID: 143805 AAG

Permit No.: Entire Source

02

PERMIT WITHDRAWN

IEPA
Division of Records Management
Releasable

JAN 04 2023

Reviewer: SSD

Type of Source: CAAPP

Withdraw Request Received: 12-27-2022

Fees Owed: 0

Ceased Operations Date Entered in Iceman: 1-1-2023

Acknowledgement Letter Sent: 1-3-2023

Comments:

Initials: tan

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 NORTH GRAND AVENUE EAST, P.O. BOX 19276, SPRINGFIELD, ILLINOIS 62794-9276 · (217) 782-3397

JB PRITZKER, GOVERNOR JOHN J. KIM, DIRECTOR

January 3, 2023

Illinois Power Resources Generating LLC
Attn: Kevin Largent
1500 Eastport Plaza Dr
Collinsville, IL 62234

I.D. No.: 143805AAG
Permit No.: 95070026
Letter Received: December 27, 2022

The Illinois EPA hereby acknowledges the receipt of your above-referenced correspondence and confirms the withdrawal of your entire source and all associated permits in accordance with your request.

If you have any questions concerning this matter, please contact Trent Nation at 217/524-1661.

William D Marr

William D. Marr
Manager, Permit Section
Bureau of Air

WDM:tan

2125 S. First Street, Champaign, IL 61820 (217) 278-5800
2009 Mall Street Collinsville, IL 62234 (618) 346-5120
9511 Harrison Street, Des Plaines, IL 60016 (847) 294-4000
595 S. State Street, Elgin, IL 60123 (847) 608-3131
2309 W. Main Street, Suite 116, Marion, IL 62959 (618) 993-7200
412 SW Washington Street, Suite D, Peoria, IL 61602 (309) 671-3022
4302 N. Main Street, Rockford, IL 61103 (815) 987-7760

PLEASE PRINT ON RECYCLED PAPER

RECEIVED
STATE OF ILLINOIS
DEC 27 2022
Environmental Protection Agency
BUREAU OF AIR

Luminant

Kevin Largent
Illinois Power Resources Generating, LLC
Luminant
7800 South Cilco Lane
Bartonville, IL 61607

December 22, 2022

Illinois Environmental Protection Agency
Bureau of Air
Bill Marr
Manager, Permit Section
1021 North Grand Avenue East
PO Box 19276
Springfield, IL 62702

Re: Illinois Power Resources Generating, LLC
Edwards Power Station I.D. No. 143805AAG

Dear Mr. Marr,

This letter is the final request to withdraw all air permits for Illinois Power Resources Generating, LLC ("IPRG"), Edwards Power Station effective January 1, 2023. Note that we previously submitted advanced notice of this action along with form 285-CAAPP, WITHDRAWAL of PERMIT or PERMIT APPLICATION.

In accordance with 35 IAC Section 225.233 Multi-Pollutant Standards (MPS), a separate letter will be timely submitted the first week of January 2023 to Kent Mohr, Compliance and Enforcement Section, Manager, that will contain the additional information required thereunder.

Please contact Jim Ross at 217-585-0925 or Jim.Ross@vistracorp.com with any questions regarding this submittal.

Sincerely,

Kevin Largent
Plant Manager-Edwards Power Station
Illinois Power Resources Generating, LLC

CH2:26616353.1

RECEIVED
STATE OF ILLINOIS
JUL 05 2022
Environmental Protection Agency
BUREAU OF AIR

Luminant

Kevin Largent
Illinois Power Resources Generating, LLC
Luminant
7800 South Cilco Lane
Bartonville, IL 61607

July 01, 2022

Illinois Environmental Protection Agency
Bureau of Air
Bill Marr
Manager, Permit Section
1021 North Grand Avenue East
PO Box 19276
Springfield, IL 62702

Re: Illinois Power Resources Generating, LLC
Edwards Power Station I.D. No. 143805AAG

Dear Mr. Marr,

This letter provides advanced notice of a request to withdraw all air permits for Illinois Power Resources Generating, LLC ("IPRG"), Edwards Power Station effective January 1, 2023. Accordingly, please find enclosed 285-CAAPP, WITHDRAWAL of PERMIT or PERMIT APPLICATION (the "Withdrawal Request").

This letter is not a written request to modify the operating permit to reflect the shutdown of the EGUs or to withdraw the air permit for the source at this time or any time prior to January 1, 2023. For Illinois EPA's administrative convenience, I am enclosing the Withdrawal Request with this advanced notice. IPRG intends for the Withdrawal Request to be deemed submitted on (and not before) January 1, 2023, the date specified on the Withdrawal Request, including for purposes of 35 IAC 225.233(g). In accordance with 35 IAC 225.233(g), notification will be timely submitted the first week of January 2023 to the Bureau of Air Compliance Section that will contain the additional information (e.g., adjusted annual emission limitations) required thereunder.

Please contact Jim Ross at 217-585-0925 or Jim.Ross@vistracorp.com with any questions regarding this submittal.

Sincerely,

Kevin Largent
Plant Manager-Edwards Power Station
Illinois Power Resources Generating, LLC
Attachments

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
DIVISION OF AIR POLLUTION CONTROL -- PERMIT SECTION
P.O. BOX 19506
SPRINGFIELD, ILLINOIS 62794-9506

FOR APPLICANT'S USE
Revision #: 0
Effective Date: 01/01/2023
Page _____ of _____
Source Designation:

RECEIVED
STATE OF ILLINOIS
JUL 05 2022
Environmental Protection Agency
BUREAU OF AIR

WITHDRAWAL OF PERMIT OR PERMIT APPLICATION

FOR AGENCY USE ONLY
ID NO.:
PERMIT NO.:
DATE:

SECTION ONE SOURCE INFORMATION

1) SOURCE NAME: Illinois Power Resources Generating LLC-Edwards Power Plant	2) SOURCE ID NO.: 143805AAG
3) SOURCE ADDRESS: 7800 Cilco Lane Bartonville, IL 61607	
4) CONTACT NAME: Mark Davis	5) CONTACT PHONE NO.: 309-633-2861

SECTION TWO INSTRUCTIONS IN BRIEF

1) COMPLETE THIS FORM IF THE APPLICANT REQUESTS TO WITHDRAW ISSUED PERMITS AND THEIR ASSOCIATED APPLICATIONS OR PENDING PERMIT APPLICATIONS.
2) SECTION THREE, NO. 1 IS USED TO WITHDRAW THE ENTIRE SOURCE, NO. 2 -7 ARE FOR SPECIFIC PERMITS.
3) A WITHDRAWAL AND SUBSEQUENT DELETION FROM THE SYSTEM IS **PERMANENT**.
4) A SHUTDOWN OR TERMINATION OF THE OPERATION IS NOT SUFFICIENT TO WITHDRAW A PERMIT. THE PERMITTEE MUST SPECIFICALLY INSTRUCT THE ILLINOIS EPA, IN WRITING, TO WITHDRAW THE UNDERLYING AUTHORIZING PERMIT(S). SUBMISSION OF THIS FORM CONSTITUTES THAT WRITTEN INSTRUCTION.
5) THE ILLINOIS EPA BILLS ANNUALLY FOR HOLDING AN PERMIT WHETHER OR NOT THE SOURCE IS IN OPERATION. TO STOP BILLING, A PERMIT MUST BE WITHDRAWN BEFORE THE FEE DUE DATE.
6) DATA AND INFORMATION REQUIRED FOR ANNUAL EMISSION REPORTS WILL STILL BE REQUIRED TO BE SUBMITTED FOR THE PORTION OF THE YEAR THAT THE SOURCE HELD A VALID PERMIT.

SECTION THREE PERMIT(S) TO WITHDRAW

1) DO YOU REQUEST TO WITHDRAW THE ENTIRE SOURCE AND ALL ASSOCIATED PERMITS?
WITHDRAW THE **ENTIRE** SOURCE: [X] YES [ ] NO, IF "NO" COMPLETE THE FOLLOWING TABLE.
Permit Withdrawal Requested as of January 1, 2023

2) APPLICATION NO.:	5) APPLICATION NO.:
3) APPLICATION NO.:	6) APPLICATION NO.:
4) APPLICATION NO.:	7) APPLICATION NO.:

SECTION FOUR SIGNATURE BLOCK

AS AUTHORIZED BY THE BELOW SIGNATORY, THE ABOVE LISTED SOURCE REQUESTS THE WITHDRAWAL OF THE ABOVE LISTED PERMITS AND THEIR ASSOSCIATED APPLICATIONS OR ANY PENDING PERMIT APPLICATIONS.

THE SIGNATORY RECOGNIZES A WITHDRAWAL FROM THE SYSTEM IS PERMANENT.

AUTHORIZED SIGNATURE:

BY: Kevin Largent

AUTHORIZED SIGNATURE

Plant Manager, Edwards Power Plant
TITLE OF SIGNATORY

Kevin Largent
TYPED OR PRINTED NAME OF SIGNATORY

07, 01, 22
DATE

THIS AGENCY IS AUTHORIZED TO REQUIRE THIS INFORMATION UNDER 39.5 OF THE ILLINOIS ENVIRONMENTAL PROTECTION ACT, 415 ILCS 5/39.5. FURTHER DISCLOSURE OF THIS INFORMATION IS REQUIRED UNDER THAT SECTION, MOREOVER AS ALSO PROVIDED IN THAT SECTION, FAILURE TO PROVIDE THIS INFORMATION MAY PREVENT THIS APPLICATION FROM BEING PROCESSED AND COULD RESULT IN THE APPLICATION BEING DENIED.

FOR APPLICANT'S USE

APPLICATION PAGE _____

Printed on Recycled Paper

Source Name: Dynegy Midwest Generation

Source ID: 125804AAB

Permit No.: Entire Source

02

IEPA-DIVISION OF RECORDS MANAGEMENT
RELEASABLE

JAN 15 2020

REVIEWER: SAB

PERMIT WITHDRAWN

Type of Source: CAAPP

Withdraw Request Received: 11-08-2019

Fees Owed: $23,736.25

Ceased Operations Date Entered in Iceman: 01-01-2020

Acknowledgement Letter Sent: 12-31-2019

Comments:

Initials: tan

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 NORTH GRAND AVENUE EAST, P.O. BOX 19276, SPRINGFIELD, ILLINOIS 62794-9276 · (217) 782-3397

JB PRITZKER, GOVERNOR JOHN J. KIM, DIRECTOR

217/785-1705

WITHDRAWAL ACKNOWLEDGMENT LETTER

December 31, 2019

Luminant
Attn: Dianna Tickner, Director, Decommissioning & Demolition
1500 Eastport Plaza Drive
Collinsville, IL 62234

IEPA-DIVISION OF RECORDS MANAGEMENT RELEASABLE

JAN 15 2020

REVIEWER: SAB

I.D. No.: 125804AAB
Source: Havana Power Plant
Date Letter Received: November 8, 2019

Withdrawal Effective: January 1, 2020

The Illinois EPA hereby acknowledges the receipt of your above-referenced letter and confirms the withdrawal of the entire source and all associated permits and pending permit applications, effective as of the beginning of January 1, 2020, in accordance with your request.

Although the source withdrawal has been granted, any outstanding annual CAAPP fee for the source should be paid consistent with the recently-concluded settlement discussions involving the Illinois EPA's Response to Renewed Request For CAAPP Fee Reconsideration, dated December 31, 2019.

If you have not already done so, please pay electronically at https://magic.collectorsolutions.com/magic-ui/Login/illinois-epa or mail your payment to Fiscal Services #2, Illinois Environmental Protection Agency, 1021 North Grand Avenue East, P.O. Box 19276, Springfield, Illinois 62794-9276. Payment by check or money order should be made payable to "Illinois Environmental Protection Agency."

If you have any questions concerning this withdrawal, you may contact Michael Reed at 217/782-4651. For questions concerning fees owed, please contact Fiscal Services at 217/782-3250.

Raymond E Pilapil MTR 12/31/2019

Raymond E. Pilapil
Manager, Permit Section
Bureau of Air

cc: Charles Koudelka, Plant Closure Director
Jim Ross, Director, Environmental

Luminant

Luminant
6555 Sierra Drive
Irving, TX 75039
o 214.812.4600
m 214.812.4600

11/6/2019

Mr. Raymond Pilapil
Manager, Permit Section
Illinois Environmental Protection Agency
Bureau of Air
1021 North Grand Avenue East
PO Box 19276
Springfield, IL 62794

RECEIVED
STATE OF ILLINOIS
NOV 8 2019
Environmental Protection Agency
BUREAU OF AIR

Re: Dynegy Midwest Generation, LLC – Havana Power Plant
Withdraw of Permits
I.D. No. 125804AAB

Dear Mr. Pilapil:

This letter requests withdraw of all air permits for Havana Power Plant effective January 1, 2020. Accordingly, please find enclosed form 285-CAAPP, WITHDRAWAL OF PERMIT OR PERMIT APPLICATION.

If you have any questions regarding this information, please contact Jim Ross 217-753-8903, Jim.Ross@vistraenergy.com.

Sincerely,

Dianna Tickner
Director, Decommissioning & Demolition

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
DIVISION OF AIR POLLUTION CONTROL -- PERMIT SECTION
P.O. BOX 19506
SPRINGFIELD, ILLINOIS 62794-9506

FOR APPLICANT'S USE
Revision #: _____
Date: ____ / ____ / ____
Page _____ of _____
Source Designation: _____

WITHDRAWAL OF PERMIT OR PERMIT APPLICATION
EFFECTIVE 1/1/2020

FOR AGENCY USE ONLY
ID NO.: 125804AAB
PERMIT NO.: Entire Source
DATE: 11-08-2019

SECTION ONE — SOURCE INFORMATION

1) SOURCE NAME: Havana Power Plant
2) SOURCE ID NO.: 125804AAB
3) SOURCE ADDRESS: 15260 N. State Route 78, Havana, IL
4) CONTACT NAME: Jim Ross
5) CONTACT PHONE NO.: 217-753-8903

SECTION TWO — INSTRUCTIONS IN BRIEF

1) COMPLETE THIS FORM IF THE APPLICANT REQUESTS TO WITHDRAW ISSUED PERMITS AND THEIR ASSOCIATED APPLICATIONS OR PENDING PERMIT APPLICATIONS.
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SECTION THREE — PERMIT(S) TO WITHDRAW

1) DO YOU REQUEST TO WITHDRAW THE ENTIRE SOURCE AND ALL ASSOCIATED PERMITS?
WITHDRAW THE **ENTIRE** SOURCE: ☒ YES ☐ NO, IF "NO" COMPLETE THE FOLLOWING TABLE.
EFFECTIVE 1/1/2020

2) APPLICATION NO.:	5) APPLICATION NO.:
3) APPLICATION NO.:	6) APPLICATION NO.:
4) APPLICATION NO.:	7) APPLICATION NO.:

SECTION FOUR — SIGNATURE BLOCK

AS AUTHORIZED BY THE BELOW SIGNATORY, THE ABOVE LISTED SOURCE REQUESTS THE WITHDRAWAL OF THE ABOVE LISTED PERMITS AND THEIR ASSOSCIATED APPLICATIONS OR ANY PENDING PERMIT APPLICATIONS.

THE SIGNATORY RECOGNIZES A WITHDRAWAL FROM THE SYSTEM IS PERMANENT.

AUTHORIZED SIGNATURE: EFFECTIVE 1/1/2020

BY:

Dianna Tichner
AUTHORIZED SIGNATURE

Director, Decommissioning + Demolition
TITLE OF SIGNATORY

Dianna Tichner
TYPED OR PRINTED NAME OF SIGNATORY

11 ; 04 , 2019
DATE

THIS AGENCY IS AUTHORIZED TO REQUIRE THIS INFORMATION UNDER 39.5 OF THE ILLINOIS ENVIRONMENTAL PROTECTION ACT, 415 ILCS 5/39.5. FURTHER DISCLOSURE OF THIS INFORMATION IS REQUIRED UNDER THAT SECTION, MOREOVER AS ALSO PROVIDED IN THAT SECTION, FAILURE TO PROVIDE THIS INFORMATION MAY PREVENT THIS APPLICATION FROM BEING PROCESSED AND COULD RESULT IN THE APPLICATION BEING DENIED.

FOR APPLICANT'S USE
_____

APPLICATION PAGE _____

DYNEGY

1500 Eastport Plaza Drive
Collinsville, IL 62234

UNITED STATES POSTAGE
PITNEY BOWES
02 1P $ 000.50⁰
0001908455 NOV 06 2019
MAILED FROM ZIP CODE 6223-

Mr. Raymond Pilapil
Illinois EPA
Bureau of Air
1021 North Grand Ave East
PO Box 19276
Springfield, IL 62794

627949276 B050

Luminant

Luminant
1500 Eastport Plaza Drive
Collinsville, IL 62234

November 6, 2019

Compliance Section
Illinois Environmental Protection Agency
Bureau of Air
1021 North Grand Avenue East
PO Box 19276
Springfield, IL 62794

Re: Change in Responsible Official – Havana Power Plant
ID Number: 125804AAB

This letter provides notification of a change in responsible official for Havana Power Plant to Dianna Tickner, Director of Decommissioning and Demolition and Charles Koudelka, Plant Closure Director. Please note that Havana Power Plant will permanently cease operation no later than December 15, 2019. Attached is the Administrative Amendment Form 273.

If you have questions, please feel free to contact Jim Ross at 217-753-8903, Jim.Ross@vistraenergy.com.

Sincerely,

Dianna Tickner
Director, Decommissioning & Demolition

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
DIVISION OF AIR POLLUTION CONTROL -- PERMIT SECTION
P.O. BOX 19506
SPRINGFIELD, ILLINOIS 62794-9506

FOR APPLICANT'S USE
Revision #: _____
Date: ____ / ____ / ____
Page _____ of _____
Source Designation:
_____

REQUEST FOR ADMINISTRATIVE PERMIT AMENDMENT FOR CAAPP PERMIT	***FOR AGENCY USE ONLY***
	ID NUMBER:
	PERMIT #:
	DATE:

GENERAL INFORMATION

1) SOURCE NAME:
Havana Power Plant

2a) ID NUMBER (IF KNOWN):	b) CAAPP PERMIT NUMBER:
125804AAB	NA
3) ENVIRONMENTAL CONTACT PERSON:	4) CONTACT PERSON'S TELEPHONE NUMBER:
Jim Ross	217-753-8903

AMENDMENT DATA

5) AN ADMINISTRATIVE PERMIT AMENDMENT SHALL ONLY BE USED FOR ONE OR MORE OF THE FOLLOWING REVISIONS TO A CAAPP PERMIT (PLEASE INDICATE THE TYPE OF AMENDMENT(S)):

☐ A) CORRECTS TYPOGRAPHICAL ERRORS;

☒ B) IDENTIFIES A CHANGE IN THE NAME, ADDRESS, OR PHONE NUMBER OF ANY PERSON IDENTIFIED IN THE PERMIT, OR PROVIDES A SIMILAR MINOR ADMINISTRATIVE CHANGE AT THE SOURCE;

☐ C) REQUIRES MORE FREQUENT MONITORING OR REPORTING BY THE PERMITTEE; OR

☐ D) ALLOWS FOR A CHANGE IN OWNERSHIP OR OPERATIONAL CONTROL OF THE SOURCE WHERE NO OTHER CHANGE IN THE PERMIT IS NECESSARY, PROVIDED THAT A WRITTEN AGREEMENT CONTAINING A SPECIFIC DATE FOR TRANSFER OF PERMIT RESPONSIBILITY, COVERAGE, AND LIABILITY BETWEEN THE CURRENT AND NEW PERMITTEES HAS BEEN SUBMITTED TO THE ILLINOIS EPA.

THIS AGENCY IS AUTHORIZED TO REQUIRE THIS INFORMATION UNDER ILLINOIS REVISED STATUTES, 1991, AS AMENDED 1992, CHAPTER 111 1/2, PAR. 1039.5. DISCLOSURE OF THIS INFORMATION IS REQUIRED UNDER THAT SECTION. FAILURE TO DO SO MAY PREVENT THIS FORM FROM BEING PROCESSED AND COULD RESULT IN THE APPLICATION BEING DENIED. THIS FORM HAS BEEN APPROVED BY THE FORMS MANAGEMENT CENTER.

FOR APPLICANT'S USE
_____

APPLICATION PAGE _____

AMENDMENT DATA (CON'T)

6) DESCRIPTION OF REQUESTED ADMINISTRATIVE PERMIT AMENDMENT:

	CURRENT PERMIT INFORMATION	AMENDED PERMIT INFORMATION
1)	Responsible Official - Byron Veech	Responsible Official - Dianna Tickner, Director, Decommissioning & Demolition Charles Koudelka, Plant Closure Director
2)		
3)		
4)		
5)		
6)		
7)		
8)		

7) DOES THE APPLICATION INCLUDE A COPY OF THOSE PARTICULAR PAGES OF THE CAAPP PERMIT WHICH ARE CLEARLY MARKED TO SHOW THE REQUESTED AMENDMENT? ☐ YES ☒ NO

SIGNATURE BLOCK

NOTE: THIS CERTIFICATION MUST BE SIGNED BY A RESPONSIBLE OFFICIAL. APPLICATIONS WITHOUT A SIGNED CERTIFICATION WILL BE RETURNED AS INCOMPLETE.

8) I CERTIFY UNDER PENALTY OF LAW THAT, BASED ON INFORMATION AND BELIEF FORMED AFTER REASONABLE INQUIRY, THE STATEMENTS AND INFORMATION CONTAINED IN THIS APPLICATION ARE TRUE, ACCURATE AND COMPLETE.

AUTHORIZED SIGNATURE:

BY: Dianna Tickner
AUTHORIZED SIGNATURE

Director, Decommissioning & Demolition
TITLE OF SIGNATORY

Dianna Tickner
TYPED OR PRINTED NAME OF SIGNATORY

11 / 06 / 2019
DATE

APPLICATION PAGE _____

CAAPP Permit Revision Checklist

SECTION 1: ADMINISTRATIVE REVIEW – Completed by Records Unit			
Source Name: HAVANA Power Station		Reviewed By: MTR	
ID #: 125804 AAB	Permit #: 95090053	Date Received: 11/8/2019	

1)	Does the Source have an issued CAAPP Permit? If no, application is not a CAAPP permit revision. Do not use this form.	☐ YES	☒ NO
2)	Did the Source submit a 273-CAAPP form for an Administrative Permit Amendment?	☒ YES	☐ NO
3)	Did the Source submit a 271-CAAPP form and check the Minor Modification box?	☐ YES	☒ NO
4)	Did the Source submit a 271-CAAPP form and check the Significant Modification box?	☐ YES	☒ NO

SECTION 2: CAAPP SPECIALIST REVIEW – Completed by CAAPP Unit Manager			
CAAPP Specialist: Michael T. Reed		Date Completed: 12/31/2019	
DETERMINATION OF TYPE OF REVISION Note that either a 273-CAAPP or 271-CAAPP must be submitted			
5)	What type of revision is the application?	☒ Administrative ☐ Minor ☐ Significant	
6)	Did the Source submit the proper CAAPP form for this type of application? If no, proceed to question 8	☒ YES	☐ NO
7)	Has a "Responsible Official", as defined in the Act, signed the application?	☐ YES	☐ NO
8)	Has the applicant been contacted to inform them to submit the proper CAAPP form? Date Contacted: Date Form Received:	☐ YES NA	☐ NO

SECTION 3: TECHNICAL REVIEW – Completed by Permit Engineer		
Engineer: Michael T. Reed	Date Completed: 12/31/2019	Due Date: 12/31/2019

	ADMINISTRATIVE PERMIT AMENDMENT Note, formal public or USEPA notice not required		
9)	Has permit been revised and final action taken within 60 days?	☒ YES	☐ NO
10)	Has a copy of the revised CAAPP permit been submitted to USEPA?	☐ YES	☒ NO
	MINOR PERMIT MODIFICATION Note, formal public notice other than notifying affected states not required		
11)	Has Community Relations been provided a copy of the application to notify the affected states and USEPA within 5 days of a complete application?	☐ YES	☐ NO
12)	Has the 45-day USEPA comment period been completed?	☐ YES	☐ NO
13)	Has the permit been revised and final action taken within 90 days, or 15 days after the USEPA's 45 day review period, whichever is later?	☐ YES	☐ NO
	SIGNIFICANT PERMIT MODIFICATION		
14)	Has the application gone through the standard CAAPP public notice procedure?	☐ YES	☐ NO
15)	Has the 45-day USEPA comment period been completed?	☐ YES	☐ NO
16)	Has the permit been revised and final action taken within 9 months?	☐ YES	☐ NO

United States Environmental Protection Agency
Acid Rain, CSAPR, and Texas SO_2 Programs

OMB Nos. 2060-0258 and 2060-0667
Approval Expires 03/31/2022

Retired Unit Exemption

For more information, see instructions and refer to 40 CFR 72.8, 97.405, 97.505, 97.605, 97.705, 97.805, and 97.905, or a comparable state regulation, as applicable.

This submission is: ☐ **New** ☒ **Revised**

STEP 1
Identify the unit by plant (source) name, State, plant code and unit ID#.

Plant (Source) Name	State	Plant Code	Unit ID#
Havana Power Station	IL	891	Boiler 9

STEP 2
Indicate the program(s) that the unit is subject to.

- ☒ Acid Rain
- ☒ CSAPR NO_x Annual
- ☒ CSAPR NO_x Ozone Season Group 1
- ☐ CSAPR NO_x Ozone Season Group 2
- ☒ CSAPR SO_2 Group 1
- ☐ CSAPR SO_2 Group 2
- ☐ Texas SO_2

STEP 3
Identify the date on which the unit was (or will be) permanently retired.

November 1, 2019

STEP 4
If the unit is subject to the Acid Rain Program, identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.8(d).

Calendar year starting January 1, 2020

STEP 5 Read the applicable special provisions.

Acid Rain Program Special Provisions

(1) A unit exempt under 40 CFR 72.8 shall not emit any sulfur dioxide and nitrogen oxides starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with 40 CFR part 73 subpart B.

(2) A unit exempt under 40 CFR 72.8 shall not resume operation unless the designated representative of the source that includes the unit submits a complete Acid Rain permit application under 40 CFR 72.31 for the unit not less than 24 months prior to the date on which the unit is first to resume operation.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 72.8 shall comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) For any period for which a unit is exempt under 40 CFR 72.8, the unit is not an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71 and is not eligible to be an opt-in source under 40 CFR part 74. As an unaffected unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR parts 70 and 71.

(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 72.8 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Administrator or the permitting authority. The owners and operators bear the burden of proof that the unit is permanently retired.

(6) On the earlier of the following dates, a unit exempt under 40 CFR 72.8(b) or (c) shall lose its exemption and become an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71: (i) the date on which the designated representative submits an Acid Rain permit application under paragraph (2); or (ii) the date on which the designated representative is required under paragraph (2) to submit an Acid Rain permit application. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under 40 CFR 72.8 shall be treated as a new unit that commenced commercial operation on the first date on which the unit resumes operation.

CSAPR NO_X Annual Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.405 shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.405 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.405 shall comply with the requirements of the CSAPR NO_X Annual Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.405 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart AAAAA, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_X Ozone Season Group 1 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.505 shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.505 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.505 shall comply with the requirements of the CSAPR NO_X Ozone Season Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.505 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart BBBBB, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_X Ozone Season Group 2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.805 shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.805 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.805 shall comply with the requirements of the CSAPR NO_X Ozone Season Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.805 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart EEEEE, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR SO_2 Group 1 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.605 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.605 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.605 shall comply with the requirements of the CSAPR SO_2 Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.605 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart CCCCC, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR SO_2 Group 2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.705 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.705 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.705 shall comply with the requirements of the CSAPR SO_2 Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.705 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart DDDDD, as a unit that commences commercial operation on the first date on which the unit resumes operation.

Texas SO_2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.905 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.905 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.905 shall comply with the requirements of the Texas SO_2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.905 shall lose its exemption on the first date on which the unit resumes operation. A retired unit that resumes operation will not receive an allowance allocation under 40 CFR 97.911. The unit may receive allowances from the Supplemental Allowance Pool pursuant to 40 CFR 97.912. All other provisions of 40 CFR part 97 subpart FFFFF regarding monitoring, reporting, recordkeeping and compliance will apply on the first date on which the unit resumes operation.

STEP 6 Read the statement of compliance and the applicable certification statements, sign, and date.

Statement of compliance

I certify that the unit identified above at STEP 1 was (or will be) permanently retired on the date identified at STEP 3 and will comply with the applicable Special Provisions listed at STEP 5.

Certification by designated representatives or alternate designated representatives

I am authorized to make this submission on behalf of the owners and operators of the source and unit for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Dianna Tickner	Director Demolition & Decommissioning Title
Owner Company Name Dynegy Midwest Generation, LLC	
Email dianna.tickner@vistraenergy.com	Phone 618-343-7929
Signature Dianna Tickner	Date 12/19/2019

Certification by certifying officials of units subject only to the Acid Rain Program for which no designated representative has been authorized

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Title
Owner Company Name	
Email	Phone
Signature	Date

Source Name: Dynergy Midwest Generation

Source ID: 155 010 AAA

Permit No.: Entire Source

02

IEPA-DIVISION OF RECORDS MANAGEMENT RELEASABLE

JAN 15 2020

REVIEWER: SAB

PERMIT WITHDRAWN

Type of Source: CAAPP

Withdraw Request Received: 11-08-2019

Fees Owed: $45,435.00

Ceased Operations Date Entered in Iceman: 01-01-2020

Acknowledgement Letter Sent: 12-31-2019

Comments:

Initials: tan

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
1021 NORTH GRAND AVENUE EAST, P.O. BOX 19276, SPRINGFIELD, ILLINOIS 62794-9276 · (217) 782-3397
JB PRITZKER, GOVERNOR JOHN J. KIM, DIRECTOR

217/785-1705

WITHDRAWAL ACKNOWLEDGMENT LETTER

IEPA-DIVISION OF RECORDS MANAGEMENT
RELEASABLE
JAN 15 2020
REVIEWER: SAB

December 31, 2019

Luminant
Attn: Dianna Tickner, Director, Decommissioning & Demolition
1500 Eastport Plaza Drive
Collinsville, IL 62234

I.D. No.:	155010AAA
Source:	Hennepin Power Plant
Date Letter Received:	November 8, 2019
Withdrawal Effective:	January 1, 2020

The Illinois EPA hereby acknowledges the receipt of your above-referenced letter and confirms the withdrawal of the entire source and all associated permits and pending permit applications, effective as of the beginning of January 1, 2020, in accordance with your request.

Although the source withdrawal has been granted, any outstanding annual CAAPP fee for the source should be paid consistent with the recently-concluded settlement discussions involving the Illinois EPA's Response to Renewed Request For CAAPP Fee Reconsideration, dated December 31, 2019.

If you have not already done so, please pay electronically at https://magic.collectorsolutions.com/magic-ui/Login/illinois-epa or mail your payment to Fiscal Services #2, Illinois Environmental Protection Agency, 1021 North Grand Avenue East, P.O. Box 19276, Springfield, Illinois 62794-9276. Payment by check or money order should be made payable to "Illinois Environmental Protection Agency."

If you have any questions concerning this withdrawal, you may contact Michael Reed at 217/782-4651. For questions concerning fees owed, please contact Fiscal Services at 217/782-3250.

Raymond E. Pilapil 12/31/2019

Raymond E. Pilapil
Manager, Permit Section
Bureau of Air

cc: Charles Koudelka, Plant Closure Director
Jim Ross, Director, Environmental

Luminant

Luminant
6555 Sierra Drive
Irving, TX 75039
o 214.812.4600
m 214.812.4600

11/6/2019

Mr. Raymond Pilapil
Manager, Permit Section
Illinois Environmental Protection Agency
Bureau of Air
1021 North Grand Avenue East
PO Box 19276
Springfield, IL 62794

RECEIVED
STATE OF ILLINOIS
NOV 8 2019
Environmental Protection Agency
BUREAU OF AIR

Re: Dynegy Midwest Generation, LLC – Hennepin Power Plant
Withdraw of Permits
I.D. No. 155010AAA

Dear Mr. Pilapil:

This letter requests withdraw of all air permits for Hennepin Power Plant effective January 1, 2020. Accordingly, please find enclosed form 285-CAAPP, WITHDRAWAL OF PERMIT OR PERMIT APPLICATION.

If you have any questions regarding this information, please contact Jim Ross 217-753-8903, Jim.Ross@vistraenergy.com.

Sincerely,

Dianna Tickner
Director, Decommissioning & Demolition

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
DIVISION OF AIR POLLUTION CONTROL -- PERMIT SECTION
P.O. BOX 19506
SPRINGFIELD, ILLINOIS 62794-9506

FOR APPLICANT'S USE
Revision #: _____
Date: ____ / ____ / ____
Page _____ of _____
Source Designation: _____

WITHDRAWAL OF PERMIT OR PERMIT APPLICATION
EFFECTIVE 1/1/2020

FOR AGENCY USE ONLY
ID NO.: 155 010 AAA
PERMIT NO.: Entire Source
DATE: 11-08-2019

SECTION ONE — SOURCE INFORMATION

1) SOURCE NAME: Hennepin Power Plant	2) SOURCE ID NO.: 155010AAA
3) SOURCE ADDRESS: 13498 E. 800th St., Hennepin, IL	
4) CONTACT NAME: Jim Ross	5) CONTACT PHONE NO.: 217-753-8903

SECTION TWO — INSTRUCTIONS IN BRIEF

1) COMPLETE THIS FORM IF THE APPLICANT REQUESTS TO WITHDRAW ISSUED PERMITS AND THEIR ASSOCIATED APPLICATIONS OR PENDING PERMIT APPLICATIONS.
2) SECTION THREE, NO. 1 IS USED TO WITHDRAW THE ENTIRE SOURCE, NO. 2 -7 ARE FOR SPECIFIC PERMITS.
3) A WITHDRAWAL AND SUBSEQUENT DELETION FROM THE SYSTEM IS **PERMANENT**.
4) A SHUTDOWN OR TERMINATION OF THE OPERATION IS NOT SUFFICIENT TO WITHDRAW A PERMIT. THE PERMITTEE MUST SPECIFICALLY INSTRUCT THE ILLINOIS EPA, IN WRITING, TO WITHDRAW THE UNDERLYING AUTHORIZING PERMIT(S). SUBMISSION OF THIS FORM CONSTITUTES THAT WRITTEN INSTRUCTION.
5) THE ILLINOIS EPA BILLS ANNUALLY FOR HOLDING AN PERMIT WHETHER OR NOT THE SOURCE IS IN OPERATION. TO STOP BILLING, A PERMIT MUST BE WITHDRAWN BEFORE THE FEE DUE DATE.
6) DATA AND INFORMATION REQUIRED FOR ANNUAL EMISSION REPORTS WILL STILL BE REQUIRED TO BE SUBMITTED FOR THE PORTION OF THE YEAR THAT THE SOURCE HELD A VALID PERMIT.

SECTION THREE — PERMIT(S) TO WITHDRAW

1) DO YOU REQUEST TO WITHDRAW THE ENTIRE SOURCE AND ALL ASSOCIATED PERMITS?
WITHDRAW THE **ENTIRE** SOURCE: ☒ YES ☐ NO, IF "NO" COMPLETE THE FOLLOWING TABLE.
EFFECTIVE 1/1/2020

2) APPLICATION NO.:	5) APPLICATION NO.:
3) APPLICATION NO.:	6) APPLICATION NO.:
4) APPLICATION NO.:	7) APPLICATION NO.:

SECTION FOUR — SIGNATURE BLOCK

AS AUTHORIZED BY THE BELOW SIGNATORY, THE ABOVE LISTED SOURCE REQUESTS THE WITHDRAWAL OF THE ABOVE LISTED PERMITS AND THEIR ASSOSCIATED APPLICATIONS OR ANY PENDING PERMIT APPLICATIONS.

THE SIGNATORY RECOGNIZES A WITHDRAWAL FROM THE SYSTEM IS PERMANENT.

AUTHORIZED SIGNATURE: EFFECTIVE 1/1/2020

BY:

Dianna Tickner
AUTHORIZED SIGNATURE

Director, Decommissioning + Demolition
TITLE OF SIGNATORY

Dianna Tickner
TYPED OR PRINTED NAME OF SIGNATORY

11 / 04 / 2019
DATE

THIS AGENCY IS AUTHORIZED TO REQUIRE THIS INFORMATION UNDER 39.5 OF THE ILLINOIS ENVIRONMENTAL PROTECTION ACT, 415 ILCS 5/39.5. FURTHER DISCLOSURE OF THIS INFORMATION IS REQUIRED UNDER THAT SECTION. MOREOVER AS ALSO PROVIDED IN THAT SECTION, FAILURE TO PROVIDE THIS INFORMATION MAY PREVENT THIS APPLICATION FROM BEING PROCESSED AND COULD RESULT IN THE APPLICATION BEING DENIED.

FOR APPLICANT'S USE
_____

APPLICATION PAGE _____

DYNEGY

1500 Eastport Plaza Drive
Collinsville, IL 62234

UNITED STATES POSTAGE
PITNEY BOWES
02 1P $ 000.50⁰
0001908455 NOV 06 2019
MAILED FROM ZIP CODE 62234

Mr. Raymond Pilapil
Illinois EPA
Bureau of Air
1021 North Grand Ave East
PO Box 19276
Springfield, IL 62794

62794$9276 B050



Luminant

Luminant
1500 Eastport Plaza Drive
Collinsville, IL 62234

RECEIVED
STATE OF ILLINOIS
NOV 8 2019
Environmental Protection Agency
BUREAU OF AIR

November 6, 2019

Compliance Section
Illinois Environmental Protection Agency
Bureau of Air
1021 North Grand Avenue East
PO Box 19276
Springfield, IL 62794

Re: Change in Responsible Official – Hennepin Power Plant
ID Number: 155010AAA

This letter provides notification of a change in responsible official for Hennepin Power Plant to Dianna Tickner, Director of Decommissioning and Demolition and Charles Koudelka, Plant Closure Director. Please note that Hennepin Power Plant has permanently ceased operation. Attached is the Administrative Amendment Form 273.

If you have questions, please feel free to contact Jim Ross at 217-753-8903, Jim.Ross@vistraenergy.com.

Sincerely,

Dianna Tickner
Director, Decommissioning & Demolition

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
DIVISION OF AIR POLLUTION CONTROL -- PERMIT SECTION
P.O. BOX 19506
SPRINGFIELD, ILLINOIS 62794-9506

FOR APPLICANT'S USE
Revision #: _____
Date: ____ / ____ / ____
Page _____ of _____
Source Designation:
_____

REQUEST FOR ADMINISTRATIVE PERMIT AMENDMENT FOR CAAPP PERMIT	***FOR AGENCY USE ONLY***
	ID NUMBER: 155010AAA
	PERMIT #: 95090052
	DATE: 11-8-19

GENERAL INFORMATION

1) SOURCE NAME:
Hennepin Power Plant

2a) ID NUMBER (IF KNOWN):	b) CAAPP PERMIT NUMBER:
155010AAA	95090052
3) ENVIRONMENTAL CONTACT PERSON:	4) CONTACT PERSON'S TELEPHONE NUMBER:
Jim Ross	217-753-8903

AMENDMENT DATA

5) AN ADMINISTRATIVE PERMIT AMENDMENT SHALL ONLY BE USED FOR ONE OR MORE OF THE FOLLOWING REVISIONS TO A CAAPP PERMIT (PLEASE INDICATE THE TYPE OF AMENDMENT(S)):

☐ A) CORRECTS TYPOGRAPHICAL ERRORS;

☒ B) IDENTIFIES A CHANGE IN THE NAME, ADDRESS, OR PHONE NUMBER OF ANY PERSON IDENTIFIED IN THE PERMIT, OR PROVIDES A SIMILAR MINOR ADMINISTRATIVE CHANGE AT THE SOURCE;

☐ C) REQUIRES MORE FREQUENT MONITORING OR REPORTING BY THE PERMITTEE; OR

☐ D) ALLOWS FOR A CHANGE IN OWNERSHIP OR OPERATIONAL CONTROL OF THE SOURCE WHERE NO OTHER CHANGE IN THE PERMIT IS NECESSARY, PROVIDED THAT A WRITTEN AGREEMENT CONTAINING A SPECIFIC DATE FOR TRANSFER OF PERMIT RESPONSIBILITY, COVERAGE, AND LIABILITY BETWEEN THE CURRENT AND NEW PERMITTEES HAS BEEN SUBMITTED TO THE ILLINOIS EPA.

THIS AGENCY IS AUTHORIZED TO REQUIRE THIS INFORMATION UNDER ILLINOIS REVISED STATUTES, 1991, AS AMENDED 1992, CHAPTER 111 1/2, PAR. 1039.5. DISCLOSURE OF THIS INFORMATION IS REQUIRED UNDER THAT SECTION. FAILURE TO DO SO MAY PREVENT THIS FORM FROM BEING PROCESSED AND COULD RESULT IN THE APPLICATION BEING DENIED. THIS FORM HAS BEEN APPROVED BY THE FORMS MANAGEMENT CENTER.

FOR APPLICANT'S USE
_____

APPLICATION PAGE _____

AMENDMENT DATA (CON'T)

6) DESCRIPTION OF REQUESTED ADMINISTRATIVE PERMIT AMENDMENT:

	CURRENT PERMIT INFORMATION	AMENDED PERMIT INFORMATION
1)	Responsible Official - Byron Veech	Responsible Official - Dianna Tickner, Director, Decommissioning & Demolition Charles Koudelka, Plant Closure Director
2)		
3)		
4)		
5)		
6)		
7)		
8)		

7) DOES THE APPLICATION INCLUDE A COPY OF THOSE PARTICULAR PAGES OF THE CAAPP PERMIT WHICH ARE CLEARLY MARKED TO SHOW THE REQUESTED AMENDMENT? ☒ YES ☐ NO

SIGNATURE BLOCK

NOTE: THIS CERTIFICATION MUST BE SIGNED BY A RESPONSIBLE OFFICIAL. APPLICATIONS WITHOUT A SIGNED CERTIFICATION WILL BE RETURNED AS INCOMPLETE.

8) I CERTIFY UNDER PENALTY OF LAW THAT, BASED ON INFORMATION AND BELIEF FORMED AFTER REASONABLE INQUIRY, THE STATEMENTS AND INFORMATION CONTAINED IN THIS APPLICATION ARE TRUE, ACCURATE AND COMPLETE.

AUTHORIZED SIGNATURE:

BY: Dianna Tickner
AUTHORIZED SIGNATURE

Director, Decommissioning & Demolition
TITLE OF SIGNATORY

Dianna Tickner
TYPED OR PRINTED NAME OF SIGNATORY

_____ / _____ / _____
DATE

APPLICATION PAGE _____

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 NORTH GRAND AVENUE EAST, P.O. BOX 19276, SPRINGFIELD, ILLINOIS 62794-9276 • (217) 782-3397
BRUCE RAUNER, GOVERNOR ALEC MESSINA, DIRECTOR

217/785-1705

"REVISED" CLEAN AIR ACT PERMIT PROGRAM (CAAPP) PERMIT

PERMITTEE

Dynegy Midwest Generation, LLC
Attn: Rick Diericx
1500 Eastport Plaza Drive
Collinsville, Illinois 62234

Application No.: 95090052 I.D. No.: 155010AAA
Operation of: Hennepin Power Station
Original Date Received: September 7, 1995
Original Date Issued: September 29, 2005
Initial Effective Date: December 21, 2017 Expiration Date[1]: December 21, 2022
Source Location: R. R. #1, Box 200AA, Hennepin, 61327 (Putnam County)
Responsible Official: ~~Byron Veech, Managing Director, Plant Operations,~~ Hennepin Power Station
Dianna Tickner, Director, Decommissioning & Demolition
Charles Koudelka, Plant Closure Director

The above-referenced permit was originally issued to the Permittee to OPERATE an electrical power generation station, pursuant to the corresponding permit application, on September 29, 2005. As a result of an automatic stay of the permit during the pendency of an administrative permit appeal, the CAAPP permit became effective on the date shown above.

Type of Permit Action: Reopening for Cause
Date Issued: December 21, 2017

Permit Authorization:

This permit revision is hereby granted to the above-designated Permittee for operation of the above referenced source. This permit is subject to the conditions contained herein.

In accordance with Section 39.5(15)(a)(i) of the Illinois Environmental Protection Act, this permit action addresses certain changes to Permit Conditions, as described in the accompanying Statement of Basis, so as to include Clean Air Act (CAA) requirements that have become applicable to the source since September 29, 2005.[2] Affected permit conditions largely reflect the addition of new or revised text to the permit; however, some conditions will also reflect deleted text that has been displaced or made obsolete by newly applicable requirements. The procedures for issuance of this permit action are the same as were applicable for initial permit issuance. 415 ILCS 5/39.5(15)(c).

---

[1] Except as addressed in Condition 8.7 of this permit.

[2] This permit revises the initial CAAPP permit for the source, which was placed into effect on the same date as a consequence of the Pollution Control Board order granting a Joint Motion to Partially Lift Stay of CAAPP Permit and Request Remand of Permit to Respondent in the pending administrative appeal. The permit reopening undertaken in this action revises the permit to assure that, together with the parallel permit actions taken to resolve the appeal, the Permittee is provided a comprehensive, up-to-date permit.

CAAPP Permit Revision Checklist

SECTION 1: ADMINISTRATIVE REVIEW – Completed by Records Unit		
Source Name: Hennepin Power Plant		Reviewed By: Tracy
ID #: 15501 0 AAA	Permit #: 95090052	Date Received: 11-8-19

1)	Does the Source have an issued CAAPP Permit? If no, application is not a CAAPP permit revision. Do not use this form.	☒ YES ☐ NO
2)	Did the Source submit a 273-CAAPP form for an Administrative Permit Amendment?	☒ YES ☐ NO
3)	Did the Source submit a 271-CAAPP form and check the Minor Modification box?	☐ YES ☒ NO
4)	Did the Source submit a 271-CAAPP form and check the Significant Modification box?	☐ YES ☒ NO

SECTION 2: CAAPP SPECIALIST REVIEW – Completed by CAAPP Unit Manager		
CAAPP Specialist: Marc		Date Completed: 11-18-19
DETERMINATION OF TYPE OF REVISION Note that either a 273-CAAPP or 271-CAAPP must be submitted		
5)	What type of revision is the application?	☒ Administrative ☐ Minor ☐ Significant
6)	Did the Source submit the proper CAAPP form for this type of application? If no, proceed to question 8	☒ YES ☐ NO
7)	Has a "Responsible Official", as defined in the Act, signed the application?	☒ YES ☐ NO
8)	Has the applicant been contacted to inform them to submit the proper CAAPP form? Date Contacted: Date Form Received:	☐ YES ☒ NO

SECTION 3: TECHNICAL REVIEW – Completed by Permit Engineer		
Engineer:	Date Completed:	Due Date:

	ADMINISTRATIVE PERMIT AMENDMENT Note, formal public or USEPA notice not required	
9)	Has permit been revised and final action taken within 60 days?	☐ YES ☐ NO
10)	Has a copy of the revised CAAPP permit been submitted to USEPA?	☐ YES ☐ NO
	MINOR PERMIT MODIFICATION Note, formal public notice other than notifying affected states not required	
11)	Has Community Relations been provided a copy of the application to notify the affected states and USEPA within 5 days of a complete application?	☐ YES ☐ NO
12)	Has the 45-day USEPA comment period been completed?	☐ YES ☐ NO
13)	Has the permit been revised and final action taken within 90 days, or 15 days after the USEPA's 45 day review period, whichever is later?	☐ YES ☐ NO
	SIGNIFICANT PERMIT MODIFICATION	
14)	Has the application gone through the standard CAAPP public notice procedure?	☐ YES ☐ NO
15)	Has the 45-day USEPA comment period been completed?	☐ YES ☐ NO
16)	Has the permit been revised and final action taken within 9 months?	☐ YES ☐ NO

United States Environmental Protection Agency
Acid Rain, CSAPR, and Texas SO_2 Programs

OMB Nos. 2060-0258 and 2060-0667
Approval Expires 03/31/2022

Retired Unit Exemption

For more information, see instructions and refer to 40 CFR 72.8, 97.405, 97.505, 97.605, 97.705, 97.805, and 97.905, or a comparable state regulation, as applicable.

This submission is: ☐ New ☒ Revised

STEP 1
Identify the unit by plant (source) name, State, plant code and unit ID#.

Plant (Source) Name	State	Plant Code	Unit ID#
Hennepin Power Station	IL	892	Boiler 1 Boiler 2

STEP 2
Indicate the program(s) that the unit is subject to.

- ☒ Acid Rain
- ☒ CSAPR NO_x Annual
- ☒ CSAPR NO_x Ozone Season Group 1
- ☐ CSAPR NO_x Ozone Season Group 2
- ☒ CSAPR SO_2 Group 1
- ☐ CSAPR SO_2 Group 2
- ☐ Texas SO_2

STEP 3
Identify the date on which the unit was (or will be) permanently retired.

November 1, 2019

STEP 4
If the unit is subject to the Acid Rain Program, identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.8(d).

Calendar year starting January 1, 2020

STEP 5 Read the applicable special provisions.

Acid Rain Program Special Provisions

(1) A unit exempt under 40 CFR 72.8 shall not emit any sulfur dioxide and nitrogen oxides starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with 40 CFR part 73 subpart B.

(2) A unit exempt under 40 CFR 72.8 shall not resume operation unless the designated representative of the source that includes the unit submits a complete Acid Rain permit application under 40 CFR 72.31 for the unit not less than 24 months prior to the date on which the unit is first to resume operation.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 72.8 shall comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) For any period for which a unit is exempt under 40 CFR 72.8, the unit is not an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71 and is not eligible to be an opt-in source under 40 CFR part 74. As an unaffected unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR parts 70 and 71.

(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 72.8 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Administrator or the permitting authority. The owners and operators bear the burden of proof that the unit is permanently retired.

(6) On the earlier of the following dates, a unit exempt under 40 CFR 72.8(b) or (c) shall lose its exemption and become an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71: (i) the date on which the designated representative submits an Acid Rain permit application under paragraph (2); or (ii) the date on which the designated representative is required under paragraph (2) to submit an Acid Rain permit application. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under 40 CFR 72.8 shall be treated as a new unit that commenced commercial operation on the first date on which the unit resumes operation.

CSAPR NO_X Annual Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.405 shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.405 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.405 shall comply with the requirements of the CSAPR NO_X Annual Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.405 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart AAAAA, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_X Ozone Season Group 1 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.505 shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.505 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.505 shall comply with the requirements of the CSAPR NO_X Ozone Season Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.505 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart BBBBB, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_X Ozone Season Group 2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.805 shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.805 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.805 shall comply with the requirements of the CSAPR NO_X Ozone Season Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.805 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart EEEEE, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR SO_2 Group 1 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.605 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.605 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.605 shall comply with the requirements of the CSAPR SO_2 Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.605 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart CCCCC, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR SO_2 Group 2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.705 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.705 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.705 shall comply with the requirements of the CSAPR SO_2 Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.705 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart DDDDD, as a unit that commences commercial operation on the first date on which the unit resumes operation.

Texas SO_2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.905 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.905 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.905 shall comply with the requirements of the Texas SO_2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.905 shall lose its exemption on the first date on which the unit resumes operation. A retired unit that resumes operation will not receive an allowance allocation under 40 CFR 97.911. The unit may receive allowances from the Supplemental Allowance Pool pursuant to 40 CFR 97.912. All other provisions of 40 CFR part 97 subpart FFFFF regarding monitoring, reporting, recordkeeping and compliance will apply on the first date on which the unit resumes operation.

STEP 6 Read the statement of compliance and the applicable certification statements, sign, and date.

Statement of compliance

I certify that the unit identified above at STEP 1 was (or will be) permanently retired on the date identified at STEP 3 and will comply with the applicable Special Provisions listed at STEP 5.

Certification by designated representatives or alternate designated representatives

I am authorized to make this submission on behalf of the owners and operators of the source and unit for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Dianna Tickner	Director Demolition & Decommissioning Title
Owner Company Name Dynegy Midwest Generation, LLC	
Email dianna.tickner@vistraenergy.com	Phone 618-343-7929
Signature Dianna Tickner	Date 12/19/2019

Certification by certifying officials of units subject only to the Acid Rain Program for which no designated representative has been authorized

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Title
Owner Company Name	
Email	Phone
Signature	Date

PERMIT REVIEW TRAVELER SHEET

I.D. # 155010AAA	Source Name Dynegy Midwest Generation LLC	Date Received 11-8-2019
Application # 95090052	Location Hennepin	Date Opened 11-19-2019

Program TITLE V	Type OPERATING	Title V Type ADMIN-ANA

Flag	Date	Section	Contact	Expiration Date

Emissions(Tons/Year)	CO	NOX	PM	SO2	VOM	Total HAP	Highest Single HAP
Current Allowable Rates	353.76	1,671.73	1,792.94	74,474.40	42.43	54.625028	27.43 - HF
Project/Total Increase							

Initial Completeness	Analyst	Unit Manager	Date of Determination	Application Complete?
CAAPP Completeness ☐ N/A				☐ Yes ☐ No
Fee Completeness ☐ N/A				☐ Yes ☐ No
Technical Completeness				☐ Yes ☐ No

Welcome Phone Call to Permit Applicant

Date	Contact Name	Telephone#	Was Additional Information Requested?

For Incomplete Applications Type of Letter Sent	Analyst	Unit Manager	Date Issued	Number of Items Requested (or Amount of Fee Requested)
Notice of Additional Fees:				$
Notice of Incompleteness(NOI)				
Request for Addditional Information(RAI)				
All Required Information Received?	☐ Yes	☐ No	Date Received	
Notice of Intent to Deny CAAPP				

Permit Processing	Analyst	Date	Unit Manager	Date
Draft Prepared for Unit Manager Review & Comments Returned to Analyst				
Final Draft Sent to Applicant for Comments				
Submitted to Word Processing			[redacted]	
Draft Permit to Community Relations ☐ N/A				
Public Comment Period Initiated				
Public Hearing Date ☐ N/A				
Public Comment Period Completed ☐ N/A				
45 Day USEPA Comment Period ☐ N/A				
USEPA Comments Received ☐ Yes ☐ No				
Responsiveness Summary Completed ☐ N/A				
Public Participation Completed				
Final Action (Fill in One)	**Analyst**	**Date**	**Unit Manager**	**Date**
☐ Permit Not Required				
☐ Grant				
☐ Deny				

Mail-Out	☐ District Office	☐ Public Participation List	☐ Cook County	☐ Health Dept
	☐ Enforcement	☐ Other	Init.	Date

Permit Electronically Sent to	Applicant	CES	DLC	Community Relations	USEPA	AQPS	FOS
Person Sending (Initials)							

Source Name: Electric Energy Inc.

Source ID: 127855 AAC

Permit No.: Entire Source

02

PERMIT WITHDRAWN

Type of Source: CAAPP

Withdraw Request Received: 12-27-2022

Fees Owed: Ø

Ceased Operations Date Entered in Iceman: 1-1-2023

Acknowledgement Letter Sent: 1-3-2023

Comments:

Division of Records Management
IEPA
Release
JAN 04 2023
Reviewer: SSD

Initials: tan

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 NORTH GRAND AVENUE EAST, P.O. BOX 19276, SPRINGFIELD, ILLINOIS 62794-9276 · (217) 782-3397

JB PRITZKER, GOVERNOR JOHN J. KIM, DIRECTOR

January 3, 2023

Electric Energy Inc
Attn: Dianna Tickner
1500 Eastport Plaza Dr
Collinsville, IL 62234

I.D. No.: 127855AAC
Permit No.: 95090120
Letter Received: December 27, 2022

The Illinois EPA hereby acknowledges the receipt of your above-referenced correspondence and confirms the withdrawal of your entire source and all associated permits in accordance with your request.

If you have any questions concerning this matter, please contact Trent Nation at 217/524-1661.

William D Marr

William D. Marr
Manager, Permit Section
Bureau of Air

WDM:tan

2125 S. First Street, Champaign, IL 61820 (217) 278-5800
2009 Mall Street Collinsville, IL 62234 (618) 346-5120
9511 Harrison Street, Des Plaines, IL 60016 (847) 294-4000
595 S. State Street, Elgin, IL 60123 (847) 608-3131
2309 W. Main Street, Suite 116, Marion, IL 62959 (618) 993-7200
412 SW Washington Street, Suite D, Peoria, IL 61602 (309) 671-3022
4302 N. Main Street, Rockford, IL 61103 (815) 987-7760

PLEASE PRINT ON RECYCLED PAPER

RECEIVED
STATE OF ILLINOIS

DEC 27 2022

Environmental Protection Agency
BUREAU OF AIR

ELECTRIC ENERGY, INC

Joppa Power Station
2100 Portland Road
Joppa, IL 62953

December 22, 2022

Illinois Environmental Protection Agency
Bureau of Air
Bill Marr
Manager, Permit Section
1021 North Grand Avenue East
PO Box 19276
Springfield, IL 62702

Re: Electric Energy, Inc.
Electric Power Station I.D. No. 127855AAC

Dear Mr. Marr,

This letter is the final request to withdraw all air permits for Electric Energy, Inc. Electric Power Station (aka, Joppa) effective January 1, 2023. Note that we previously submitted advanced notice of this action along with form 285-CAAPP, WITHDRAWAL of PERMIT or PERMIT APPLICATION.

In accordance with 35 IAC Section 225.233 Multi-Pollutant Standards (MPS), a separate letter will be timely submitted the first week of January 2023 to Kent Mohr, Compliance and Enforcement Section, Manager, that will contain the additional information required thereunder.

Please contact Jim Ross at 217-585-0925 or Jim.Ross@vistracorp.com with any questions regarding this submittal.

Sincerely,

Dianna Tickner

Dianna Tickner
Sr Director, Demolition & Decommissioning
Electric Energy, Inc.

RECEIVED
STATE OF ILLINOIS
JUL 05 2022
Environmental Protection Agency
BUREAU OF AIR

ELECTRIC ENERGY, INC.
1500 Eastport Plaza Drive
Collinsville, IL 62234

July 01, 2022

Illinois Environmental Protection Agency
Bureau of Air
Bill Marr
Manager, Permit Section
1021 North Grand Avenue East
PO Box 19276
Springfield, IL 62702

Re: Electric Energy, Inc.;
Joppa Power Station I.D. No. 127855AAC

Dear Mr. Marr,

On May 24, 2022, Electric Energy, Inc. ("EEI") transmitted a letter requesting withdrawal of all air permits for the above-referenced power station effective January 1, 2023. I write to withdrawal that letter and enclosure, and to replace it with this letter and enclosure.

This letter provides advanced notice of a request to withdraw all air permits for EEI, Joppa Power Station effective January 1, 2023. Accordingly, please find enclosed 285-CAAPP, WITHDRAWL of PERMIT or PERMIT APPLICATION (the "Withdrawal Request").

This letter is not a written request to modify the operating permit to reflect the shutdown of the EGUs or to withdraw the air permit for the source at this time or any time prior to January 1, 2023. For Illinois EPA's administrative convenience, I am enclosing the Withdrawal Request with this advanced notice. EEI intends for the Withdrawal Request to be deemed submitted on (and not before) January 1, 2023, the date specified on the Withdrawal Request, including for purposes of 35 IAC 225.233(g). In accordance with 35 IAC 225.233(g), notification will be timely submitted the first week of January 2023 to the Bureau of Air Compliance Section that will contain the additional information (e.g., adjusted annual emission limitations) required thereunder.

Please contact Jim Ross at 217-585-0925 or Jim.Ross@vistracorp.com with any questions regarding this submittal.

Sincerely,

Byron Veech
Plant Manager, Joppa Power Station

Attachments

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
DIVISION OF AIR POLLUTION CONTROL – PERMIT SECTION
P.O. BOX 19506
SPRINGFIELD, ILLINOIS 62794-9506

FOR APPLICANT'S USE
Revision #: 0
Effective Date: 01 / 01 / 2023
Page _____ of _____
Source Designation: _____

RECEIVED
STATE OF ILLINOIS
JUL 05 2022
Environmental Protection Agency
BUREAU OF AIR

WITHDRAWAL OF PERMIT OR PERMIT APPLICATION

FOR AGENCY USE ONLY
ID NO.:
PERMIT NO.:
DATE:

SECTION ONE — SOURCE INFORMATION

1) SOURCE NAME: Electric Energy, Inc. - Joppa Power Station	2) SOURCE ID NO.: 127855AAC
3) SOURCE ADDRESS: 2100 Portland Rd Joppa, Illinois 62593	
4) CONTACT NAME: Bruce Parker	5) CONTACT PHONE NO.: 331-264-1980

SECTION TWO — INSTRUCTIONS IN BRIEF

1) COMPLETE THIS FORM IF THE APPLICANT REQUESTS TO WITHDRAW ISSUED PERMITS AND THEIR ASSOCIATED APPLICATIONS OR PENDING PERMIT APPLICATIONS.
2) SECTION THREE, NO. 1 IS USED TO WITHDRAW THE ENTIRE SOURCE, NO. 2 -7 ARE FOR SPECIFIC PERMITS.
3) A WITHDRAWAL AND SUBSEQUENT DELETION FROM THE SYSTEM IS **PERMANENT**.
4) A SHUTDOWN OR TERMINATION OF THE OPERATION IS NOT SUFFICIENT TO WITHDRAW A PERMIT. THE PERMITTEE MUST SPECIFICALLY INSTRUCT THE ILLINOIS EPA, IN WRITING, TO WITHDRAW THE UNDERLYING AUTHORIZING PERMIT(S). SUBMISSION OF THIS FORM CONSTITUTES THAT WRITTEN INSTRUCTION.
5) THE ILLINOIS EPA BILLS ANNUALLY FOR HOLDING AN PERMIT WHETHER OR NOT THE SOURCE IS IN OPERATION. TO STOP BILLING, A PERMIT MUST BE WITHDRAWN BEFORE THE FEE DUE DATE.
6) DATA AND INFORMATION REQUIRED FOR ANNUAL EMISSION REPORTS WILL STILL BE REQUIRED TO BE SUBMITTED FOR THE PORTION OF THE YEAR THAT THE SOURCE HELD A VALID PERMIT.

SECTION THREE — PERMIT(S) TO WITHDRAW

1) DO YOU REQUEST TO WITHDRAW THE ENTIRE SOURCE AND ALL ASSOCIATED PERMITS?
WITHDRAW THE **ENTIRE** SOURCE: [x] YES [ ] NO, IF "NO" COMPLETE THE FOLLOWING TABLE.
Withdrawal Requested as of January 1, 2023

2) APPLICATION NO.:	5) APPLICATION NO.:
3) APPLICATION NO.:	6) APPLICATION NO.:
4) APPLICATION NO.:	7) APPLICATION NO.:

SECTION FOUR — SIGNATURE BLOCK

AS AUTHORIZED BY THE BELOW SIGNATORY, THE ABOVE LISTED SOURCE REQUESTS THE WITHDRAWAL OF THE ABOVE LISTED PERMITS AND THEIR ASSOSCIATED APPLICATIONS OR ANY PENDING PERMIT APPLICATIONS.

THE SIGNATORY RECOGNIZES A WITHDRAWAL FROM THE SYSTEM IS PERMANENT.

AUTHORIZED SIGNATURE:

BY: _____
AUTHORIZED SIGNATURE

Plant Manager, Electric Energy, Inc. - Joppa Power Plant
TITLE OF SIGNATORY

Byron Veech
TYPED OR PRINTED NAME OF SIGNATORY

01 / 01 / 2022
DATE

THIS AGENCY IS AUTHORIZED TO REQUIRE THIS INFORMATION UNDER 39.5 OF THE ILLINOIS ENVIRONMENTAL PROTECTION ACT, 415 ILCS 5/39.5. FURTHER DISCLOSURE OF THIS INFORMATION IS REQUIRED UNDER THAT SECTION, MOREOVER AS ALSO PROVIDED IN THAT SECTION, FAILURE TO PROVIDE THIS INFORMATION MAY PREVENT THIS APPLICATION FROM BEING PROCESSED AND COULD RESULT IN THE APPLICATION BEING DENIED.

FOR APPLICANT'S USE

APPLICATION PAGE

ELECTRIC ENERGY, INC.

1500 Eastport Plaza Drive
Collinsville, IL 62234

May 24, 2022

RECEIVED
STATE OF ILLINOIS
JUN 01 2022
Environmental Protection Agency
BUREAU OF AIR

Illinois Environmental Protection Agency
Bureau of Air
Manager, Permits Section
1021 North Grand Avenue East
PO Box 19276
Springfield, IL 62702

Re: Electric Energy, Inc;
Joppa Power Station I.D. No. 127855AAC

To Whom it May Concern:

This letter requests withdraw of all air permits for Electric Energy, Inc., Joppa Power Station effective January 1, 2023. Accordingly, please find enclosed 285-CAAPP, WITHDRAWL of PERMIT or PERMIT APPLICATION.

Please contact Jim Ross at 217-585-0925 or jim.ross@vistracorp.com with any questions regarding this submittal.

Sincerely,

Byron Veech
Plant Manager, Joppa Power Station

RECEIVED
STATE OF ILLINOIS
JUN 1 2022
Environmental Protection Agency
BUREAU OF AIR

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
DIVISION OF AIR POLLUTION CONTROL – PERMIT SECTION
P.O. BOX 19506
SPRINGFIELD, ILLINOIS 62794-9506

FOR APPLICANT'S USE
Revision #: 0
Effective Date: 01 / 01 / 2023
Page _____ of _____
Source Designation: _____

WITHDRAWAL OF PERMIT OR PERMIT APPLICATION

FOR AGENCY USE ONLY
ID NO.: 127 855 AAC
PERMIT NO.: Entire Source
DATE: 6-1-2022

SECTION ONE — SOURCE INFORMATION

1) SOURCE NAME: Electric Energy, Inc. - Joppa Power Station	2) SOURCE ID NO.: 127855AAC
3) SOURCE ADDRESS: 2100 Portland Rd Joppa, Illinois 62593	
4) CONTACT NAME: Bruce Parker	5) CONTACT PHONE NO.: 331-264-1980

SECTION TWO — INSTRUCTIONS IN BRIEF

1) COMPLETE THIS FORM IF THE APPLICANT REQUESTS TO WITHDRAW ISSUED PERMITS AND THEIR ASSOCIATED APPLICATIONS OR PENDING PERMIT APPLICATIONS.
2) SECTION THREE, NO. 1 IS USED TO WITHDRAW THE ENTIRE SOURCE, NO. 2 -7 ARE FOR SPECIFIC PERMITS.
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4) A SHUTDOWN OR TERMINATION OF THE OPERATION IS NOT SUFFICIENT TO WITHDRAW A PERMIT. THE PERMITTEE MUST SPECIFICALLY INSTRUCT THE ILLINOIS EPA, IN WRITING, TO WITHDRAW THE UNDERLYING AUTHORIZING PERMIT(S). SUBMISSION OF THIS FORM CONSTITUTES THAT WRITTEN INSTRUCTION.
5) THE ILLINOIS EPA BILLS ANNUALLY FOR HOLDING AN PERMIT WHETHER OR NOT THE SOURCE IS IN OPERATION. TO STOP BILLING, A PERMIT MUST BE WITHDRAWN BEFORE THE FEE DUE DATE.
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SECTION THREE — PERMIT(S) TO WITHDRAW

1) DO YOU REQUEST TO WITHDRAW THE ENTIRE SOURCE AND ALL ASSOCIATED PERMITS?
WITHDRAW THE **ENTIRE** SOURCE: [x] YES [ ] NO, IF "NO" COMPLETE THE FOLLOWING TABLE.

2) APPLICATION NO.:	5) APPLICATION NO.:
3) APPLICATION NO.:	6) APPLICATION NO.:
4) APPLICATION NO.:	7) APPLICATION NO.:

SECTION FOUR — SIGNATURE BLOCK

AS AUTHORIZED BY THE BELOW SIGNATORY, THE ABOVE LISTED SOURCE REQUESTS THE WITHDRAWAL OF THE ABOVE LISTED PERMITS AND THEIR ASSOSCIATED APPLICATIONS OR ANY PENDING PERMIT APPLICATIONS.

THE SIGNATORY RECOGNIZES A WITHDRAWAL FROM THE SYSTEM IS PERMANENT.

AUTHORIZED SIGNATURE:

BY: _____
AUTHORIZED SIGNATURE

Plant Manager, Electric Energy, Inc. - Joppa Power Plant
TITLE OF SIGNATORY

Byron Veech
TYPED OR PRINTED NAME OF SIGNATORY

05 / 24 / 2022
DATE

THIS AGENCY IS AUTHORIZED TO REQUIRE THIS INFORMATION UNDER 39.5 OF THE ILLINOIS ENVIRONMENTAL PROTECTION ACT, 415 ILCS 5/39.5. FURTHER DISCLOSURE OF THIS INFORMATION IS REQUIRED UNDER THAT SECTION, MOREOVER AS ALSO PROVIDED IN THAT SECTION, FAILURE TO PROVIDE THIS INFORMATION MAY PREVENT THIS APPLICATION FROM BEING PROCESSED AND COULD RESULT IN THE APPLICATION BEING DENIED.

FOR APPLICANT'S USE

APPLICATION PAGE _____

127855AAC
9509 0130

ELECTRIC ENERGY, INC

Joppa Power Station
2100 Portland Road
Joppa, IL 62953

RECEIVED
STATE OF ILLINOIS
SEP 19 2022
Environmental Protection Agency
BUREAU OF AIR

September 16, 2022

Illinois Environmental Protection Agency
Bureau of Air, Compliance Section #40
1021 North Grand Avenue East
Springfield, Illinois 62794-9276

Re: Change in Responsible Official
Joppa Power Station, I.D.: 127855AAC

This letter provides notification of a change in responsible official for Electric Energy, Inc. - Joppa Power Plant (Joppa Power Plant) to Dianna Tickner, Director of Decommissioning and Demolition and Charles Koudelka, Vice President, Plant Closure. Attached is 273-CAAPP Administrative Amendment Form and 500-CAAPP Delegation of Authority for Responsible Official

If you have questions regarding this submission, please contact Jennifer Marshall at 618.343.7884 (jennifer.marshall@vistracorp.com).

Sincerely,

Byron Veech
Plant Manager
Electric Energy, Inc.

Attachments

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
DIVISION OF AIR POLLUTION CONTROL -- PERMIT SECTION
P.O. BOX 19506
SPRINGFIELD, ILLINOIS 62794-9506

FOR APPLICANT'S USE
Revision #: _____
Date: ____ / ____ / ____
Page _____ of _____
Source Designation:
_____

DELEGATION OF AUTHORITY FOR RESPONSIBLE OFFICIAL TO A REPRESENTATIVE

FOR AGENCY USE ONLY
ID NUMBER:
PERMIT #:
DATE:

THIS FORM SHALL BE USED BY A RESPONSIBLE OFFICIAL TO DELEGATE AUTHORITY TO A REPRESENTATIVE OF SUCH PERSON FOR SIGNATURE ON APPLICATIONS OR CERTIFICATION OF REPORTS TO BE SUBMITTED PURSUANT TO THE CLEAN AIR ACT.

THIS FORM SHALL ONLY BE USED FOR A CORPORATION AT WHICH A PRESIDENT, SECRETARY, TREASURER, OR VICE-PRESIDENT OF THE CORPORATION IN CHARGE OF BUSINESS FUNCTION, OR ANY OTHER PERSON WHO PERFORMS SIMILAR POLICY OR DECISION MAKING FUNCTIONS FOR THE CORPORATION TO TRANSFER THE AUTHORITY AS A RESPONSIBLE OFFICIAL TO A REPRESENTATIVE OF SUCH PERSON. THE REPRESENTATIVE OF SUCH PERSON MUST BE RESPONSIBLE FOR THE OVERALL OPERATION OF ONE OR MORE MANUFACTURING, PRODUCTION, OR OPERATING FACILITIES APPLYING FOR OR SUBJECT TO A PERMIT.

NOTE: THIS TRANSFER OF DELEGATION OF AUTHORITY IS APPLICABLE ONLY IF THE FACILITY EMPLOYS MORE THAN 250 PERSONS OR HAS A GROSS ANNUAL SALES OR EXPENDITURES EXCEEDING $25 MILLION (IN SECOND QUARTER 1980 DOLLARS).

SOURCE INFORMATION

1) SOURCE NAME: Electric Energy, Inc.

2) DATE FORM PREPARED: September 16, 2022

3) SOURCE ID NO. (IF KNOWN): 127855AAC

TRANSFER OF AUTHORITY

4) I, THE UNDERSIGNED, BEING A PRESIDENT, SECRETARY, TREASURER, OR VICE-PRESIDENT OF THE CORPORATION IN CHARGE OF BUSINESS FUNCTION, OR OTHER PERSON WHO PERFORMS SIMILAR POLICY OR DECISION MAKING FUNCTIONS FOR THE CORPORATION, HEREBY TRANSFER THE AUTHORITY AS A RESPONSIBLE OFFICIAL TO Dianna Tickner &Charles Koudelka, THEY BEING A REPRESENTATIVE AND RESPONSIBLE FOR THE OVERALL OPERATION OF ONE OR MORE MANUFACTURING, PRODUCTION, OR OPERATING FACILITIES APPLYING FOR OR SUBJECT TO A PERMIT.

AUTHORIZED SIGNATURE

Plant Manager, Electric Energy, Inc.
TITLE OF SIGNATORY

Byron Veech
TYPED OR PRINTED NAME OF SIGNATORY

9 / 16 / 2022
DATE

Byron Veech
DELEGATED REPRESENTATIVE

Plant Manager, Electric Energy, Inc.
TITLE OF DESIGNATED REPRESENTATIVE

THIS AGENCY IS AUTHORIZED TO REQUIRE THIS INFORMATION UNDER ILLINOIS REVISED STATUTES, 1991, AS AMENDED 1992, CHAPTER 111 1/2, PAR. 1039.5. DISCLOSURE OF THIS INFORMATION IS REQUIRED UNDER THAT SECTION. FAILURE TO DO SO MAY PREVENT THIS FORM FROM BEING PROCESSED AND COULD RESULT IN THE APPLICATION BEING DENIED. THIS FORM HAS BEEN APPROVED BY THE FORMS MANAGEMENT CENTER.

FOR APPLICANT'S USE
_____

APPLICATION PAGE _____

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
DIVISION OF AIR POLLUTION CONTROL -- PERMIT SECTION
P.O. BOX 19506
SPRINGFIELD, ILLINOIS 62794-9506

FOR APPLICANT'S USE
Revision #: _____
Date: ____ / ____ / ____
Page _____ of _____
Source Designation:
_____

REQUEST FOR ADMINISTRATIVE PERMIT AMENDMENT FOR CAAPP PERMIT

FOR AGENCY USE ONLY
ID NUMBER:
PERMIT #:
DATE:

GENERAL INFORMATION

1) SOURCE NAME:
Electric Energy, Inc.

2a) ID NUMBER (IF KNOWN):	b) CAAPP PERMIT NUMBER:
127855AAC	95090120
3) ENVIRONMENTAL CONTACT PERSON:	4) CONTACT PERSON'S TELEPHONE NUMBER:
Jennifer Marshall	618-343-7884

AMENDMENT DATA

5) AN ADMINISTRATIVE PERMIT AMENDMENT SHALL ONLY BE USED FOR ONE OR MORE OF THE FOLLOWING REVISIONS TO A CAAPP PERMIT (PLEASE INDICATE THE TYPE OF AMENDMENT(S)):

☐ A) CORRECTS TYPOGRAPHICAL ERRORS;

☒ B) IDENTIFIES A CHANGE IN THE NAME, ADDRESS, OR PHONE NUMBER OF ANY PERSON IDENTIFIED IN THE PERMIT, OR PROVIDES A SIMILAR MINOR ADMINISTRATIVE CHANGE AT THE SOURCE;

☐ C) REQUIRES MORE FREQUENT MONITORING OR REPORTING BY THE PERMITTEE; OR

☐ D) ALLOWS FOR A CHANGE IN OWNERSHIP OR OPERATIONAL CONTROL OF THE SOURCE WHERE NO OTHER CHANGE IN THE PERMIT IS NECESSARY, PROVIDED THAT A WRITTEN AGREEMENT CONTAINING A SPECIFIC DATE FOR TRANSFER OF PERMIT RESPONSIBILITY, COVERAGE, AND LIABILITY BETWEEN THE CURRENT AND NEW PERMITTEES HAS BEEN SUBMITTED TO THE ILLINOIS EPA.

THIS AGENCY IS AUTHORIZED TO REQUIRE THIS INFORMATION UNDER ILLINOIS REVISED STATUTES, 1991, AS AMENDED 1992, CHAPTER 111 1/2, PAR. 1039.5. DISCLOSURE OF THIS INFORMATION IS REQUIRED UNDER THAT SECTION. FAILURE TO DO SO MAY PREVENT THIS FORM FROM BEING PROCESSED AND COULD RESULT IN THE APPLICATION BEING DENIED. THIS FORM HAS BEEN APPROVED BY THE FORMS MANAGEMENT CENTER.

FOR APPLICANT'S USE
_____

APPLICATION PAGE _____

AMENDMENT DATA (CON'T)

6) DESCRIPTION OF REQUESTED ADMINISTRATIVE PERMIT AMENDMENT:

	CURRENT PERMIT INFORMATION	AMENDED PERMIT INFORMATION
1)	Responsible Official - Byron Veech	Responsible Official Dianna Ticker-Dir. Decommissioning & Demolition
2)		Charles Koudelka - VP, Plant Closure
3)		
4)		
5)		
6)		
7)		
8)		

7) DOES THE APPLICATION INCLUDE A COPY OF THOSE PARTICULAR PAGES OF THE CAAPP PERMIT WHICH ARE CLEARLY MARKED TO SHOW THE REQUESTED AMENDMENT? ☐ YES ☐ NO

SIGNATURE BLOCK

NOTE: THIS CERTIFICATION MUST BE SIGNED BY A RESPONSIBLE OFFICIAL. APPLICATIONS WITHOUT A SIGNED CERTIFICATION WILL BE RETURNED AS INCOMPLETE.

8) I CERTIFY UNDER PENALTY OF LAW THAT, BASED ON INFORMATION AND BELIEF FORMED AFTER REASONABLE INQUIRY, THE STATEMENTS AND INFORMATION CONTAINED IN THIS APPLICATION ARE TRUE, ACCURATE AND COMPLETE.

AUTHORIZED SIGNATURE:

BY: _____
AUTHORIZED SIGNATURE

Plant Manager, Electric Energy, Inc.
TITLE OF SIGNATORY

Byron Veech
TYPED OR PRINTED NAME OF SIGNATORY

9 / 16 / 2022
DATE

APPLICATION PAGE _____

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 N TH GRAND AVENUE EAST, P.O. BOX 19276, SPRINGFIELD, ILLINOIS 62794-9276 • (217) 782-3397
BRUCE RAUNER, GOVERNOR ALEC MESSINA, DIRECTOR

05

"REVISED"
CLEAN AIR ACT PERMIT PROGRAM (CAAPP) PERMIT

PERMITTEE

Electric Energy, Inc.
Attn: Rick Diericx
1500 Eastport Plaza Drive
Collinsville, Illinois 62234

Application No.: 95090120 I.D. N .: 127855AAC
Operation of: Electric Power Plant
Original Date Received: September 8, 1995
Original Date Issued: September 29, 2005
Initial Effective Date: June 8, 2017 Ex irati Date : June 8, 2022
Source Location: 2100 Portland Road, Joppa, Massa ounty
Responsible Official: ~~Gregory T. Russell, Managin Director, Plant Operations~~ Dianna Tickner, Director of Decommissioning and Demolition & Charles Koudelka, VP Plant Closure

The above-referenced permit was originally issued to the Permittee to OPERATE an electrical power generation station, pursuant to the corresponding permit application, on September 29, 2005. As a result of an automatic stay of the permit during the pendency of an administrative permit appeal, the CAAPP permit became effective on the date shown above.

T e of Permit Action: Significant Modification
Date Received: November 21, 2016
Date Issued: June 8, 2017

Permit Authorization:
This permit is hereby granted to Electric Energy, Inc., for operation of the above referenced source. This permit is subject to the terms and conditions contained herein.

In accordance with Section 39.5(14)(c) of the Illinois Environmental Protection Act, this permit action addresses certain changes to Permit Conditions, as discussed in the accompanying Statement of Basis, resulting from the settlement resolution of an administrative permit appeal filed in 2005 before the Pollution Control Board.[2] These revisions involve negotiated changes to the issued CAAPP permit that were significant in nature and could not be appropriately addressed as part of the permit reopening, a minor modification or an administrative amendment. The procedures for issuance of this permit action are the same as were applicable for initial permit issuance. 415 ILCS 5/39.5(14)(c)(iii).

Bureau of Air Permit Section

File Organization Cover Sheet

Source Name:	Waukegan Generating Station	
ID No.:	097190AAC	
Application No.:	95090047	
Category:	03N Air Permit - Correspondence	
Item Date:	11/30/2022	
Keyword:	Choose an item.	*
Comment:	Retired Unit Exemption	*
Part:	Choose an item. of Choose an item.	*

* If applicable

IEPA - DIVISION OF RECORDS MANAGEMENT
RELEASABLE

JAN 18 2023

REVIEWER: MED

RECEIVED
STATE OF ILLINOIS
NOV 30 2022
Environmental Protection Agency
BUREAU OF AIR

MWG
Midwest Generation, LLC
Will County Generating Station
529 E. 135th Street
Romeoville, Illinois 60446

November 28, 2022

Via overnight mail:
Illinois Environmental Protection Agency
Bureau of Air - Compliance & Enforcement Section (MC 11)
1021 North Grand Avenue East
Springfield, IL 62702

Copy via overnight mail to:
U.S. EPA
CAMD – Market Operations Branch
Attn: Exemptions
1200 Pennsylvania Avenue, NW
WJC South, 4th Floor, Room # 4153C
Washington, DC 20004

Subject: Midwest Generation, LLC - Waukegan Generating Station
Retired Unit Exemption Forms
Illinois EPA Station ID No. 097190AAC
Plant Code 883
Lake County, Illinois

To whom it may concern:

Midwest Generation, LLC hereby submits the enclosed Retired Unit Exemption forms for Waukegan Generating Station Units 7 and 8. Both units were officially retired on June 1, 2022. The forms give the specific date of last operation for each unit.

If you have any questions, please contact me at (724) 255-3220 or Marsha Layman at (815) 641-0797.

Sincerely,

Sharene Shealey
Director, Environmental

Enclosures

IEPA - DIVISION OF RECORDS MANAGEMENT
RELEASABLE

JAN 18 2023

REVIEWER: MED

United States Environmental Protection Agency
Acid Rain, CSAPR, and Texas SO_2 Programs

OMB Nos. 2060-0258 and 2060-0667
Approval Expires 05/31/2025

Retired Unit Exemption

For more information, see instructions and refer to 40 CFR 72.8, 97.405, 97.505, 97.605, 97.705, 97.805, 97.905, 97.1005 or a comparable state regulation, as applicable.

This submission is: ■ New ☐ Revised

STEP 1
Identify the unit by plant (source) name, State, plant code and unit ID#.

Plant (Source) Name	State	Plant Code	Unit ID#
Waukegan Generating Station	IL	883	7

STEP 2
Indicate the program(s) that the unit is subject to.

- ■ Acid Rain
- ■ CSAPR NO_x Annual
- ☐ CSAPR NO_x Ozone Season Group 1
- ☐ CSAPR NO_x Ozone Season Group 2
- ■ CSAPR NO_x Ozone Season Group 3
- ■ CSAPR SO_2 Group 1
- ☐ CSAPR SO_2 Group 2
- ☐ Texas SO_2

STEP 3
Identify the date on which the unit was (or will be) permanently retired.

May 29, 2022

STEP 4
If the unit is subject to the Acid Rain Program, identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.8(d).

Calendar year starting January 1, 2023

STEP 5 Read the applicable special provisions.

Acid Rain Program Special Provisions

(1) A unit exempt under 40 CFR 72.8 shall not emit any sulfur dioxide and nitrogen oxides starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with 40 CFR part 73 subpart B.

(2) A unit exempt under 40 CFR 72.8 shall not resume operation unless the designated representative of the source that includes the unit submits a complete Acid Rain permit application under 40 CFR 72.31 for the unit not less than 24 months prior to the date on which the unit is first to resume operation.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 72.8 shall comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) For any period for which a unit is exempt under 40 CFR 72.8, the unit is not an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71 and is not eligible to be an opt-in source under 40 CFR part 74. As an unaffected unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR parts 70 and 71.

(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 72.8 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Administrator or the permitting authority. The owners and operators bear the burden of proof that the unit is permanently retired.

(6) On the earlier of the following dates, a unit exempt under 40 CFR 72.8(b) or (c) shall lose its exemption and become an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71: (i) the date on which the designated representative submits an Acid Rain permit application under paragraph (2); or (ii) the date on which the designated representative is required under paragraph (2) to submit an Acid Rain permit application. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under 40 CFR 72.8 shall be treated as a new unit that commenced commercial operation on the first date on which the unit resumes operation.

CSAPR NO_x Annual Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.405 shall not emit any NO_x, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.405 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.405 shall comply with the requirements of the CSAPR NO_x Annual Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.405 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart AAAAA, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_x Ozone Season Group 1 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.505 shall not emit any NO_x, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.505 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.505 shall comply with the requirements of the CSAPR NO_x Ozone Season Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.505 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart BBBBB, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_x Ozone Season Group 2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.805 shall not emit any NO_x, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.805 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.805 shall comply with the requirements of the CSAPR NO_x Ozone Season Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.805 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart EEEEE, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_x Ozone Season Group 3 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.1005 shall not emit any NO_x, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.1005 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.1005 shall comply with the requirements of the CSAPR NO_x Ozone Season Group 3 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.1005 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR SO_2 Group 1 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.605 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.605 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.605 shall comply with the requirements of the CSAPR SO_2 Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.605 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart CCCCC, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR SO_2 Group 2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.705 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.705 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.705 shall comply with the requirements of the CSAPR SO_2 Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.705 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart DDDDD, as a unit that commences commercial operation on the first date on which the unit resumes operation.

Texas SO_2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.905 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.905 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.905 shall comply with the requirements of the Texas SO_2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.905 shall lose its exemption on the first date on which the unit resumes operation. A retired unit that resumes operation will not receive an allowance allocation under 40 CFR 97.911. The unit may receive allowances from the Supplemental Allowance Pool pursuant to 40 CFR 97.912. All other provisions of 40 CFR part 97 subpart FFFFF regarding monitoring, reporting, recordkeeping and compliance will apply on the first date on which the unit resumes operation.

STEP 6 Read the statement of compliance and the applicable certification statements, sign, and date.

Statement of compliance

I certify that the unit identified above at STEP 1 was (or will be) permanently retired on the date identified at STEP 3 and will comply with the applicable Special Provisions listed at STEP 5.

Certification by designated representatives or alternate designated representatives

I am authorized to make this submission on behalf of the owners and operators of the source and unit for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Paulo Rocha	Title Plant Manager
Owner Company Name Midwest Generation, LLC	
Email Paulo.Rocha@nrg.com	Phone (847) 421 7095
Signature [signature]	Date 11/29/2022

Certification by certifying officials of units subject only to the Acid Rain Program for which no designated representative has been authorized

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Title
Owner Company Name	
Email	Phone
Signature	Date

United States Environmental Protection Agency
Acid Rain, CSAPR, and Texas SO_2 Programs

OMB Nos. 2060-0258 and 2060-0667
Approval Expires 05/31/2025

Retired Unit Exemption

For more information, see instructions and refer to 40 CFR 72.8, 97.405, 97.505, 97.605, 97.705, 97.805, 97.905, 97.1005 or a comparable state regulation, as applicable.

This submission is: ■ New ☐ Revised

STEP 1
Identify the unit by plant (source) name, State, plant code and unit ID#.

Plant (Source) Name	State	Plant Code	Unit ID#
Waukegan Generating Station	IL	883	8

STEP 2
Indicate the program(s) that the unit is subject to.

- ■ Acid Rain
- ■ CSAPR NO_x Annual
- ☐ CSAPR NO_x Ozone Season Group 1
- ☐ CSAPR NO_x Ozone Season Group 2
- ■ CSAPR NO_x Ozone Season Group 3
- ■ CSAPR SO_2 Group 1
- ☐ CSAPR SO_2 Group 2
- ☐ Texas SO_2

STEP 3
Identify the date on which the unit was (or will be) permanently retired.

May 6, 2022

STEP 4
If the unit is subject to the Acid Rain Program, identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.8(d).

Calendar year starting January 1, 2023

STEP 5 Read the applicable special provisions.

Acid Rain Program Special Provisions

(1) A unit exempt under 40 CFR 72.8 shall not emit any sulfur dioxide and nitrogen oxides starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with 40 CFR part 73 subpart B.

(2) A unit exempt under 40 CFR 72.8 shall not resume operation unless the designated representative of the source that includes the unit submits a complete Acid Rain permit application under 40 CFR 72.31 for the unit not less than 24 months prior to the date on which the unit is first to resume operation.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 72.8 shall comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) For any period for which a unit is exempt under 40 CFR 72.8, the unit is not an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71 and is not eligible to be an opt-in source under 40 CFR part 74. As an unaffected unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR parts 70 and 71.

(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 72.8 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Administrator or the permitting authority. The owners and operators bear the burden of proof that the unit is permanently retired.

(6) On the earlier of the following dates, a unit exempt under 40 CFR 72.8(b) or (c) shall lose its exemption and become an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71: (i) the date on which the designated representative submits an Acid Rain permit application under paragraph (2); or (ii) the date on which the designated representative is required under paragraph (2) to submit an Acid Rain permit application. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under 40 CFR 72.8 shall be treated as a new unit that commenced commercial operation on the first date on which the unit resumes operation.

CSAPR NO_x Annual Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.405 shall not emit any NO_x, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.405 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.405 shall comply with the requirements of the CSAPR NO_x Annual Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.405 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart AAAAA, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_x Ozone Season Group 1 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.505 shall not emit any NO_x, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.505 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.505 shall comply with the requirements of the CSAPR NO_x Ozone Season Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.505 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart BBBBB, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_x Ozone Season Group 2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.805 shall not emit any NO_x, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.805 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.805 shall comply with the requirements of the CSAPR NO_x Ozone Season Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.805 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart EEEEE, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_x Ozone Season Group 3 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.1005 shall not emit any NO_x, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.1005 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.1005 shall comply with the requirements of the CSAPR NO_x Ozone Season Group 3 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.1005 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR SO_2 Group 1 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.605 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.605 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.605 shall comply with the requirements of the CSAPR SO_2 Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.605 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart CCCCC, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR SO_2 Group 2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.705 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.705 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.705 shall comply with the requirements of the CSAPR SO_2 Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.705 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart DDDDD, as a unit that commences commercial operation on the first date on which the unit resumes operation.

Plant Code 883; Unit 8

Texas SO_2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.905 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.905 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.905 shall comply with the requirements of the Texas SO_2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.905 shall lose its exemption on the first date on which the unit resumes operation. A retired unit that resumes operation will not receive an allowance allocation under 40 CFR 97.911. The unit may receive allowances from the Supplemental Allowance Pool pursuant to 40 CFR 97.912. All other provisions of 40 CFR part 97 subpart FFFFF regarding monitoring, reporting, recordkeeping and compliance will apply on the first date on which the unit resumes operation.

STEP 6 Read the statement of compliance and the applicable certification statements, sign, and date.

Statement of compliance

I certify that the unit identified above at STEP 1 was (or will be) permanently retired on the date identified at STEP 3 and will comply with the applicable Special Provisions listed at STEP 5.

Certification by designated representatives or alternate designated representatives

I am authorized to make this submission on behalf of the owners and operators of the source and unit for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Paulo Rocha	Title Plant Manager
Owner Company Name Midwest Generation, LLC	
Email Paulo.Rocha@nrg.com	Phone 847-421-7095
Signature 	Date 11/29/2022

Certification by certifying officials of units subject only to the Acid Rain Program for which no designated representative has been authorized

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Title
Owner Company Name	
Email	Phone
Signature	Date

Bureau of Air Permit Section

File Organization Cover Sheet

Source Name:	Will County Generating Station	
ID No.:	197810AAK	
Application No.:	95090080	
Category:	03N Air Permit - Correspondence	
Item Date:	12/2/2022	
Keyword:	Choose an item.	*
Comment:	Retired Unit Exemption Forms	*
Part:	Choose an item. of Choose an item.	*

* If applicable

IEPA - DIVISION OF RECORDS MANAGEMENT
RELEASABLE

FEB 05 2023

REVIEWER: RDH

MWG
Midwest Generation, LLC
Will County Generating Station
529 E. 135th Street
Romeoville, Illinois 60446

November 30, 2022

Via overnight mail:
Illinois Environmental Protection Agency
Bureau of Air - Permit Section (MC 11)
1021 North Grand Avenue East
Springfield, IL 62702

RECEIVED
STATE OF ILLINOIS
DEC 02 2022
Environmental Protection Agency
BUREAU OF AIR

Copy via overnight mail to:
U.S. EPA
CAMD – Market Operations Branch
Attn: Exemptions
1200 Pennsylvania Avenue, NW
WJC South, 4th Floor, Room # 4153C
Washington, DC 20004

Subject: Midwest Generation, LLC - Will County Generating Station
Retired Unit Exemption Forms
Illinois EPA Station ID No. 197810AAK
Plant Code 884
Will County, Illinois

To whom it may concern:

Midwest Generation, LLC hereby submits the enclosed Retired Unit Exemption forms for Will County Generating Station Units 3 and 4. Both units were officially retired on July 1, 2022. The forms give the specific last date of operation for each unit.

If you have any questions, please contact me at (724) 255-3220 or Marsha Layman at (815) 641-0797.

Sincerely,

Sharene Shealey
Director, Environmental

Enclosures

United States Environmental Protection Agency
Acid Rain, CSAPR, and Texas SO_2 Programs

OMB Nos. 2060-0258 and 2060-0667
Approval Expires 05/31/2025

Retired Unit Exemption

For more information, see instructions and refer to 40 CFR 72.8, 97.405, 97.505, 97.605, 97.705, 97.805, 97.905, 97.1005 or a comparable state regulation, as applicable.

This submission is: ■ **New** ☐ **Revised**

STEP 1
Identify the unit by plant (source) name, State, plant code and unit ID#.

Plant (Source) Name	State	Plant Code	Unit ID#
Will County Generating Station	IL	884	3

STEP 2
Indicate the program(s) that the unit is subject to.

- ■ Acid Rain
- ■ CSAPR NO_x Annual
- ☐ CSAPR NO_x Ozone Season Group 1
- ☐ CSAPR NO_x Ozone Season Group 2
- ■ CSAPR NO_x Ozone Season Group 3
- ■ CSAPR SO_2 Group 1
- ☐ CSAPR SO_2 Group 2
- ☐ Texas SO_2

STEP 3
Identify the date on which the unit was (or will be) permanently retired.

April 8, 2015

STEP 4
If the unit is subject to the Acid Rain Program, identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.8(d).

Calendar year starting January 1, 2023

STEP 5 Read the applicable special provisions.

Acid Rain Program Special Provisions

(1) A unit exempt under 40 CFR 72.8 shall not emit any sulfur dioxide and nitrogen oxides starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with 40 CFR part 73 subpart B.

(2) A unit exempt under 40 CFR 72.8 shall not resume operation unless the designated representative of the source that includes the unit submits a complete Acid Rain permit application under 40 CFR 72.31 for the unit not less than 24 months prior to the date on which the unit is first to resume operation.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 72.8 shall comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) For any period for which a unit is exempt under 40 CFR 72.8, the unit is not an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71 and is not eligible to be an opt-in source under 40 CFR part 74. As an unaffected unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR parts 70 and 71.

(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 72.8 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Administrator or the permitting authority. The owners and operators bear the burden of proof that the unit is permanently retired.

(6) On the earlier of the following dates, a unit exempt under 40 CFR 72.8(b) or (c) shall lose its exemption and become an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71: (i) the date on which the designated representative submits an Acid Rain permit application under paragraph (2); or (ii) the date on which the designated representative is required under paragraph (2) to submit an Acid Rain permit application. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under 40 CFR 72.8 shall be treated as a new unit that commenced commercial operation on the first date on which the unit resumes operation.

CSAPR NO_x Annual Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.405 shall not emit any NO_x, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.405 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.405 shall comply with the requirements of the CSAPR NO_x Annual Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.405 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart AAAAA, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_x Ozone Season Group 1 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.505 shall not emit any NO_x, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.505 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.505 shall comply with the requirements of the CSAPR NO_x Ozone Season Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.505 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart BBBBB, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_x Ozone Season Group 2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.805 shall not emit any NO_x, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.805 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.805 shall comply with the requirements of the CSAPR NO_x Ozone Season Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.805 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart EEEEE, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_x Ozone Season Group 3 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.1005 shall not emit any NO_x, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.1005 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.1005 shall comply with the requirements of the CSAPR NO_x Ozone Season Group 3 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.1005 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR SO_2 Group 1 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.605 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.605 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.605 shall comply with the requirements of the CSAPR SO_2 Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.605 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart CCCCC, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR SO_2 Group 2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.705 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.705 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.705 shall comply with the requirements of the CSAPR SO_2 Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.705 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart DDDDD, as a unit that commences commercial operation on the first date on which the unit resumes operation.

Texas SO_2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.905 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.905 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.905 shall comply with the requirements of the Texas SO_2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.905 shall lose its exemption on the first date on which the unit resumes operation. A retired unit that resumes operation will not receive an allowance allocation under 40 CFR 97.911. The unit may receive allowances from the Supplemental Allowance Pool pursuant to 40 CFR 97.912. All other provisions of 40 CFR part 97 subpart FFFFF regarding monitoring, reporting, recordkeeping and compliance will apply on the first date on which the unit resumes operation.

STEP 6 Read the statement of compliance and the applicable certification statements, sign, and date.

Statement of compliance

I certify that the unit identified above at STEP 1 was (or will be) permanently retired on the date identified at STEP 3 and will comply with the applicable Special Provisions listed at STEP 5.

Certification by designated representatives or alternate designated representatives

I am authorized to make this submission on behalf of the owners and operators of the source and unit for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Phillip Raush	Title Plant Manager
Owner Company Name Midwest Generation, LLC	
Email Phillip.Raush@nrg.com	Phone 815-207-5412
Signature	Date 11/30/22

Certification by certifying officials of units subject only to the Acid Rain Program for which no designated representative has been authorized

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Title
Owner Company Name	
Email	Phone
Signature	Date

United States Environmental Protection Agency
Acid Rain, CSAPR, and Texas SO_2 Programs

OMB Nos. 2060-0258 and 2060-0667
Approval Expires 05/31/2025

Retired Unit Exemption

For more information, see instructions and refer to 40 CFR 72.8, 97.405, 97.505, 97.605, 97.705, 97.805, 97.905, 97.1005 or a comparable state regulation, as applicable.

This submission is: ■ **New** ☐ **Revised**

STEP 1
Identify the unit by plant (source) name, State, plant code and unit ID#.

Plant (Source) Name	State	Plant Code	Unit ID#
Will County Generating Station	IL	884	4

STEP 2
Indicate the program(s) that the unit is subject to.

- ■ Acid Rain
- ■ CSAPR NO_x Annual
- ☐ CSAPR NO_x Ozone Season Group 1
- ☐ CSAPR NO_x Ozone Season Group 2
- ■ CSAPR NO_x Ozone Season Group 3
- ■ CSAPR SO_2 Group 1
- ☐ CSAPR SO_2 Group 2
- ☐ Texas SO_2

STEP 3
Identify the date on which the unit was (or will be) permanently retired.

June 14, 2022

STEP 4
If the unit is subject to the Acid Rain Program, identify the first full calendar year in which the unit meets (or will meet) the requirements of 40 CFR 72.8(d).

Calendar year starting January 1, 2023

STEP 5 Read the applicable special provisions.

Acid Rain Program Special Provisions

(1) A unit exempt under 40 CFR 72.8 shall not emit any sulfur dioxide and nitrogen oxides starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with 40 CFR part 73 subpart B.

(2) A unit exempt under 40 CFR 72.8 shall not resume operation unless the designated representative of the source that includes the unit submits a complete Acid Rain permit application under 40 CFR 72.31 for the unit not less than 24 months prior to the date on which the unit is first to resume operation.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 72.8 shall comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) For any period for which a unit is exempt under 40 CFR 72.8, the unit is not an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71 and is not eligible to be an opt-in source under 40 CFR part 74. As an unaffected unit, the unit shall continue to be subject to any other applicable requirements under 40 CFR parts 70 and 71.

(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 72.8 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Administrator or the permitting authority. The owners and operators bear the burden of proof that the unit is permanently retired.

(6) On the earlier of the following dates, a unit exempt under 40 CFR 72.8(b) or (c) shall lose its exemption and become an affected unit under the Acid Rain Program and 40 CFR parts 70 and 71: (i) the date on which the designated representative submits an Acid Rain permit application under paragraph (2); or (ii) the date on which the designated representative is required under paragraph (2) to submit an Acid Rain permit application. For the purpose of applying monitoring requirements under 40 CFR part 75, a unit that loses its exemption under 40 CFR 72.8 shall be treated as a new unit that commenced commercial operation on the first date on which the unit resumes operation.

CSAPR NO_x Annual Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.405 shall not emit any NO_x, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.405 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.405 shall comply with the requirements of the CSAPR NO_x Annual Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.405 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart AAAAA, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_x Ozone Season Group 1 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.505 shall not emit any NO_x, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.505 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.505 shall comply with the requirements of the CSAPR NO_x Ozone Season Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.505 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart BBBBB, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_x Ozone Season Group 2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.805 shall not emit any NO_x, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.805 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.805 shall comply with the requirements of the CSAPR NO_x Ozone Season Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.805 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart EEEEE, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR NO_x Ozone Season Group 3 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.1005 shall not emit any NO_x, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.1005 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.1005 shall comply with the requirements of the CSAPR NO_x Ozone Season Group 3 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.1005 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR SO_2 Group 1 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.605 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.605 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.605 shall comply with the requirements of the CSAPR SO_2 Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.605 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart CCCCC, as a unit that commences commercial operation on the first date on which the unit resumes operation.

CSAPR SO_2 Group 2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.705 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.705 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.705 shall comply with the requirements of the CSAPR SO_2 Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.705 shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under 40 CFR part 97 subpart DDDDD, as a unit that commences commercial operation on the first date on which the unit resumes operation.

Texas SO_2 Trading Program Special Provisions

(1) A unit exempt under 40 CFR 97.905 shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under 40 CFR 97.905 shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under 40 CFR 97.905 shall comply with the requirements of the Texas SO_2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under 40 CFR 97.905 shall lose its exemption on the first date on which the unit resumes operation. A retired unit that resumes operation will not receive an allowance allocation under 40 CFR 97.911. The unit may receive allowances from the Supplemental Allowance Pool pursuant to 40 CFR 97.912. All other provisions of 40 CFR part 97 subpart FFFFF regarding monitoring, reporting, recordkeeping and compliance will apply on the first date on which the unit resumes operation.

STEP 6 Read the statement of compliance and the applicable certification statements, sign, and date.

Statement of compliance

I certify that the unit identified above at STEP 1 was (or will be) permanently retired on the date identified at STEP 3 and will comply with the applicable Special Provisions listed at STEP 5.

Certification by designated representatives or alternate designated representatives

I am authorized to make this submission on behalf of the owners and operators of the source and unit for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Phillip Raush	Title Plant Manager
Owner Company Name Midwest Generation, LLC	
Email Phillip.Raush@nrg.com	Phone 815-207-5412
Signature P.J. Raush	Date 11/30/22

Certification by certifying officials of units subject only to the Acid Rain Program for which no designated representative has been authorized

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	Title
Owner Company Name	
Email	Phone
Signature	Date

119 020 AAE
Dynegy Midwest Gen.
ALL FILES
CAT: 02

PERMIT
WITHDRAWN

DEC 16 2016

REVIEWER JRM

WITHDRAWAL LETTER RECEIVED: ☑ YES ☐ NO 7-6-16

Permit(s) opened? ☑ NO ☐ YES, DATE CLOSED:

FEES OWED: ☐ YES ☑ NO $ -0-

ERMS SOURCE: ☑ NO ☐ YES/Notified EIS Coordinator:

DELETED FROM ICEMAN ☑ YES ☐ NO/ACES NUMBER: 11-17-16

ACKNOWLEDGEMENT LETTER SENT: ☑ YES ☐ NO 11-17-16

TYPE OF SOURCE: TV/paper plant Permit #: 95090096

NOTES: wld permit per company's request

Initials

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 NORTH GRAND AVENUE EAST, P.O. BOX 19276, SPRINGFIELD, ILLINOIS 62794-9276 • (217) 782-3397

BRUCE RAUNER, GOVERNOR ALEC MESSINA, ACTING DIRECTOR

217/785-1705

November 17, 2016

Dynegy Midwest Generation, LLC
Attn: Larry J. Waite, PE
1500 Eastport Plaza Drive
Collinsville, IL 62234

I.D. No.: 119020AAE
Application No.: 95090096
Operation of: Power Utility Plant in Wood River, Illinois

The Illinois EPA hereby acknowledges the receipt of your above-referenced letter and confirms the withdrawal of your Title V Operating Permit, your pending Title V Operating Permit application and all underlying construction and operating permits in accordance with your request.

If you have any questions concerning this matter, please contact Jim Scott at 217/785-1705.

Raymond E Pilapil/jws

Raymond E. Pilapil
Manager, Permit Section
Division of Air Pollution Control

REP:jws

BOA-Lasalle CPRS/BOA/MANAGEMENT
R.I. JRB
DEC 16 2016
REVIEWER JRM

Dynegy Midwest Generation, LLC
1500 Eastport Plaza Drive
Collinsville, Illinois 62234

JUL 06 2016
Environmental Protection Agency
BUREAU OF AIR

DYNEGY

June 30, 2016

Mr. Raymond E. Pilapil
Acting Manager, Permit Section
Division of Air Pollution Control, Bureau of Air
Illinois Environmental Protection Agency
1021 North Grand Avenue East
Springfield, IL 62794

DEC 16 2016
REVIEWER JRM

Re: Wood River Power Station, Facility ID No. 119020AAE
Notice of Permanent Retirement

Dear Mr. Pilapil:

Dynegy Midwest Generation, LLC (DMG) hereby notifies the Illinois Environmental Protection Agency, Bureau of Air that it has permanently retired Wood River Power Station (Facility ID No. 119020AAE), effective May 31, 2016.

This permanent retirement affects all emission units at the facility, except for the emergency diesel fire pump and its associated diesel storage tank, the gasoline storage tank, and the diesel storage tank serving mobile equipment. These four remaining emission units were determined to be exempt from air permitting requirements, per a Permit Not Required letter issued by Illinois EPA's Bureau of Air on June 16, 2016.

DMG therefore requests withdrawal and termination of all air permits and associated pending applications for Wood River Power Station, including CAAPP permit 95090096 which is currently stayed by order of the Illinois Pollution Control Board. A listing of the permits and pending applications to be withdrawn and terminated is attached. Also attached is a completed form 285-CAAPP.

The facility's air emissions have been near zero since May 31, 2016, when the last generating unit was mothballed. DMG recently submitted payment for the first installment of the Annual Title V Permit Fee that was billed via Illinois EPA invoice dated May 15, 2016. Because air emissions have ceased and air permits are being withdrawn, DMG believes it has no obligation for payment of further permit fees for Wood River.

The Fugitive Dust Control Plan and Operating Program submitted November 20, 2015 is also hereby withdrawn. This operating program was associated with former coal handling and storage operations and associated traffic areas at Wood River. The former coal storage stockpile has been drawn down and currently contains no more than 10,000 tons of material. Deliveries of coal to the facilities have ceased, and coal will no longer be added to or removed from the former stockpile area using coal conveyors or other formerly-utilized stationary coal handling equipment. If the small amount of coal that remains in the former coal storage stockpile area is removed at some time in the future, mobile equipment will be used.

1700-0012-2748
95090096
TV/POWER

The Episode Action Plan for Wood River Power Station, submitted most recently on July 23, 2014 is also hereby withdrawn.

Emissions of nitrogen oxides from sources at Wood River Power Station totaled 2182 tons in CY 2014 and 1558 tons in CY 2015. DMG believes the reduction in nitrogen oxides emissions achieved through permanent retirement of these sources should be eligible for use as emission offset credits. We wish to inform Illinois EPA that DMG will consider making such offset credits available to other entities that need to acquire and use them in the future.

DMG also notifies IEPA that it will not submit periodic reports documenting operations at Wood River Power Station for periods after June 30, 2016.

If you have questions regarding this submittal, please contact Rick Diericx at 618-343-7761.

Sincerely,
Dynegy Midwest Generation, LLC

CJ Saladino
Vice President and General Manager, Plant Operations

Attachments

Attachment

Listing of Air Permits and Associated Pending Applications for Wood River Power Station (Facility ID No. 119020AAE) for Withdrawal and Termination Due To Permanent Facility Retirement

Permits

Permit/Application Number	Permit Type	Subject	Date Issued
95090096	Title V/CAAPP	Power Plant/Electrical Power Generation ***(Note: this permit was stayed by Board Order of the Illinois Pollution Control Board dated February 16, 2006, Case No. PCB 06-74)***	9/29/2005
91060046	Construction	Natural Gas Ignitor/Warm-Up System Units	6/24/1991
93060002	Construction	Fuel Storage Tank	7/7/1993
95080021	Construction	Temporary Auxiliary Oil Fired Boiler	2/29/1996
95080128	Construction	Natural Gas Igniter System	11/21/1995
01060001	Construction	Emission Reduction Project	3/05/2002
01060002	Construction	Unit 5 Electrostatic Precipitator	6/08/2001
08020011	Construction	Sorbent Injection System for Unit 5	6/12/2008
12050055	Construction	Sorbent Injection System for Unit 4 Boiler	8/24/2012
14080028	Construction	Unit 4 Precipitator Efficiency Improvement	9/10/2014
83050010	Operating	Coal Dust Removal Systems	12/02/1992
73020997	Operating	Coal Handling and Storage	3/29/1995
73020943	Operating	Storage Tanks	3/31/1994
73020062	Operating	Wood River Unit #4	7/17/2001
73010719	Operating	Wood River Unit #5	3/10/1997
73010720	Operating	Wood River Units #1, 2, and 3	6/15/1994
98100067	Joint	Dry Fly Ash System	11/13/1998
98040018	Joint	Natural Gas Igniter System	5/04/1998

Pending Applications

Subject	Date Submitted
CAAPP Renewal Application	12/28/2009
CAAPP Amendment Application (owner name change)	8/8/2011
CAAPP Amendment Application (Responsible Official change)	8/9/2011
CAAPP Amendment Application (owner address change)	7/7/2014

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
DIVISION OF AIR POLLUTION CONTROL -- PERMIT SECTION
P.O. BOX 19506
SPRINGFIELD, ILLINOIS 62794-9506

FOR APPLICANT'S USE
Revision #: _____
Date: ____ / ____ / ____
Page _____ of _____
Source Designation:
_____

WITHDRAWAL OF PERMIT OR PERMIT APPLICATION

FOR AGENCY USE ONLY
ID NO.:
PERMIT NO.:
DATE:

SECTION ONE — *SOURCE INFORMATION*

1) SOURCE NAME: Wood River Power Station
2) SOURCE ID NO.: 119020AAE
3) SOURCE ADDRESS: 1 Chessen Lane, Alton, Illinois 62024
4) CONTACT NAME: Rick Diericx
5) CONTACT PHONE NO.: 618-343-7761

SECTION TWO — *INSTRUCTIONS IN BRIEF*

1) COMPLETE THIS FORM IF THE APPLICANT REQUESTS TO WITHDRAW ISSUED PERMITS AND THEIR ASSOCIATED APPLICATIONS OR PENDING PERMIT APPLICATIONS.
2) SECTION THREE, NO. 1 IS USED TO WITHDRAW THE ENTIRE SOURCE, NO. 2 -7 ARE FOR SPECIFIC PERMITS.
3) A WITHDRAWAL AND SUBSEQUENT DELETION FROM THE SYSTEM IS **PERMANENT**.
4) A SHUTDOWN OR TERMINATION OF THE OPERATION IS NOT SUFFICIENT TO WITHDRAW A PERMIT. THE PERMITTEE MUST SPECIFICALLY INSTRUCT THE ILLINOIS EPA, IN WRITING, TO WITHDRAW THE UNDERLYING AUTHORIZING PERMIT(S). SUBMISSION OF THIS FORM CONSTITUTES THAT WRITTEN INSTRUCTION.
5) THE ILLINOIS EPA BILLS ANNUALLY FOR HOLDING AN PERMIT WHETHER OR NOT THE SOURCE IS IN OPERATION. TO STOP BILLING, A PERMIT MUST BE WITHDRAWN BEFORE THE FEE DUE DATE.
6) DATA AND INFORMATION REQUIRED FOR ANNUAL EMISSION REPORTS WILL STILL BE REQUIRED TO BE SUBMITTED FOR THE PORTION OF THE YEAR THAT THE SOURCE HELD A VALID PERMIT.

SECTION THREE — *PERMIT(S) TO WITHDRAW*

1) DO YOU REQUEST TO WITHDRAW THE ENTIRE SOURCE AND ALL ASSOCIATED PERMITS?
WITHDRAW THE **ENTIRE** SOURCE: ☒ YES ☐ NO, IF "NO" COMPLETE THE FOLLOWING TABLE.

2) APPLICATION NO.:	5) APPLICATION NO.:
3) APPLICATION NO.:	6) APPLICATION NO.:
4) APPLICATION NO.:	7) APPLICATION NO.:

SECTION FOUR — *SIGNATURE BLOCK*

AS AUTHORIZED BY THE BELOW SIGNATORY, THE ABOVE LISTED SOURCE REQUESTS THE WITHDRAWAL OF THE ABOVE LISTED PERMITS AND THEIR ASSOSCIATED APPLICATIONS OR ANY PENDING PERMIT APPLICATIONS.

THE SIGNATORY RECOGNIZES A WITHDRAWAL FROM THE SYSTEM IS PERMANENT.

AUTHORIZED SIGNATURE:

BY: CJ Saladino
AUTHORIZED SIGNATURE

Vice President
TITLE OF SIGNATORY

C J Saladino
TYPED OR PRINTED NAME OF SIGNATORY

06 / 29 / 2016
DATE

THIS AGENCY IS AUTHORIZED TO REQUIRE THIS INFORMATION UNDER 39.5 OF THE ILLINOIS ENVIRONMENTAL PROTECTION ACT, 415 ILCS 5/39.5. FURTHER DISCLOSURE OF THIS INFORMATION IS REQUIRED UNDER THAT SECTION, MOREOVER AS ALSO PROVIDED IN THAT SECTION, FAILURE TO PROVIDE THIS INFORMATION MAY PREVENT THIS APPLICATION FROM BEING PROCESSED AND COULD RESULT IN THE APPLICATION BEING DENIED.

FOR APPLICANT'S USE
_____

APPLICATION PAGE _____

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2020 Form EIA-860 Data - Schedule 3, 'Generator Data' (Retired & Canceled Units Only)

Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Technology	Prime Mover	Unit Code	Ownership	Duct Burners	Can Bypass Heat Recovery Steam Generator?	RTO/ISO LMP Node Designation	RTO/ISO Location Designation for Reporting Wholesale Sales Data to FERC	Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Minimum Load (MW)	Uprate or Derate Completed During Year	Month Uprate or Derate Completed	Year Uprate or Derate Completed	Status	Synchronized to Transmission Grid	Operating Month	Operating Year	Retirement Month	Retirement Year
49756	Illinois Power Resources Generating LLC	856	E D Edwards	IL	Peoria	1	Conventional Steam Coal	ST		S	X	X	AMIL.EDWARDS1	AMIL.EDWARDS1	136.0	0.850	95.0	105.0	70.0	N			RE	X	5	1960	12	2015
49756	Illinois Power Resources Generating LLC	860	Sterling Avenue	IL	Peoria	1	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.0		15.0	15.0		N			RE	X	12	1967	4	2009
49756	Illinois Power Resources Generating LLC	860	Sterling Avenue	IL	Peoria	2	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.0		15.0	15.0		N			RE	X	12	1967	4	2009
520	Illinois Power Generating Co	861	Coffeen	IL	Montgomery	1	Conventional Steam Coal	ST		S	X	X	AMIL.COFFEEN1	AMIL.COFFEEN1	388.9	0.850	330.0	335.0	190.0	N			RE	X	12	1965	11	2019
520	Illinois Power Generating Co	861	Coffeen	IL	Montgomery	2	Conventional Steam Coal	ST		S	X	X	AMIL.COFFEEN2	AMIL.COFFEEN2	616.5	0.900	565.0	580.0	265.0	N			RE	X	9	1972	11	2019
12384	Midwest Generations EME LLC	865	Bloom	IL	Cook	331	Petroleum Liquids	GT		S	X	X			19.0		11.2	14.2		N			RE	X	4	1971	1	2003
12384	Midwest Generations EME LLC	865	Bloom	IL	Cook	332	Petroleum Liquids	GT		S	X	X			19.0		13.5	16.8		N			RE	X	4	1971	1	2003
12384	Midwest Generations EME LLC	865	Bloom	IL	Cook	333	Petroleum Liquids	GT		S	X	X			19.0		12.7	15.7		N			RE	X	4	1971	1	2003
12384	Midwest Generations EME LLC	865	Bloom	IL	Cook	334	Petroleum Liquids	GT		S	X	X			19.0		11.4	16.9		N			RE	X	4	1971	1	2003
12384	Midwest Generations EME LLC	865	Bloom	IL	Cook	341	Petroleum Liquids	GT		S	X	X			19.0		13.7	16.9		N			RE	X	5	1971	1	2003
12384	Midwest Generations EME LLC	865	Bloom	IL	Cook	342	Petroleum Liquids	GT		S	X	X			19.0		13.7	14.1		N			RE	X	5	1971	1	2003
12384	Midwest Generations EME LLC	865	Bloom	IL	Cook	343	Petroleum Liquids	GT		S	X	X			19.0		11.9	15.0		N			RE	X	5	1971	1	2003
12384	Midwest Generations EME LLC	865	Bloom	IL	Cook	344	Petroleum Liquids	GT		S	X	X			19.0		12.3	15.2		N			RE	X	5	1971	1	2003
12384	Midwest Generations EME LLC	866	Calumet	IL	Cook	311	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		14.7	17.9		N			RE	X	6	1969	12	2004
12384	Midwest Generations EME LLC	866	Calumet	IL	Cook	312	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		14.1	17.4		N			RE	X	6	1969	12	2004
12384	Midwest Generations EME LLC	866	Calumet	IL	Cook	313	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		12.3	15.9		N			RE	X	6	1969	12	2004
12384	Midwest Generations EME LLC	866	Calumet	IL	Cook	314	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		14.8	18.4		N			RE	X	6	1969	12	2004
12384	Midwest Generations EME LLC	866	Calumet	IL	Cook	321	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		14.1	17.4		N			RE	X	6	1996	12	2004
12384	Midwest Generations EME LLC	866	Calumet	IL	Cook	322	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		14.2	18.0		N			RE	X	6	1996	12	2004
12384	Midwest Generations EME LLC	866	Calumet	IL	Cook	323	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		14.2	17.5		N			RE	X	6	1969	12	2004
12384	Midwest Generations EME LLC	866	Calumet	IL	Cook	324	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		14.2	17.5		N			RE	X	6	1969	12	2004
12384	Midwest Generations EME LLC	866	Calumet	IL	Cook	331	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		15.1	18.4		N			RE	X	6	1969	12	2004
12384	Midwest Generations EME LLC	866	Calumet	IL	Cook	332	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		13.0	17.3		N			RE	X	6	1969	12	2004
12384	Midwest Generations EME LLC	866	Calumet	IL	Cook	333	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		13.6	17.2		N			RE	X	6	1969	12	2004
12384	Midwest Generations EME LLC	866	Calumet	IL	Cook	341	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		13.7	17.9		N			RE	X	6	1970	12	2004
12384	Midwest Generations EME LLC	866	Calumet	IL	Cook	342	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		14.0	17.2		N			RE	X	6	1970	12	2004
12384	Midwest Generations EME LLC	866	Calumet	IL	Cook	343	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		13.6	16.8		N			RE	X	6	1970	12	2004
12384	Midwest Generations EME LLC	866	Calumet	IL	Cook	344	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		8.3	11.5		N			RE	X	6	1970	12	2004
12384	Midwest Generations EME LLC	867	Crawford	IL	Cook	311	Natural Gas Fired Combustion Turbine	GT		S	X	X			17.3		17.3	13.9		N			RE	X	7	1968	3	2005
12384	Midwest Generations EME LLC	867	Crawford	IL	Cook	312	Natural Gas Fired Combustion Turbine	GT		S	X	X			17.3		13.7	17.0		N			RE	X	6	1968	3	2005
12384	Midwest Generations EME LLC	867	Crawford	IL	Cook	313	Natural Gas Fired Combustion Turbine	GT		S	X	X			17.3		14.4	17.9		N			RE	X	7	1968	3	2005
12384	Midwest Generations EME LLC	867	Crawford	IL	Cook	314	Natural Gas Fired Combustion Turbine	GT		S	X	X			17.3		13.9	17.3		N			RE	X	7	1968	3	2005
12384	Midwest Generations EME LLC	867	Crawford	IL	Cook	321	Natural Gas Fired Combustion Turbine	GT		S	X	X			17.3		14.7	18.3		N			RE	X	7	1968	3	2005
12384	Midwest Generations EME LLC	867	Crawford	IL	Cook	322	Natural Gas Fired Combustion Turbine	GT		S	X	X			17.3		14.7	18.3		N			RE	X	7	1968	3	2005
12384	Midwest Generations EME LLC	867	Crawford	IL	Cook	323	Natural Gas Fired Combustion Turbine	GT		S	X	X			17.3		13.9	17.3		N			RE	X	7	1968	3	2005
12384	Midwest Generations EME LLC	867	Crawford	IL	Cook	324	Natural Gas Fired Combustion Turbine	GT		S	X	X			17.3		14.2	17.7		N			RE	X	6	1968	3	2005
12384	Midwest Generations EME LLC	867	Crawford	IL	Cook	331	Natural Gas Fired Combustion Turbine	GT		S	X	X			17.3		14.2	17.7		N			RE	X	7	1968	3	2005
12384	Midwest Generations EME LLC	867	Crawford	IL	Cook	332	Natural Gas Fired Combustion Turbine	GT		S	X	X			17.3		13.8	17.1		N			RE	X	7	1968	3	2005
12384	Midwest Generations EME LLC	867	Crawford	IL	Cook	333	Natural Gas Fired Combustion Turbine	GT		S	X	X			17.3		14.3	17.8		N			RE	X	7	1968	3	2005
12384	Midwest Generations EME LLC	867	Crawford	IL	Cook	334	Natural Gas Fired Combustion Turbine	GT		S	X	X			17.3		13.7	17.0		N			RE	X	6	1968	3	2005
12384	Midwest Generations EME LLC	867	Crawford	IL	Cook	7	Conventional Steam Coal	ST		S	X	X			239.3		213.0	216.0		N			RE	X	5	1958	8	2012
12384	Midwest Generations EME LLC	867	Crawford	IL	Cook	8	Conventional Steam Coal	ST		S	X	X			358.1		319.0	326.0		N			RE	X	4	1961	8	2012
12384	Midwest Generations EME LLC	870	Electric Junction	IL	DuPage	311	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		14.6	17.7		N			RE	X	6	1970	12	2004
12384	Midwest Generations EME LLC	870	Electric Junction	IL	DuPage	312	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		15.0	18.3		N			RE	X	6	1970	12	2004
12384	Midwest Generations EME LLC	870	Electric Junction	IL	DuPage	313	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		15.1	18.3		N			RE	X	6	1970	12	2004
12384	Midwest Generations EME LLC	870	Electric Junction	IL	DuPage	314	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		14.7	17.9		N			RE	X	6	1970	12	2004
12384	Midwest Generations EME LLC	870	Electric Junction	IL	DuPage	321	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		14.9	18.8		N			RE	X	6	1970	12	2004
12384	Midwest Generations EME LLC	870	Electric Junction	IL	DuPage	322	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		14.6	17.7		N			RE	X	6	1970	12	2004
12384	Midwest Generations EME LLC	870	Electric Junction	IL	DuPage	323	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		14.4	17.5		N			RE	X	6	1970	12	2004
12384	Midwest Generations EME LLC	870	Electric Junction	IL	DuPage	324	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		15.3	18.7		N			RE	X	6	1970	12	2004
12384	Midwest Generations EME LLC	870	Electric Junction	IL	DuPage	331	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		14.7	17.9		N			RE	X	8	1970	12	2004
12384	Midwest Generations EME LLC	870	Electric Junction	IL	DuPage	332	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		15.1	18.5		N			RE	X	8	1970	12	2004
12384	Midwest Generations EME LLC	870	Electric Junction	IL	DuPage	333	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		14.7	17.8		N			RE	X	6	1970	12	2004
12384	Midwest Generations EME LLC	870	Electric Junction	IL	DuPage	334	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		14.7	17.9		N			RE	X	4	1971	12	2004
12384	Midwest Generations EME LLC	870	Electric Junction	IL	DuPage	341	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		9.5	12.8		N			RE	X	4	1971	12	2004
12384	Midwest Generations EME LLC	870	Electric Junction	IL	DuPage	342	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		9.8	12.8		N			RE	X	4	1971	12	2004
12384	Midwest Generations EME LLC	870	Electric Junction	IL	DuPage	343	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		10.4	13.2		N			RE	X	4	1971	12	2004
12384	Midwest Generations EME LLC	870	Electric Junction	IL	DuPage	344	Natural Gas Fired Combustion Turbine	GT		S	X	X			19.0		9.9	12.8		N			RE	X	4	1971	12	2004
12384	Midwest Generations EME LLC	874	Joliet 9	IL	Will	311	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		15.8	19.3		N			RE	X	5	1969	12	2004
12384	Midwest Generations EME LLC	874	Joliet 9	IL	Will	312	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		14.5	17.7		N			RE	X	5	1969	12	2004
12384	Midwest Generations EME LLC	874	Joliet 9	IL	Will	313	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		14.6	17.8		N			RE	X	5	1969	12	2004
12384	Midwest Generations EME LLC	874	Joliet 9	IL	Will	314	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		14.0	17.2		N			RE	X	5	1969	12	2004
12384	Midwest Generations EME LLC	874	Joliet 9	IL	Will	321	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		14.1	17.3		N			RE	X	5	1969	12	2004
12384	Midwest Generations EME LLC	874	Joliet 9	IL	Will	322	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		14.1	17.3		N			RE	X	5	1969	12	2004
12384	Midwest Generations EME LLC	874	Joliet 9	IL	Will	323	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		14.1	17.3		N			RE	X	5	1969	12	2004
12384	Midwest Generations EME LLC	874	Joliet 9	IL	Will	324	Natural Gas Fired Combustion Turbine	GT		S	X	X			18.4		13.9	17.8		N			RE	X	5	1969	12	2004
12384	Midwest Generations EME LLC	877	Lombard	IL	DuPage	311	Petroleum Liquids	GT		S	X	X			22.1		16.2	21.2		N			RE	X	6	1969	12	2004
12384	Midwest Generations EME LLC	877	Lombard	IL	DuPage	312	Natural Gas Fired Combustion Turbine	GT		S	X	X			22.1		18.4	23.0		N			RE	X	6	1969	12	2004
12384	Midwest Generations EME LLC	877	Lombard	IL	DuPage	321	Petroleum Liquids	GT		S	X	X			22.1		15.5	20.2		N			RE	X	6	1969	12	2004
12384	Midwest Generations EME LLC	877	Lombard	IL	DuPage	322	Petroleum Liquids	GT		S	X	X			22.1		18.8	21.7		N			RE	X	6	1969	12	2004
12384	Midwest Generations EME LLC	877	Lombard	IL	DuPage	331	Petroleum Liquids	GT		S	X	X			22.1		16.2	21.2		N			RE	X	6	1969	12	2004
12384	Midwest Generations EME LLC	877	Lombard	IL	DuPage	332	Natural Gas Fired Combustion Turbine	GT		S	X	X			22.1		18.3	22.9		N			RE	X	6	1969	12	2004
12384	Midwest Generations EME LLC	882	Sabrooke	IL	Winnebago	311	Petroleum Liquids	GT		S	X	X			18.4		12.8	16.1		N			RE	X	5	1969	12	2004
12384	Midwest Generations EME LLC	882	Sabrooke	IL	Winnebago	312	Petroleum Liquids	GT		S	X	X			18.4		12.4	15.6		N			RE	X	5	1969	12	2004
12384	Midwest Generations EME LLC	882	Sabrooke	IL	Winnebago	321	Petroleum Liquids	GT		S	X	X			18.4		11.4	15.2		N			RE	X	5	1969	12	2004
12384	Midwest Generations EME LLC	882	Sabrooke	IL	Winnebago	322	Petroleum Liquids	GT		S	X	X			18.4		13.5	16.9		N			RE	X	5	1969	12	2004
12384	Midwest Generations EME LLC	882	Sabrooke	IL	Winnebago	331	Petroleum Liquids	GT		S	X	X			19.0		11.0	13.8		N			RE	X	5	1970	12	2004
12384	Midwest Generations EME LLC	882	Sabrooke	IL	Winnebago	332	Petroleum Liquids	GT		S	X	X			19.0		12.8	16.4		N			RE	X	5	1970	12	2004
12384	Midwest Generations EME LLC	882	Sabrooke	IL	Winnebago	341	Petroleum Liquids	GT		S	X	X			19.0		12.5	14.0		N			RE	X	5	1970	12	2004
12384	Midwest Generations EME LLC	882	Sabrooke	IL	Winnebago	342	Petroleum Liquids	GT		S	X	X			19.0		13.1	16.6		N			RE	X	5	1970	12	2004
12384	Midwest Generations EME LLC	883	Waukegan	IL	Lake	6	Conventional Steam Coal	ST		S	X	X			121.0		100.0	100.0		N			RE	X	1	1952	12	2007
12384	Midwest Generations EME LLC	884	Will County	IL	Will	1	Conventional Steam Coal	ST		S	X	X			187.5		151.0	166.0		N			RE	X	7	1955	12	2010
12384	Midwest Generations EME LLC	884	Will County	IL	Will	2	Conventional Steam Coal	ST		S	X	X			183.7		148.0	154.0		N			RE	X	3	1955	12	2010
12384	Midwest Generations EME LLC	884	Will County	IL	Will	3	Conventional Steam Coal	ST		S	X	X			299.2	0.850	251.0	262.0	95.0	N			RE	X	6	1957	4	2015
12384	Midwest Generations EME LLC	886	Fisk Street	IL	Cook	19	Conventional Steam Coal	ST		S	X	X			374.0		326.0	326.0		N			RE	X	7	1968	8	2012
5517	Dynegy Midwest Generation Inc	889	Baldwin Energy Complex	IL	Randolph	3	Conventional Steam Coal	ST		S	X	X	AMIL.BALDW153	AMIL.BALDW153	634.5	0.900	621.0	630.0	250.0	N			RE	X	4	1975	8	2020
5517	Dynegy Midwest Generation Inc	891	Havana	IL	Mason	1	Petroleum Liquids	ST		S	X	X			46.0		45.6	44.8		N			RE	X	9	1947	1	2012
5517	Dynegy Midwest Generation Inc	891	Havana	IL	Mason	2	Petroleum Liquids	ST		S	X	X			46.0		45.6	44.8		N			RE	X	7	1947	1	2012
5517	Dynegy Midwest Generation Inc	891	Havana	IL	Mason	3	Petroleum Liquids	ST		S	X	X			46.0		45.6	44.8		N			RE	X	11	1948	1	2012
5517	Dynegy Midwest Generation Inc	891	Havana	IL	Mason	4	Petroleum Liquids	ST		S	X	X			46.0		45.6	44.8		N			RE	X	3	1950	1	2012
5517	Dynegy Midwest Generation Inc	891	Havana	IL	Mason	5	Petroleum Liquids	ST		S	X	X			46.0		45.6	44.8		N			RE	X	6	1950	1	2012
5517	Dynegy Midwest Generation Inc	891	Havana	IL	Mason	6	Conventional Steam Coal	ST		S	X	X	AMIL.HAVANA86	AMIL.HAVANA86	488.0	0.900	411.0	434.0	95.0	N			RE	X	6	1978	11	2019
5517	Dynegy Midwest Generation Inc	892	Hennepin Power Station	IL	Putnam	1	Conventional Steam Coal	ST		S	X	X	AMIL.HENNEPN81	AMIL.HENNEPN81	75.0	0.800	68.0	70.0	25.0	N			RE	X	6	1953	11	2019
5517	Dynegy Midwest Generation Inc	892	Hennepin Power Station	IL	Putnam	2	Conventional Steam Coal	ST		S	X	X	AMIL.HENNEPN82	AMIL.HENNEPN82	231.3	0.850	218.0	225.0	80.0	N			RE	X	9	1959	11	2019
5517	Dynegy Midwest Generation Inc	894	Oglesby	IL	LaSalle	1	Natural Gas Fired Combustion Turbine	GT		S	X	X			17.5		13.5	15.8		N			RE	X	10	1970	1	2013
5517	Dynegy Midwest Generation Inc	894	Oglesby	IL	LaSalle	2	Natural Gas Fired Combustion Turbine	GT		S	X	X			17.5		13.5	15.8		N			RE	X	9	1970	1	2013
5517	Dynegy Midwest Generation Inc	894	Oglesby	IL	LaSalle	3	Natural Gas Fired Combustion Turbine	GT		S	X	X			17.5		13.5	15.8		N			RE	X	10	1970	1	2013
5517	Dynegy Midwest Generation Inc	894	Oglesby	IL	LaSalle	4	Natural Gas Fired Combustion Turbine	GT		S	X	X			17.5		13.5	15.8		N			RE	X	10	1970	1	2013
5517	Dynegy Midwest Generation Inc	895	Stallings	IL	Madison	1	Natural Gas Fired Combustion Turbine	GT		S	X	X			23.8		20.5	22.3		N			RE	X	8	1970	1	2013
5517	Dynegy Midwest Generation Inc	895	Stallings	IL	Madison	2	Natural Gas Fired Combustion Turbine	GT		S	X	X			23.8		20.5	22.3		N			RE	X	8	1970	1	2013
5517	Dynegy Midwest Generation Inc	895	Stallings	IL	Madison	3	Natural Gas Fired Combustion Turbine	GT		S	X	X			23.8		20.5	22.3		N			RE	X	9	1970	1	2013
5517	Dynegy Midwest Generation Inc	895	Stallings	IL	Madison	4	Natural Gas Fired Combustion Turbine	GT		S	X	X			23.8		20.5	22.3		N			RE	X	8	1970	1	2013
5517	Dynegy Midwest Generation Inc	897	Vermilion	IL	Vermilion	2	Conventional Steam Coal	ST		S	X	X			108.8		99.0	99.0		N			RE	X	11	1956	11	2011
5517	Dynegy Midwest Generation Inc	897	Vermilion	IL	Vermilion	3	Petroleum Liquids	GT		S	X	X			15.0		10.0	12.0		N			RE	X	8	1967	11	2011
5517	Dynegy Midwest Generation Inc	897	Vermilion	IL	Vermilion	ST1	Conventional Steam Coal	ST		S	X	X			73.5		62.0	63.0		N			RE	X	5	1955	11	2011
5517	Dynegy Midwest Generation Inc	898	Wood River	IL	Madison	1	Natural Gas Steam Turbine	ST		S	X	X			50.0		38.7	39.7		N			RE	X	11	1949	10	2011
5517	Dynegy Midwest Generation Inc	898	Wood River	IL	Madison	2	Natural Gas Steam Turbine	ST		S	X	X			50.0		38.7	39.7		N			RE	X	11	1949	10	2011
5517	Dynegy Midwest Generation Inc	898	Wood River	IL	Madison	3	Natural Gas Steam Turbine	ST		S	X	X			50.0		38.7	39.7		N			RE	X	10	1950	10	2011
5517	Dynegy Midwest Generation Inc	898	Wood River	IL	Madison	4	Conventional Steam Coal	ST		S	X	X	AMIL.WOODRW84	AMIL.WOODRW84	112.5	0.850	89.0	91.0	35.0	N			RE	X	6	1954	5	2016
5517	Dynegy Midwest Generation Inc	898	Wood River	IL	Madison	5	Conventional Steam Coal	ST		S	X	X	AMIL.WOODRW85	AMIL.WOODRW85	387.6	0.850	371.0	374.0	115.0	N			RE	X	7	1964	5	2016
19436	Union Electric Co - (MO)	913	Venice	IL	Madison	2	Petroleum Liquids	ST		S	X	X			40.0	0.850	38.0	36.0		N			RE	X	5	1942	8	2000
19436	Union Electric Co - (MO)	913	Venice	IL	Madison	3	Petroleum Liquids	ST		S	X	X			98.0	0.850	82.0	78.0		N			RE	X	7	1943	12	2002
19436	Union Electric Co - (MO)	913	Venice	IL	Madison	4	Petroleum Liquids	ST		S	X	X			98.0	0.850	82.0	78.0		N			RE	X	3	1948	12	2002
19436	Union Electric Co - (MO)	913	Venice	IL	Madison	5	Petroleum Liquids	ST		S	X	X			98.0	0.900	86.0	82.5		N			RE	X	9	1950	12	2002
19436	Union Electric Co - (MO)	913	Venice	IL	Madison	6	Petroleum Liquids	ST		S	X	X			100.0		86.0	82.5		N			RE	X	12	1950	12	2002
19436	Union Electric Co - (MO)	913	Venice	IL	Madison	GT1	Petroleum Liquids	GT		S	X	X			37.5		26.0	30.0		N			RE	X	10	1967	9	2011
19436	Union Electric Co - (MO)	913	Venice	IL	Madison	ST1	Petroleum Liquids	ST		S	X	X			40.0		38.0	36.0		N			RE	X	2	1942	8	2000
2188	City of Breese - (IL)	934	Breese	IL	Clinton	ST2	Petroleum Liquids	ST		S	X	X			2.0		2.0	2.0		N			RE	X	8	1960	1	2003
3037	City of Carlyle - (IL)	936	Carlyle	IL	Clinton	1	Petroleum Liquids	IC		S	X	X			3.0	0.800	3.0	3.0	1.5	N			RE	X	8	1971	8	2017
3040	City of Carmi - (IL)	937	Carmi	IL	White	11	Petroleum Liquids	IC		S	X	X			2.7	0.800	2.7	2.7	1.5	N			RE	X	12	1963	12	2019
3040	City of Carmi - (IL)	937	Carmi	IL	White	5	Natural Gas Internal Combustion Engine	IC		S	X	X			0.6	0.800	0.5	0.5	0.2	N			RE	X	12	1945	7	2013
3040	City of Carmi - (IL)	937	Carmi	IL	White	8	Petroleum Liquids	IC		S	X	X			0.7	0.800	0.5	0.5	0.2	N			RE	X	12	1939	5	2014
6141	City of Fairfield- (IL)	940	Fairfield	IL	Wayne	IC5	Petroleum Liquids	IC		S	X	X			2.4	0.800	2.4	2.4	1.0	N			RE	X	1	1967	6	2020
6141	City of Fairfield- (IL)	940	Fairfield	IL	Wayne	IC6	Petroleum Liquids	IC		S	X	X			2.4	0.800	2.4	2.4	1.0	N			RE	X	1	1967	6	2020
6141	City of Fairfield- (IL)	940	Fairfield	IL	Wayne	IC7	Petroleum Liquids	IC		S	X	X			2.7	0.800	2.7	2.7	1.0	N			RE	X	3	1979	6	2020
11736	City of Marshall - (IL)	949	Marshall (IL)	IL	Clark	1	Petroleum Liquids	IC		S	X	X	AMIL.IP.IMEA	AMIL.IP.IMEA	0.9	0.800	0.8	0.8	0.5	N			RE	X	88	1948	2	2006
11736	City of Marshall - (IL)	949	Marshall (IL)	IL	Clark	2	Petroleum Liquids	IC		S	X	X	AMIL.IP.IMEA	AMIL.IP.IMEA	0.9	0.800	0.8	0.8	0.5	N			RE	X	88	1948	2	2006
11736	City of Marshall - (IL)	949	Marshall (IL)	IL	Clark	3	Petroleum Liquids	IC		S	X	X	AMIL.IP.IMEA	AMIL.IP.IMEA	1.2	0.800	1.1	1.1	0.5	N			RE	X	88	1953	2	2006
14840	City of Peru - (IL)	955	Peru (IL)	IL	LaSalle	10	Petroleum Liquids	IC		S	X	X	AMIL.IP.IMEA	AMIL.IP.IMEA	2.0	0.800	2.0	2.0	0.2	N			RE	X	2	2003	4	2011
14840	City of Peru - (IL)	955	Peru (IL)	IL	LaSalle	3	Petroleum Liquids	IC		S	X	X	AMIL.IP.IMEA	AMIL.IP.IMEA	1.8		1.8	1.8		N			RE	X	5	2002	11	2010
14840	City of Peru - (IL)	955	Peru (IL)	IL	LaSalle	4	Natural Gas Steam Turbine	ST		S	X	X	AMIL.IP.

Generator Retirements

As of August 29, 2023

MISO Generators Approved to Retire (Public)

Disclaimer: This listing serves as public notice of generator retirements. This does not include generators on suspension. This information is being provided as-is, with no guarantee of the completeness or accuracy of the data.

Unit Description	Area	State	No of Units	Total MW	Fuel Type	Retirement Date
Kickapoo 1-8	AMIL	IL	8	12.8	Oil	12/1/2005
Blount 1	MGE (ATC)	WI	1	6.8	Coal	1/1/2006
West Faribault 2 and 3	XEL (NSP)	MN	2	31	Gas	1/1/2007
Presque Isle 1 & 2	WEC (ATC)	MI	2	62	Coal	1/1/2007
Hallock 1-8	AMIL	IL	8	12.8	Diesel	1/1/2007
Culley 1	SIGE	IN	1	46	Coal	1/1/2007
Tazewell Power Modules 1-14	AMIL	IL	14	25.6	Diesel	1/1/2007
Maquoketa 1	AMIL	IL	1	2.1	Diesel	6/7/2007
Hoot Lake 1	OTP	MN	1	7.5	Coal	10/22/2007
Pulliam 3	WPS (ATC)	WI	1	26	Coal	12/31/2007
Pulliam 4	WPS (ATC)	WI	1	29	Coal	12/31/2007
Miami Fort 5*	DEO&K	OH	1	80	Coal	1/29/2008
Oak Creek 9	WEC (ATC)	WI	1	18	Coal	9/1/2008
Sterling 1 & 2	AMIL	IL	2	42.4	Gas	1/2/2009
Presque Isle 3	WEC (ATC)	MI	1	58	Coal	10/1/2009
Presque Isle 4	WEC (ATC)	MI	1	58	Coal	10/1/2009
Lakeside 6 & 7	CWLP	IL	2	76	Coal	10/1/2009
Black Hawk 3 & 4	ALTE (ATC)	WI	2	54	Gas	4/1/2010
Rock River 1 & 2	ALTE (ATC)	WI	2	150	Gas	4/1/2010
Austin DTST 2, 3 & 4	SMMPA	MN	3	25.5	Coal	4/8/2010
Edgewater CTA & CTB*	FE	OH	2	52	Oil	10/1/2010
Gaylord 5	METC	MI	1	14	Gas	10/14/2010
Edwardsport 6, 7 & 8	DEI	IN	3	160	Coal & Oil	11/1/2010
Burger 4 & 5*	FE	OH	2	330	Coal	12/31/2010
Michigan City 2 & 3	NIPS	IN	2	120	Coal	3/15/2011
Mitchell 4, 5, 6 & 11	NIPS	IN	4	420	Coal	3/15/2011
Miami-Wabash CT4	DEI	IN	1	16	Oil	4/1/2011
Blount 3, 4 & 5	MGE (ATC)	WI	3	90.1	Coal	6/1/2011
6thtreet 2_A, 4, 7 & 8	ALTW (ITCM)	IA	4	55	Gas	6/1/2011
Conners Creek 15 & 16	METC	MI	2	270	Coal	6/1/2011
Lansing 3	ALTW (ITCM)	IA	1	35	Coal	7/22/2011
Venice CTG	AMMO	MO	1	25	Gas	9/1/2011
Viaduct CTG	AMMO	MO	1	25	Gas	9/1/2011
Lakefront 4	WPS (ATC)	WI	1	10	Coal	11/1/2011
8thtreet 2 (Dubuque)	ALTW (ITCM)	IA	1	15	Coal	12/31/2011
Vermilion 1, 2 & 3	AMIL	IL	3	171	Coal	1/13/2012
Gallagher 1 & 3	DEI	IN	2	280	Coal	1/31/2012
Wood River 1, 2 & 3	AMIL	IL	3	116.3	Coal	3/6/2012
Alma 1, 2 & 3	DPC	WI	3	60	Coal	6/1/2012
Pearl 1	AMIL	IL	1	22	Coal	6/1/2012
Havana 1-5	AMIL	IL	5	224	Coal	6/8/2012
Stallings 1, 2, 3, & 4	AMIL	IL	4	88	Gas	12/31/2012
Oglesby 1, 2, 3, & 4	AMIL	IL	4	63	Gas	12/31/2012
Conners Creek DG11	METC	MI	2	5	Diesel	3/1/2013
Dayton DG11	METC	MI	5	10	Diesel	3/1/2013
Kewaunee 1	WPS (ATC)	WI	1	570.1	Nuclear	5/7/2013
Austin DTCT	MMPA	MN	1	5	Gas	8/31/2013
Thetford 5, 6 & 7	METC	MI	3	51	Gas	9/14/2013
Thetford 8 & 9	METC	MI	2	34	Gas	9/14/2013
Fair Station 1 & 2	ALTW (ITCM)	IA	2	64	Coal	9/30/2013

Unit Description	Area	State	No of Units	Total MW	Fuel Type	Retirement Date
Mitchell 9	NIPS	IN	1	17	Gas	10/1/2013
Gaylord 4	METC	MI	1	17	Gas	11/1/2013
Harbor Beach 1	METC	MI	1	103	Coal	12/31/2013
Harbor Beach Peaker	METC	MI	1	4	Diesel	12/31/2013
Morrow A, B	METC	MI	1	22.5	Gas	3/13/2014
Independence 5, 6, 7, 1A, 3A, 3B, 4A & 4B	ALTW (ITCM)	IA	8	18.3	Diesel	6/1/2014
Alma 4	DPC	WI	1	50	Coal	9/8/2014
River Rouge 1	ITCT	MI	1	250	Coal	9/26/2014
Hutsonville 3 & 4	AMIL	IL	2	152.6	Coal	10/25/2014
Alma 5	DPC	WI	1	75	Coal	10/27/2014
Meredosia 1, 2 & 3	AMIL	IL	3	363	Coal	11/30/2014
Howard Bend 1	AMMO	MO	1	50	Oil	1/31/2015
Ratts 1 & 2	HE (Vectran)	IN	2	250	Coal	2/4/2015
Walter Scott 1 & 2	MEC	IA	2	131	Coal	3/31/2015
Key City 1-4	XEL (NSP)	MN	4	72	Oil	3/31/2015
Trenton Channel 8	METC	MI	1	100	Coal	4/1/2015
White Pine 2	WEC (ATC)	MI	1	20	Gas	4/15/2015
Cobb 1, 2 & 3	METC	MI	3	183	Gas	5/31/2015
Thetford 1	METC	MI	1	37	Gas	5/31/2015
Whiting A	METC	MI	1	17	Gas	5/31/2015
Weadock A	METC	MI	1	17	Gas	5/31/2015
Morgan City 3 & 4	LEPA	LA	2	58	Gas	5/31/2015
Plaquemine 1 & 2	LEPA	LA	2	44	Gas	5/31/2015
Pulliam 5 & 6	WPS (ATC)	WI	2	115	Coal	6/1/2015
Weston 1	WPS (ATC)	WI	1	60	Coal	6/1/2015
Little Gypsy 1	EES	LA	1	227.9	Gas	6/1/2015
Escanaba 1 & 2	UPPC (ATC)	MI	2	25	Coal	6/15/2015
Hunter 4	CLEC	LA	1	80	Coal	9/1/2015
Stoneman 1 & 2	DPC	WI	2	52	Biomass	11/2/2015
Nelson Dewey 1 & 2	ALTE (ATC)	WI	2	220	Coal	12/31/2015
Edgewater 3	ALTE (ATC)	WI	1	71	Coal	12/31/2015
Silver Lake 1, 2, 3 & 4	MMPA	MN	4	99	Gas	12/31/2015
Edwards 1	AMIL	IL	1	103.1	Coal	1/1/2016
Meredosia 4	AMIL	IL	1	186	Coal	1/12/2016
D.G. Hunter ST3	CLEC	LA	1	58.64	Gas	3/21/2016
Neal 1 & 2	MEC	IA	2	496	Coal	4/15/2016
Cobb 4 & 5	METC	MI	2	320	Coal	4/15/2016
Weadock 7 & 8	METC	MI	2	310	Coal	4/15/2016
Whiting 1, 2 & 3	METC	MI	3	328	Coal	4/15/2016
Wabash River 2-5	DEI	IN	4	435	Coal	4/16/2016
Eagle Valley 3, 4, 5 & 6 (at Pritichard station)	IPL	IN	4	302	Coal	4/16/2016
Trenton Channel 7	METC	MI	1	110	Coal	4/16/2016
CWLD Plant D Gen 5	CWLD	MO	1	16.5	Coal	4/30/2016
Cooper - Grand Forks	OTP	ND	1	4.9	Diesel	5/31/2016
Michoud 2	EES	LA	1	261.8	Gas	6/1/2016
Ninemile Point 3	EES	LA	1	169.8	Gas	6/1/2016
Michoud 3	EES	LA	1	541.9	Gas	6/1/2016
Endicott Generating Station	METC	MI	1	60	Coal	6/1/2016
Mabelvale	EES	AR	2	28	Gas	6/1/2016
Willow Glen 2 & 4	EES	LA	2	661.9	Gas	6/1/2016
Wabash River 1 (ST)	DEI	IN	1	84.5	Coal	6/1/2016
Austin North East	SMP	MN	1	30	Coal	6/1/2016
Wood River 4 & 5	AMIL	IL	2	473.23	Coal	6/1/2016
Escanaba CT	UPPC (ATC)	MI	1	13.13	Gas	6/1/2016
Sabine 2	EES	TX	1	213	Gas	6/1/2016
River Rouge 2	METC	MI	1	260	Coal	6/30/2016
Pontiac North	ITCT	MI	1	19	Coal	8/12/2016

Unit Description	Area	State	No of Units	Total MW	Fuel Type	Retirement Date
Coleman 1,2,3	BREC	KY	3	443	Coal	9/1/2016
Newton 2	AMIL	IL	1	615	Coal	9/15/2016
Dow GT300	EES	LA	1	119	Gas	11/11/2016
White Pine 1	WEC (ATC)	MI	1	20	Gas	11/27/2016
Wabash River 6	DEI	IN	1	318	Coal	12/7/2016
Teche Power Station Unit 1	CLEC	LA	1	20	Gas	1/1/2017
Juneau County 31	WPS (ATC)	WI	1	18	Oil	3/1/2017
Bonin 2 & 3	LAFA	LA	2	171	Gas	4/1/2017
Stanton 1	GRE	MN	1	188	Coal	5/1/2017
8thtreet 3 & 4 (Dubuque)	ALTW (ITCM)	IA	3	69	Coal	6/1/2017
Sutherland 3	ALTW (ITCM)	IA	1	79.5	Gas	6/1/2017
Sutherland Steam 1	ALTW (ITCM)	IA	1	28.4	Gas	6/22/2017
Grinnell 1 & 2	ALTW (ITCM)	IA	2	47.1	Gas	8/31/2017
Paulding Gen	SMEPA	MS	1	20	Oil	8/31/2017
Fox Lake Unit 1 and 3	ALTW (ITCM)	MN	2	91.2	Gas	11/1/2017
North Centerville CT 1 and 2	ALTW (ITCM)	IA	2	46.5	Oil	11/1/2017
St. Clair Unit 4	ITCT	MI	1	158	Coal	11/13/2017
Flambeau CT	XEL (NSP)	WI	1	16	Gas	12/31/2017
Kirksville CTG	AMMO	MO	1	14	Gas	1/1/2018
Black Dog 3 & 4	XEL (NSP)	MN	2	255	Coal	2/15/2018
Broadway Avenue – BAGS Unit 1	SIGE	IN	1	53	Gas	2/15/2018
Pleasant Prairie 1 & 2	WEC (ATC)	WI	2	1188	Coal	4/10/2018
Bailly 7 & 8	NIPS	IN	2	480	Coal	5/31/2018
Henderson Station	EES-EMI	MS	4	56.5	Coal	5/31/2018
Connersville CT 1 & 2	DEI	IN	2	92	Oil	6/1/2018
Miami Wabash 1,2,3,5,6	DEI	IN	5	85	Oil	6/1/2018
Red Cedar Generating Station	ALTW (ITCM)	IA	1	13.1	Gas	6/1/2018
Wheaton Unit 5	XEL (NSP)	WI	1	70	Gas & Oil	6/1/2018
Baxter Wilson 2	EES-EMI	MS	1	677.9	Gas & Oil	6/1/2018
Kapp Unit 2	ALTW (ITCM)	IA	1	106.5	Coal	6/1/2018
Rex Brown Plant Unit 3	EES-EMI	MS	1	23.5	Gas	6/1/2018
Taconite Harbor Unit 3	MP	MN	1	75	Coal	6/1/2018
Benndale	SMEPA	MS	1	16	Gas	8/29/2018
Kapp Unit 2	ALTW (ITCM)	IA	1	112	Gas	9/6/2018
Edgewater Unit 4	ALTE (ATC)	WI	1	309.2	Coal	9/30/2018
Pulliam Units 7 and 8	WPS (ATC)	WI	2	210	Coal	10/31/2018
Buras Plant Unit 8	EES	LA	1	11	Gas & Oil	10/31/2018
Hastings Unit 1	GRE	MN	1	8.8	Oil	11/2/2018
Lake Marion Unit 1	GRE	MN	1	8.8	Oil	11/2/2018
FibroMinn	OTP	MN	1	62	Biomass	11/13/2018
Morrow Units 1 and 2	SMEPA	MS	2	400	Coal	11/17/2018
Straits Unit 1	METC	MI	1	21	Gas	11/30/2018
Campbell Unit A	METC	MI	1	12	Gas	11/30/2018
Gaylord Units 1, 2 and 3	METC	MI	3	50	Gas	11/30/2018
Sterlington 7B	EES	LA	1	65	Gas	1/1/2019
Henderson Municipal Power & Light Units 1&2	BREC	KY	2	312	Coal	2/1/2019
St. Clair Unit 1	ITCT	MI	1	158	Coal	3/27/2019
Presque Isle 5,6,7,8,9	MIUP (ATC)	MI	5	359	Coal	3/31/2019
Northeast - NET Units 1 & 2	SIGE	IN	1	22.5	Gas	5/5/2019
Granite City Units 1,2,3,4	XEL (NSP)	MN	4	72	Gas & Oil	6/1/2019
Bay Front Unit 4	XEL (NSP)	WI	1	22.6	Biomass	6/1/2019
Rex Brown 4 & 5	EES-EMI	MS	2	209.2	Gas	6/11/2019
Reid Unit1	BREC	KY	1	50	Coal	6/24/2019
Thetford 2	METC	MI	1	37	Gas	6/26/2019
Burnips 6	METC	MI	1	23	Gas	7/29/2019
Woodville Renewable Power Project	EES	TX	1	45.5	Biomass	8/12/2019
Baldwin 3	AMIL	IL	1	650	Coal	9/4/2019

Unit Description	Area	State	No of Units	Total MW	Fuel Type	Retirement Date
Coffeen Units 1 and 2	AMIL	IL	2	1101	Coal	11/1/2019
Hennepin Units 1 and 2	AMIL	IL	3	366	Coal	11/1/2019
Havana Unit 6	AMIL	IL	1	543	Coal	11/1/2019
Plant D7	CWLD	MO	1	22	Coal	12/6/2019
Duck Creek Unit 1	AMIL	IL	1	517	Coal	12/15/2019
Hancock Unit 11-2	ITCT	MI	1	24	Gas	12/22/2019
Hancock Unit 11-4	ITCT	MI	1	22	Gas	12/22/2019
Broadway Avenue - BAGS Unit 2	SIGE	IN	1	88.8	Gas	12/22/2019
River Rouge Unit 3	ITCT	MI	1	170	Coal	6/1/2020
Nelson 4	EES	LA	1	424.7	Gas	6/1/2020
Sterlington Unit 7C	EES	LA	1	20	Gas	6/1/2020
Rock River 6	ALTE (ATC)	WI	1	34.3	Gas	6/1/2020
Sheepskin 1	ALTE (ATC)	WI	1	27.9	Gas	6/1/2020
White Pine 3	MIUP (ATC)	MI	1	20	Coal	6/1/2020
Rock River 3 & 5	ALTE (ATC)	WI	2	67.9	Gas	6/1/2020
Rock River 4	ALTE (ATC)	WI	1	14.4	Gas	6/1/2020
Bailly Unit 10	NIPS	IN	1	33	Gas	7/15/2020
Sabine Cogen	EES	TX	3	52.8	Gas	7/31/2020
Meramec CTG 1	AMMO	MO	1	70	Oil	12/29/2020
Community Wind North (G586)	XEL (NSP)	MN	1	3.6	Wind	12/31/2020
Jeffers Wind (G442)	XEL (NSP)	MN	1	6	Wind	12/31/2020
Sterlington 1-4 & 6-10	LAGN	LA	9	98.5	Gas	12/31/2020
Dallman Units 31 & 32	CWLP	IL	2	180	Coal	3/1/2021
Gallagher Units 2 and 4	DEI	IN	2	280	Coal	6/1/2021
Petersburg Unit 1	IPL	IN	1	253	Coal	6/1/2021
River Rouge Unit 3	ITCT	MI	1	110	Coal	6/1/2021
Schahfer Unit 14 & 15	NIPS	IN	2	1096.4	Coal	10/1/2021
Moulton and Champepadan Wind	GRE	MN	2	3.96	Wind	11/30/2021
Dolet Hills	CLEC	LA	1	304.8	Coal	12/31/2021
Boswell Units 1 and 2	MP	MN	2	150	Coal	1/1/2022
Portage CT	UPPC (ATC)	MI	1	27	Oil	1/11/2022
Lewis & Clark Unit 1	MDU	MT	1	52.3	Coal	2/15/2022
Elk River Station	GRE	MN	3	49	Biomass	3/22/2022
Lake Front T6	WPS (ATC)	WI	1	33	Coal	9/19/2022
Gallagher Unit 2 and 4	DEI	IN	2	280	Coal	12/31/2022
St. Clair Unit 2,3,6 and 7	ITCT	MI	4	1100	Coal	12/31/2022
Meramec CTG 2	AMMO	MO	1	50	Oil	12/31/2022
Weston Unit 2	WPS (ATC)	WI	1	24	Coal	2/7/2023
Baxter Wilson Unit 1	EES	MS	1	494.3	Gas	3/30/2023
Robert NewBerry	MIUP (ATC)	MI	1	2	Oil	5/31/2023
Karn Unit 1&2	METC	MI	2	515	Coal	6/1/2023
Northeast Peaker 11-1	ITCT	MI	1	13.2	Coal	6/1/2023
Petersburg Unit 2	IPL	IN	1	6.8	Coal	7/1/2023
Riverside Unit 5	MEC	IA	1	136	Coal	12/11/2023
Waterford Unit 1	EES	LA	1	411.2	Gas	2/17/2024
* Former MISO Generation Resources						

APPENDIX H: Illinois EPA Response to FLM Comments

National Park Service Regional Haze SIP feedback for the Illinois Environmental Protection Agency

October 13, 2023

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1 Executive Summary

The National Park Service (NPS) appreciates the opportunity to review the Illinois Environmental Protection Agency's (IEPA) August 2023 draft of the Illinois Regional Haze State Implementation Plan (SIP) for the Second Implementation Period (2018-2028). The NPS and U.S. Forest Service held a federal land manager (FLM) consultation call with IEPA on October 4, 2023, where we shared a summary of FLM conclusions and recommendations on the draft SIP. This technical feedback document details NPS conclusions and recommendations during the formal FLM regional haze consultation period, as required by 42 U.S.C. §7491(d).

While Illinois does not contain any NPS-managed Class I areas, emissions from sources in the state affect visibility at Mammoth Cave National Park in Kentucky, Great Smoky Mountains National Park in North Carolina and Tennessee, Isle Royale National Park in Michigan, and Voyageurs National Park in Minnesota. We appreciate IEPA's continued involvement in the Lake Michigan Air Directors Consortium (LADCO) and commitment to reducing haze-causing pollutants in the region which will help improve visibility in all Class I areas.

The NPS commends Illinois for the significant reductions of haze-causing emissions achieved since 1999, including reductions that have occurred or will occur within this planning period. Clean air and clear views across the region have undoubtedly improved from these emission reductions and will continue to improve as a result of additional Electric Generating Unit (EGU) emission reductions under the Illinois Climate and Equitable Jobs Act of 2021 (CEJA).

However, NPS Class I areas have not yet reached the regional haze rule goal of no human-caused visibility impairment. It is with this in mind that we reviewed the Illinois draft SIP and now offer facility-specific feedback and recommendations for additional reductions to include in the SIP's long-term strategy. Overall, the NPS finds that there may be additional opportunities to implement cost-effective emission reductions at Illinois sources affecting visibility in our Class I areas. These include potential reductions at the EGUs that will continue to operate through this planning period as well as opportunities to address emissions from several larger non-EGU sources. Each of the facilities reviewed by NPS staff during the FLM consultation period was also on the list the NPS previously presented to IEPA for consideration in 2019 and remains relevant today. These NPS recommendations are intended to help strengthen the SIP and further progress toward regional haze goals.

This document provides overarching feedback on source selection, four-factor cost analyses, and cost thresholds in Section 2 and facility-specific four-factor reviews and recommendations in Section 3. Cost calculation worksheets to support NPS analyses presented in Section 3 are available as Attachment 2 (Attachment2_NPS-IL-RH_Workbooks-Reference.zip).

Specifically, the NPS recommends that IEPA improve the draft SIP by:

- Adjusting source selection criteria to capture more of the Illinois facilities and emission units contributing to visibility impairment in NPS Class I areas (Section 2.1)
- Providing additional analysis and documentation for four-factor analyses (Section 2.2)
- Identifying the criteria used to make SIP determinations and establishing a cost-effectiveness threshold in line with other states for this round of regional haze planning (Section 2.3)
- Evaluating and implementing additional cost-effective control measures for EGUs operating through 2045 (Section 3.1, 3.2, and 3.4)
- Conducting four-factor analyses for all nine coal-fired boilers at Archer Daniels Midland (ADM) and implementing cost-effective sulfur dioxide (SO_2) emission reductions (Section 3.2)
- Obtaining facility-specific vendor quotes to support the cost calculations for the two kilns at Rain Carbon and implementing cost-effective control strategies at the facility (Section 3.3)
- Conducting additional four-factor analyses for the Wood River and Marathon refineries, and Fuyao Glass (Sections 3.5, and 3.6) and implementing cost-effective controls identified through these analyses.

We appreciate this consultation opportunity and look forward to continuing to work with Illinois to improve and protect air quality and visibility in our Class I areas. The emission reductions identified through the regional haze process are necessary for incremental progress toward the ultimate regional haze goal of no human-caused impairment in Class I areas. The NPS encourages Illinois to continue its role as an environmental leader and take this once-in-a-decade opportunity to make a difference for clean air and clear views in our national parks.

2 Overarching Feedback

2.1 Source Selection

The NPS agrees that the sources selected by Illinois are significantly affecting visibility in Class I areas. The NPS also recommends that Illinois revise the source screening metrics to consider additional facilities as described below.

Consistent with LADCO recommendations, IEPA used the Q/d method as a surrogate for source visibility impacts, where Q was the computed as the sum of SO_2, NO_x, NH_3, and $PM_{2.5}$ for the 2016 base year. In the first screening step, Illinois set a *"unit-level Q/d threshold of greater than 4 to begin evaluating individual units"* to be considered for four-factor analysis. In the second screening step, Illinois grouped those units by source and considered sources having a facility-wide Q/d surrogate impact greater than 10 for four-factor analysis. IEPA then excluded EGU

facilities subject to the Illinois Multi-Pollutant Standards and Combined Pollutant Standard requirements as well as a facility with a scheduled retirement in 2027 under the Climate and Equitable Jobs Act. This resulted in the selection of five facilities for four-factor analysis in the IEPA SIP: (1) Prairie State Generating Station – Marissa, (2) Southern Illinois Power Coop – Marion, (3) Rain CII Carbon – Robinson, (4) Lafarge Midwest (now Holcim) – Grand Chain, and (5) Archer Daniels Midland – Decatur.

The NPS agrees that Q/d is an appropriate surrogate metric to use in source screening analyses; the original 2019 NPS source screening recommendations were based on capturing 80% of the Q/d surrogate impact in each NPS Class I area. However, the NPS finds that Illinois' application of the threshold to individual emission units, rather than the entire facility, inappropriately excluded emission units and/or facilities that have been identified as contributing to visibility impairment in NPS Class I areas.

For example, Illinois selected two of the nine coal-fired circulating fluidized-bed boilers at the Archer Daniels Midland Company (ADM) facility, even though the remaining seven units are significant SO_2 emission sources and accounted for 63% of the 9,926 tons/year of facility-wide SO_2 emissions in 2020. Based on 2020 emissions data reported by IEPA and EPA's Clean Air Markets Program Database (CAMPD), boilers 1–7 emitted 6,283 tons/year SO_2. In comparison, boilers 8 and 9, the two selected for analysis by Illinois, emitted 3,643 tons/year SO_2, which accounts for 37% of the facility-wide SO_2 emissions. As such, the individual unit screening approach used by IEPA arbitrarily omitted most of the facility SO_2 emissions from review. The NPS finds that additional controls on boilers 1–7 may be cost-effective and recommends that they be included in the Illinois source selection process.

The LADCO regional planning organization identified a Q/d threshold of 4 applied to the *entire facility* as an appropriate screening metric. The additional sources recommended for review by the NPS in this document all exceed this LADCO recommended threshold.

The NPS updated and revised the original 2019 list of recommendations based on more recent information, including Area of Influence (AOI) analyses released by the VISTAS[1] and CENSARA[2] regional planning organizations.[3] Additionally, the NPS removed facilities that have closed or are scheduled for closure or have reduced their emissions since the 2019 list was developed. The full list of Illinois sources recently considered for analysis by the NPS are in Table 1 below.

[1] "VISTAS" is the Visibility Improvement State and Tribal Association of the Southeast, a Regional Planning Organization (RPO) supporting development of regional haze SIPs. Participating states: AL, FL, GA, KY, MS, NC, SC, TN, VA, and WV. (https://www.metro4-sesarm.org/)

[2] "CENSARA" is the Central States Air Resource Agencies, a Regional Planning Organization (RPO) supporting development of regional haze SIPs. Participating states: AR, IA, KS, LA, MO, NE, OK, and TX. (https://censara.org/)

[3] Area of Influence Analyses (AOI) are more robust screening metrics that in addition to emissions over distance calculations for individual facilities, also account for meteorology using back trajectories and residence time analyses that are extinction-weighted based on visibility monitoring. The NPS reconciled the original 2019 list of sources recommended for analysis with the AOI analyses produced by the RPOs. Similar to the Q/d analysis, the NPS sorted the AOI results to capture 80% of the AOI impact in any NPS Class I area.

Table 1. Updated NPS review of Illinois sources, color coding is described the narrative below.

Facility Name	NO_x	SO_2	Q	Distance to NPS Class I Area	Q/d	Most affected NPS Class I Area (Q/d)	CENSARA AOI List?	VISTAS AOI List?
Joppa Steam	2,512	8,243	10,755	252	42.76	MACA	Yes ISLE & MACA	Yes MACA, GRSM
Prairie State Generating Station	3,894	9,772	13,666	340	40.24	MACA	Yes MACA, ISLE	No
Archer Daniels Midland Co	1,950	9,527	11,477	381	30.08	MACA	Yes ISLE	Yes MACA, GRSM
Rain CII Carbon LLC	368	6,810	7,179	242	29.63	MACA	Yes ISLE	Yes MACA, GRSM
Illinois Power Generating Co, Newton	1,880	4,632	6,512	271	24.03	MACA	Yes ISLE, MACA	Yes MACA, GRSM
Southern Illinois Power Coop, Marion	1,080	2,927	4,007	262	15.30	MACA	No	Yes MACA, GRSM
Dynegy Midwest Generation LLC, Baldwin Energy Complex	1,785	1,475	3,260	353	9.24	MACA	Yes ISLE	No
Tate & Lyle Ingredients Americas LLC	412	2,729	3,141	382	8.22	MACA	Yes ISLE	Yes GRSM
ConocoPhillips Co	1,402	1,495	2,897	395	7.34	MACA	Yes ISLE	No
Fuyao Glass Illinois Inc	2,048	240	2,288	375	6.10	MACA	Yes ISLE	No
Marathon Petroleum Co LLC	1,101	177	1,278	243	5.25	MACA	No	No
Holcim US Inc	476	409	885	253	3.49	MACA	No	No

Sources highlighted in gray are no longer recommended for review by the NPS because they have either shut down or converted to natural gas and reduced emissions to levels that are no longer a concern. Sources highlighted in blue are no longer recommended for review by the NPS due to pending shutdowns prior to end of the planning period. Sources highlighted in green were selected for four-factor analysis by Illinois and reviewed by the NPS during the consultation process. Sources highlighted in orange were not selected by Illinois but were on the 2019 NPS list of sources recommended for review.

Based on this information the NPS requests that, in addition to ADM boilers 1–7, IEPA also complete four-factor analyses for three additional facilities:

1. Fuyao Glass Illinois Inc.,
2. WRB Refining LP Wood River Refinery, and the
3. Marathon Petroleum Co LLC. Refinery.

Table 2 shows the 2020 emissions for these three facilities and resulting Q/d for the nearest NPS Class I area, Mammoth Cave National Park in Kentucky.

Table 2. Additional facilities recommended for four-factor analysis

Facility Name	2020 NO_x emissions (tons)	2020 SO_2 emissions (tons)	Q	Distance to NPS Class I Area (km)	Q/d
Fuyao Glass Illinois Inc	2,272	214	2,487	375	6.6
WRB Refining LP Wood River Refinery	1,820	948	2,768	395	7.0
Marathon Petroleum Co LLC	1,245	136	1,381	243	5.7

2.2 Four-Factor Cost Analyses

The NPS generally recommends improving the four-factor cost analyses by better documenting IEPA rationale for control determinations.

The cost analyses provided by IEPA would benefit from including additional calculation details. For example, draft SIP Table 3.2D, *Illinois Coal to PRB Coal Switching Control Option Costs*, lists several cost components in different dollar years. It is not clear how the costs in this table add to the value given as the total annual cost of the control measure. Next to the total annual cost, the table says, *"Using Consumer Price Index ("CPI") data of 2016 and 2017 through May 2020 for adjusting the 2017 data, total annual cost of the control measure in 2020$.*" It is not clear exactly how the component costs were adjusted.

It would be helpful to include links to all references cited or to include references as part of the SIP. While many citations to references do include a link, there are some that do not. For example, draft SIP Table 3.2C cited a source reference titled *"U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report."* A link to this report would clarify the reference. The SIP also refers in several places to an U.S. Environmental Protection Agency (EPA) document called the *"Menu of Control Options"* (also referred to as the *"Menu of Control Measures"*) with a 2006 date but does not include a link to the specific document. A Google search located an EPA document called *"Menu of Control Measures"* with a 2022 date (https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation), but it is not clear if this is the same cited reference. In addition, the draft SIP listed some attached files that were not included in the FLM consultation draft, e.g., "Appendix A Table A1, Excel workbooks including prairie_state_retrofit_cost_tool_2019_06_04" and "prairie_state_scr_cost_manual_spreadsheet." The NPS recommends including these files as part of the SIP.

Some of the control measure costs taken from the cited references are older than what EPA recommends for use in estimating current control measure costs. For example, draft SIP Table 3.4, *Repowering to Integrated Gasification Combined Cycle Control Option*, cites capital and fixed Operation & Maintenance (O&M) costs in 2006 dollars. The resulting cost-effectiveness estimate was then scaled from 2006 to 2020 using the Consumer Price Index (CPI).

In the Control Cost Manual, EPA does not recommend escalating costs beyond five years:

> *"It should be noted that the accuracy associated with escalation (and its reverse, de-escalation) declines the longer the time period over which this is done. Escalation with a time horizon of more than five years is typically not considered appropriate as such escalation does not yield a reasonably accurate estimate."*

In addition, the Control Cost Manual does not recommend using the CPI to adjust costs for inflation when estimating control costs:

> *"The CPI is not recommended because the price change of interest is among consumer goods and services which have little relevance to capital project spending or industrial intermediate goods such as raw materials such as reagents… One index that has been used extensively by EPA for escalation purposes is the Chemical Engineering Plant Cost Index (CEPCI), an index that tracks costs of equipment, construction labor, buildings, and supervision in chemical process industries. Other cost indexes exist, such as Marshall & Swift (M&S), another equipment cost index that is widely used. "*[4]

The NPS recommends using facility-specific cost estimates for control measures where possible rather than using estimates prepared for other purposes. For example, draft SIP Table 3.4, *Repowering to Integrated Gasification Combined Cycle Control Option*, lists capital and fixed O&M costs in dollars per kilowatt taken from the EPA *"Menu of Control Measures*" document. Also, as discussed in a subsequent section on the Rain Carbon II facility, the draft SIP cites cost per ton for semi-dry scrubbing from a Bay Area Air Quality Management District (BAAQMD) report for a California facility.

As noted by EPA in its Regional Haze State Implementation Plan Guidance:

> *"We recommend that states exercise caution before accepting or rejecting controls based on generic cost estimates if adequately documented source-specific estimates are available or can be prepared…If a cost quote or opinion prepared for one source is adopted or adapted to another source, EPA recommends the state explain in its SIP submittal how the source for which the original cost estimate was made is relevant to estimating the cost of compliance for the source in question."* [5].

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[4] Control Cost Manual, 7th edition, Section 1, Chapter 2, Cost Estimation: Concepts and Methodology, pp. 18-19. Available at: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.

[5] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, p. 32. Available at: https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period.

2.3 Cost Thresholds

In its review of the five sources selected for four-factor analysis, IEPA did not find any controls measures that were considered cost-effective. However, the draft SIP does not identify the criteria or thresholds that were used to make this determination. The NPS recommends that Illinois establish a cost-effectiveness threshold to document the rationale behind the control cost conclusions and long-term strategy determinations presented in the SIP. Documenting the criteria used to make control determinations, including how control costs (statutory factor 1) were evaluated, is consistent with the regional haze rule requirements:

> *The State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment. The State should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources.* ***The State must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures*** *for inclusion in its long-term strategy.* [40 CFR § 51.308 (f)(2)(i); Emphasis added.]

In their 2019 regional haze guidance, the EPA recommends that a useful metric for reporting and evaluating the costs of compliance is the estimated cost per ton of pollutant reduced.[6] Identifying a cost threshold in the SIP will ensure that the basis for long-term strategy determinations is transparent.

Many states have identified a cost-effectiveness threshold (annual dollars/ton reduced) in their proposals in this round of regional haze planning. When considering factors such as the impact of inflation since the first round of haze planning, improvements in the applicability and efficiency of control technologies, and the need to address smaller sources in subsequent rounds of haze planning, the NPS recommends that reasonable cost-effectiveness thresholds for the second round should be higher than those used in the first round of haze planning. For example, other states have proposed the following cost/ton thresholds in the second planning period:

- A range from $4,000 to $6,500/ton in Arizona
- $5,000/ton in Arkansas (EGUs) and Texas
- A range from $5,000 to $10,000/ton in Nevada
- $5,800/ton (2019 dollars) in Hawaii
- $6,100/ton in Idaho
- $10,000/ton in Colorado and Oregon

[6] 2019 EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, Part II, Step 4: Characterization of factors for emission control measures, c) Characterizing the cost of compliance (statutory factor 1).

The controls evaluated and recommended by the NPS for Illinois sources are within these cost-effectiveness ranges. This suggests that additional controls may be cost-effective for Illinois sources. From EPA's 2019 regional haze guidance document:

> *When the cost/ton of a possible measure is within the range of the cost/ton values that have been incurred multiple times by sources of similar type to meet regional haze requirements or any other CAA requirement, this weighs in favor of concluding that the cost of compliance is not an obstacle to the measure being considered necessary to make reasonable progress.*

The NPS recommends that Illinois establish and disclose a cost-effectiveness threshold in the SIP that is within the range of those established by other states in this round of regional haze planning.

3 Facility-Specific Feedback

3.1 Prairie State Generating Station

Prairie State Generating Station is a power plant located near Marissa, Illinois that includes two identical dry-bottom pulverized coal wall-fired boilers. These boilers began operating in 2011 and 2012 and are equipped with wet flue gas desulfurization (WFGD) for SO_2 emissions control, selective catalytic reduction (SCR) for nitrogen oxides (NO_x) emissions control, and electrostatic precipitators to control particulate matter emissions.

Despite 98% SO_2 control efficiency, emissions remain significant (e.g., 9,187 tons in 2022) and the current SO_2 emissions rate is approximately ~ 0.16 lb/MMBtu. Emissions from the two boilers are shown in Table 3 below.

Prairie State is scheduled to close in 2045 under CEJA. This closure date is near the end of the fourth regional haze planning period. Given this timeframe and the relatively high SO_2 emissions from the facility, the NPS recommends that Illinois consider and evaluate:

Options to improve scrubber efficiency and
The addition of Dry Sorbent Injection (DSI) to increase SO_2 control (the NPS estimates DSI costs for these boilers at $8,732/ton and $10,188/ton SO_2 removed.)

Table 3. Prairie State Generation Station emissions

Unit ID	Year	SO_2 Mass (short tons)	SO_2 Rate (lbs/MMBtu)	NO_x Mass (short tons)	NO_x Rate (lbs/MMBtu)
1	2012	2,073	0.12	1,108	0.07
1	2013	2,168	0.11	1,118	0.07
1	2014	2,922	0.11	1,541	0.07
1	2015	3,907	0.13	1,890	0.07
1	2016	4,505	0.15	1,895	0.07
1	2017	4,779	0.17	1,868	0.07
1	2018	5,535	0.17	2,052	0.07
1	2019	5,277	0.17	1,985	0.06
1	2020	5,253	0.16	2,033	0.06
1	2021	5,182	0.16	2,078	0.07
1	2022	5,157	0.17	1,983	0.07
2	2012	629	0.10	414	0.08
2	2013	2,551	0.11	1,270	0.06
2	2014	2,774	0.13	1,265	0.07
2	2015	3,940	0.15	1,735	0.07
2	2016	4,126	0.16	1,652	0.07
2	2017	4,970	0.17	1,931	0.07
2	2018	4,843	0.15	1,987	0.06
2	2019	5,464	0.16	2,140	0.06
2	2020	4,519	0.15	1,862	0.07
2	2021	5,355	0.16	2,043	0.06
2	2022	4,030	0.16	1,719	0.07

Source: EPA Clean Air Markets Program Data, https://campd.epa.gov/.

According to the draft SIP, Illinois concluded that, because the Prairie State scrubbers are achieving 98% SO_2 reduction, which is above the EPA Base Case v.5.13 assumed removal efficiency of 96%, it is not possible to achieve further emissions reductions with the existing systems. However, NPS review finds that the emissions rate is still relatively high for boilers equipped with wet scrubbing, at approximately 0.15 to 0.17 lb/MMBtu as shown in Table 3. According to the EPA Control Cost Manual, new WFGD systems can achieve SO_2 removal efficiencies of 99% and limestone wet flue gas scrubbers in use in 2019 achieved SO_2 emissions rates as low as 0.02 lb/MMBtu, with the top 50% achieving an average of 0.04 lb/MMBtu.[7] A recent search of the EPA CAMPD database for boilers equipped with WFGD found over 50 units with three-year average emissions rates less than 0.12 lb/MMBtu.[8] In addition, Prairie

[7] USEPA Control Cost Manual 7th Edition, Section 5, Chapter 1, SO_2 and Acid Gas Controls, Table 1.3, p. 1-12.
[8] Based on 2020-2022 average emissions rates computed using CAMPD data downloaded from https://campd.epa.gov/data/custom-data-download. See the Excel spreadsheet CAMPD_boiler_SO_2_rates.xlsx.

State's existing scrubbers have achieved lower SO_2 emissions rates in the past as shown in Figures 1 and 2.

Figure 1. Prairie State Unit 1 SO_2 Emissions Rate History

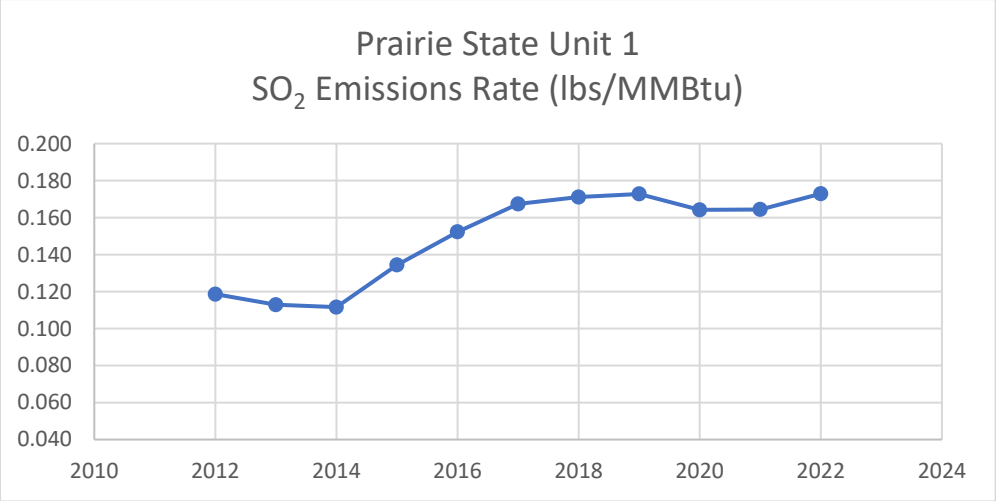
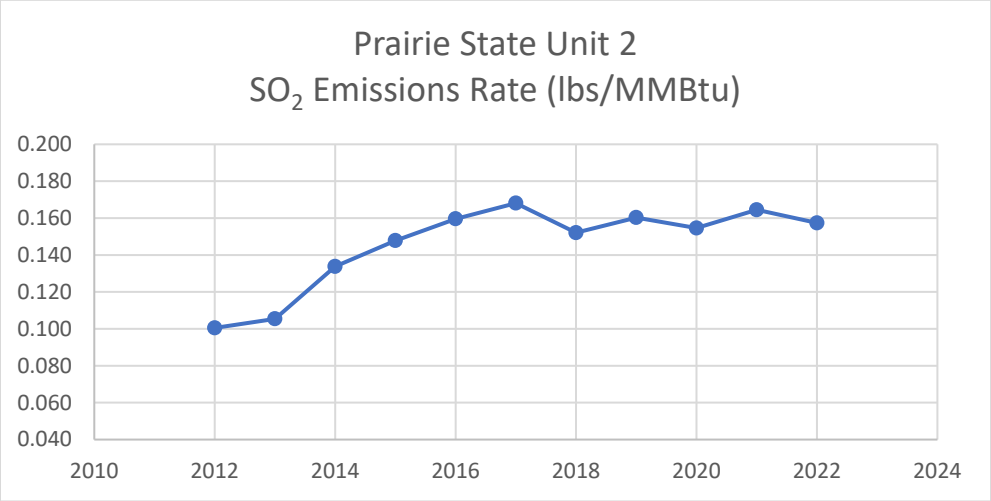


Figure 2. Prairie State Unit 2 SO_2 Emissions Rate History



The NPS recommends IEPA undertake a technical review of the existing wet scrubbers to identify opportunities to reduce SO_2 emissions through optimization or upgrades to the units (at a minimum, these scrubbers should be able to achieve the lower emission rates demonstrated in the past). This recommendation is consistent with guidance in EPA's 2021 Clarification memo:

> *[I]n some cases, states may be able to achieve greater control efficiencies, and, therefore, lower emission rates, using their existing measures. Considering efficiency improvements for an existing control (e.g., using additional reagent to increase the efficiency of an existing scrubber) as a potential measure is generally reasonable since in many cases such improvements may only involve additional operation and maintenance costs. States should generally include efficiency improvements for sources' existing measures as control options in their four-factor analyses in addition to other types of emission reduction measures. (Section 3.2—Control Options for Four-Factor Analysis)*

The NPS also estimated the cost-effectiveness of adding DSI systems to Prairie State's two boilers using the method developed for EPA's Integrated Planning Model (IPM) by Sargent and Lundy.[9] NPS estimates show that an additional 3,807 tons of SO_2 could be removed at a cost of $8,732/ton and $10,188/ton for Units 1 and 2, respectively. The calculations are documented in the accompanying Excel workbooks included in Attachment 2, titled *Prairie_State_Unit_1_DSI.xlsx* and *Prairie_State_Unit_2_DSI.xlsx*. The NPS recommends that Illinois evaluate the addition of DSI to Units 1 and 2.

3.2 Archer Daniels Midland (ADM)

3.2.1 Facility Background & Recent Emissions

Archer Daniels Midland Company (ADM) is a biochemical and food processing company located in Decatur, Illinois, 381 km from Mammoth Cave National Park. ADM's major contributors to visibility impairment are the nine cogeneration coal-fired circulating-fluidized bed boilers (Cogen-CFB Boilers). Boilers 1–5 were installed in 1987, Boiler 6 was installed in 1991, Boiler 7 in 1995, and Boilers 8 and 9 were installed in 1995 and 1997 respectively. The units are subject to Illinois' CEJA 415 ILCS 5/9.15(k) that requires emissions from the source to be zero by January 1, 2045.

Particulate matter (PM) emissions are controlled by baghouses. NO_x emissions are controlled using low-NO_x burners and SNCR systems. SO_2 emissions are controlled by using a blend of

[9] IPM Model – Updates to Cost and Performance for APC Technologies Dry Sorbent Injection for SO_2/HCl Control Cost Development Methodology, Sargent and Lundy, November 2022. Available at: https://www.epa.gov/system/files/documents/2023-01/13527-002%20DSI%20Cost%20Methodology%20-%20Final.pdf.

limestone, 60% Western low sulfur coal, and DSI systems. Table 4 below compiles 2020 data from IEPA and EPA's CAMPD[10].

Table 4. Recent emissions data for ADM Boilers 1–9

Unit ID	Heat Input Capacity (mmBtu/hr)	Sum of the Operating Time	Steam Load (1000 lb)	SO_2 Mass (short tons)	SO_2 Rate (lbs/mmBtu)	NO_x Mass (short tons)	NO_x Rate (lbs/mmBtu)	Heat Input (mmBtu)
FBC1	492	8,289	2,708,961	992	0.554	176	0.098	3,582,916
FBC2	492	8,175	2,651,753	840	0.479	172	0.098	3,507,251
FBC3	492	7,983	2,597,373	852	0.496	167	0.097	3,435,327
FBC4	492	8,251	2,668,224	909	0.515	165	0.093	3,529,036
FBC5	492	8,049	2,613,554	942	0.545	161	0.093	3,456,729
FBC6	700	7,859	2,579,172	969	0.568	159	0.093	3,411,254
FBC7	750	8,155	2,269,210	779	0.519	148	0.099	3,001,293
FBC8	1,500	7,242	4,953,124	1,625	0.496	404	0.123	6,551,081
FBC9	1,500	7,995	7,260,332	2,018	0.376	316	0.065	10,735,303
Totals	6,910		30,301,703	9,926		1,867		41,210,190

Based upon NPS estimates using 2020 emissions of SO_2 and NO_x, ADM's Q/d impact at Mammoth Cave National Park is 31 and this source is on the AOI lists for Mammoth Cave, Great Smoky Mountains, and Isle Royale National Parks using the VISTAS and CENSARA AOI analyses.

3.2.2 NPS Cost of Compliance Review for ADM

Statutory factor 1 in regional haze review is the cost of compliance.

NPS review of the cost of compliance analysis provided by IEPA finds that ADM has pre-combustion and post-combustion add-on control systems for PM, NO_x and SO_2 emissions.

The NPS finds that:

> The current baghouses represent effective control for PM.
> Although SCR would reduce NO_x to as low as 0.04 lb/mmBtu, the relatively high capital cost of this control strategy coupled with the relatively short remaining useful life means that it would not be cost-effective, especially when the low emission rates achieved by the existing SNCR systems are considered.

The NPS concludes that ADM is not effectively controlled with respect to SO_2. The NPS analysis focused on reducing SO_2 emissions by replacing or upgrading the existing DSI systems.

[10] Because CAMPD does not contain SO_2 emissions data for ADM, we used 2020 SO_2 emission rates from the "test report 2020" tab in IEPA's "adm_retrofit_cost_tool_2019_06_04" file multiplied by CAMPD heat inputs to generate annual emissions in ton/yr.

Documentation[11] provided by Sargent & Lundy in its November 2022 update to the EPA's IPM assumes that DSI can achieve up to 90% control with milled trona and a baghouse. As a result, NPS analyses assumed 80%–86% control down to 0.08 lb/mmBtu.[12] The following sections describe how the NPS applied the updated DSI cost model.

Capital Costs Calculations

The DSI model requires Unit Size in Gross Mega Watt (MW). The only data available to the NPS during consultation was unit heat input in mmBtu/hr from IEPA's Table 3.2. Instead of using the IPM default value of 9,500 Btu/kWh, NPS analysis used 2022 CAMPD data for coal-fired Circulating Fluidized-Bed (CFB) boilers to estimate this value (10,476 Btu/kWh). (IEPA used 2,930 Btu/kWh, which seems improbable and is likely an error. This resulted in an overestimate of boiler output by more than a factor of 3 and inflated the capital costs by about 50%.)

IEPA's "adm_retrofit_cost_tool_2019_06_04" file contains SO_2 emission rates in lb/mmBtu for 2018–2020, but no SO_2 tons/year for 2019 or 2020. Figure 3 below shows SO_2 emission rates for all nine CFBs is below and indicates a significant increase over the most recent emission years available.

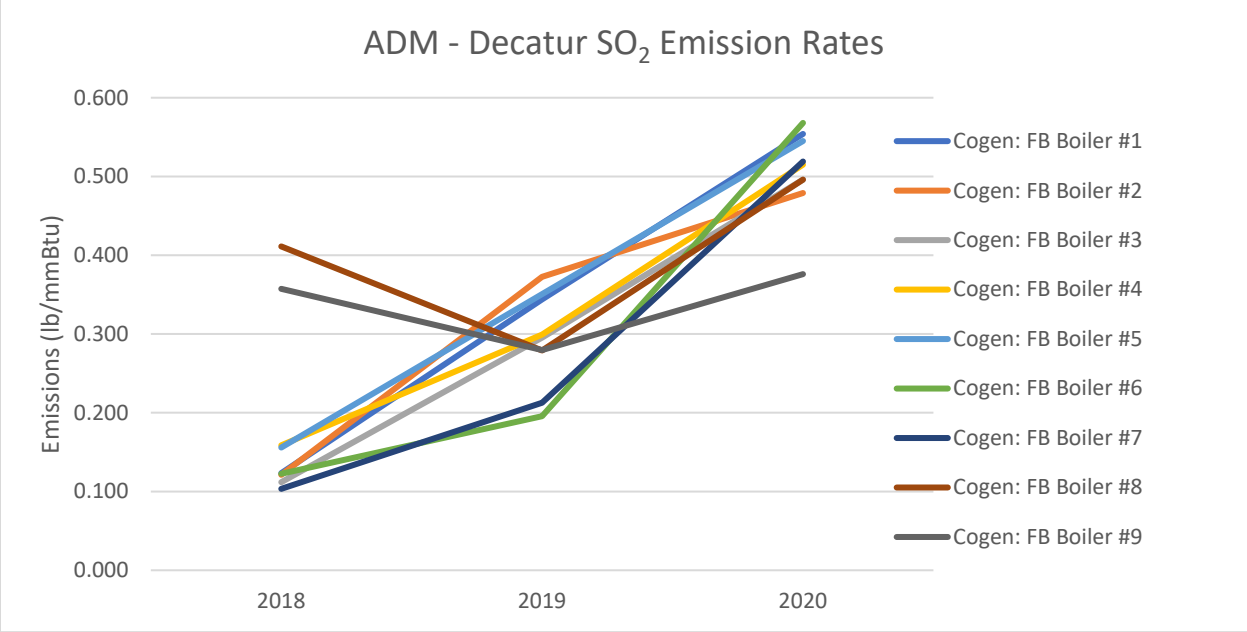


Figure 3. SO_2 emission rates from ADM Boilers 1–9 have increased significantly, 2018–2020

Because of the significant increase in SO_2 emission rates, NPS analysis used the most-recent (2020) emission rates (lb/mmBtu) instead of a multi-year average that would typically be used.

[11] IPM Model - Updates to Cost and Performance for APC Technologies SCR Cost Development Methodology for Oil/Gas Fired Boilers (epa.gov) A baghouse used with sorbents generally achieve a higher SO_2 removal efficiency (50 to 98%) than that of an ESP.

[12] In 2022 CAMPD, Unit 4 at the Boswell Energy Center achieved 0.03 lb SO_2/mmBtu with DSI, while Unit B1 at the J. P. Madgett facility achieved 0.08 lb SO_2/mmBtu.

2022 CAMPD data shows two coal-fired CFBs with DSI at 0.08 lb/mmBtu or lower, so NPS analysis adjusted the SO_2 removal efficiency to achieve this emission rate.

Cost-Effectiveness

The NPS did not have unit-specific SO_2 emission rates in tons/year for 2020, so rates were estimated based upon the 2020 SO_2 emission rates (lb/mmBtu) provided by IEPA multiplied by the 2020 heat inputs (mmBtu/yr) from CAMPD. The results were labeled as "Target" 2020 annual SO_2 emissions in tons/year.

Operation and Maintenance

With these "Target" estimated annual emissions, the NPS adjusted the annual Gross Load (in MWh) so that "Uncontrolled SO_2" calculated by the workbook approximated the "Target" estimated SO_2 emissions in 2020. (The annual heat input values provided by IEPA's Table 2.3 appear to be an error because they exceeded the maximum capacities of CFBs 1–7 by 2–3 times.) Assuming that DSI would not be fully operational on all nine CFBs until the end of the 2028 planning period, and that all CFBs would cease operation by 2045 to comply with CEJA, NPS calculations assumed an equipment life of 17 years. Results of the NPS cost analysis are shown in Table 5 below.

Table 5. NPS Estimated DSI cost-effectiveness for SO_2 emission reductions from ADM Boilers 1-9

Emission Unit	Unit Size (Gross MW)	2020 Uncontrolled SO_2 Emission Rate (ton/yr)	2020 Uncontrolled SO_2 Emission Rate (lb/mmBtu)	Controlled SO_2Emission Rate (lb/mmBtu)	Control Efficiency (%)	SO_2 Emission Reduction (tons/year)	Remaining SO_2 Emissions (tons/year)	Cost-Effectiveness ($/ton)
Boiler #1	47	992	0.554	0.08	85	844	149	$ 3,504
Boiler #2	47	840	0.479	0.08	83	698	142	$ 3,837
Boiler #3	47	852	0.496	0.08	83	707	145	$ 3,793
Boiler #4	47	909	0.515	0.08	85	773	136	$ 3,668
Boiler #5	47	942	0.545	0.08	85	801	141	$ 3,586
Boiler #6	67	969	0.568	0.08	86	834	135	$ 3,679
Boiler #7	72	779	0.519	0.08	84	655	123	$ 4,134
Boiler #8	143	1,625	0.496	0.08	84	1,364	261	$ 3,382
Boiler #9	143	2,018	0.376	0.08	80	1,694	324	$ 3,403
Totals	660	9,926				8,369	1,556	

The estimated Cost of Compliance for adding DSI SO_2 controls is consistent with values accepted by other states and could reduce emissions from this facility by 8,369 tons/year.

As noted in Section 2, thresholds for average cost-effectiveness used by other states in the second round of regional haze planning range from $4,000 to $10,000/ton. The NPS recommends that DSI controls for ADM are cost-effective.

3.2.3 Other Statutory Factors

Statutory Factor 2 – Time Necessary for Compliance

The time necessary for compliance includes the time the Agency needs to develop, propose, and implement regulations, which usually takes around two years. For affected sources, the time needed to implement the evaluated control measures usually requires 18 months to five years. The NPS assumed 18 months for DSI.

Statutory Factor 3 - Energy and Non-Air Quality Environmental Impacts of Compliance

Addition or upgrading of the exiting DSI system would not introduce any new or unusual impacts.

Statutory Factor 4 - Remaining Useful Life of Potentially Affected Sources

The remaining useful life of the boilers was estimated by IEPA to be between 15 and 22 years, and the units are subject to Illinois' CEJA 415 ILCS 5/9.15(k) that requires emissions from the source to be zero by January 1, 2045. NPS analyses assumed a 17-year remaining useful life from the 2028 end of this planning period.

3.2.4 Four-Factor Analysis Conclusions & Recommendations

The NPS recommends that upgrading existing DSI or adding new DSI to the ADM boilers is a very cost-effective way to reduce SO_2 emissions from this facility by over 8,000 tons/year. The NPS also concludes that, due to the higher capital costs of SCR and the existing level of control, the addition of SCR would not be cost-effective for controlling NO_x and that that PM emissions are effectively controlled.

3.3 Rain CII Carbon LLC

The Rain Carbon facility, located in Robinson, Illinois, produces calcined petroleum coke from green petroleum coke (GPC). The main sources of emissions are the two rotary calcining kilns. The primary energy sources for the kilns are residual hydrocarbons in the kiln gases and a portion of the GPC feedstock that is burned for fuel. The kilns are equipped with a multi-clone collector and baghouses for control of particulate matter, but do not have controls for NO_x or SO_2 emissions. Table 6 shows recent emissions presented in Table 2.2 of the draft SIP.

Table 6. Rain II Carbon Facility Reported Emissions

	Emissions (tons/year)				
Pollutant	**2015**	**2016**	**2017**	**2018**	**2019**
$PM_{2.5}$	152	143	247	151	188
NO_x	225	255	371	278	343
SO_2	2,160	3,836	6,810	4,163	5,452

Table 3.2 of the draft SIP shows potential options for add-on SO_2 controls, including dry flue gas desulfurization, semi-dry flue gas desulfurization, and wet flue gas desulfurization. Included in Table 3.2 are SO_2 control cost-effectiveness estimates taken from a variety of other documents,

including a 2015 Bay Area Air Quality Management District (BAAQMD) workshop report[13] that range from $2,400/ton of SO_2 removed to over $88,000/ton of SO_2.

Table 4.2 of the draft SIP gives estimated costs for the Rain facility updated to 2022 dollars, based on estimates in Table 3.2. The most cost-effective option in Table 4.2 is $9,570/ton SO_2 removed for semi-dry flue gas desulfurization. According to the draft SIP discussion, this value was obtained by taking the cost-effectiveness estimate from the BAAQMD workshop report estimate for a Phillips 66 petroleum coke facility in the San Francisco Bay Area and updating it to 2020$. The BAAQMD staff derived its cost-effectiveness estimate of $8,700/ton SO_2 removed for a semi-dry scrubbing system by communicating with multiple control equipment vendors and the facility's staff. The workshop report does not contain details of the cost calculations. Without detailed cost information, the NPS cannot evaluate whether the cost-effectiveness estimate from the BAAQMD workshop report is applicable to the Rain II Carbon facility's calcining kilns. While it may be possible to apply the EPA Control Cost Manual's cost-estimating methodology to the Rain facility kilns, this would require kiln operations data, which are not provided in the draft SIP. The NPS recommends that IEPA prepare a detailed cost analysis for SO_2 emissions reduction specific to the Rain facility, as this is a significant SO_2 emission source and is on the NPS Q/d and AOI lists for Mammoth Cave, Great Smoky Mountains, and Isle Royale National Parks. Alternatively, IEPA could require installation of a spray-dry absorbing system as mandated by the BAAQMD for petroleum coke facilities. The NPS recommends including facility-specific vendor quotes where possible.

3.4 Southern Illinois Power Cooperative, Marion

The Southern Illinois Power Cooperative (SIPCO) operates an EGU near Marion, Illinois, which uses two natural gas-fired turbines and a single fossil fuel-fired boiler. Boiler #123 is CFB coal-fired boiler built in 2001 with a firing capacity of 1400 MMBtu/hr. The boiler can burn a variety of solid fuels, including coal, coal refuse, petroleum coke, tire-derived fuel, and wood chips. SO_2 emissions are controlled by means of limestone injection. In addition, the boiler is equipped with SNCR for NO_x emissions control and a baghouse for PM control. According to the draft SIP, the limestone injection system achieves a 90% reduction in SO_2 emissions. Recent SO_2 emissions for the boiler are shown in Table 7 below.

[13] *Bay Area 2010 Clean Air Plan Control Measure SSM 8, BAAQMD Regulation 9, Rule 14: Petroleum Coke Calcining Operations, Draft Workshop Report*, William Thomas Saltz, May 8, 2015.

Table 7. Southern Illinois Power Cooperative emissions.

Unit ID	Year	SO_2 Mass (short tons)	SO_2 Rate (lbs/mmBtu)	NO_x Rate (lbs/mmBtu)	NO_x Mass (short tons)
123	2010	2,013	0.41	0.10	466
123	2011	1,990	0.44	0.10	455
123	2012	1,836	0.38	0.10	467
123	2013	2,030	0.43	0.10	483
123	2014	2,197	0.47	0.11	550
123	2015	1,622	0.34	0.09	421
123	2016	1,620	0.35	0.08	380
123	2017	1,510	0.32	0.08	389
123	2018	1,962	0.37	0.08	410
123	2019	2,039	0.40	0.07	389
123	2020	860	0.26	0.09	310
123	2021	1,652	0.33	0.09	482
123	2022	2,806	0.50	0.08	447

Source: EPA Clean Air Markets Program Data, https://campd.epa.gov/.

While the four-factor analysis concluded that it is not possible to improve the efficiency of the existing SO_2 controls, IEPA did evaluate fuel-switching and repowering to integrated gasification combined cycle (IGCC) as options for emissions control. The analysis evaluated the cost-effectiveness of these options for the combination of Boilers 4 and 123, but Boiler 4 has since stopped operating. The cost-effectiveness for the fuel-switching ranged from $2,064 (2020 dollars) per ton of emissions (NO_x+SO_2) removed to $4,073 (2020 dollars) per ton of emissions. The cost-effectiveness of repowering to IGCC was estimated at $6,509 (2020 dollars) per ton of emissions. These costs are well within the range of cost-effectiveness thresholds deemed reasonable by other states. However, the draft SIP concluded: "Based on the size of yearly emissions, the cost of the control measure evaluated in this analysis, and the remaining useful life of the boilers, IEPA will not be proposing any new NO_x or SO_2 reduction measures for SIPCO's boilers in the second implementation period."

The draft SIP did not evaluate the cost-effectiveness of adding post-combustion SO_2 controls to Boiler 123. The NPS estimated the cost-effectiveness of adding a DSI system to Boiler 123 using the method developed for EPA's IPM. The cost calculations are documented in the accompanying Excel workbook titled *SIPCO_DSI.xlsx*. The estimate assumed a remaining useful life of 20 years, an input SO_2 emissions rate of 0.386 lb/MMBtu based on the most recent five years of data, and a controlled SO_2 emissions rate of 0.08 lb/MMBtu. Estimated costs are summarized in Table 8 below. The estimated cost-effectiveness of $3,485/ton to remove an additional 1,472 tons/year of SO_2 is well within cost-effectiveness thresholds selected by other states for this planning period.

Table 8. Estimated costs for SIPCO Boiler 123 DSI system (2022 dollars)

Total Capital Investment	$9,687,794	
Capital Recovery Cost	$1,023,719	/yr
Fixed O&M	$ 338,788	/yr
Variable O&M	$3,767,690	/yr
Total Annual Cost	$5,130,197	/yr
Uncontrolled SO_2	$ 1,864	ton/yr
SO_2 Removed	$ 1,472	tons/year
Cost-Effectiveness	$ 3,485	$/ton

The NPS also estimated costs for adding WFGD and spray dry absorbing (SDA) to Boiler 123 using the Wet and Dry Scrubbers Cost Calculation Spreadsheet provided in the Control Cost Manual.[14] The cost estimates are documented in the accompanying Excel workbooks *SIPCO_SO2_costs_EPA_spreadsheet_WFGD.xlsm* and *SIPCO_SO2_costs_EPA_spreadsheet_SDA.xlsm*. The resulting estimates suggest that 1,670 tons of SO_2 could be removed at a cost of $12,846/ton SO_2 and 1,575 tons of SO_2 could be removed at a cost of $11,335/ton SO_2 using WFGD and SDA, respectively. While these estimates are higher than the cost-effectiveness estimate for DSI, the Control Cost Manual states that its costs and estimating methodology are valid for a "study" estimate with a probable error of 30% percent[15] and thus actual scrubber costs may be lower than those presented here.

The NPS recommends that IEPA update its cost-effectiveness estimates for fuel-switching and repowering options for Boiler 123 alone, as Boiler 4 is no longer operating. The NPS also recommends that IEPA evaluate DSI, WFGD, and SDA for Boiler 123 and select a cost-effective method to reduce emissions in this planning period.

3.5 Wood River and Marathon Petroleum Co LLC Refineries

The Marathon and Wood River (previously known as Conoco Phillips) refineries were both included in the original list of sources recommended for analysis by the NPS. These facilities were not selected by IEPA for four-factor analysis in the draft SIP. The emissions from these facilities as reported in the 2020 National Emissions Inventory (NEI) are shown in Table 9 below. Both facilities have a Q/d metric greater than 4 for the closest NPS Class I area, Mammoth Cave National Park in Kentucky.

[14] Available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[15] EPA Control Cost Manual 7th edition, Section 1, Chapter 2, Cost Estimation: Concepts and Methodology, Section 2.3, pg. 6. Available at: https://www.epa.gov/sites/default/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.

Table 9. Wood River and Marathon Refinery Emissions.

Facility Name	2020 NO_x emissions (tons)	2020 SO_2 emissions (tons)	Q	Distance to NPS Class I Area (km)	Q/d
WRB Refining LP Wood River Refinery	1,820	948	2,768	395	7.0
Marathon Petroleum Co LLC	1,245	136	1,381	243	5.7

The NPS recommends Illinois require a four-factor analysis for NO_x emissions from the large NO_x units (those with greater than 40 MMBtu heat input), including the heaters and boilers at the Wood River refinery and the catalytic cracking unit and combustion sources at the Marathon refinery. The NPS also recommends the analysis consider reducing sulfur content in the refinery fuel gas at both facilities as a strategy to reduce facility-wide SO_2 emissions from the numerous small SO_2 sources at the facilities.

3.6 Fuyao Glass Illinois Inc

Fuyao Glass Illinois operates a glass facility in Decatur, Illinois. This facility was included in the original list of sources recommended for analysis by the NPS but was not selected by IEPA for analysis in the draft SIP. The facility's emissions as reported in the 2020 NEI are shown in Table 10 below. The facility has a Q/d of 6.6 for the closest Class I area, Mammoth Cave National Park in Kentucky. The source is also on the CENSARA AOI list for Isle Royale National Park in Michigan.

Table 10. Fuyao Glass 2020 emissions.

Facility Name	2020 NO_x emissions (tons)	2020 SO_2 emissions (tons)	Q	Distance to NPS Class I Area (km)	Q/d
Fuyao Glass Illinois Inc	2,272	214	2,487	375	6.6

The NPS recommends IEPA conduct a four-factor analysis of Fuyao Glass including evaluation of SCR to control NO_x emissions and a catalytic ceramic filter system to control multiple pollutants. There is a glass furnace successfully operating with SCR to control NO_x emissions at the Vitro Flat Glass LLC-Carlisle Plant in Pennsylvania. Oregon has recently issued a permit for Owens-Brockway, which is installing a ceramic filter to control PM, SO_2, and NO_x emissions from a glass furnace. This permit is included in Attachment 2 for reference. In addition, Texas obtained vendor quotes and analyzed the costs of installing a catalytic ceramic filter system on the Vitro Flat Glass LLC, Works No 4 Wichita Falls Plant in their recent regional haze SIP.[16] While Texas estimated NO_x and SO_2 control costs separately, the NO_x control costs for Melting

[16] According to TCEQ documents, Texas evaluated the costs for Tri-Mer's Catalytic Ceramic Filter system based on vendor quotes. The NPS did not have the information necessary to evaluate the cost analysis, but the estimated control costs presented by Texas appear reasonable.

Furnace Line No 2 (which has very similar annual NO_x emissions (2,533 tons/year) to those at Fuayo Glass) were estimated at $3,200/ton NO_x for a 15-year remaining useful life and $2,900/ton NO_x for a 30-year remaining useful life. The NPS recommends that combined cost-effectiveness values be calculated for multi-pollutant control systems. These costs suggest that a catalytic ceramic filter system could be very cost-effective.

3.7 Other

3.7.1 Illinois Power Generating Co, Newton; and Dynegy Midwest Generation LLC, Baldwin Energy Complex

The pending facility shutdowns that will occur in 2027 and 2025, respectively, will address visibility concerns associated with these facilities. Consistent with EPA guidance, the NPS recommends these shutdowns are made federally enforceable and included in the SIP.

3.7.2 Tate & Lyle Ingredients Americas LLC

This facility was included in the original list of sources recommended for analysis by the NPS but was not selected by IEPA for four-factor analysis in the draft SIP. The facility has since replaced its coal-fired boilers with natural gas. According to annual emissions data provided by IEPA, the facility's emissions have dropped significantly as a result of the boiler replacement and the Q/d for the nearest NPS Class I area is now below 4. The NPS agrees that it is now not necessary to complete a four-factor analysis for this facility.

3.7.3 Holcim US Inc

This facility was included in the original list of sources recommended for analysis by the NPS and was selected by IEPA for four-factor analysis. Based on the draft SIP, this facility is currently equipped with dry absorbent addition for SO_2 control and SCR for NO_x control. The NPS has no further control recommendations for this source.

USDA United States Department of Agriculture | Forest Service | Mark Twain National Forest Supervisor's Office

401 Fairgrounds Road
Rolla, MO 65401
573-364-4621
Fax: 573 364-6844

File Code: 2580
Date: October 13, 2023

Ms. Julie Armitage
Director, Bureau of Air
Illinois E.P.A.

Dear Ms. Armitage:

On August 14, 2023, the State of Illinois submitted a draft Regional Haze State Implementation Plan describing your proposal to continue improving air quality by reducing regional haze impacts at mandatory Class I areas across the region. We appreciate the opportunity to work closely with the State through the initial evaluation, development, and subsequent review of this Plan. Cooperative efforts, such as these, ensure that together we will continue to make progress toward the Clean Air Act's goal of natural visibility conditions at our Class I areas.

This letter acknowledges that the USDA's Forest Service has received and conducted a substantive review of your proposed Regional Haze State Implementation Plan. This review satisfies your requirements under the Federal regulations 40 C.F.R. § 51.308(i)(2). However, only the U.S. Environmental Protection Agency (EPA) can make a final determination about the document's completeness. Therefore, only the EPA has the authority to approve the document.

Enclosed are comments to this letter based on our review, and we look forward to your response required by 40 C.F.R. § 51.308(i)(3). Again, we appreciate the opportunity to work closely with the State of Illinois. The Forest Service compliments you on your hard work and dedication to significant improvement in our nation's air quality values and visibility.

For further information, please contact Alexia Prosperi at alexia.prosperi@usda.gov.

Sincerely,

MICHAEL A. CRUMP
Acting Forest Supervisor

Enclosure

cc:
Alexia Prosperi
Trent Wickman

Illinois Draft Regional Haze State Implementation Plan (RH SIP) - Specific Comments

The USDA Forest Service (USFS) recognizes the significant emission reductions of nitrogen oxides (NOx) and sulfur dioxide (SO_2) made in Illinois in the last 15 years due to economic and regulatory drivers. These reductions directly led to measured visibility improvement and numerous other air quality related benefits at Hercules Glades Wilderness Area and other nearby USDA Forest Service Class I areas in the Southeast and Midwest US over that time.

Overall, the USFS finds that the draft RH SIP is well organized and comprehensive. The Long-Term Strategies for this planning period appear to indicate that Forest Service Class I Areas will continue to show visibility improvements better than the Uniform Rate of Progress (URP) through 2028, and we appreciate the commitment by Illinois EPA Bureau of Air (IL Air Program) to evaluate progress in meeting the visibility goals during the 5-year progress reports. However, we offer these specific comments on the draft RH SIP for IL Air Program review and consideration.

Source Selection

The choice of an emissions over distance (Q/d) unit and source threshold produces a number of emission sources for further analysis that is unique to the particular circumstances in each state. Our overriding concern is that a sufficient number of sources is selected. In this case, IL has selected an appropriate number of sources that account for a large portion of the impacts at USFS Class I areas. However, the USFS believes that the use of Q/d greater than 4 selection for emission units at sources with a Q/d greater than 10 may leave out units that should be evaluated because cost-effective controls could be identified. This is of particular note for Archer Daniels Midland.

Selection of Cost Threshold

In the draft RH SIP, there does not seem to be a cost-effectiveness threshold selected. Instead, all controls are deemed to be not cost effective – even those lower than $2,000 per ton. Other states have cost thresholds ranging from $4,000 to $10,000 per ton in their SIPs. It is reasonable to expect that the second and subsequent planning periods will require controls at sources with lower emissions and thus potentially less cost-effective controls (i.e., higher $/ton figures).

Cost of Control Technologies

Overall, the control costs for the facilities in the four-factor analysis appear to be reasonable. The USFS appreciates the explanations related to remaining useful life and enforceable shutdowns. More often than not, the cost of control technologies is listed for NOx and SO2 separately. However, there are certain control technologies that do not have this breakdown and instead list the cost per ton removed of NOx and SO2 combined. In these situations, such as Table 3.2D in Prairie States four-factor analysis in Appendix A and Table 3.4 in SIPCOs, the USFS would like to see the cost per ton for each pollutant individually.

Additionally, it seems that some controls are not evaluated without an explanation as to why. For example, Archer Daniels Midland seems to have the potential for fuel switching or adjusting the ratio of low to high sulfur fuel being utilized. This potential is not analyzed. The USFS would like to see an explanation as to why this control method is not further evaluated, or to see the control method examined in more detail.

Lack of Control Technology Recommendations

In the draft RH SIP, the IL Air Program argues that the costs and potential negative energy and environmental impacts from implementing NOx and/or SO_2 control technology outweigh any further reductions in emissions of either pollutant across the analyzed facilities.

As mentioned above, there is no cost threshold selected in the draft RH SIP. Without this, it is difficult to determine whether a control is cost effective. However, many other states did set a threshold in this

round. This value was typically between $4,000 and $10,000 per ton. In the draft RH SIP, there are numerous control options presented that would be lower than these thresholds. The USFS asks that the IL Air Program revisit the cost threshold and control costs to provide better context on potential control technologies for the analyzed facilities and consider the implementation of said control technologies, or provide explanation as to why a higher cost per ton threshold is valid in IL.

Furthermore, the draft RH SIP mentions numerous facilities that will need to have emissions at 0 in 2030 or 2045. While the USFS appreciates these efforts towards improved visibility, these shutdowns occur beyond the 2028 review year for the second-round of RH SIPs. Therefore, it is important to still consider cost effective controls, especially for the 2045 facilities.

Enforceability

The IL Air Program noted that there are enforceable shutdowns scheduled to occur before 2028, and more facilities required to have 0 emissions by 2030 or 2045, including some of the facilities undergoing four-factor analysis. As stated above, the USFS appreciates these efforts towards visibility improvements.

In the draft RH SIP, the analysis of Holcim states that only 1 of their 2 kilns has been operational since 2016. However, it is unclear whether this is tied to a permit. The USFS asks that language is added to ensure the shutdown is enforceable . If the lack of operations of Kiln #2 is not tied to an enforceable permit requirement, the USFS would like to see the unit evaluated in a four-factor analysis.

Additionally, the draft RH SIP discloses the fuel being utilized in the boilers at Archer Daniels Midland as 60% low sulfur coal, more specifically low-sulfur Powder River Basin ("PRB") coal, and Illinois high sulfur coal blends. It is unclear whether the use of 60% low sulfur fuel is tied to a permit. If it is not tied to a permit, the USFS would like to see this language added to the permit, as it would make the use of at least 60% low sulfur coal enforceable. Additionally, the USFS would like to know if IL has investigated high heat content, lower sulfur coal as an option.

Illinois EPA Response to FLM Comments and Recommendations for the Regional Haze Second Implementation Period SIP

Comment Letter 1 – National Park Service

Comment 1:

> "However, the NPS finds that Illinois' application of the threshold to individual emission units, rather than the entire facility, inappropriately excluded emission units and/or facilities that have been identified as contributing to visibility impairment in NPS Class I areas.
>
> For example, Illinois selected two of the nine coal-fired circulating fluidized-bed boilers at the Archer Daniels Midland Company (ADM) facility, even though the remaining seven units are significant SO_2 emission sources and accounted for 63% of the 9,926 tons/year of facility-wide SO_2 emissions in 2020. Based on 2020 emissions data reported by IEPA and EPA's Clean Air Markets Program Database (CAMPD), boilers 1–7 emitted 6,283 tons/year SO_2. In comparison, boilers 8 and 9, the two selected for analysis by Illinois, emitted 3,643 tons/year SO_2, which accounts for 37% of the facility-wide SO_2 emissions. As such, the individual unit screening approach used by IEPA arbitrarily omitted most of the facility SO_2 emissions from review. The NPS finds that additional controls on boilers 1–7 may be cost-effective and recommends that they be included in the Illinois source selection process."

Response 1:

> The USEPA Clarification memo provides States with "discretion to choose any source selection threshold or methodology that is reasonable; however, whatever choices states make should be reasonably explained and produce a reasonable outcome." (pg. 3).
>
> Illinois' Q/d surrogate is based on 2016 data projected to 2028, the end of the second implementation period, to incorporate shutdown of units and continued implementation of Illinois' LTS from the first Regional Haze implementation period. Illinois' source selection threshold and methodology achieved a reasonable result as units with Q/d greater than 4 and facilities with Q/d greater than 10 constitute 71.4% of all point emissions of NOx, SO_2, PM, etc. with Q/d greater than 1 in Illinois. The list of point sources considered for four factor analysis includes all the largest emission units in Illinois and captures 49.4% of all 2016 NOx and SO_2 emissions in Illinois. However, in the case of ADM, Illinois EPA did perform a four-factor analysis of all of the cogeneration boilers, 1 - 9, while only boilers 8 and 9 met the selection criteria.

Comment 2:

> "Based on this information the NPS requests that, in addition to ADM boilers 1–7, IEPA also complete four-factor analyses for three additional facilities:
>
> 1. Fuyao Glass Illinois Inc.,
> 2. WRB Refining LP Wood River Refinery, and the

3. Marathon Petroleum Co LLC. Refinery. “

Response 2:

All three of the sources did not meet Illinois’ selection criteria and were therefore not selected for four-factor analysis. Illinois’ selection criteria was reasonable since it produced a reasonable result for the second implementation period, see also response 1. It should also be noted that the two refinery sources, Wood River and Marathon, were considered during the first implementation period and are unlikely to have reasonable emissions reductions in the second implementation period. Additionally, Wood River, Marathon, and Fuyao Glass will be subject to the Good Neighbor Transport FIP, where the significant emission units at these sources will be subject to emission standards the USEPA considers to be equivalent to, or more stringent than, Reasonably Available Control Technology (“RACT”). Analysis for these sources now would not be able to take into consideration the additional controls required by the Transport FIP.

Comment 3:

“The cost analyses provided by IEPA would benefit from including additional calculation details. For example, draft SIP Table 3.2D, *Illinois Coal to PRB Coal Switching Control Option Costs*, lists several cost components in different dollar years. It is not clear how the costs in this table add to the value given as the total annual cost of the control measure. Next to the total annual cost, the table says, *“Using Consumer Price Index (“CPI”) data of 2016 and 2017 through May 2020 for adjusting the 2017 data, total annual cost of the control measure in 2020$.*” It is not clear exactly how the component costs were adjusted. “

Response 3:

In general, the individual cost factors were calculated in the year the prices were given, then converted to 2020 dollars using the Consumer Price Index (“CPI”) for All Urban Consumers in the US city average, before finally being summed to the total annual cost in 2020 dollars. The CPI is taken from the US Bureau of Labor Statistics. For example, in the Prairie State Four-Factor analysis Table 3.2D, *Illinois Coal to PRB Coal Switching Control Option Costs*, the cost of Prairie State mine-mouth transportation is negative $5,723,867.46 in 2016 dollars because the facility would no longer have the current Illinois coal transportation costs if it were to switch to PRB coal. The cost in 2016 dollars is converted to 2020 dollars through the following equation:

$$(2020\$\ costs) = (2016\$\ costs) * \frac{May\ 2020\ CPI}{May\ 2016\ CPI}$$

e.g. Prairie State mine-mouth transportation cost

$$(2020\$\ costs) = (-\$5{,}723{,}867) * \frac{256.389}{240.229} = -\$6{,}109{,}026$$

The total annual cost of the control measure is the sum of all annual cost factors (Illinois coal cost, Prairie State mine-mouth transportation cost, PRB coal cost, and PRB coal railroad transportation cost) after they have been converted to 2020 dollars.

Comment 4:

"It would be helpful to include links to all references cited or to include references as part of the SIP. While many citations to references do include a link, there are some that do not. For example, draft SIP Table 3.2C cited a source reference titled *"U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report."* A link to this report would clarify the reference.

The SIP also refers in several places to an U.S. Environmental Protection Agency (EPA) document called the *"Menu of Control Options"* (also referred to as the *"Menu of Control Measures"*) with a 2006 date but does not include a link to the specific document. A Google search located an EPA document called *"Menu of Control Measures"* with a 2022 date (https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation), but it is not clear if this is the same cited reference.

In addition, the draft SIP listed some attached files that were not included in the FLM consultation draft, e.g., "Appendix A Table A1, Excel workbooks including prairie_state_retrofit_cost_tool_2019_06_04" and "prairie_state_scr_cost_manual_spreadsheet." The NPS recommends including these files as part of the SIP. "

Response 4:

Links have been included for references cited. References utilized in tables are listed at the bottom of the table.

The reference document has been clarified to be "*Menu of Control Measures,"* 2012.

Comment 5:

"In the Control Cost Manual, EPA does not recommend escalating costs beyond five years:

In addition, the Control Cost Manual does not recommend using the CPI to adjust costs for inflation when estimating control costs:

The NPS recommends using facility-specific cost estimates for control measures where possible rather than using estimates prepared for other purposes."

Response 5:

Illinois EPA employed estimation methodologies that it considered to be reasonable and appropriate at the time of the analyses. It is unlikely Illinois EPA would have reached

different conclusions given the relatively small differences in the estimation methodologies suggested in the above comments.

Comment 6:

"The NPS recommends that Illinois establish a cost-effectiveness threshold to document the rationale behind the control cost conclusions and long-term strategy determinations presented in the SIP."

Response 6:

Cost is only one of the four factors to consider in a weight-of-evidence determination for control measures to make reasonable progress. Illinois did not set a bright-line threshold, but utilized a weight of evidence approach to determine if a source required additional control measures for reasonable progress. Illinois is projected to have a 22.5% reduction in NOx and a 48.2% reduction in SO_2 emissions from point sources from 2016 to the end of the second implementation period in 2028 due solely to EGUs already shutdown, scheduled to shutdown, or fuel switched. In the second implementation period, Illinois has achieved significant emissions reductions while improving towards natural visibility in 2064 at a rate better than projected by the uniform rate of progress glidepath for all Class I areas impacted by Illinois.

While Illinois has not set a bright-line cost threshold, for reference, the cost effectiveness of control measures for EGUs in the first implementation period was $1,952 per ton for SO_2 and $2,984 per ton for NOx in 2011 dollars. In May 2020 dollars, this would be $2,215 per ton for SO_2 and $3,389 per ton for NOx utilizing the CPI.

Prairie State Generating Station

Comment 7:

"Prairie State is scheduled to close in 2045 under CEJA. This closure date is near the end of the fourth regional haze planning period. Given this timeframe and the relatively high SO_2 emissions from the facility, the NPS recommends that Illinois consider and evaluate:

Options to improve scrubber efficiency and
The addition of Dry Sorbent Injection (DSI) to increase SO_2 control (the NPS estimates DSI costs for these boilers at $8,732/ton and $10,188/ton SO_2 removed.)"

The NPS recommends IEPA undertake a technical review of the existing wet scrubbers to identify opportunities to reduce SO_2 emissions through optimization or upgrades to the units (at a minimum, these scrubbers should be able to achieve the lower emission rates demonstrated in the past)."

Response 7:

Prairie State is controlled at the BACT level as required by PSD with over 98% SO_2 removal efficiency, which includes an existing DSI system. Prairie State is subject to

federally enforceable emission limits of 0.07 lb/mmBtu for NOx and 0.182 lb/mmBtu for SO_2. For this implementation period, additional review of the existing wet scrubbers is unnecessary since Prairie State is considered well controlled at a similar or more stringent level than the four factors for reasonable progress.

Archer Daniels Midland

Comment 8:

"Instead of using the IPM default value of 9,500 Btu/kWh, NPS analysis used 2022 CAMPD data for coal-fired Circulating Fluidized-Bed (CFB) boilers to estimate this value (10,476 Btu/kWh). (IEPA used 2,930 Btu/kWh, which seems improbable and is likely an error. This resulted in an overestimate of boiler output by more than a factor of 3 and inflated the capital costs by about 50%.)"

Response 8:

The Illinois EPA four-factor analysis used an estimated 10,000 Btu/kWhr for all boilers for ADM, as indicated in under the ADM four-factor analysis Sections 3.1.1 and 3.1.2. A conversion factor of 0.293 was used to convert mmBtu/hr to MW but was not multiplied with 10,000 Btu/kWhr.

Comment 9:

"The estimated Cost of Compliance for adding DSI SO_2 controls is consistent with values accepted by other states and could reduce emissions from this facility by 8,369 tons/year.

As noted in Section 2, thresholds for average cost-effectiveness used by other states in the second round of regional haze planning range from $4,000 to $10,000/ton. The NPS recommends that DSI controls for ADM are cost-effective."

Response 9:

Current ADM SO_2 emissions are required to be at least 90% controlled utilizing an optimized coal blend, limestone injection, and DSI on all 9 of the cogeneration boilers.

Rain CII Carbon LLC

Comment 10:

"The NPS recommends that IEPA prepare a detailed cost analysis for SO_2 emissions reduction specific to the Rain facility, as this is a significant SO_2 emission source and is on the NPS Q/d and AOI lists for Mammoth Cave, Great Smoky Mountains, and Isle Royale National Parks. Alternatively, IEPA could require installation of a spray-dry absorbing system as mandated by the BAAQMD for petroleum coke facilities. The NPS recommends including facility-specific vendor quotes where possible. "

Response 10:

Illinois relied on evaluated estimates from USEPA, BAAQMD, and a study conducted by its own MJO, LADCO, to inform SO_2 control cost-effectiveness for this category, and it was not necessary to obtain facility-specific vendor quotes.

Southern Illinois Power Cooperative

Comment 11:

"The NPS recommends that IEPA update its cost-effectiveness estimates for fuel-switching and repowering options for Boiler 123 alone, as Boiler 4 is no longer operating. The NPS also recommends that IEPA evaluate DSI, WFGD, and SDA for Boiler 123 and select a cost-effective method to reduce emissions in this planning period."

Response 11:

New cost calculations for fuel switching to PRB coal for boiler unit 123 is $3,801.91 per ton of NOx and SO_2 in 2020 dollars. Cost calculation for repowering for boiler unit 123 is $8,395.90 per ton of NOx and SO_2 in 2020 dollars. SIPCO currently has add-on controls under PSD with efficiency of 90%-94% for SO_2, which is equivalent to or better than BACT, and is considered well controlled. SIPCO also currently has WFGD and DSI controls for boiler 123.

Wood River and Marathon Petroleum Co LLC Refineries, Fuyao Glass Illinois

Comment 12:

"The NPS recommends Illinois require a four-factor analysis for NO_x emissions from the large NO_x units (those with greater than 40 MMBtu heat input), including the heaters and boilers at the Wood River refinery and the catalytic cracking unit and combustion sources at the Marathon refinery. The NPS also recommends the analysis consider reducing sulfur content in the refinery fuel gas at both facilities as a strategy to reduce facility-wide SO_2 emissions from the numerous small SO_2 sources at the facilities."

"The NPS recommends IEPA conduct a four-factor analysis of Fuyao Glass including evaluation of SCR to control NOx emissions and a catalytic ceramic filter system to control multiple pollutants."

Response 12:

See response 2.

Comment Letter 2 – USDA Forest Service

Comment 13:

"Source Selection
The choice of an emissions over distance (Q/d) unit and source threshold produces a number of emission sources for further analysis that is unique to the particular

circumstances in each state. Our overriding concern is that a sufficient number of sources is selected. In this case, IL has selected an appropriate number of sources that account for a large portion of the impacts at USFS Class I areas. However, the USFS believes that the use of Q/d greater than 4 selection for emission units at sources with a Q/d greater than 10 may leave out units that should be evaluated because cost-effective controls could be identified. This is of particular note for Archer Daniels Midland."

Response 13:

The Illinois EPA has a reasonable source selection process since it produced a reasonable result. The sources considered for four factor analysis utilizing the selection threshold of unit Q/d greater than 4 and facility Q/d greater than 10 includes 71.4% of emissions from point sources with Q/d greater than 1 in Illinois. However, in the case of ADM, Illinois EPA has performed four-factor analysis for all boilers 1-9, with only boilers 8 and 9 meeting the selection criteria. See also response 1.

Comment 14:

"In the draft RH SIP, there does not seem to be a cost-effectiveness threshold selected. Instead, all controls are deemed to be not cost effective – even those lower than $2,000 per ton. Other states have cost thresholds ranging from $4,000 to $10,000 per ton in their SIPs. It is reasonable to expect that the second and subsequent planning periods will require controls at sources with lower emissions and thus potentially less cost-effective controls (i.e., higher $/ton figures)."

Response 14:

Illinois is not setting a bright-line cost threshold in this implementation period. Cost was only one of the four factors considered for determining potential emission control measures. See also response 6.

Comment 15:

"Overall, the control costs for the facilities in the four-factor analysis appear to be reasonable. The USFS appreciates the explanations related to remaining useful life and enforceable shutdowns. More often than not, the cost of control technologies is listed for NOx and SO2 separately. However, there are certain control technologies that do not have this breakdown and instead list the cost per ton removed of NOx and SO2 combined. In these situations, such as Table 3.2D in Prairie States four-factor analysis in Appendix A and Table 3.4 in SIPCOs, the USFS would like to see the cost per ton for each pollutant individually."

Response 15:

The Illinois EPA has listed costs per ton removed for NOx and SO_2 separately where it was appropriate. For cases where the cost per ton removed of NOx and SO_2 were combined, it was due to the same control measure reducing both NOx and SO_2

simultaneously. For example, in Table 3.2D in Prairie State four-factor analysis, the cost effectiveness of fuel switching from Illinois coal to PRB coal is calculated in dollars per combined NOx and SO_2 tons since both NOx and SO_2 are simultaneously reduced by the fuel switch.

Comment 16:

"Additionally, it seems that some controls are not evaluated without an explanation as to why. For example, Archer Daniels Midland seems to have the potential for fuel switching or adjusting the ratio of low to high sulfur fuel being utilized. This potential is not analyzed. The USFS would like to see an explanation as to why this control method is not further evaluated, or to see the control method examined in more detail."

Response 16:

For some sources, fuel switching was not further evaluated due to technical infeasibility or the source having already fuel switched. In the case of ADM, the source has already switched from Illinois coal to a fuel blend of PRB coal, Illinois Coal, and natural gas optimized to limit SO_2 to the extent possible while maintaining proper operation of the boiler units and the energy requirements of the source. All boilers are also controlled with limestone injection in the boiler beds and DSI as a post-combustion control.

Comment 17:

"As mentioned above, there is no cost threshold selected in the draft RH SIP. Without this, it is difficult to determine whether a control is cost effective. However, many other states did set a threshold in this round. This value was typically between $4,000 and $10,000 per ton. In the draft RH SIP, there are numerous control options presented that would be lower than these thresholds. The USFS asks that the IL Air Program revisit the cost threshold and control costs to provide better context on potential control technologies for the analyzed facilities and consider the implementation of said control technologies, or provide explanation as to why a higher cost per ton threshold is valid in IL."

Response 17:

Cost is only one of the four factors considered for determining emission control measures. Illinois did not set a bright-line threshold, but utilized a weight of evidence approach to determine if a source required additional control measures for reasonable progress. Further, there has been significant emissions reductions in Illinois in the second implementation period, directly contributing to the reduction of haze in class 1 areas affected by Illinois. See also response 6.

Comment 18:

"The USFS asks that language is added to ensure the shutdown is enforceable. If the lack of operations of Kiln #2 [at Holcim] is not tied to an enforceable permit requirement, the USFS would like to see the unit evaluated in a four-factor analysis."

"It is unclear whether the use of 60% low sulfur fuel [at ADM] is tied to a permit. If it is not tied to a permit, the USFS would like to see this language added to the permit, as it would make the use of at least 60% low sulfur coal enforceable."

Response 18:

Holcim Kiln #2 has been idle and has reported zero emissions since 2016. Illinois expects that any future utilization of the kiln will require additional permit action which would limit emissions appropriately.

ADM is currently utilizing a blend of PRB coal, Illinois Coal, and natural gas optimized to limit SO_2 to the extent possible while maintaining proper operation of the boiler units. All cogeneration boilers are controlled utilizing both limestone injection in the boiler beds and DSI as a post combustion control. Cogeneration Boilers 1 - 8 are subject to a requirement for 90% control of SO_2. Cogeneration Boiler 9 is subject to a 92% control requirement.