Agenda

Environmental Protection Commission

Wednesday, August 9, 2023
Teleconference: 631-618-4607 PIN: 484 733 354#
Video Conference: https://meet.google.com/rzo-uidn-tvg
502 East 9th Street, Des Moines, Iowa 50319
DNR 2 North Conf Room

Wednesday, August 9, 2023
10:00 AM – EPC Business Meeting

If you are unable to attend the business meeting, comments may be submitted for public record to Alicia Plathe at Alicia.Plathe@dnr.iowa.gov or 502 East 9th St, Des Moines IA 50319 up to 24 hours prior to the business meeting.

1	Approval of Agenda	
2	Approval of the Minutes (Packet Page 3)	
3	Monthly Reports (Packet Page 8)	Ed Tormey (Information)
4	Director's Remarks	Kayla Lyon (Information)
5	Contract Amendment with Stantec Consulting Services Inc., Program Management and Communication Outreach and Mitigation Strategies (Packet Page 12)	Kathryne Clark (Decision)
6	Contract Amendment with AECOM and Atkins North America, Floodplain Mapping Services (Packet Page 15)	Kathryne Clark (Decision)
7	Contract with Iowa Department of Agriculture and Land Stewardship (IDALS), Protect Rathbun Lake Project (Packet Page 19)	Steve Konrady (Decision)
8	Contract Amendment with Iowa Department of Agriculture and Land Stewardship (IDALS), Big Hollow Lake Watershed Project (Packet Page 21)	Miranda Haes (Decision)
9	Water Use and Allocation Annual Permit Fee (Packet Page 23)	Heidi Cline (Decision)
10	State Implementation Plan Revision for Regional Haze (Packet Page 25)	Matthew Johnson (Decision)
11	General Discussion	
12	Upcoming Meetings • Tuesday, September 19, 2023, Wallace Building • Tuesday, October 17, 2023, Wallace Building	

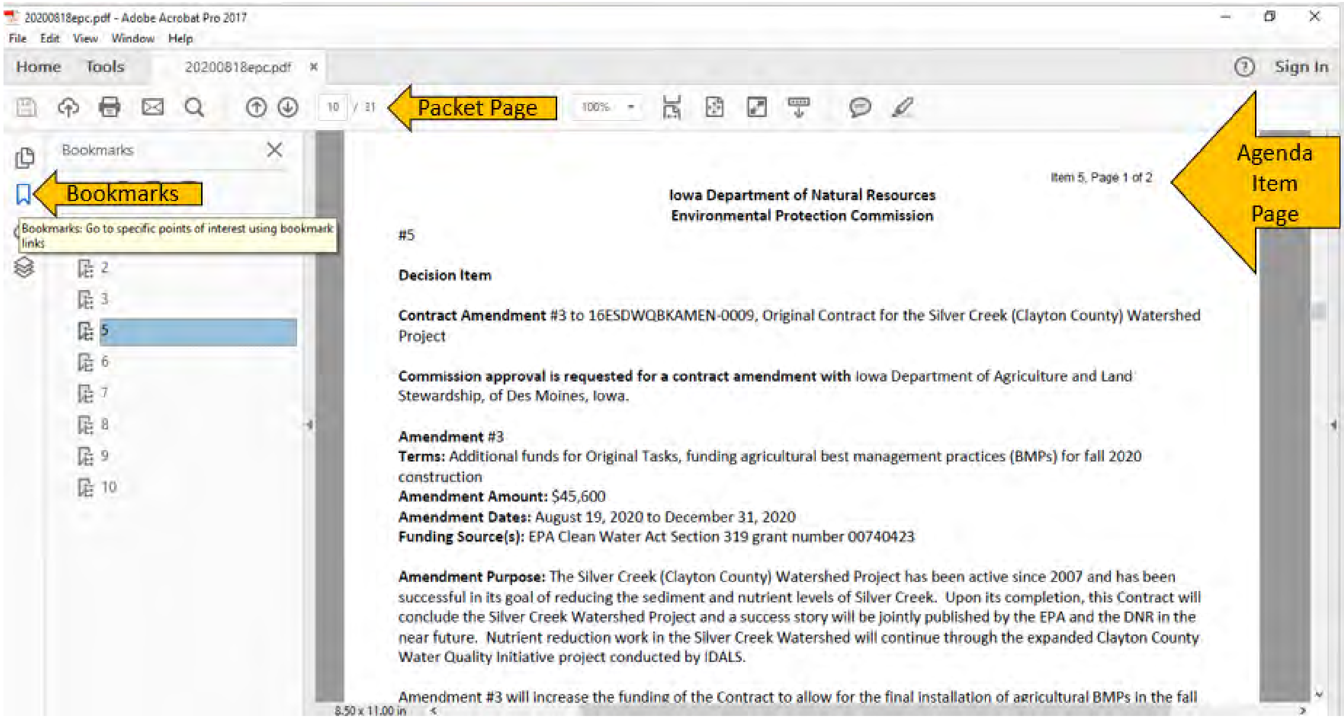
For details on the EPC meeting schedule, visit http://www.iowadnr.gov/About-DNR/Boards-Commissions

[1]Comments during the public participation period regarding proposed rules or notices of intended action are not included in the official comments for that rule package unless they are submitted as required in the Notice of Intended Action.

Any person with special requirements such as those related to mobility or hearing impairments who wishes to participate in the public meeting should promptly contact the DNR or ADA Coordinator at 515-725-8200, Relay Iowa TTY Service 800-735-7942, or Webmaster@dnr.iowa.gov to advise of specific needs.

Utilize bookmarks to transition between agenda items or progress forwards and backwards in the packet page by page with the Packet Page number on the agenda.

The upper right-hand corner will indicate the Agenda Item Number and the page of the agenda item.



MINUTES OF THE ENVIRONMENTAL PROTECTION COMMISSION MEETING

June 20, 2023

Video Teleconference
and
Wallace State Office Building

Approved by the Commission TBD

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Meeting Minutes

Call To Order

The meeting of the Environmental Protection Commission (Commission or EPC) was called to order by Acting Chairperson Amy Echard at 10:00 am on June 20, 2023 via a combination of in-person and video/teleconference attendees.

Commissioners Present

Brad Bleam
Rebecca Dostal
Amy Echard
Patricia Foley
Lisa Gochenour-virtual
Roger Zylstra

Commissioners Absent

Mark Stutsman
Harold Hommes

Approval of Agenda

Motion was made by Roger Zylstra to approve the agenda as presented. Seconded by Patricia Foley.
The Acting Chairperson asked for the Commissioners to approve the motion by saying aye. There were no nay votes. Motion passes.

Approved as Presented

Approval of Minutes

Motion was made by Rebecca Dostal to approve the May 16, 2023 EPC minutes as presented. Seconded by Patricia Foley.
The Acting Chairperson asked for the Commissioners to approve the motion by saying aye. There were no nay votes. Motion passes.

Approved as Presented

Monthly Reports

- Division Administrator Ed Tormey asked Brian Hutchins, Supervisor of the Air Quality Bureau Compliance and Monitoring section, to present some information regarding the Canadian wildfires and how they are impacting air quality in the state.
- Brian Hutchins gave a presentation that included the exceedances of the National Ambient Air Quality Standards, when and how the wildfire smoke impacted Iowa, what Air Quality advisories have been issued, maps from AirNow.gov and the current status of the wildfires. He also answered questions regarding whether the fires would affect attainment.

Information

Grant Funding For Two Environmental Management System (EMS) Proposals

Laurie Rasmus presented two EMS grant funding proposals; one for Solid Waste Management Commission of Scott County and the other for Metro Waste Authority.

Public Comments – None

Written Comments – None

Motion was made by Rebecca Dostal to approve the item as presented. Seconded by Patricia Foley.
Roger Zylstra-aye, Patricia Foley-aye, Lisa Gochenour-aye, Amy Echard-aye, Brad Bleam-aye, Rebecca Dostal-aye. Motion passes.

APPROVED AS PRESENTED

CONTRACT WITH THE UNIVERSITY OF NORTHERN IOWA, IOWA WASTE REDUCTION CENTER (IWRC)

Bill Blum requested Commission approval for a service contract with the University of Northern Iowa, IWRC, at Cedar Falls, Iowa.

Public Comments – None

Written Comments – None

Motion was made by Roger Zylstra to approve the item as presented. Seconded by Brad Bleam.
Roger Zylstra-aye, Patricia Foley-aye, Lisa Gochenour-aye, Amy Echard-aye, Brad Bleam-aye, Rebecca Dostal-aye.

APPROVED AS PRESENTED

GRANT AGREEMENT AMENDMENT WITH REGION XII COUNCIL OF GOVERNMENTS-IOWA WASTE EXCHANGE

Bill Blum presented on the request to extend a contract with Region XII Council of Governments to fulfill services for the Iowa Waste Exchange. Bill answered questions related to the process after the final amendment and the issuance of a new Request for Proposals. Amie Davidson answered questions related to the increase of the grant amount and how that relates to the tonnage fee. She clarified that the tonnage fee paid per ton has stayed the same but the amount of waste disposed has increased, therefore increasing the amount of fees paid to the Department.

Public Comments – None

Written Comments – None

Motion was made by Rebecca Dostal to approve the item as presented. Seconded by Brad Bleam.
Roger Zylstra-aye, Patricia Foley-aye, Lisa Gochenour-aye, Amy Echard-aye, Brad Bleam-aye, Rebecca Dostal-aye.

APPROVED AS PRESENTED

CLEAN WATER AND DRINKING WATER STATE REVOLVING LOAN FUND-FY2024 INTENDED USE PLAN

Theresa Enright presented the Intended Use Plan for state fiscal year 2024 for the Clean Water and Drinking Water State Revolving Loan Funds. Theresa mentioned that the Bipartisan Infrastructure Law (BIL) funding is included in the Intended Use Plan. Theresa also mentioned that the criteria for loan forgiveness is reviewed annually and that there is a new focus federally to include criteria that would benefit disadvantaged Iowa communities.

Public Comments – None

Written Comments – None

Motion was made by Patricia Foley to approve the item as presented. Seconded by Rebecca Dostal.
Roger Zylstra-aye, Patricia Foley-aye, Lisa Gochenour-aye, Amy Echard-aye, Brad Bleam-aye, Rebecca Dostal-aye.

APPROVED AS PRESENTED

CONTRACT WITH THE STATE HYGIENIC LABORATORY (SHL) AT THE UNIVERSITY OF IOWA-2024 SHL SERVICES IN SUPPORT OF THE DNR AIR QUALITY BUREAU

Brian Hutchins presented a contract with the State Hygienic Lab to perform ambient monitoring and related services in support of the DNR Air Quality Bureau. Brian answered questions on air monitoring sites and how they relate to those in Polk and Linn County. The overlap is primarily in laboratory services and not site locations. He also answered questions related to the lead levels over the years and what caused those levels and how the levels were decreased.

Public Comments – None

Written Comments – None

Motion was made by Rebecca Dostal to approve the item as presented. Seconded by Patricia Foley.
Roger Zylstra-aye, Patricia Foley-aye, Lisa Gochenour-aye, Amy Echard-aye, Brad Bleam-aye, Rebecca Dostal-aye.

APPROVED AS PRESENTED

CONTRACT WITH LINN COUNTY-AIR QUALITY 28E AGREEMENT

Jim McGraw presented a contract with Linn County to help conduct programs for the abatement, control, and prevention of air pollution within Linn County. Jim answered questions related to the data collected by both Polk and Linn County and how it is shared instantaneous with DNR.

Public Comments – None

Written Comments – None

Motion was made by Roger Zylstra to approve the item as presented. Seconded by Rebecca Dostal.
Roger Zylstra-aye, Patricia Foley-aye, Lisa Gochenour-aye, Amy Echard-aye, Brad Bleam-aye, Rebecca Dostal-aye.

APPROVED AS PRESENTED

CONTRACT WITH POLK COUNTY-AIR QUALITY 28E AGREEMENT

Jim McGraw presented a contract with Polk County to help conduct programs for the abatement, control, and prevention of air pollution within Polk County.

Public Comments – None

Written Comments – None

Motion was made by Rebecca Dostal to approve the item as presented. Seconded by Brad Bleam.
Roger Zylstra-aye, Patricia Foley-aye, Lisa Gochenour-aye, Amy Echard-aye, Brad Bleam-aye, Rebecca Dostal-aye.

APPROVED AS PRESENTED

CONTRACT WITH THE UNIVERSITY OF NORTHERN IOWA-AIR EMISSIONS ASSISTANCE PROGRAM

Jim McGraw presented on a contract with The University of Northern Iowa for Iowa's Air Emissions Assistance Program that provides technical air quality assistance to Iowa's small businesses.

Public Comments – None

Written Comments – None

Motion was made by Patricia Foley to approve the item as presented. Seconded by Roger Zylstra.
Roger Zylstra-aye, Patricia Foley-aye, Lisa Gochenour-aye, Amy Echard-aye, Brad Bleam-aye, Rebecca Dostal-aye.

APPROVED AS PRESENTED

GENERAL DISCUSSION

- Ed Tormey reported that the July agenda is typically pretty light and in past years the July meeting has been canceled due to lack of items. DNR will keep the Commissioners informed whether that is the case this year.
- Roger Zylstra stated he will be absent for the July meeting.
- Rebecca Dostal stated she will be absent for the August meeting.

ADJOURN

The Acting Chairperson adjourned the Environmental Protection Commission meeting at 11:39 am on June 20, 2023.

ADJOURNED

Monthly Waiver Report July 2023							
Item #	DNR Reviewer	Facility/City	Program	Subject	Decision	Date	Agency
1	John Curtin	Waterloo WPCF - Independence	Air Quality Construction Permits	Waiver of Initial Stack Test Requirement for an open flare for an anaerobic lagoon.	Approved	6.28.23	23aqw130
2	John Curtin	Waterloo WPCF - Easton	Air Quality Construction Permits	Waiver of Initial Stack Test Requirement for an open flare for anaerobic digesters.	Approved	6.28.23	23aqw131
3	Tom Roos	Storm Lake WWTF	Wastewater	Request to reuse treated effluent from the Storm Lake Wastewater Treatment Facility for the purpose of watering public plantings throughout the community. Additional uses may also include dust control in construction areas.	Approved	7.3.23	23cpw132
4	Julie Duke	Tyson Fresh Meats, Inc	AQ	Increase biogas flow from 600 scfm to 700 scfm for 7 days, resulting in houly emissions increase.	Approved	5.31.23	23aqw133
5	Danjin Zulic	Arconic US LLC	Air Quality Construction Permits	Waiver of Initial Stack Test Requirement.	Approved	7.6.23	23aqw134
6	Karen Kuhn	Hyponex Corp	Air Quality Construction Permits	Waiver of Initial Stack Test Requirement.	Approved	7.6.23	23aqw135
7	Julie Duke	Western Iowa Energy LLC	AQ	request to contruction prior to permit issuance Facility expansion includes increasing refining capacity volume (not throughput) & installing new deacidification and distillation columns to low-quality animal fat & veg oil.	Approved	6.20.23	23aqw136
8	Julie Duke	Bertch Cabinet	AQ	Installation of this new line will require experts from the equipment manufacture from both inside and outside the U.S. to assist with install. Variance needed to coordinate travel.	Approved	6.21.23	23aqw137
9	Lucas Tenborg	Clysar, LLC	AQ	DNR received a request for a variance from Condition 5, Operating Requirements with Associated Monitoring and Recordkeeping in permit 95-A-104-S4.	Approved	7.10.23	23aqw138
10	Nate Tatar	Vigen Memorial Home	Air Quality Construction Permits	Waiver of Initial Stack Test Requirement.	Approved	12-14-22	23aqw139
11	Nate Tatar	Hy-Line International - Minburn	Air Quality Construction Permits	Waiver of Initial Stack Test Requirement.	Approved	7.11.23	23aqw140
12	Nate Tatar	Hy-Line International-Woodward Research	Air Quality Construction Permits	Waiver of Initial Stack Test Requirement.	Approved	7.11.23	23aqw141
13	Nate Tatar	Hubbard Feeds, Inc - Iowa City	Air Quality Construction Permits	Waiver of Initial Stack Test Requirement.	Approved	7.14.23	23aqw142
14	Karen Kuhn	Progressive Foundry Inc	Air Quality Construction Permits	Waiver of Initial Stack Test Requirement.	Approved	7.14.23	23aqw143
15	Jaeyoung Park	City of Des Moines	CP Wastewater	The City of Norwalk is requesting variance from the Iowa Design Standards Chapter 13-13.4.3 (Pump Openings) for installing a submersible lift station with pumps that do not have the capability to pass a 3-inch spherical solid.	Approved	7.13.23	23cpw144
16	Michael Hermsen	Mo. Valley Grain, Inc.	Air Quality Construction Permit	Waiver of Initial Stack Test Requirement.	Approved	7.17.23	23cpw145
17	Lucas Tenborg	TrinityRail Maintenance Services	AQ	Variance request for use of temporary third-party flare to operate in-place of two permitted flares for three months. The third-party flare is expected to provide the same level of VOC and HAP control as the permitted Flare, no increase in emissions.	Approved	7.18.23	23aqw146
18	Julie Duke	Ag Processing inc	AQ	Request to allow for an additional twelve months to start construction of the Cooling Tower (EU 73, Construction Permit 22-A-056) and Rotary Conditioner (EU 74, Construction Permit 22-A-083).	Approved	7.18.23	23aqw147

Iowa Department of Natural Resources
Environmental Services Division
Second Quarter Report of Manure Releases

During the period April 1, 2023, through June 30, 2023, 6 reports of manure releases were forwarded to the central office. A general summary and count by field office is presented below.

		Total Incidents		Surface Water Impacts		Feedlot		Confinement		Land Application		Transport		Hog		Cattle		Poultry		Other	
Month	**Year**	**Cur**	**Yr Ago**	**Cur**	**Yr Ago**	**Cur**	**Yr Ago**	**Cur**	**Yr Ago**	**Cur**	**Yr Ago**	**Cur**	**Yr Ago**	**Cur**	**Yr Ago**	**Cur**	**Yr Ago**	**Cur**	**Yr Ago**	**Cur**	**Yr Ago**
Jan	2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	2023	0	1	0	1	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
Mar	2023	0	1	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
Apr	2023	4	3	2	1	0	0	2	2	2	0	0	1	3	3	1	0	0	0	0	0
May	2023	0	1	0	0	0	0	0	1	0	0	0	0	0	1	0	0	0	0	0	0
Jun	2023	2	1	2	1	0	1	1	0	0	0	1	0	2	0	0	1	0	0	0	0
	Total	**6**	**7**	**4**	**3**	**0**	**1**	**3**	**5**	**2**	**0**	**1**	**1**	**5**	**4**	**1**	**3**	**0**	**0**	**0**	**0**

Total Number of Incidents per Field Office for the Selected Period	Field Office 1		Field Office 2		Field Office 3		Field Office 4		Field Office 5		Field Office 6	
	Current	**Previous**	**Current**	**Previous**	**Current**	**Previous**	**Current**	**Previous**	**Current**	**Previous**	**Current**	**Previous**
Total	2	0	0	0	1	2	0	1	2	2	1	0

Iowa Department of Natural Resources
Environmental Services Division
Second Quarter Report of Hazardous Conditions

During the period April 1, 2023, through June 30, 2023, 149 reports of hazardous conditions were forwarded to the central office. A general summary and count by field office is presented below. This does not include releases from underground storage tanks, which are reported separately.

				Substance						Mode													
		Total Incidents		Agrichemical		Petroleum Products		Other Chemicals		Transport		Fixed Facility		Pipeline		Railroad		Fire		Other*		CR-ERNS	
Month	Year	Cur	Yr Ago	Cur	Yr Ago	Cur	Yr Ago	Cur	Yr Ago	Cur	Yr Ago	Cur	Yr Ago	Cur	Yr Ago	Cur	Yr Ago	Cur	Yr Ago	Cur	Yr Ago	Cur	Yr Ago
Jan	2023	35	33	1	2	27	18	9	14	15	10	14	19	0	0	1	0	0	0	1	1	4	3
Feb	2023	22	35	1	2	15	22	6	13	6	11	13	14	0	0	1	0	0	0	2	4	0	6
Mar	2023	46	35	1	1	37	27	10	7	13	9	28	19	0	0	0	0	1	0	2	6	2	1
Apr	2023	48	45	11	8	28	31	12	10	14	15	19	19	1	0	3	4	2	0	1	4	8	3
May	2023	50	46	18	15	28	26	13	15	16	15	22	21	0	2	2	1	1	1	1	3	8	3
Jun	2023	51	55	13	8	26	30	16	26	22	22	14	17	1	0	1	3	0	1	2	5	11	7
	Total	**252**	**249**	**45**	**36**	**161**	**154**	**66**	**85**	**86**	**82**	**110**	**109**	**2**	**2**	**8**	**8**	**4**	**2**	**9**	**23**	**33**	**23**

* Other includes dumping, theft, vandalism and unknown
** CR-ERNS incidents are ongoing releases as defined by Federal regulations. These reports are included in "Total Incidents" and "Substance" counts but not in "Mode" counts.

Total Number of Incidents per Field Office This Selected Period	Field Office 1		Field Office 2		Field Office 3		Field Office 4		Field Office 5		Field Office 6	
	Current	Year Ago	Current	Year Ago	Current	Year Ago	Current	Year Ago	Current	Year Ago	Current	Year Ago
Total	25	17	10	21	9	5	44	40	36	31	25	32

Iowa Department of Natural Resources
Environmental Services Division
Second Quarter 2023 Report of Wastewater By-passes

During the period April 1, 2023 through June 30, 2023, 30 reports of wastewater by-passes were received by the department. A general summary and count by field office is presented below. This does not include by-passes resulting from precipitation events (including flood water infiltration) or bypasses resulting in basement backups.

Quarter	Total	Avg. Length (days)	Avg. Volume (MGD)	Sampling Required	Fish Kill
1ST Quarter '23	52 (37)	0.429	0.981	2	0(0)
2ND Quarter '23	30 (35)	0.332	0.036	1	0(0)
3RD Quarter '22	34 (32)	0.250	0.016	1	0(0)
4TH Quarter '22	45 (25)	0.972	0.095	1	0(0)

(numbers in parentheses are for same period last year)

Total Number of Incidents per Field Office This Quarter:

Field Office	**1**	**2**	**3**	**4**	**5**	**6**
Reports	5	4	3	2	7	9

Iowa Department of Natural Resources
Environmental Protection Commission

#5

Decision Item

Contract Amendment #1 to 23ESDLQBAClar-0001, Stantec Consulting Services Inc.

Commission approval is requested for a contract amendment with Stantec Consulting Services Inc. of Nashville, TN (Stantec).

Contract Terms:
Amendment #1 to 23ESDLQBAClar-0001
Amendment Amount: $446,489
Amendment Dates: 10/1/2023 to 9/30/2025
Funding Source(s): FEMA Cooperating Technical Partner (CTP) Grant

Amendment Purpose: The purpose of this contract amendment is to add funding for Program Management (PM) and Communication Outreach and Mitigation Strategies (COMS) for Floodplain Mapping Services for DNR's Floodplain Mapping Program for the period stated above.

Original Contract Purpose: The services in the original contract facilitate communication with stakeholders and assist in compliance with FEMA's complex standards and guidelines. This includes development and management of the data platform for storing, analyzing and distributing two-dimensional base-level (2D BLE) models being created by our flood study contractors that will be used to update Flood Insurance Rate Maps (FIRMs) and improve flood risk information. Attachment A below is the Statement of Work and Pricing from the original contract.

Original Selection Process Summary: Stantec was chosen through the State's competitive RFP process. It was the only vendor to submit a proposal. DNR selected Stantec for this project because it demonstrated the necessary qualifications to perform the proposed tasks. This contract is for professional services.

	Amount	Timeframe	Purpose
Original Contract Terms	$420,204	10/1/2022 to 9/30/2023	Program Management & Community Engagement
Current Amendment	$446,489	10/1/2023 to 9/30/2025	Additional funding
Total	**$866,693**		

Kathryne Clark, GIS Section Supervisor, Land Quality Bureau
Environmental Services Division
August 8, 2023

Attachment A
Scope of Work from Original Contract

Project Management

The Contractor will provide the following floodplain mapping services:

- State and Local Business Plans and/or Updates
- Global Program Management Activities
- Global Outreach for Mapping
- Training to State and Local Officials
- Mitigation Planning Technical Assistance
- Staffing
- Technical Pilot Projects
- Mentoring and Best Practices
- Minimal Map Printing
- Coordinated Needs Management Strategy (CNMS)
- Programmatic Quality Assurance/Quality Control (QA/QC) Plans

Community Outreach Mitigation Strategies Services

- Strategic Business Plan and/or Update
- Strategic Planning for Community Engagement
- Meeting and Process Facilitation
- Mitigation Support
- Communication and Outreach to Communities
- Training and Community Capability Development
- Mitigation Planning Technical Assistance
- Staffing
- CERC Special Projects
- Mentoring

Services

Contractor will provide cloud hosting of 2D BLE modeling data and 2D BLE data distribution to mapping partners and the public if requested.

Pricing from Original Contract

Fixed Fee Services

Position Description/Job Classification	All-inclusive Hourly Rates
Administrative Assistant	$99.00
Planner	$123.00
GIS Analyst	$127.00
Project Engineer	$135.00
Application Developer	$154.00
Senior Planner	$169.00
Senior GIS Analyst	$175.00
Senior Application Developer	$182.00
Senior Project Engineer	$184.00
Project Manager	$190.00
Principal	$210.00
Senior Principal	$240.00

Cloud Based Hosting

	Monthly	Yearly
Year 1	$ 8,500.00	$ 102,000.00
Year 2	$ 8,713.00	$ 104,556.00
Year 3	$ 8,931.00	$ 107,172.00
Year 4	$ 9,154.00	$ 109,848.00
Year 5	$ 9,383.00	$ 112,596.00
Year 6	$ 9,617.00	$ 115,404.00

The above costs apply to cloud storage requirements that are under 6TBs, if the storage requirements exceed 6TBs, these costs will increase.

Total Costs for Year 1

Personnel	$ 318,204.00
Cloud Based Hosting	$ 102,000.00
Total	**$ 420,204.00**

Iowa Department of Natural Resources
Environmental Protection Commission

#6

Decision Item

Contract Amendment #1 to 23ESDLQBAClark-0002, AECOM Technical Services, Inc. and 23ESDLQBAClar-003, Atkins North America, Inc.

Commission approval is requested for contract amendments with
AECOM Technical Services, Inc. of Kansas City, Missouri
Atkins North America, Inc. of Alexandria, Virginia

Terms:
Amendment #1 to 23ESDLQBAClark-0002 and 23ESDLQBAClark-003
Amendment Amount: $1,456,815
Amendment Dates: 10/1/2023 to 9/30/2025
Funding Source(s): grant from the Federal Emergency Management Agency (FEMA)

Amendment Purpose: The purpose of this contract amendment is to add money to the original contract to complete new projects that fall within the original tasks without extending the time of performance previously allowed.

Original Contract Purpose: The purpose of these contracts is to provide Floodplain Mapping Services for the development of flood risk management data, and potentially, Flood Insurance Rate Maps (FIRMs) in specified watersheds and counties in the State of Iowa. Please see Attachment A for the Statement of Work and Pricing from the original contract. This additional funding will provide for updates to five counties using two-dimensional (2D) base-level engineering (BLE) outputs and new 2D Zone AE stream reaches.

Original Selection Process Summary: The contractors listed above were chosen through the State's competitive RFP process. They were chosen for the professional services listed in Attachment A because they met the pre-qualification minimum scoring requirement of 75% of possible points.

Contract History: The DNR has begun mapping the entire State of Iowa using two-dimensional base level engineering (2D BLE), this will be the primary activity for floodplain mapping services while continuing to update and maintain existing mapping when appropriate. While not regulatory to begin with, the 2D BLE data will be used in subsequent years to update mapping and will require all of the services listed in the Statement of Work. The services listed in the Statement of Work will support the DNR working with FEMA to create and maintain accurate up-to-date flood hazard data, the eventual development of FIRMs and Flood Insurance Studies (FISs) for counties in Iowa and selected FIRM panels for Physical Map Revisions (PMRs) primarily using 2D BLE data.

	Amount	Timeframe	Purpose
Original Contract	$4,948,918	10/1/2022 to 9/30/2025	Floodplain Mapping Services
Current Amendment	$1,456,815	10/1/2023 to 9/30/2025	Add funding
Total	$6,405,733		

Kathryne Clark, GIS Section Supervisor, Land Quality Bureau
Environmental Services Division
August 9, 2023

Attachment A
Scope of Work from Original Contract

Floodplain Mapping Services
The services listed below will be competitively bid as Task Orders.

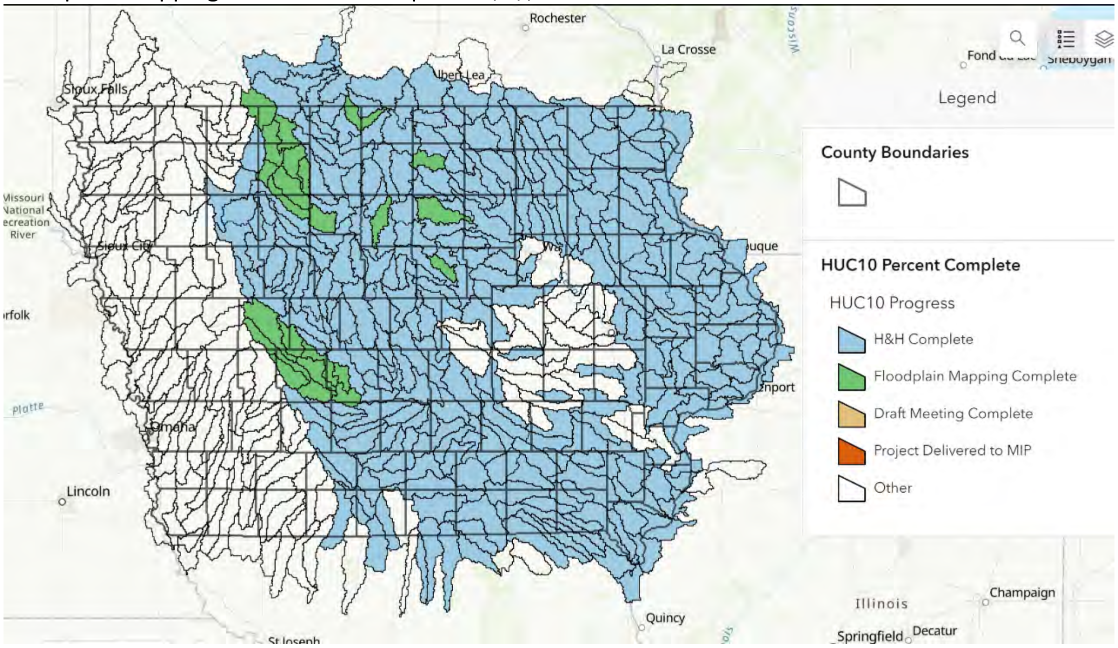
The Contractor will provide the following floodplain mapping services:

- Project Risk Identification and Mitigation
- Perform Discovery
- Perform Community Engagement and Project Outreach
- Develop Flood Risk Products
- Independent QA/QC of Flood Risk Products
- Perform Field Survey
- Develop Topographic Data
- Perform Independent QA/QC Topographic Data
- Prepare Base Map
- Develop Hydrologic Data
- Perform Independent QA/QC Hydrologic Data
- Develop Hydraulic Data
- Perform Independent QA/QC Hydraulic Data
- Perform Floodplain Mapping
- Perform Independent QA/QC Floodplain Mapping
- Develop FIRM Database
- Produce Preliminary Map Products
- Perform Independent QA/QC Produce Preliminary Map Products
- Distribute Preliminary Map Products
- Post-Preliminary Map Production
- Perform 2D BLE modeling according to Iowa DNR specifications
- Provide 2D BLE outreach
- Perform 2D BLE refinement
- Develop 2D BLE FP Mapping
- Develop 2D BLE Flood Risk products

Pricing from Original Contract

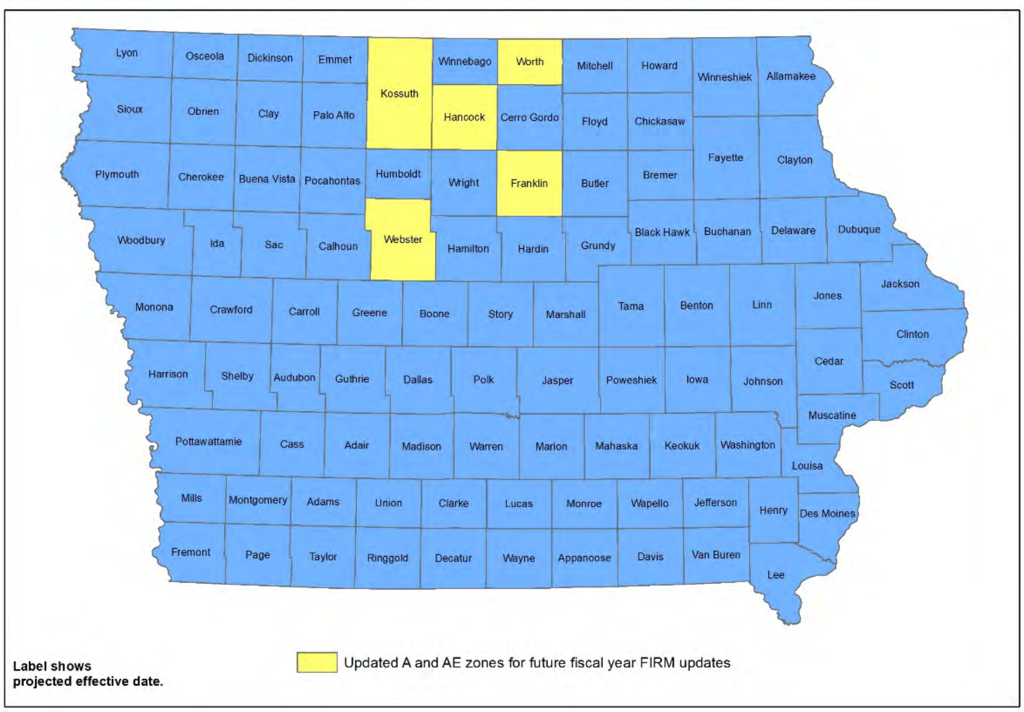
The source of funding for Task Orders to be performed under this Contract shall be $4,948,918 of the FEMA Cooperating Technical Partner (CTP) Grant No. EMK-2022-CA-00009 awarded to the DNR for the 39-month Period of Performance beginning on October 1, 2022. There is no guarantee as to the number of individual Task Orders that will be allotted to any prequalified Contractor. Payment shall be for satisfactory completion of the Task Orders developed in accordance with the provisions of this Contract, provided that Contractor has complied with the terms of this Contract. Payment for the work performed by Contractor according to the terms of this Contract shall be allotted in lump sum portions of $4,948,918 with no guarantee as to the number or dollar value of individual Task Orders. This Contract will be amended as necessary to reflect the amounts of future FEMA CTP grants.

Floodplain Mapping - 2D BLE Status Update 8/9//2023



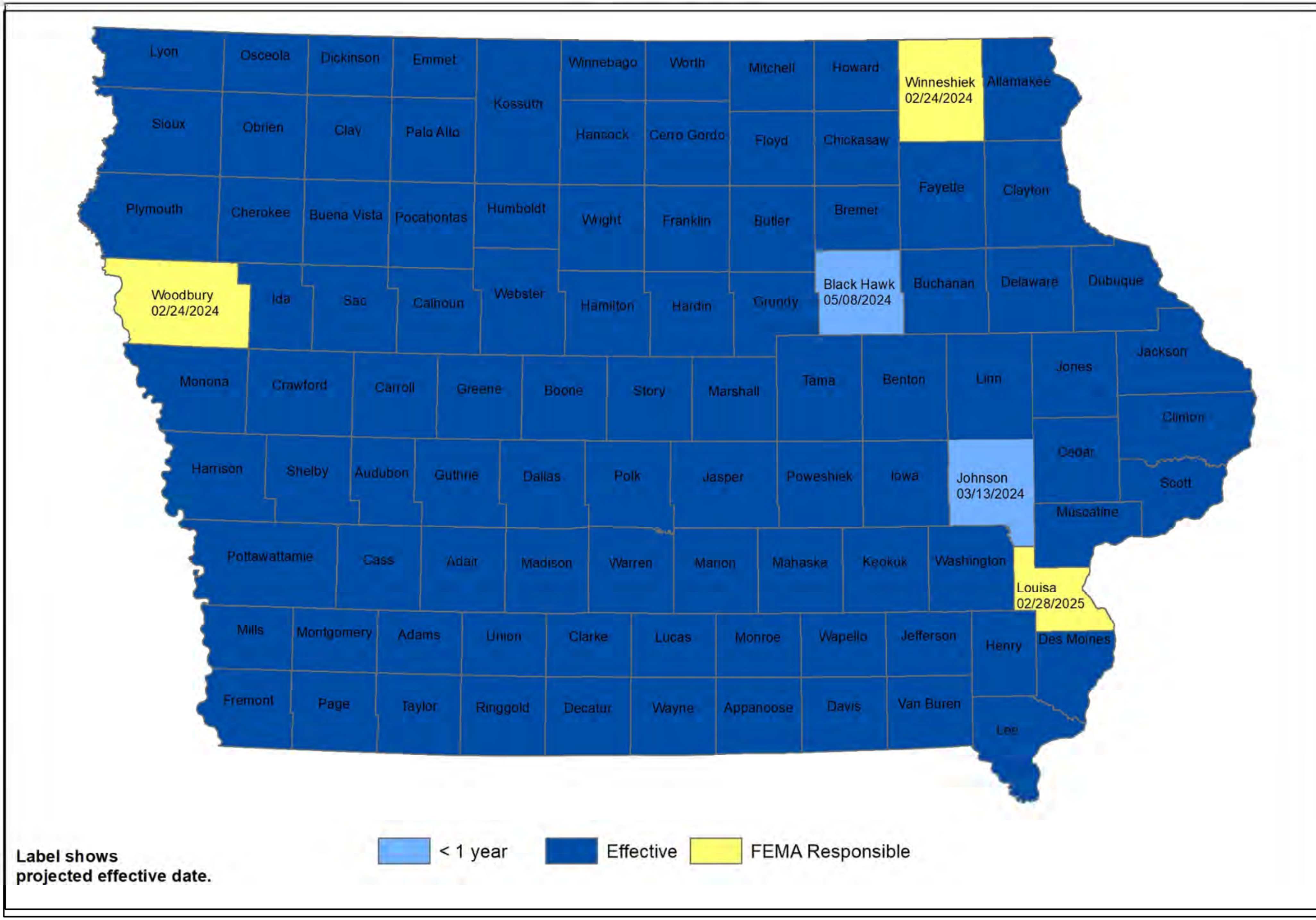
As was true with the earlier draft flood hazard data developed by the Iowa Flood Center, 2D BLE modeling is the first step in a multi-stage process. The hydrology and hydraulic models come first, then mapping – actual lines delineating flood zones; afterward meetings to present the draft mapping to communities, get feedback and work with them to incorporate any local data or knowledge to inform the mapping takes place.

Floodplain Mapping Projects
Federal Fiscal Year 2023 Grant



The federal fiscal year 2023 grant from FEMA responds to FEMA guidance by using 2D BLE models and new stream reaches to create A and AE zones for five Iowa counties – Franklin, Hancock, Kossuth, Webster and Worth. FIRM updates for these counties will be proposed in future grant proposals.

Effective Flood Insurance Rate Map (FIRM) Progress
August 2023



Iowa Department of Natural Resources
Environmental Protection Commission

Item # 7

Decision Item

Commission approval is requested for a Contract with Iowa Department of Agriculture and Land Stewardship (IDALS) (Protect Rathbun Lake Project)

Contract Terms:

Amount: Not to exceed $464,242
Dates: August 15, 2023 to June 30, 2026.
Funding Source(s): U.S. Environmental Protection Agency Section 319 Grants to DNR (FFY22 Grant)
Statutory Authority: Funds are administered by DNR under statutory authority granted by Iowa Code section 455B.103 and under 11 IAC 118.4.

Background:
This Contract will continue to support the Protect Rathbun Lake Project, an ongoing water quality and watershed improvement project administered by IDALS and carried out by the Wayne Soil and Water Conservation District.

Contract Purpose: The overall goal of the Protect Rathbun Lake Project is to reduce sediment and phosphorus delivery to Rathbun Lake and the lake's tributaries through implementing the Rathbun Lake Watershed Management Plan (WMP). Project activities will assist landowners to apply best management practices (BMPs) that will reduce sediment and phosphorus delivery to Rathbun Lake and its tributaries.

This phase of the WMP includes the installation of BMPs treating 820 acres. At least 410 acres addressed with BMPs will be priority land with the remaining acres considered associate priority land (adjacent to or otherwise essential for the protection of priority land). These BMPs will reduce the annual delivery of sediment and phosphorus to Rathbun Lake by an estimated 2,435 tons and 3,545 pounds respectively. Contracted activities will include the application of BMPs in the 56 targeted sub-watersheds in which Protect Rathbun Lake efforts are currently underway as well as the installation of practices with landowners in one additional sub-watershed, the newly targeted South Fork Chariton River #4 sub-watershed.

Statement of Work/Task:
Task 1: Provide Project Coordinator
Task 2: Submit to DNR the Annual Work Plan and Budget
Task 3: Carry Out Project Activities in the Project Workplan
Task 4: Provide Quarterly Financial Report
Task 5: Provide Quarterly Progress Report
Task 6: Submit Annual Report
Task 7: Submit Final Project Report

Contract History:
The DNR has contracted with IDALS to administer Section 319-funded watershed projects since the early 1990s. The purpose of the contracts with IDALS is to provide funds and project management support to IDALS, which then enters into subsequent agreements with soil and water conservation districts to implement the specific watershed implementation project activities.

Contracts for watershed projects overlap to enable project work to continue without interruption, as new contracts are executed with each new Section 319 grant award. In this manner, project coordinators who work with farmers and landowners to implement conservation practices within watersheds can do so continuously between contracts. Projects typically spend their oldest contract dollars first before utilizing new contract funds.

Below is a list of contracts with IDALS over the previous five years that support the Protect Rathbun Lake Project:

Contract #1: Timeframe: July 1, 2018 to June 30, 2021; Amount $250,000
Contract #2: Timeframe: July 16, 2019 to June 30, 2022; Amount $407,706
Contract #3: Timeframe: July 21, 2020 to June 30, 2022; Amount $140,874
Contract #4: Timeframe: June 1, 2021 to June 30, 2024; Amount $427,620
Contract #5: Timeframe: November 11, 2022 to June 30, 2025; Amount $515,269

Partnerships Summary:

The DNR's primary partnerships for this contract include:

- IDALS Division of Soil Conservation and Water Quality
- Rathbun Regional Water Association
- Appanoose, Clarke, Decatur, Lucas, Monroe, and Wayne (lead) County Soil and Water Conservation Districts
- Appanoose, Clarke, Decatur, Lucas, Monroe, and Wayne Counties
- US Department of Agriculture Farm Service Agency and Natural Resources Conservation Service
- US Army Corps of Engineers
- US Environmental Protection Agency
- Iowa Farm Bureau Federation, state and local
- And participating landowners of the Rathbun Lake Watershed

Budget Summary:

Rathbun Lake Proposed Budget (2-year budget)	**Contract Amount (DNR 319 Costs)**	Match Funding Share (State/Local)	Leveraged Funds (Non-Match)
Staffing/Admin Support (Top Line Costs)	**$276,775.00**	$129,200.00	$30,000.00
Watershed Practice Support* (Bottom Line Costs)	**$187,467.00**	$332,373.00	$160,530.00
Totals	**$464,242.00**	$461,573.00	$190,530.00
Overall Proposed Project Total	$1,116,345.00		

*Practices targeted by the project include, but are not limited to: terraces, grade stabilization structures, water and sediment control basins, hayland planting, and grazing system improvements. DNR 319 funds will primarily support terraces, grade stabilization structures, and water and sediment control basins. Additionally, the DNR funds fully support a special summer construction incentive which aids producers in installing practices during fair weather and offsets costs to their farm operation as a result of growing season construction.

Steve Konrady, Water Quality Bureau
Environmental Services Division
August 9, 2023

Iowa Department of Natural Resources
Environmental Protection Commission

 # 8

Decision Item

Contract Amendment No. 1 with Iowa Department of Agriculture and Land Stewardship

Commission approval is requested for a Contract Amendment with Iowa Department of Agriculture and Land Stewardship (IDALS), of Des Moines, Iowa.

Amendment Amount: $80,250
Total Amount (Original Contract plus Amendment): $177,500
Amendment Dates: August 11, 2023 to January 31, 2026
Funding Source(s): EPA Clean Water Act Section 319 grant number 00740429

Amendment Purpose: The purpose of this Contract Amendment is to designate additional Section 319 funding to support the Big Hollow Lake Watershed Project. This Contract Amendment will work to carry out the goals of the Big Hollow Lake Watershed Project for the stated Contract Amendment term. In particular, additional grant funding will be provided to ensure a project coordinator can be provided for the length of the Contract. The watershed project will be funded by the DNR-administered EPA 319 grant funds along with other partner entities: IDALS, Des Moines County Soil and Water Conservation District, Des Moines County Conservation, NRCS, and FSA, as well as match funding from landowners.

Original Contract Purpose: The purpose of this Contract is to designate Section 319 funding to support the Big Hollow Lake Watershed Project. This Contract will work to carry out the goals of the Big Hollow Lake Watershed Management Plan for the stated Contract term.

Original Selection Process Summary: Statute or federal grant contracting with IDALS is authorized by 11 IAC 117.5(5) and 118.7, which allows for agreements with entities without competition when the law or federal grant requires them. In addition, intergovernmental contracting with IDALS is authorized under 11 IAC 118.4. Contracts with public agencies for laboratory work, scientific field measurement and environmental quality evaluation services necessary to implement Iowa Code Chapter 455B is authorized under Iowa Code section 455B.103(3).

Contract History:

Original Contract Terms: Amount $97,250; Timeframe: February 1, 2023 to January 31, 2026; Purpose: To carry out the goals of the Big Hollow Lake Project.

Miranda Haes, NE Iowa Basin Coordinator, Water Quality Bureau
Environmental Services Division
August 9, 2023

STATEMENT OF WORK (No amendment to the original contract)

Task 1. **Provide Project Coordinator –** Contractor shall hire and maintain a project coordinator position for the duration of the Contract. ***Timeframe* -** Continuous

Task 2. **Submit to DNR the Annual Work Plan and Budget –** The Contractor shall submit to DNR an annual Work Plan and Budget consistent with the Statement of Work. ***Timeframe* –** No later than May 1 of each year

Task 3. **Carry Out Project Activities in the Project Workplan –** For each approved annual Work Plan and Budget, the Contractor shall timely carry out the project activities identified therein. The Contractor shall submit to the DNR documentation of compliance with the Work Plans and Budgets in the form of invoices. ***Timeframe* –** No later than June 30th of each state fiscal year.

Task 4. **Provide Quarterly Financial Report –** The Contractor shall submit to DNR a quarterly financial report. This report shall summarize the expenses incurred during the previous month, identify the funding programs used to pay these expenses, and list the amounts incurred by each funding program. ***Timeframe* –** 10/15, 1/15, 4/15 yearly *Note: Quarterly reports are superseded by annual reports for the expected 7/15 report as follows*

Task 5. **Provide Quarterly Progress Report –** The Contractor shall submit to DNR a quarterly report of the progress made in the preceding quarter toward completion of the required project activities included in the most recently approved annual Work Plan and Budget. ***Timeframe* –** 10/15, 1/15, 4/15 yearly *Note: Quarterly reports are superseded by annual reports for the expected 7/15/ report*

Task 6. **Submit Annual Report** – The Contractor shall submit to DNR an annual report that describes all work activities carried out as part of the project during the previous project fiscal period, discuss progress made toward achieving the overall Work Plan, provides summaries of and evaluates water quality monitoring data collected un the project, summarize water quality improvements made, and identify total documented project cost incurred during the previous project fiscal year, funding programs used to pay these costs, and the amounts paid by each funding program. ***Timeframe*** – 8/15 yearly

Task 7. **Final Project Report –** Total Section 319 funds expended by the project, summary of other funds, summary of accomplishments and objectives, comparison of actual accomplishments to objectives established by annual work plans and project implementation plan, summary of water quality improvements (load reductions), explanation of unmet objectives, and all other reporting requirements in the Section 319 guidance document. ***Timeframe* –** Due no later than 45 days prior to the expiration of this Contract.

AMENDMENT BUDGET

Budgets are submitted by the Contractor as part of the EPA-approved Project Implementation Plan (once per Contract) and Work Plan and Budget (annually). The Contractor has submitted the following budget overview with the Project Implementation Plan for 319 funds to be incorporated into the Contract for the full term:

Amendment Budget Item	**Amount of 319 Funds**
Top Line/Administrative Costs	
Coordinator Salary and Benefits	$71,000
IDALS Conservation Assistant Support	$5,000
Travel/Training	$750
Supplies	$500
Information/Outreach	$3,000
AMENDMENT TOTAL:	**$80,250**
Original Contract Total:	$97,250
AMENDED CONTRACT TOTAL:	**$177,500**

Iowa Department of Natural Resources
Environmental Protection Commission

#9

Decision Item

Topic: Water Supply – Water Use & Allocation Annual Permit Fee

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The Commission is asked to approve the Water Use and Allocation Program annual permit fee of $115.00 per permit for SFY 2024.

Background

Water use permits are required of any person or entity using more than 25,000 gallons of water in a single day during the year, and are issued for a period of up to 10 years. Iowa Code §455B.265(6) authorizes the Department to charge a fee for the permits and to collect up to $500,000 per year through these fees. The fee is required to be based on the Department's "reasonable cost of reviewing applications, issuing permits, ensuring compliance with the terms of the permits, and resolving water interference complaints." There are two types of fees in the Water Use and Allocation Program: an application fee and an annual permit fee. This request is for the determination of the annual permit fee for SFY 2024.

The annual permit fee is calculated as follows:

- Each year, the Commission is asked to set the annual permit fee based on the costs for administering the water use program for the previous calendar years and on the anticipated expenses for the next fiscal years.
- The Department reviews the annual permit fee each year and adjusts the fee as necessary to cover all reasonable costs required to develop and administer the water use permitting program.
- The annual permit fee is based on the number of active permits.
- Each permit holder pays the same annual permit fee.
- The Department requests Commission approval of the amount of the annual permit fee no later than September 30th of each year.
- The annual permit fee due date is December 1st; and the Department is required to provide an annual fee notice to each permittee at least 60 days prior to the fee due date (i.e., no later than October 1st).
- The annual permit fee history: $135 in 2010-2011, $95 in 2012, $66 in 2013-2014, $99 in 2015-2016, $66 in 2017, $134 in 2018-2019, $95.00 in 2020-2022, and $115 in 2023.

Stakeholder Meeting and Fee Analysis

At the Water Use Stakeholder meeting on July 19, 2023, the program's activities and budget were reviewed for the past and future years. In the SFY 2024 budget, there are 4.0 FTE staff persons and routine expenses. The budget less the anticipated application fee, anticipated general fund, and carryforward was used to determine the annual fee. The Department proposed a $115.00 annual fee in order to have stability in budgeting and less annual fluctuation of the fee. All fee monies are held in the water use permit fund to be used for the water use and allocation program needs.

<u>Annual Permit Fee Calculation:</u>
A. Budget – Average application fee revenue – Anticipated General Fund – Carryforward spent = Annual permit fee revenue

$613,956 – $34,000 – $184,190 – $20,646 = $375,120 for annual permit fee revenue

B. Annual permit fee revenue/number of active permits that would pay fee in SFY 2024 = Annual permit fee per permit

$375,120 / 3,262 = $115.00 per permit

Therefore, a $115.00 annual water use permit fee was proposed by the Department for SFY 2024. The stakeholder members participating in the meeting supported that proposal.

Based on the budget and stakeholder input, the annual water use permit fee for SFY 2024 should be $115.00.

Heidi Cline, Drinking Water Program Coordinator
Water Supply Engineering Section
Environmental Services Division
August 9, 2023

Iowa Department of Natural Resources
Environmental Protection Commission

#10

Decision Item

TOPIC: State Implementation Plan Revision for Regional Haze (2019-2028)

The Commission is requested to approve the State Implementation Plan (SIP) revision that reduces Iowa's emissions to provide for visibility improvements in downwind mandatory Class I Federal areas (Class I areas). After approval from the Commission, the plan and its appendices will be submitted to U.S. EPA for federal notice and approval.

Reason for SIP Revision

EPA's regional haze rule requires states to periodically submit comprehensive 10-year plans that contain control measures necessary to make reasonable progress towards eliminating, by 2064, man-made visibility impairment in 156 Class I areas across the U.S. The initial regional haze plans were due in 2007 and covered the 2009-2018 timeframe. This plan addresses the second implementation period, 2019-2028. While Iowa does not contain a Class I area, the state must address its visibility impacts on such areas in Minnesota, Michigan, and Missouri. In those areas, the leading cause of visibility impairment is particles formed from emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

Iowa's regional haze plan includes new cost-effective control measures that will reduce SO_2 emissions by ~9,700 tons per year. The new measures require MidAmerican Energy Company to implement dry scrubber improvements at both Louisa Generating Station (LGS) and Walter Scott Jr. Energy Center – Unit 3 (WSEC-3) by December 31, 2023. New control measures to reduce NO_X emissions from these facilities were determined to be unwarranted at this time. The modified air construction permits that contain the enforceable requirements for the new SO_2 control measures are included in Appendix E. The plan's other appendices are available upon request.

Summary of Federal Land Manager and Public Comment Activities

The regional haze program requires that each state consult with the Federal Land Managers (FLM) prior to obtaining public comment. The FLMs are responsible for managing and protecting the Class I areas under their agency's jurisdiction. Oversight of a given Class I area falls to either the National Park Service (NPS), the U.S. Fish and Wildlife Service (FWS), or the USDA Forest Service (FS). Each agency has at least one FLM representative actively engaged in regional haze consultation activities.

DNR held its formal 60-day FLM consultation period from October 11 through December 9, 2022, and received comments from the FS and the NPS. In general, the FLMs were supportive of Iowa's plan and the associated SO_2 emissions reductions, but both suggested the DNR review additional facilities for potential controls. The NPS also suggested the DNR establish and consider [more expensive] cost-effectiveness thresholds. DNR did not make substantive modifications to Iowa's plan in response to the FLM's comments.

During the public comment period held February 13 through March 16, 2023, the DNR received 59 written comment letters, with 8 being unique. Two speakers provided verbal comments during the public hearing held on March 16, 2023. DNR made minor modifications to the plan for clarification and documentation purposes in response to the comments, but no substantive revisions as were requested by some commenters. Separate responsiveness summaries for the FLM consultation period and the public comment period are included in the plan.

Matthew Johnson, Environmental Specialist Senior
Program Development and Support Section, Air Quality Bureau
Environmental Services Division

Memo Date: July 24, 2023

Appendix E: Air Quality Construction Permits

This appendix contains the Air Quality Construction Permits the DNR is including with Iowa's regional haze SIP for the second planning period (2019-2028). The Louisa Generating Station (LGS) main boiler permit and the Walter Scott Jr. Energy Center – Unit 3 (WSEC-3) permit both include new SO_2 emission limits, new operating conditions, and compliance demonstrations requiring implementation by December 31, 2023. The new requirements for regional haze are found in conditions 1c. and 5.P – 5.R.

The current WSEC-4 permit was not modified for regional haze purposes but is included to incorporate its existing SO_2 and NO_X emission limits into Iowa's SIP for the purpose of preventing future visibility impairment. Table E-1 summarizes the three permits included with this plan.

Table E-1. Summary of the air construction permits included with this SIP revision. Each unit is a coal-fired EGU.

Company	Facility Name	Facility ID	Unit	DNR Permit Number[1]	Permit Issuance Date
MidAmerican Energy Co.	Louisa Generating Station	58-07-001	Main Boiler	05-A-031-P6	July 20, 2023
MidAmerican Energy Co.	Walter Scott Jr. Energy Center	78-01-026	Unit 3	75-A-357-P9	July 20, 2023
MidAmerican Energy Co.	Walter Scott Jr. Energy Center	78-01-026	Unit 4	03-A-425-P4	December 5, 2011

[1] The DNR's air construction permits are issued by emission point, and incorporate all state and federal air quality requirements applicable to that emission point and its associated emission unit(s). Existing conditions unrelated to regional haze are outside the scope of this plan.

Air Quality Construction Permit

Permit Number: 05-A-031-P6

Plant Number: 58-07-001

Company: MidAmerican Energy Co. – Louisa Station

Contact Person:
Janelle Spies
Senior Environmental Analyst

(563) 262-2884
Janelle.spies@midamerican.com

8602 172nd Street
Muscatine, Iowa 52761

Responsible Party:
Todd Horchem
General Manager

(563) 333-4144

8602 172nd Street
Muscatine, Iowa 52761

Permitted Equipment

Emission Point ID: EP-1

Emission Unit(s) and Control Equipment:

EU ID	Description	Maximum Rated Capacity	Control Equipment Description and ID
EU1	Louisa Boiler	8,000 MMBtu/hr	Dry Electrostatic Precipitator (DESP, CE1), Lime Spray Dryer Flue Gas Desulfurization (FGD, CE1B), Baghouse (CE1C), Mercury (Hg) Sorbent Injection (CE1D), Low NOx Burners (LNB) & Overfire Air (OFA) (CE2)

Equipment Location: 8602 172nd St.
Muscatine, IA 52761

Issuance of this permit shall not relieve the owner or operator of the responsibility to comply fully with applicable provisions of the State Implementation Plan (SIP), and any other requirements of local, state, and federal law.

Project Number	Project Description	Stack Testing	Issuance Date
21-348	Establish Regional Haze SO2 Limit	No	07/20/23

Under the Direction of the Director of the
Department of Natural Resources

PERMIT CONDITIONS

1a. Best Available Control Technology (BACT) Emission Limits

The owner or operator is required to report all emissions as required by law, regardless of whether a specific emission limit has been established in this permit. The following emission limits shall not be exceeded:

Pollutant	Tons/Yr[1]	Additional Limits
Federal Particulate Matter (PM)	NA	0.03 lb/MMBTU[2]
State Particulate Matter (PM)	1,019	0.027 lb/MMBTU[2]
PM_{10}	1,019	0.027 lb/MMBTU[2]
Opacity[3]	NA	10%[4]
Sulfur Dioxide (SO_2)[3]	NA	0.96 lb/MMBTU[5]
Nitrogen Oxides (NO_x)[3]	NA	0.5 lb/MMBTU[5]
Volatile Organic Compounds	135.98	0.0036 lb/MMBTU[2]
Carbon Monoxide (CO)[3]	15,864	0.42 lb/MMBTU[6]

[1] Standard is a 12-month rolling total.
[2] The emission limit is expressed as the average of three (3) runs.
[3] Compliance with the emission standards shall be demonstrated through the use of Continuous Emission Monitoring Systems (CEMS). See Condition 5 and Condition 6 for more information on compliance with the use of CEMS.
[4] Standard is a one (1) hour average.
[5] This standard is a 30-day rolling average not including periods of startup, shutdown, and malfunction (SSM).
[6] Standard is a one (1) calendar day average not including periods of SSM.

1b. New Source Performance Standards (NSPS) Emission Limits

The owner or operator is required to report all emissions as required by law, regardless of whether a specific emission limit has been established in this permit. The following emission limits shall not be exceeded:

Pollutant	Emission Standard[1]	Reference/Basis
Federal PM	43 ng/J heat input[2]	567 IAC 23.1(2)"a"[3]
Opacity[4]	20%[5]	567 IAC 23.1(2)"a"[3]
SO_2[4]	520 ng/J heat input[6]	567 IAC 23.1(2)"a"[3]
NO_x[4]	300 ng/J heat input[7]	567 IAC 23.1(2)"a"[3]

[1] Standard is expressed as the average of three (3) runs.
[2] 43 ng/J = 0.10 lb/MMBTU. See 40 CFR §60.42(a)(1).
[3] IAC reference to New Source Performance Standards (NSPS) Subpart D (Standards of Performance for Fossil-Fuel-fired Steam Generators for Which Construction Is Commenced After August 17, 1971; 40 CFR §60.40 – 40 CFR §60.46).
[4] Compliance with the emission standards shall be demonstrated through the use of a CEMS. See Condition 12 and Condition 16 for more information on compliance with the use of CEMS.
[5] Opacity shall not exceed 20% (6-minute average), except for one (1) 6-minute period per hour of not more than 27% opacity. See 40 CFR §60.42(a)(2).
[6] 520 ng/J = 1.20 lb/MMBTU. Emission limit per 40 CFR §60.43(a)(2) when the unit is combusting solid fossil fuel or solid fossil fuel and wood residue. Per 40 CFR §60.43 alternative limits are:

- 340 ng/J heat input (0.80 lb/MMBTU) when combusting liquid fossil fuel or liquid fossil fuel and wood residue [40 CFR §60.43(a)(2)].
- Per 40 CFR §60.43(b), when different fossil fuels are combusted simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$\frac{[y(340) + z(520)]}{y+z}$$

Where:

PS_{SO2} = the prorated standard for SO_2 when burning different fuels simultaneously, in nanograms per joule (ng/J) heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired.
y = the percentage of total heat input derived from liquid fossil fuel
z = the percentage of total heat input derived from solid fossil fuel.

1b. NSPS Limits (continued)

- Per 40 CFR §60.43(d), as an alternate to meeting the requirements of 40 CFR §60.43(a) and 40 CFR §60.43(b), an owner or operator can petition the Administrator (in writing) to comply with 40 CFR §60.43Da(i)(3) or comply with 40 CFR §60.42b(k)(4) as applicable to the affected source. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in 40 CFR §60.43Da(i)(3) or 40 CFR §60.42b(k)(4) as applicable to the affected source.

Per 40 CFR §60.43(c), compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.
In addition, per 40 CFR §60.45(g)(2), excess emissions are defined as:

- For affected facilities electing not to comply with 40 CFR §60.43(d), any three (3) hour period during which the average emissions [arithmetic average of three (3) contiguous one (1) hour periods] of SO_2 as measured by a CEMS exceed the applicable standard in 40 CFR §60.43; or
- For affected facilities electing to comply with 40 CFR §60.43(d), any thirty (30) operating day period during which the average emissions [arithmetic average of all one (1) hour periods during the thirty (30) operating days) of SO_2 as measured by a CEMS exceed the applicable standard in 40 CFR §60.43. Facilities complying with the thirty (30) day SO_2 standard shall use the most current associated SO_2 compliance and monitoring requirements in 40 CFR §60.48Da and 40 CFR §60.49Da or 40 CFR §60.45b and 40 CFR §60.47b as applicable.

[7] 300 ng/J = 0.70 lb/MMBTU. Emission limit per 40 CFR §60.43(a)(3) when the unit is combusting solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25%, by weight, or more of coal refuse). Per 40 CFR §60.44 alternative limits are:

- 86 ng/J heat input (0.20 lb/MMBTU) when combusting gaseous fossil fuel.
- 129 ng/J heat input (0.30 lb/MMBTU) when combusting liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.
- liquid fossil fuel or liquid fossil fuel and wood residue [40 CFR §60.43(a)(2)].
- Per 40 CFR §60.44(b), when different fossil fuels are combusted simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$\frac{[w(260) + x(86) + y(130) + z(300)]}{w + x + y + z}$$

Where:

PS_{NO_x} = the prorated standard for NO_x when burning different fuels simultaneously, in nanograms per joule (ng/J) heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired.
w = the percentage of total heat input derived from lignite
x = the percentage of total heat input derived from gaseous fossil fuel
y = the percentage of total heat input derived from liquid fossil fuel
z = the percentage of total heat input derived from solid fossil fuel.

- Per 40 CFR §60.44(e), as an alternate to meeting the requirements of 40 CFR §60.43(a) and 40 CFR §60.43(b), an owner or operator can petition the Administrator (in writing) to comply with 40 CFR §60.43Da(e)(3). If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in 40 CFR §60.43Da(e)(3).

In addition, per 40 CFR §60.45(g)(3), excess emissions are defined as:

- For affected facilities electing not to comply with 40 CFR §60.44(e), any three (3) hour period during which the average emissions [arithmetic average of three (3) contiguous one (1) hour periods] of SO_2 as measured by a CEMS exceed the applicable standard in 40 CFR §60.44; or
- For affected facilities electing to comply with 40 CFR §60.44(e), any thirty (30) operating day period during which the average emissions [arithmetic average of all one (1) hour periods during the thirty (30) operating days) of NO_x as measured by a CEMS exceed the applicable standard in 40 CFR §60.44. Facilities complying with the thirty (30) day NO_x standard shall use the most current associated NO_x compliance and monitoring requirements in 40 CFR §60.48Da and 40 CFR §60.49Da.

1c. Regional Haze Limit

Pollutant	lb/hr	tons/yr	Other Limits	Reference/Basis
Sulfur Dioxide (SO_2)	800[1,2]	NA	NA	567 IAC 22.9(6)

[1]Limit based on 65.6 percent reduction of SO_2 emissions from the baseline years of 2017 to 2019. Compliance with the limit is based on continuous emissions monitoring as specified in permit condition 6.
[2] Limit based on 30-day rolling average. Limit is applicable at all times including periods of Boiler startup, shutdown, and malfunction.

1d. Other Emission Limits

The owner or operator is required to report all emissions as required by law, regardless of whether a specific emission limit has been established in this permit. The following emission limits shall not be exceeded:

Pollutant	lb/hr	Tons/yr[1]	Additional Limits	Reference/Basis
PM_{10}	258.7[2, 3]	NA	NA	NAAQS
SO_2[4]	3,449.6[5, 6]	NA	NA	NAAQS
NO_x[4]	1,724.8[6]	7,555[7]	NA	NAAQS
CO[4]	3,622[3, 6]	NA	NA	NAAQS

[1] Standard is a 12-month rolling total.
[2] The emission limit is expressed as the average of three (3) runs.
[3] Emission rate used in the computer aided dispersion model to demonstrate predicted attainment of the National Ambient Air Quality Standards (NAAQS).
[4] Compliance with the emission standards shall be demonstrated through the use of a CEMS. See Condition 5 and Condition 6 for more information on compliance with the use of CEMS.
[5] Emission limit carried over from EPA Prevention of Significant Deterioration (PSD) permit. This emission limit was also used in order to net Project Number 05-511 out of PSD review. The SO_2 emissions of this unit shall not exceed:

- 153,600 lbs/calendar day and/or
- 6,400 lbs/hr for more than five (5) hours in any calendar day.

[6] This standard is a 30-day rolling average.
[7] Emission rate used to demonstrate a reduction in emissions for Project Number 04-750 (installation of OFA and LNB). This rate was corrected in Project Number 05-511 to reflect the actual size of the boiler.

2. Compliance Demonstration(s)

Compliance Demonstration Table

Pollutant	Compliance Methodology	Frequency	Test Run Time	Test Method
PM – Federal	None	NA	1 hour	40 CFR 60, Appendix A, Method 5
PM – State	None	NA	1 hour	40 CFR 60, Appendix A, Method 5 40 CFR 51 Appendix M Method 202
PM_{10}	None	NA	1 hour	40 CFR 51, Appendix M, 201A with 202
Opacity	Continuous Opacity Monitoring System (COMS)[1]	Continuous	1 hour	40 CFR 60, Appendix A, Method 9
SO_2	Continuous Emission Monitoring System (CEMS)[1]	Continuous	1 hour	40 CFR 60, Appendix A, Method 6C
NO_x	Continuous Emission Monitoring System (CEMS)[1]	Continuous	1 hour	40 CFR 60, Appendix A, Method 7E
VOC	None	NA	1 hour	40 CFR 63, Appendix A, Method 320 or 40 CFR 60, Appendix A, Method 18
CO	Continuous Emission Monitoring System (CEMS)[1]	Continuous	1 hour	40 CFR 60, Appendix A, Method 10

[1] See Condition 6 of the permit for the continuous monitoring requirements.

2. Compliance Demonstration(s) (Continued)

<u>If an initial stack test is specified in the “Compliance Demonstration Table,”</u> the owner or the owner’s authorized agent shall demonstrate compliance with the emission limitations contained in Condition 1 within the applicable time period specified below:

- Within sixty (60) days after achieving the maximum production rate and no later than one hundred eighty (180) days after the initial startup date of the proposed equipment for the addition of new equipment or the physical modification of existing equipment or control equipment.
- Within ninety (90) days of the issuance of this permit if there is no physical modification to any emission units or control equipment.

<u>If any additional stack testing beyond an initial test (i.e. quarterly, semi-annual, annual, etc.) is required in “Compliance Demonstration Table,”</u> the owner or the owner’s authorized agent shall demonstrate compliance with the emission limitations contained in Condition 1 as specified in the “Compliance Demonstration Table.” See Conditions 12.A.(4) and 12.B.(5) for notification and reporting requirements.

If stack testing is required, the owner or the owner’s authorized agent shall use the test method and run time listed in the “Compliance Demonstration Table” unless another testing methodology is approved by the Department prior to testing.

Each emissions compliance test must be approved by the Department. Unless otherwise specified by the Department, each test shall consist of three (3) separate runs. The arithmetic mean of three (3) acceptable test runs shall apply for compliance, unless otherwise indicated by the Department.

Per 567 IAC 25.1(7)”a”, at the Department’s request, a pretest meeting shall be held not later than fifteen (15) days before the owner or operator conducts the compliance demonstration. A testing protocol shall be submitted to the Department no later than fifteen (15) days before the owner or operator conducts the compliance demonstration. Representatives from the Department shall attend this meeting, along with the owner and the testing firm, if any. It shall be the responsibility of the owner to coordinate and schedule the pretest meeting. A representative of the Department shall be allowed to witness the test(s). The Department shall reserve the right to impose additional, different, or more detailed testing requirements.

The owner shall be responsible for the installation and maintenance of test ports. The unit(s) being sampled shall be operated in a normal manner at its maximum continuous output as rated by the equipment manufacturer, or the rate specified by the owner as the maximum production rate at which this unit(s) will be operated. In cases where compliance is to be demonstrated at less than the maximum continuous output as rated by the manufacturer, and it is the owner's intent to limit the capacity to that rating, the owner may submit evidence to the Department that this unit(s) has been physically altered so that capacity cannot be exceeded, or the Department may require additional testing, continuous monitoring, reports of operating levels, or any other information deemed necessary by the Department to determine whether this unit(s) is in compliance.

3. Emission Point Characteristics

This emission point shall conform to the specifications listed below:

Parameter	Value
Stack Height (feet from the ground)	610 Feet
Discharge Style	Vertical Unobstructed Discharge
Stack Outlet Dimensions (inches)	360 inch Diameter
Exhaust Temperature (°F)	200 °F
Exhaust Flowrate (scfm)	2,384,500 scfm

The temperature and flowrate are intended to be representative and characteristic of the design of the permitted emission point. The Department recognizes that the temperature and flow rate may vary with changes in the process and ambient conditions. If it is determined that any of the emission point characteristics above are different than the values stated, the owner or operator shall submit a request either by electronic mail or written correspondence to the Department within thirty (30) days of the discovery to determine if a permit amendment is required, or submit a permit application requesting to amend the permit.

4. Federal Standards

A. New Source Performance Standards (NSPS):
The following subparts apply to the emission unit(s) in this permit:

EU ID	Subpart	Title	Type	State Reference (567 IAC)	Federal Reference (40 CFR)
EU1	A	General Provisions	NA	23.1(2)	§60.1 – §60.19
	D	Fossil-Fuel-fired Steam Generators for Which Construction Is Commenced After August 17, 1971	NA	23.1(2)"a"	§60.40 –§60.46

NOTE: The absence of the inclusion of any NSPS requirements as part of this permit does not relieve the owner or operator from any obligation to comply with all applicable NSPS conditions.

B. National Emission Standards for Hazardous Air Pollutants (NESHAP): For information only: This equipment is of the source category affected by the following federal regulation: *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units* [40 CFR Part 63, Subpart UUUUU].

NOTE: The absence of the inclusion of any NESHAP requirements as part of this permit does not relieve the owner or operator from any obligation to comply with all applicable NESHAP conditions.

C. Acid Rain:
The facility (plant number 58-07-001) is considered an affected source under 40 CFR 72, 73, 75, 76, 77, and 78 definitions as emission units at this source are subject to the acid rain emission reduction requirements or the acid rain emission limitations, as adopted by the Department by reference (See 567 IAC 22.120 – 567 IAC 22.148). This emission unit is subject to the SO_2 allowance allocation, NO_x emission limitations, and monitoring provisions of the federal acid rain program.

5. Operating Requirements with Associated Monitoring and Recordkeeping

Unless specified by a federal regulation, all records as required by this permit shall be kept on-site for a minimum of two (2) years and shall be available for inspection by the Department. Records shall be legible and maintained in an orderly manner. The operating requirements and associated recordkeeping for this permit shall be:

A. The owner or operator shall maintain records of SO_2 emissions for each calendar day and shall submit a summary of such emissions to the Department within thirty (30) calendar days of the end of each calendar quarter.

B. This unit shall be limited to firing bituminous coal, sub-bituminous coal, #2 fuel oil, and natural gas.

i. The owner or operator shall keep records of whenever bituminous coal is combusted at the facility.

C. The sulfur (S) content of any coal fired in the unit shall not exceed 2.0 lb/MMBTU.

i. The owner or operator shall maintain records of the sulfur (S) content of all coal or combination of coals fired in the boiler.

D. MidAmerican Energy shall be responsible for the construction and use of a new stack at the Grain Processing Corporation (GPC), Muscatine, Iowa to handle the exhaust from the boilers prior to commencement of operation of the Louisa Generating Station. Such stack shall be constructed according to the specification in the agreement between MidAmerican Energy and the Grain Processing Corporation, dated July 6, 1979. Detailed plans and specifications, and a construction schedule for this proposed stack shall be submitted to the EPA or its delegate not later than January 1, 1980.

5. Operating Requirements with Associated Monitoring and Recordkeeping (continued)

E. A bag leak detection system must be installed to meet the following criteria:
   (1) At least one detector must be located in each compartment of the baghouse.
   (2) The bag leak detection system must be installed, operated, calibrated and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in "Fabric Filter Bag Leak Detection Guidance", EPA-454/R-98-015, September 1997.
   (3) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.
   (4) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.
   (5) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensors.
   (6) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel.
   (7) The system's instrumentation and alarm may be shared among detectors.
   (8) The system's alarm shall sound no more than 5% of the operating time during a 6 month period.

   i. The following records must be maintained from the bag leak detection system:
      (1) The date, time and duration of each system alarm.
      (2) The time corrective action was initiated and completed
      (3) A brief description of the cause of the alarm and the corrective action
      (4) A record of the percent of operating time during each 6 month period that the alarm sounds. In calculating the operating time percentage,
         a. If an inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted.
         b. If corrective action is required, each alarm shall be counted as a minimum of 1 hour.
         c. If it takes longer than 1 hour to initiate corrective action, the alarm time shall be counted as the actual amount of time taken to initiate corrective action.

F. Trucks which haul either ash or sludge shall either be covered with a tarp or enclosed.

G. The waste material collected by the fabric filter and stored in the FGD waste silo system shall be processed through a pug-mill during loadout to increase the material moisture content to a minimum of 20%. Water wagons shall be used to wet the waste material during disposal site grading activities.

H. The following conditions are required on the haul roads when combusting bituminous coal at the facility (plant # 58-07-001) to meet the BACT emission rates:
   (1) Haul truck loads shall be enclosed or covered.
   (2) For paved roads:
      (i) Fugitive emissions of paved haul roads shall be controlled to an effective control efficiency of 80% by either water flushing followed by sweeping or using a street sweeper that is certified to achieve a pick-up efficiency of 80%. The control efficiency of 80% shall be achieved by water flushing followed by sweeping or using a certified sweeper on the paved haul roads once per day. The water spray rate shall be a minimum of 0.23 gallons per square yard.
      (ii) If water flushing followed by sweeping cannot be accomplished because the ambient air temperature (as measured at the facility during daylight operating hours) will be less than 35 F, or conditions due to weather, in combination with the application of the water, could create hazardous driving conditions, then the water flushing and sweeping shall be postponed and accomplished as soon after the scheduled date as the conditions preventing the application have abated.
      (iii) Water flushing and sweeping need not occur when a rain gage located at the site indicates that at least 0.2 inches of precipitation (water equivalent) has occurred within the preceding 24-hr time period or the paved road(s) will not be used on a given day.

5. Operating Requirements with Associated Monitoring and Recordkeeping (continued)

(3) For unpaved roads:
(i) Fugitive emissions from unpaved haul roads shall be controlled by applying a chemical dust suppressant. A control efficiency of 95% shall be maintained on all unpaved haul roads. MidAmerican may elect to use any chemical dust suppressant that is capable of achieving the 95% control efficiency. In the event that the manufacturer or distributor of a chemical dust suppressant recommends different amounts of chemical dust suppressant or MidAmerican chooses to use a different chemical dust suppressant, MidAmerican shall notify DNR of the change in application rates and/or chemical dust suppressant and the manufacturer's/distributor's recommendations.
(ii) If the selected chemical dust suppressant cannot be applied because the ambient air temperature (as measured at the facility during daylight operating hours) will be less than 35 F, or conditions due to weather, in combination with the application of the chemical dust suppressant, could create hazardous driving conditions, then the chemical dust suppressant application shall be postponed and accomplished as soon after the scheduled date as the conditions preventing the application have abated.

I. When bituminous coal is combusted, a log shall be kept showing the following for haul roads:
(1) Paved roads:
a. Records of either the use of a certified street sweeper or the applications shall be maintained and shall include
- The dates of each application
- The amount of water applied
- The areas treated, and
- The operator's initials.

b. If water is not applied when scheduled then the records should so indicate and provide an explanation.
(2) Unpaved roads:
a. Records of the applications shall be maintained and shall include:
- The dates of each application
- The chemical dust suppressant used
- The application intensity (gal/sq yd)
- Dilution ratio
- The operator's initials, and
- Documentation of road and weather conditions, if necessary.

b. If the suppressant is not applied as planned, then the records should so indicate and provide an explanation.

J. The owner or operator is not required to operate the Electrostatic Precipitator (ESP, CE 1) as long as the owner or operator is able to demonstrate compliance with the emission limits listed in Condition 1 of this permit without the ESP in operation.

K. The owner or operator is allowed, but not required, to combust coal which has been treated with chemicals to aid in mercury (Hg) emissions control. The following additives have been approved by the Department for use by the owner or operator:
a. a mineral composite of calcium silicate components,
b. other calcium compounds containing iron and aluminum,
c. calcium bromide
d. calcium chloride
e. potassium iodide

L. Prior to the use of any additional chemicals to aid in mercury (Hg) emissions control, the owner or operator shall supply material data to the Department for review and approval. This data shall include, but is not limited to:
a. A description of the chemical additive
b. Information demonstrating the potential impact on mercury emissions and any other HAPs regulated by an applicable state or federal standard, and
c. An evaluation of the impact on all NSR regulated air emissions.

M. The owner or operator shall record if treated coal is combusted and with what chemicals the coal has been treated.

5. Operating Requirements with Associated Monitoring and Recordkeeping (continued)

N. Per 567 IAC 33.3(18)”f”(1), prior to beginning actual construction of the project (Project Number 13-467) the owner or operator shall document:
(1) A description of the project (Project Number 13-467),
(2) Identification of the emission unit(s) whose emissions of a regulated NSR pollutant could be affected by the project (Project Number 13-467), and
(3) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions (BAE), the projected actual emissions (PAE), the amount of emissions excluded under paragraph “3” of the definition of *“projected actual emissions”* in subrule 33.3(1), an explanation describing why such amount was excluded, and any netting analysis if applicable.
(4) Per 567 IAC 33.3(18)”f”(1), the owner or operator shall maintain a record of the information required in Condition 5.K. of this permit for a period of five (5) years.

O. The owner or operator shall meet all applicable recordkeeping and reporting requirements under NSPS Subparts A and D.

Regional Haze Requirements

P. The owner or operator shall complete Lime Spray Dryer FGD (CE1B) enhancements to achieve the SO2 emission limit specified in condition 1c by December 31, 2023.

i. The owner or operator shall maintain record of the completion date of Lime Spray Dryer FGD (CE1B) enhancements to achieve SO2 emission limit as specified in condition 1c.

Q. Within 60 operating days after completion of Lime Spray Dryer FGD (CE1B) enhancements, the owner or operator shall conduct an SO2 emissions study to determine the minimum additive injection rate to achieve SO2 reduction of 65.6 percent below the average of 2017-2019 baseline emissions. The minimum additive injection rate shall be determined during varying boiler operating loads. The study shall also include development and identification of an averaging period for the minimum additive injection rate, if applicable.

i. The owner or operator shall submit the SO2 study results to the Department for review and approval.
ii. The owner or operator shall maintain the SO2 study results onsite and make the results available for inspection.

R. The owner or operator shall maintain the Lime Spray Dryer FGD (CE1B) minimum additive injection rate at the rates determined during the SO2 emissions study at corresponding boiler loads. The minimum additive injection rate shall be maintained at all times while Louisa Boiler is in operation except during periods of boiler start-up.

i. The owner or operator shall properly operate and maintain equipment to monitor the additive injection rate to the Lime Spray Dryer FGD (CE1B). The monitoring devices and any recorders shall be installed, calibrated, operated and maintained in accordance with the manufacturer’s recommendations, instructions and operating manuals or per written facility specific operation and maintenance plan.

ii. The owner or operator shall continuously collect and record the additive injection rate to Lime Spray Dryer FGD (CE1B). The owner or operator shall calculate and record the additive injection rate based on the averaging period determined during the SO2 study, if applicable. If the additive injection rate to Lime Spray Dryer FGD (CE1B) falls below the value determined during the SO2 emissions study, the owner or operator shall investigate the Lime Spray Dryer FGD (CE1B) and make corrections to it. The owner or operator shall maintain a record of all corrective actions taken.

6. Continuous Emission Monitoring Systems (CEMS)

Continuous emission monitoring for the BACT and other emission limits for PM, SO_2 and NO_x shall be determined by all continuous monitoring and reporting methods which may be specified in 40 CFR Part 60, Subpart Da as of the date of initial source startup (i.e., operation of the boiler for any purpose), with the exception that the control efficiency of the sulfur dioxide removal device need not be demonstrated. Notwithstanding the fact that the Louisa Generating Station is still not subject to 40 CFR Part 60, Subpart Da as no increase in the hourly emission rate of an affected NSPS pollutant has occurred, Subpart Da is being referenced to specify methods for determining compliance with the BACT emission rates which were established under the PSD regulations promulgated pursuant to Section 110 of the Act (42 U.S.C. 7410).

A. The following monitoring systems are required:

- *Opacity:*

  The facility (plant number 58-07-001) shall install, calibrate, maintain and operate a continuous monitoring system (CEMS) on EP 1, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator). This system shall be designed to meet the 40 CFR 60, Appendix B, Performance Specification 1 (PS1).

- *SO_2:*

  The owner or operator shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) and record the output of the system, for measuring sulfur dioxide (SO_2) emissions.

  The system shall be designed to meet the 40 CFR 60, Appendix B, Performance Specification 2 (PS2) and Performance Specification 6 (PS6) requirements. The specifications of 40 CFR 60, Appendix F (Quality Assurance/Quality Control) shall apply. Appendix F requirements shall be supplemented with a notice to the Department with the dates of the annual relative accuracy test audit.

- *O_2 or CO_2:*

  The owner or operator shall install, calibrate, maintain, and operate a CEMS and record the output of the system, for measuring the oxygen (O_2) or carbon dioxide (CO_2) content of the flue gases at each location where SO_2 emissions are monitored.

- *CO:*

  Compliance with the carbon monoxide (CO) emission limits of this permit shall be continuously demonstrated by the owner or operator through the use of a CEMS. Therefore, the facility shall install, calibrate, maintain and operate a CEMS on EP 1 for measuring CO emissions discharged to the atmosphere and record the output of the system. The system shall be designed to meet the 40 CFR 60 Appendix B, Performance Specification 4 (PS4) and Performance Specification 6 (PS6) requirements. The specifications of 40 CFR 60, Appendix F (Quality Assurance/Quality Control) shall apply. Appendix F requirements shall be supplemented with a notice to the Department with the dates of the annual relative accuracy test audit.

6. Continuous Emission Monitoring (Continued)

- *Flowmeter:*

  The owner or operator shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of 40 CFR 60, Appendix B, Performance Specification 6 and 40 CFR 60, Appendix F, Procedure 1. In addition, the owner or operator shall record the output of the system, for measuring the volumetric flow of exhaust gases discharged to the atmosphere or

  Alternatively, data from a continuous flow monitoring system certified according to the requirements of 40 CFR §75.20(c) and 40 CFR 75, Appendix A, and continuing to meet the applicable quality control and quality assurance requirements of 40 CFR §75.21 and 40 CFR 75, Appendix B, may be used.

B. The CEMS required in Condition 6.A. for SO_2, and either O_2 or CO_2 shall be operated and the data recorded during all periods of operation including periods of startup, shutdown, malfunction, or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

C. The following data requirements shall apply to all CEMS for non-NSPS emission standards in this permit:

(1) The CEMS required by this permit shall be operated and data recorded during all periods of operation of the emission unit except for CEM breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.
(2) The 1-hour average SO_2 and CO_2 emission rates measured by the CEMS required by this permit shall be used to calculate compliance with the emission standards of this permit. At least 2 data points must be used to calculate each 1-hour average.
(3) For each hour of missing emission data (SO_2 or CO_2), the owner or operator shall substitute data by:
(i) If the monitor data availability is equal to or greater than 95.0%, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:
(a) For the missing data period less than or equal to 24 hours, substitute the average of the hourly concentrations recorded by a pollutant concentration monitor for the hour before and the hour after the missing data period.
(b) For a missing data period greater than 24 hours, substitute the greater of:
- The 90th percentile hourly concentration recorded by a pollutant concentration monitor during the previous 720 quality-assured monitor operating hours; or
- The average of the hourly concentrations recorded by a pollutant concentration monitor for the hour before and the hour after the missing data period.

(ii) If the monitor data availability is at least 90.0% but less than 95.0%, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:
(a) For a missing data period of less than or equal to 8 hours, substitute the average of the hourly concentrations recorded by a pollutant concentration monitor for the hour before and the hour after the missing data period.
(b) For the missing data period of more than 8 hours, substitute the greater of:
- The 95th percentile hourly pollutant concentration recorded by a pollutant concentration monitor during the previous 720 quality-assured monitor operating hours; or
- The average of the hourly concentrations recorded by a pollutant concentration monitor for the hour before and the hour after the missing data period.

(iii) If the monitor data availability is less than 90.0%, the owner or operator shall obtain actual emission data by an alternate testing or monitoring method approved by the Department.

D. If requested by the Department, the owner/operator shall coordinate the quarterly cylinder gas audits with the Department to afford the Department the opportunity to observe these audits. The relative accuracy test audits shall be coordinated with the Department.

7. Department Review

This permit is issued under the authority of 567 Iowa Administrative Code (IAC) 22.3. The proposed equipment has been evaluated for conformance with Iowa Code Chapter 455B; 567 IAC Chapters 20 – 35; and 40 Code of Federal Regulations (CFR) Parts 51, 52, 60, 61, and 63 and has the potential to comply. This permit is issued based on information submitted by the applicant. Any misinformation, false statements or misrepresentations by the applicant or by the applicant's representative(s) shall cause this permit to be void.

No review has been undertaken on the engineering aspects of the equipment or control equipment other than the potential of that equipment for reducing air contaminant emissions. The Department assumes no liability, directly or indirectly, for any loss due to damage to persons or property caused by, resulting from, or arising out of the design, installation, maintenance or operation of the proposed equipment.

8. Owner and Operator Responsibility

This permit is for the construction and operation of specific emission unit(s), control equipment, and emission point as described in this permit and in the application for this permit. The permit holder, owner, and operator of the facility shall assure that the installation of the equipment listed in this permit conforms to the design in the application (i.e. type, maximum rated capacity, etc.). No person shall construct, install, reconstruct or alter this emission unit(s), control equipment, or emission point without the required amended permit.

Any owner or operator of the specified emission unit(s), control equipment, or emission point, including any person who becomes an owner or operator subsequent to the date on which this permit is issued, is responsible for assuring that the installation, operation, and maintenance of the equipment listed in this permit is in compliance with the provisions of this permit and all other applicable requirements and that adequate operation and maintenance is provided to ensure that no condition of air pollution is created.

9. Transferability

Unless the equipment is portable, this permit is not transferable from one location to another or from one piece of equipment to another. See Condition 12.A.(2) for notification requirements for relocating portable equipment (567 IAC 22.3(3)"f").

10. Construction

A. General Requirements:
It is the owner's responsibility to ensure that construction conforms to the final plans and specifications as submitted.

In permit amendments, all provisions of the original permit remain in full force and effect unless they are specifically changed by the permit amendment. If a proposed project is not timely completed, the owner or operator shall seek a permit amendment in order to revert back to the most recent previous version of the permit. The previous, unchanged permit provisions are included in the amendment for your convenience only and are unappealable.

This permit or amendment shall become void if any one of the following conditions occurs:
(1) The construction or implementation of the proposed project, as it affects the emission point permitted herein, is not initiated within eighteen (18) months after the permit issuance date; or
(2) The construction or implementation of the proposed project, as it affects the emission point permitted herein, is not completed within thirty-six (36) months after the permit issuance date; or
(3) The construction or implementation of the proposed project, as it affects the emission point permitted herein, is not completed within a time period specified elsewhere in this permit.

B. Changes to Plans and Specifications:
The owner or operator shall amend this permit or amendment prior to startup of the equipment if:
(1) Any changes are made to the final plans and specifications submitted for the proposed project; or
(2) This permit becomes void.

Changes to the final plans and specification shall include changes to plans and specifications for permitted equipment and control equipment and the specified operation thereof.

C. Amended Permits:
The owner or operator may continue to act under the provisions of the previous permit for the affected emission unit(s) and emission point, together with any previous amendment to the permit, until one of the following conditions occurs:
(1) The proposed project authorized by this amendment is completed as it affects the emission unit(s) and emission point permitted herein; or
(2) This current amendment becomes void.

11. Excess Emissions

Per 567 IAC 24.1(1), excess emissions during a period of startup, shutdown, or cleaning of control equipment are not a violation of the emission standard if it is accomplished expeditiously and in a manner consistent with good practice for minimizing emissions except when another regulation applicable to the unit or process provides otherwise. Cleaning of control equipment, which does not require the shutdown of process equipment, shall be limited to one (1) six-minute period per one (1) hour period.

An incident of excess emissions other than the above is a violation and may be subject to criminal penalties according to Iowa Code 455B.146A. If excess emissions are occurring, either the control equipment causing the excess shall be repaired in an expeditious manner, or the process generating the emissions shall be shut down within a reasonable period of time, as specified in 567 IAC 24.1.

An incident of excess emissions shall be orally reported by telephone, electronic mail or in person to the appropriate field office within eight (8) hours of, or at the start of, the first working day following the onset of the incident [See Permit Condition 12.B.(1)]. A written report of an incident of excess emissions shall be submitted as a follow-up to all required initial reports within seven (7) days of the onset of the upset condition [See Permit Condition 12.B.(2)].

12. Notification, Reporting, and Recordkeeping

A. The owner or operator shall furnish the Department the following written notifications:
(1) Per 567 IAC 22.3(3)“b”:
(a) The date construction, installation, or alteration is initiated postmarked within thirty (30) days following initiation of construction, installation, or alteration.
(b) The actual date of startup, postmarked within fifteen (15) days following the start of operation.
(2) Per 567 IAC 22.3(3)“f,” when portable equipment for which a permit has been issued is to be transferred from one location to another, the Department shall be notified:
(a) At least fourteen (14) days before equipment relocation if the equipment will be located in a nonattainment area for the National Ambient Air Quality Standards (NAAQS) or a maintenance area for the NAAQS.
(b) At least seven (7) days before equipment relocation.
(3) Per 567 IAC 22.3(8), a new owner shall notify the Department of the transfer of equipment ownership within thirty (30) days of the occurrence. The notification shall include the following information:
- The date of ownership change; the name, address, and telephone number of the responsible official, the contact person, and the owner of the equipment both before and after the ownership change; and the construction permit number(s) of the equipment changing ownership.

(4) Unless specified per a federal regulation, the owner or the owner’s authorized agent shall notify the Department in writing not less than thirty (30) days before a required test or performance evaluation of a continuous emission monitor [567 IAC 25.1(7)]. The notification shall include:
- The time; the place; the name of the person who will conduct the tests; and other information as required by the Department.

If the owner or operator does not provide timely notice to the Department, the Department shall not consider the test results or performance evaluation results to be a valid demonstration of compliance with the applicable rules or permit conditions. Upon written request, the Department may allow a notification period of less than thirty (30) days.

12. Notification, Reporting, and Recordkeeping

B. The owner or operator shall furnish the Department with the following reports:
   (1) Per 567 IAC 24.1(2), an incident of excess emissions as defined in 567 IAC 20.2 shall be reported within eight (8) hours or at the start of the first working day following the onset of the incident. The report may be made by electronic mail, in person or by telephone.
   (2) Per 567 IAC 24.1(3), a written report of an incident of excess emissions as defined in 567 IAC 20.2 shall be submitted as a follow-up to all required initial reports to the Department within seven (7) days of the onset of the upset condition.
   (3) Operation of this emission unit(s) or control equipment outside of those operating parameters specified in Permit Condition 5 in accordance to the schedule set forth in 567 IAC 24.1.
   (4) Per 567 IAC 25.1(6), the owner or operator of any facility required to install a continuous monitoring system or systems shall provide quarterly reports to the Director, no later than thirty (30) calendar days following the end of the calendar quarter, on forms provided by the Director.
   (5) Per 567 IAC 25.1(7), a written compliance demonstration report for each compliance testing event, whether successful or not, postmarked no later than six (6) weeks after the completion of the test period unless other regulations provide for other notification requirements. In that case, the more stringent reporting requirement shall be met.

C. All data, records, reports, documentation, construction plans, and calculations required under this permit shall be available at the plant during normal business hours for inspection and copying by federal, state, or local air pollution regulatory agencies and their authorized representatives, for a minimum of two (2) years from the date of recording unless otherwise required by another applicable law (i.e. NSPS, NESHAP, etc.)

D. Information regarding this permit should be sent to the attention of the following individuals based on the type of information being submitted: change in ownership (Air Quality Bureau Records Center), permit correspondence (Construction Permit Supervisor), stack testing correspondence (Stack Test Coordinator), and reports and notifications (Compliance Unit Supervisor and DNR Field Office). The addresses are:

Air Quality Bureau Iowa Department of Natural Resources 502 E. 9th St. Des Moines, IA 50319 Telephone: (515) 725-8200 Fax: (515) 725-9501	DNR Field Office 6 1023 West Madison Washington, IA 52353 Telephone: (319) 653-2135 Fax: (319) 653-2856

13. Appeal Rights

All conditions within an original permit may be appealed, subject to the appeal rights set forth in 561 IAC Chapter 7. Amended conditions within a permit amendment may be appealed, subject to the appeal rights set forth in 561 IAC Chapter 7. In permit amendments, all provisions of the original permit remain in full force and effect unless they are specifically changed by the permit amendment. The previous, unchanged permit provisions are included in the amendment for your convenience only and are unappealable.

14. Permit History

Permit No.	Project No.	Description	Date	Stack Testing
05-A-031-P	04-750	Original State Issued PSD Permit	03/01/05	Yes
05-A-031-P1	05-511	Added FGD & Baghouse	02/14/06	Yes
05-A-031-P2	11-259	Allowed Use of Refined Coal	09/28/11	No
05-A-031-P3	13-467	Added Hg Control	06/03/14	No
05-A-031-P4	19-298	Amend Exhaust Flowrate and Temperature	04/02/20	No
05-A-031-P5	21-442	Modify approved chemical list in Condition 5	4/13/22	No

END OF PERMIT

Air Quality Construction Permit

Permit Number: 75-A-357-P9

Plant Number: 78-01-026

Company: MidAmerican Energy Co - Walter Scott Jr. Energy Center

Contact Person:
Richard Parker
General Manager

(712) 352-5458
Richard.parker@midamerican.com

7215 Navajo Street
Council Bluffs, Iowa 51501

Responsible Party:
Richard Parker
General Manager

(563) 262-2865

7215 Navajo Street
Council Bluffs, Iowa 51501

Permitted Equipment

Emission Point ID: EP 003

Emission Unit(s) and Control Equipment:

EU ID	Description	Maximum Rated Capacity	Control Equipment Description and ID
003	Boiler #3	7700 MMBtu/hr 450 tph coal	Dry Electrostatic Precipitator (CE003), Low NOx Burners (LNB) & Overfire Air (OFA) (CE003A), FGD Spray Scrubber (CE003B), Baghouse (CE003C), Activated Carbon Injection (CE003D)

Equipment Location: 7215 Navajo Street
Council Bluffs, IA 51501

Issuance of this permit shall not relieve the owner or operator of the responsibility to comply fully with applicable provisions of the State Implementation Plan (SIP), and any other requirements of local, state, and federal law.

Project Number	Project Description	Stack Testing	Issuance Date
21-355	Establish Regional Haze SO2 Limit	None	07/20/23

Under the Direction of the Director of the
Department of Natural Resources

PZ

PERMIT CONDITIONS

1a. Best Available Control Technology (BACT) Emission Limits

The owner or operator is required to report all emissions as required by law, regardless of whether a specific emission limit has been established in this permit. The following emission limits shall not be exceeded:

Pollutant	Tons/Yr[1]	Additional Limits
State Particulate Matter (PM)	911	0.027 lb/MMBTU[2]
PM_{10}	911	0.027 lb/MMBTU[2]
$PM_{2.5}$	843.2	0.025 lb/MMBTU[2]
Opacity[3]	NA	10%[4]
Carbon Monoxide (CO)[3]	14,165	0.42 lb/MMBTU[5]
Carbon Dioxide (CO_2)[3]	NA	2,419 lb/MWh (net)[6, 7]
Carbon Dioxide equivalents (CO_2e)[8]	7,223,389	NA

[1] Standard is a 12-month rolling total. The standard includes all periods of operation including periods of startup, shutdown, and malfunction (SSM).
[2] Standard is expressed as the average of three (3) stack test runs.
[3] Compliance with the emission standards shall be demonstrated through the use of Continuous Emission Monitoring Systems (CEMS). See Condition 12 and Condition 16 for more information on compliance with the use of CEMS.
[4] Standard is a one (1) hour average.
[5] Standard is a one (1) calendar day average not including periods of SSM.
[6] Standard is a 30-day rolling average not including periods of startup, shutdown, and malfunction (SSM).
[7] MWh = megawatt-hour. MWh (net) shall be determined by subtracting the metered megawatt-hour value for station service from the metered megawatt-hour value for gross generation. Alternatively, net generation may be obtained directly from a power metering device for net generation, if the metering instrument is electrically equivalent to gross generation minus station service.
[8] Compliance shall be determined by multiplying the mass of each greenhouse gas (GHG) as defined in 40 CFR §98.6 by its respective global warming potential (GWP) as defined in 40 CFR Part 98, Table A-1 and summing the results. The version of Table A-1 used shall be the version promulgated as of the October 30, 2009 which listed the following GWPs:

- $CO_2 = 1$
- $CH_4 = 21$
- $N_2O = 310$

The CO_2 mass emissions shall be obtained from the required CEMS and the mass emissions for methane (CH_4) and nitrous oxide (N_2O) shall be determined by the stack testing required in Condition 12.

1b. New Source Performance Standards (NSPS) Limits

Pollutant	Emission Standard[1]	Reference (567 IAC)
Federal PM	43 ng/J heat input[2]	23.1(2)"a"[3]
Opacity[4]	20%[5]	23.1(2)"a"[3]
SO_2[4]	520 ng/J heat input[6]	23.1(2)"a"[3]
NO_x[4]	300 ng/J heat input[7]	23.1(2)"a"[3]

[1] Standard is expressed as the average of three (3) runs.
[2] 43 ng/J = 0.10 lb/MMBTU. See 40 CFR §60.42(a)(1).
[3] IAC reference to New Source Performance Standards (NSPS) Subpart D (Standards of Performance for Fossil-Fuel-fired Steam Generators for Which Construction Is Commenced After August 17, 1971; 40 CFR §60.40 – 40 CFR §60.46).
[4] Compliance with the emission standards shall be demonstrated through the use of a CEMS. See Condition 12 and Condition 16 for more information on compliance with the use of CEMS.
[5] Opacity shall not exceed 20% (6-minute average), except for one (1) 6-minute period per hour of not more than 27% opacity. See 40 CFR §60.42(a)(2).
[6] 520 ng/J = 1.20 lb/MMBTU. Emission limit per 40 CFR §60.43(a)(2) when the unit is combusting solid fossil fuel or solid fossil fuel and wood residue. Per 40 CFR §60.43 alternative limits are:

- 340 ng/J heat input (0.80 lb/MMBTU) when combusting liquid fossil fuel or liquid fossil fuel and wood residue [40 CFR §60.43(a)(2)].

1b. NSPS Limits (continued)

- Per 40 CFR §60.43(b), when different fossil fuels are combusted simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{SO2} = \frac{[y(340) + z(520)]}{y+z}$$

Where:

PS_{SO2} = the prorated standard for SO_2 when burning different fuels simultaneously, in nanograms per joule (ng/J) heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired.
y = the percentage of total heat input derived from liquid fossil fuel
z = the percentage of total heat input derived from solid fossil fuel.

- Per 40 CFR §60.43(d), as an alternate to meeting the requirements of 40 CFR §60.43(a) and 40 CFR §60.43(b), an owner or operator can petition the Administrator (in writing) to comply with 40 CFR §60.43Da(i)(3) or comply with 40 CFR §60.42b(k)(4) as applicable to the affected source. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in 40 CFR §60.43Da(i)(3) or 40 CFR §60.42b(k)(4) as applicable to the affected source.

Per 40 CFR §60.43(c), compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.
In addition, per 40 CFR §60.45(g)(2), excess emissions are defined as:

- For affected facilities electing not to comply with 40 CFR §60.43(d), any three (3) hour period during which the average emissions [arithmetic average of three (3) contiguous one (1) hour periods] of SO_2 as measured by a CEMS exceed the applicable standard in 40 CFR §60.43; or
- For affected facilities electing to comply with 40 CFR §60.43(d), any thirty (30) operating day period during which the average emissions [arithmetic average of all one (1) hour periods during the thirty (30) operating days) of SO_2 as measured by a CEMS exceed the applicable standard in 40 CFR §60.43. Facilities complying with the thirty (30) day SO_2 standard shall use the most current associated SO_2 compliance and monitoring requirements in 40 CFR §60.48Da and 40 CFR §60.49Da or 40 CFR §60.45b and 40 CFR §60.47b as applicable.

[7] 300 ng/J = 0.70 lb/MMBTU. Emission limit per 40 CFR §60.43(a)(3) when the unit is combusting solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25%, by weight, or more of coal refuse). Per 40 CFR §60.44 alternative limits are:

- 86 ng/J heat input (0.20 lb/MMBTU) when combusting gaseous fossil fuel.
- 129 ng/J heat input (0.30 lb/MMBTU) when combusting liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.
- liquid fossil fuel or liquid fossil fuel and wood residue [40 CFR §60.43(a)(2)].
- Per 40 CFR §60.44(b), when different fossil fuels are combusted simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{NOx} = \frac{[w(260) + x(86) + y(130) + z(300)]}{w + x + y + z}$$

Where:

PS_{NOx} = the prorated standard for NO_x when burning different fuels simultaneously, in nanograms per joule (ng/J) heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired.
w = the percentage of total heat input derived from lignite
x = the percentage of total heat input derived from gaseous fossil fuel
y = the percentage of total heat input derived from liquid fossil fuel
z = the percentage of total heat input derived from solid fossil fuel.

- Per 40 CFR §60.44(e), as an alternate to meeting the requirements of 40 CFR §60.43(a) and 40 CFR §60.43(b), an owner or operator can petition the Administrator (in writing) to comply with 40 CFR §60.43Da(e)(3). If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in 40 CFR §60.43Da(e)(3).

In addition, per 40 CFR §60.45(g)(3), excess emissions are defined as:

- For affected facilities electing not to comply with 40 CFR §60.44(e), any three (3) hour period during which the average emissions [arithmetic average of three (3) contiguous one (1) hour periods] of SO_2 as measured by a CEMS exceed the applicable standard in 40 CFR §60.44; or
- For affected facilities electing to comply with 40 CFR §60.44(e), any thirty (30) operating day period during which the average emissions [arithmetic average of all one (1) hour periods during the thirty (30) operating days) of NO_x as measured by a CEMS exceed the applicable standard in 40 CFR §60.44. Facilities complying with the thirty (30) day NO_x standard shall use the most current associated NO_x compliance and monitoring requirements in 40 CFR §60.48Da and 40 CFR §60.49Da.

1c. Regional Haze Limit

Pollutant	lb/hr	tons/yr	Other Limits	Reference/Basis
Sulfur Dioxide (SO_2)	770[1,2]	NA	NA	567 IAC 22.9(6)

[1]Limit based on 72 percent reduction of SO_2 emissions from the baseline years of 2017 to 2019. Compliance with the limit is based on continuous emissions monitoring as specified in permit condition 6.
[2]Limit based on 30-day rolling average. Limit is applicable at all times including periods of Boiler 3 startup, shutdown, and malfunction.

1d. Other Emission Limits

Pollutant	lb/hr[1]	tons/yr[2]	Other Limits	Reference/Basis
PM_{10}	207.9 [2, 3, 4]	NA	NA	NAAQS
$PM_{2.5}$	192.5 [2, 4]	NA	NA	Insignificant for modeling
Sulfur Dioxide (SO_2)	NA	12,632.1 [5]	NA	PSD synthetic minor
Nitrogen Oxides (NO_x)	NA	6,547.5 [5]	NA	PSD synthetic minor
Volatile Organic Compounds (VOC)	30.7 [5]	NA	NA	PSD minor increase
Carbon Monoxide (CO)	12,863 [6]	NA	NA	Insignificant for modeling

[1] Standard is a twelve (12) month rolling total.
[2] Standard is expressed as the average of three (3) stack test runs.
[3] Emission rate used in the computer aided dispersion model in Project Number 06-250 to demonstrate no exceedances of the National Ambient Air Quality Standards (NAAQS).
[4] Emission rate used in Project Number 13-466 to show there was no change in hourly emissions for this unit and that the project (PN 13-466) has impacts below the significant increase threshold.
[5] Emission rate set in order to demonstrate Project Number 13-466 does not have a significant increase in emissions.
[6] Emission limit was set based on dispersion modeling to demonstrate Project Number 13-466 would not have a significant impact on the ambient air.

2. Compliance Demonstration(s)

Compliance Demonstration Table

Pollutant	Compliance Methodology	Frequency	Test Run Time	Test Method
PM – State	None	NA	1 hour	40 CFR 60, Appendix A, Method 5 40 CFR 51 Appendix M Method 202
PM_{10}	None	NA	1 hour	40 CFR 51, Appendix M, 201A with 202
$PM_{2.5}$	None	NA	1 hour	40 CFR 51, Appendix M, 201A with 202
Opacity	COMS [1, 2]	Continuous	1 hour	40 CFR 60, Appendix A, Method 9
SO_2	CEMS [2, 3]	Continuous	1 hour	40 CFR 60, Appendix A, Method 6C
NO_x	CEMS [2, 3]	Continuous	1 hour	40 CFR 60, Appendix A, Method 7E
VOC	None	NA	1 hour	40 CFR 63, Appendix A, Method 320 or 40 CFR 60, Appendix A, Method 18
CO	CEMS [2, 3]	Continuous	1 hour	40 CFR 60, Appendix A, Method 10
Pb	None	NA	1 hour	40 CFR 60, Appendix A, Method 12
TRS	None	NA	1 hour	40 CFR 60, Appendix A, Method 16B
CO_2	CEMS [2, 3]	Continuous	1 hour	40 CFR 60, Appendix A, Method 3
CH_4	None	NA	1 hour	40 CFR 60, Appendix A, Method 18
N_2O	None	NA	1 hour	40 CFR 60, Appendix A, Method 320
CO_2e	Recordkeeping	See Footnote 1	NA	NA
Mercury	None	NA	1 hour	40 CFR 63, Appendix A, Method 320 or 40 CFR 60, Appendix A, Method 18

[1] See footnote 8 in Condition 1.a of the permit for the required recordkeeping requirements.
[2] COMS = Continuous Opacity Monitoring System.
[3] See Condition 6 of the permit for continuous emission monitoring requirements.
[4] CEMS = Continuous Emission Monitoring System.

2. Compliance Demonstration(s) (Continued)

If an initial stack test is specified in the "Compliance Demonstration Table," the owner or the owner's authorized agent shall demonstrate compliance with the emission limitations contained in Condition 1 within the applicable time period specified below:

- Within sixty (60) days after achieving the maximum production rate and no later than one hundred eighty (180) days after the initial startup date of the proposed equipment for the addition of new equipment or the physical modification of existing equipment or control equipment.
- Within ninety (90) days of the issuance of this permit if there is no physical modification to any emission units or control equipment.

If any additional stack testing beyond an initial test (i.e. quarterly, semi-annual, annual, etc.) is required in "Compliance Demonstration Table," the owner or the owner's authorized agent shall demonstrate compliance with the emission limitations contained in Condition 1 as specified in the "Compliance Demonstration Table." See Conditions 12.A.(4) and 12.B.(5) for notification and reporting requirements.

If stack testing is required, the owner or the owner's authorized agent shall use the test method and run time listed in the "Compliance Demonstration Table" unless another testing methodology is approved by the Department prior to testing.

Each emissions compliance test must be approved by the Department. Unless otherwise specified by the Department, each test shall consist of three (3) separate runs. The arithmetic mean of three (3) acceptable test runs shall apply for compliance, unless otherwise indicated by the Department.

Per 567 IAC 25.1(7)"a", at the Department's request, a pretest meeting shall be held not later than fifteen (15) days before the owner or operator conducts the compliance demonstration. A testing protocol shall be submitted to the Department no later than fifteen (15) days before the owner or operator conducts the compliance demonstration. Representatives from the Department shall attend this meeting, along with the owner and the testing firm, if any. It shall be the responsibility of the owner to coordinate and schedule the pretest meeting. A representative of the Department shall be allowed to witness the test(s). The Department shall reserve the right to impose additional, different, or more detailed testing requirements.

The owner shall be responsible for the installation and maintenance of test ports. The unit(s) being sampled shall be operated in a normal manner at its maximum continuous output as rated by the equipment manufacturer, or the rate specified by the owner as the maximum production rate at which this unit(s) will be operated. In cases where compliance is to be demonstrated at less than the maximum continuous output as rated by the manufacturer, and it is the owner's intent to limit the capacity to that rating, the owner may submit evidence to the Department that this unit(s) has been physically altered so that capacity cannot be exceeded, or the Department may require additional testing, continuous monitoring, reports of operating levels, or any other information deemed necessary by the Department to determine whether this unit(s) is in compliance.

3. Emission Point Characteristics

This emission point shall conform to the specifications listed below:

Parameter	Value
Stack Height (feet from the ground)	550
Discharge Style	Vertical unobstructed
Stack Outlet Dimensions (inches)	300
Exhaust Temperature (ºF)	250
Exhaust Flowrate (scfm)	2,100,000

The temperature and flowrate are intended to be representative and characteristic of the design of the permitted emission point. The Department recognizes that the temperature and flow rate may vary with changes in the process and ambient conditions. If it is determined that any of the emission point characteristics above are different than the values stated, the owner or operator shall submit a request either by electronic mail or written correspondence to the Department within thirty (30) days of the discovery to determine if a permit amendment is required, or submit a permit application requesting to amend the permit.

4. Federal Standards

A. New Source Performance Standards (NSPS):
The following subparts apply to the emission unit(s) in this permit:

EU ID	Subpart	Title	Type	State Reference (567 IAC)	Federal Reference (40 CFR)
003	A	General Provisions	NA	23.1(2)	§60.1 – §60.19
	D	Fossil-Fuel-fired Steam Generators for Which Construction is Commenced After August 17, 1971	NA	23.1(2)"a"	§60.40 – §60.46

NOTE: The absence of the inclusion of any NSPS requirements as part of this permit does not relieve the owner or operator from any obligation to comply with all applicable NSPS conditions.

B. National Emission Standards for Hazardous Air Pollutants (NESHAP):

For information only: This emission unit is of the source category affected by the following federal regulation: Coal- and Oil-Fired Electric Utility Steam Generating Units [40 CFR Part 63, Subpart UUUUU].

NOTE: The absence of the inclusion of any NESHAP requirements as part of this permit does not relieve the owner or operator from any obligation to comply with all applicable NESHAP conditions.

C. Acid Rain:
The facility (plant number 78-01-026) is considered an affected source under 40 CFR 72, 73, 75, 76, 77, and 78 definitions as emission units at this source are subject to the acid rain emission reduction requirements or the acid rain emission limitations, as adopted by the Department by reference (See 567 IAC 22.120 – 567 IAC 22.148). This emission unit is subject to the SO_2 allowance allocation, NO_x emission limitations, and monitoring provisions of the federal acid rain program.

5. Operating Requirements with Associated Monitoring and Recordkeeping

Unless specified by a federal regulation, all records as required by this permit shall be kept on-site for a minimum of two (2) years and shall be available for inspection by the Department. Records shall be legible and maintained in an orderly manner. The operating requirements and associated recordkeeping for this permit shall be:

A. This unit shall be limited to firing coal, with fuel oil for startup
B. A bag leak detection system must be installed to meet the following criteria:
(1) At least one detector must be located in each compartment of the baghouse.
(2) The bag leak detection system must be installed, operated, calibrated and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in "Fabric Filter Bag Leak Detection Guidance", EPA-454/R-98-015, September 1997.
(3) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.
(4) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.
(5) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensors.
(6) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel.
(7) The system's instrumentation and alarm may be shared among detectors.
(8) The system's alarm shall sound no more than 5% of the operating time during a 6 month period.

5. Operating Requirements with Associated Monitoring and Recordkeeping (continued)

C. The following records must be maintained from the bag leak detection system:
  (1) The date, time and duration of each system alarm.
  (2) The time corrective action was initiated and completed
  (3) A brief description of the cause of the alarm and the corrective action
  (4) A record of the percent of operating time during each 6 month period that the alarm sounds. In calculating the operating time percentage,
    (i) If an inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted.
    (ii) If corrective action is required, each alarm shall be counted as a minimum of 1 hour.
    (iii) If it takes longer than 1 hour to initiate corrective action, the alarm time shall be counted as the actual amount of time taken to initiate corrective action.

D. Trucks which haul either ash or sludge shall either be covered with a tarp or enclosed.

E. The waste material collected by the fabric filter and stored in the FGD waste silo system shall be processed through a pug-mill during loadout to increase the material moisture content to a minimum of 20%. Water wagons shall be used to wet the waste material during disposal site grading activities. This requirement does not apply to waste material being sold for beneficial use.

F. The owner or operator is allowed, but not required, to combust coal which has been treated with chemicals to aid in mercury (Hg) emissions control. The following additives have been approved by the Department for use by the owner or operator:
    (1) a mineral composite of calcium silicate components,
    (2) other calcium compounds containing iron and aluminum,
    (3) calcium bromide
    (4) calcium chloride
    (5) potassium iodide

G. Prior to the use of any additional chemicals to aid in mercury (Hg) emissions control, the owner or operator shall supply material data to the Department for review and approval. This data shall include, but is not limited to:
    (1) A description of the chemical additive
    (2) Information demonstrating the potential impact on mercury emissions and any other HAPs regulated by an applicable state or federal standard, and
    (3) An evaluation of the impact on all NSR regulated air emissions.

H. The owner or operator shall record if treated coal is combusted and with what chemicals the coal has been treated.

I. The following conditions are required, at startup of WSEC 4, on the haul roads to meet the BACT emission rates:
  (1) For paved roads:
    (i) Fugitive emissions of paved haul roads shall be controlled to an effective control efficiency of 80% by either water flushing followed by sweeping or using a street sweeper that is certified to achieve a pick-up efficiency of 80%. The control efficiency of 80% shall be achieved by either using a certified sweeper once per day or by water flushing followed by sweeping of the paved haul roads once per day. The water spray rate shall be a minimum of 0.23 gallons per square yard.
    (ii) If water flushing followed by sweeping cannot be accomplished because the ambient air temperature (as measured at the facility during daylight operating hours) will be less than 35 F, or conditions due to weather, in combination with the application of the water, could create hazardous driving conditions, then the water flushing and sweeping shall be postponed and accomplished as soon after the scheduled date as the conditions preventing the application have abated.
    (iii) Water flushing and sweeping need not occur when a rain gage located at the site indicates that at least 0.2 inches of precipitation (water equivalent) has occurred within the preceding 24-hr time period or the paved road(s) will not be used on a given day.
  (2) For unpaved roads:
    (i) Fugitive emissions from unpaved haul roads shall be controlled by applying a chemical dust suppressant. A control efficiency of 95% shall be maintained on all unpaved haul roads. The owner or operator may elect to use any chemical dust suppressant that is capable of achieving the 95% control efficiency. In the event that the manufacturer or distributor of a chemical dust suppressant recommends different amounts of chemical dust suppressant or MidAmerican chooses to use a different chemical dust suppressant, MidAmerican shall notify DNR of the change in application rates and/or chemical dust suppressant and the manufacturer's/distributor's recommendations.
    (ii) If the selected chemical dust suppressant cannot be applied because the ambient air temperature (as

measured at the facility during daylight operating hours) will be less than 35 F, or conditions due to weather, in combination with the application of the chemical dust suppressant, could create hazardous driving conditions, then the chemical dust suppressant application shall be postponed and accomplished as soon after the scheduled date as the conditions preventing the application have abated.

J. A log shall be kept showing the following for haul roads, after startup of WSEC 4:
  (1) Paved roads:
    (i) Records of either the use of a certified sweeper or the applications shall be maintained and shall include
      - The dates of each application or use of certified sweeper
      - The amount of water applied (if applicable),
      - The areas treated or swept by certified sweeper, and
      - The operator's initials.
    (ii) If water is to be used and is not applied when scheduled then the records should so indicate and provide an explanation.
  (2) Unpaved roads:
    (i) Records of the applications shall be maintained and shall include:
      - The dates of each application
      - The chemical dust suppressant used
      - The application intensity (gal/sq yd)
      - Dilution ratio
      - The operator's initials, and
      - Documentation of road and weather conditions, if necessary.
    (ii) If the suppressant is not applied as planned, then the records should so indicate and provide an explanation.

K. The owner or operator is not required to operate the Electrostatic Precipitator (ESP, CE 003) as long as the owner or operator is able to demonstrate compliance with the emission limits listed in Condition 1 of this permit without the ESP in operation.

L. The owner or operator shall not operate Boilers 1 (EP 001) and 2 (EP 002) after the work on Boiler 3 (EP 003) associated with Project Number 13-466 has been completed and Boiler 3 (EP 003) has commenced fuel combustion. Within sixty (60) days of Boiler 3 (EP 003) commencing fuel combustion after the completion of the work associated with Project Number 13-466, the owner or operator shall make Boilers 1 (EP 001) and 2 (EP 002) inoperable.

M. The owner or operator shall prepare a work practice manual documenting all efficiency practices (i.e. a *"Work Practices Manual"*) at the facility, and submit the manual to the Department prior to the completion of construction of Project Number 13-466. This manual shall specifically address control equipment operation, boiler cleanliness practices (such as soot-blowing frequency), document the existing steam turbine design efficiency and combustion control optimizations at the plant, and all other efficiencies at the plant (Plant Number 78-01-025). The *Work Practices Manual* shall be implemented upon the later of the Department's review and approval or the completion of construction of Project Number 13-466. The *Work Practices Manual* shall be revised and submitted to the Department as necessary to document any proposed efficiency changes at the facility. The revised manual shall be implemented upon the Department's approval of the proposed changes.

N. The owner or operator shall submit excess emission and monitoring system performance reports to the Administrator semiannually for each six-month period in the calendar year, as required in 40 CFR 60.45(g). All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSDP report shall include the information required in 40 CFR 60.7(c).

O. The owner or operator is required to meet all applicable recordkeeping and reporting requirements under NSPS Subparts A and D.

Regional Haze Requirements

P. The owner or operator shall complete FGD Spray Scrubber (CE003B) enhancements to achieve the SO2 emission limit specified in condition 1c by December 31, 2023.

   i. The owner or operator shall maintain record of the completion date of FGD Spray Scrubber (CE003B) enhancements to achieve SO2 emission limit as specified in condition 1c.

Q. Within 60 operating days after completion of FGD Spray Scrubber (CE003B) enhancements, the owner or operator shall conduct an SO2 emissions study to determine the minimum additive injection rate to achieve SO2 reduction of 72 percent below the average of 2017-2019 baseline emissions. The minimum additive injection rate shall be determined during varying boiler operating loads. The study shall also include development and identification of an averaging period for the minimum additive injection rate, if applicable.

   i. The owner or operator shall submit the SO2 study results to the Department for review and approval.
   ii. The owner or operator shall maintain the SO2 study results onsite and make the results available for inspection.

R. The owner or operator shall maintain the FGD Spray Scrubber (CE003B) minimum additive injection rate at the rates determined during the SO2 emissions study at corresponding boiler loads. The minimum additive injection rate shall be maintained at all times while Boiler 3 is in operation except during periods of boiler start-up.

   i. The owner or operator shall properly operate and maintain equipment to monitor the additive injection rate to the FGD Spray Scrubber (CE003B). The monitoring devices and any recorders shall be installed, calibrated, operated and maintained in accordance with the manufacturer's recommendations, instructions and operating manuals or per written facility specific operation and maintenance plan.

   ii. The owner or operator shall continuously collect and record the additive injection rate to FGD Spray Scrubber (CE003B). The owner or operator shall calculate and record the additive injection rate based on the averaging period determined during the SO2 study, if applicable. If the additive injection rate to FGD Spray Scrubber (CE003B) falls below the value determined during the SO2 emissions study, the owner or operator shall investigate the FGD Spray Scrubber (CE003B) and make corrections to it. The owner or operator shall maintain a record of all corrective actions taken.

6. Continuous Emission Monitoring Systems (CEMS)

The following continuous emission monitoring requirements apply to this emission point and its associated emission unit(s) and control equipment:

A. The following monitoring systems are required:

- *Opacity:*

  In accordance with 40 CFR §60.45(a), the owner or operator shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere except as provided under 40 CFR §60.45(b).

  The system shall be designed to meet the 40 CFR 60, Appendix B, Performance Specification 1 (PS1).

  Per 40 CFR §60.45(b)(5), the owner or operator may petition the Administrator (in writing) to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.

- *SO_2:*

  In accordance with 40 CFR §60.45(a), the owner or operator shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) and record the output of the system, for measuring sulfur dioxide (SO_2) emissions, except as provided by 40 CFR §60.45(b).

  The system shall be designed to meet the 40 CFR 60, Appendix B, Performance Specification 2 (PS2) and Performance Specification 6 (PS6) requirements. The specifications of 40 CFR 60, Appendix F (Quality Assurance/Quality Control) shall apply. Appendix F requirements shall be supplemented with a notice to the Department with the dates of the annual relative accuracy test audit.

  This monitor shall also be used to demonstrate compliance with the non-NSPS emission standards in this permit.

- *NO_x:*

  In accordance with 40 CFR §60.45(a), the owner or operator shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) and record the output of the system, for measuring nitrogen oxide (NO_x) emissions, except as provided by 40 CFR §60.45(b).

  The system shall be designed to meet the 40 CFR 60, Appendix B, Performance Specification 2 (PS2) and Performance Specification 6 (PS6) requirements. The specifications of 40 CFR Appendix F (Quality Assurance/Quality Control) shall apply. Appendix F requirements shall be supplemented with a notice to the Department with the dates of the annual relative accuracy test audit.

  This monitor shall also be used to demonstrate compliance with the non-NSPS emission standards in this permit.

- *O_2 or CO_2:*

  In accordance with 40 CFR §60.45(a), the owner or operator shall install, calibrate, maintain, and operate a CEMS and record the output of the system, for measuring the oxygen (O_2) or carbon dioxide (CO_2) content of the flue gases at each location where SO_2 or NO_x emissions are monitored.

6. Continuous Emission Monitoring (Continued)

- *CO:*

  Compliance with the carbon monoxide (CO) emission limits of this permit shall be continuously demonstrated by the owner or operator through the use of a CEMS. Therefore, the owner or operator shall install, calibrate, maintain, and operate a CEMS for measuring CO emissions discharged to the atmosphere and record the output of the system.

  The system shall be designed to meet the 40 CFR 60, Appendix B, Performance Specification 4A (PS4A) and Performance Specification 6 (PS6) requirements. The specifications of 40 CFR 60, Appendix F (Quality Assurance/Quality Control) shall apply. Appendix F requirements shall be supplemented with a notice to the Department with the dates of the annual relative accuracy test audit.

- *Wattmeter:*

  The owner or operator shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in megawatt-hour on a continuous basis; and record the output of the monitor for demonstrating compliance with the output-based standard under Condition 10a. of this permit.

- *Flowmeter:*

  The owner or operator shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of 40 CFR 60, Appendix B, Performance Specification 6 and 40 CFR 60, Appendix F, Procedure 1. In addition, the owner or operator shall record the output of the system, for measuring the volumetric flow of exhaust gases discharged to the atmosphere or

  Alternatively, data from a continuous flow monitoring system certified according to the requirements of 40 CFR §75.20(c) and 40 CFR 75, Appendix A, and continuing to meet the applicable quality control and quality assurance requirements of 40 CFR §75.21 and 40 CFR 75, Appendix B, may be used.

B. The CEMS required in Condition 6.A. for SO_2, NO_x, and either O_2 or CO_2 shall be operated and the data recorded during all periods of operation including periods of startup, shutdown, malfunction, or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

C. The following data requirements shall apply to all CEMS for non-NSPS emission standards in this permit:

(1) The CEMS required by this permit shall be operated and data recorded during all periods of operation of the emission unit except for CEM breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.
(2) The 1-hour average SO_2, NO_x, CO, and CO_2 emission rates measured by the CEMS required by this permit shall be used to calculate compliance with the emission standards of this permit. At least 2 data points must be used to calculate each 1-hour average.
(3) For each hour of missing emission data (NO_x, SO_2, CO, or CO_2), the owner or operator shall substitute data by:
   (i) If the monitor data availability is equal to or greater than 95.0%, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:
      (a) For the missing data period less than or equal to 24 hours, substitute the average of the hourly concentrations recorded by a pollutant concentration monitor for the hour before and the hour after the missing data period.
      (b) For a missing data period greater than 24 hours, substitute the greater of:
      - The 90th percentile hourly concentration recorded by a pollutant concentration monitor during the previous 720 quality-assured monitor operating hours; or
      - The average of the hourly concentrations recorded by a pollutant concentration monitor for the hour before and the hour after the missing data period.

6. Continuous Emission Monitoring (Continued)

(ii) If the monitor data availability is at least 90.0% but less than 95.0%, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:

(a) For a missing data period of less than or equal to 8 hours, substitute the average of the hourly concentrations recorded by a pollutant concentration monitor for the hour before and the hour after the missing data period.

(b) For the missing data period of more than 8 hours, substitute the greater of:

- The 95^{th} percentile hourly pollutant concentration recorded by a pollutant concentration monitor during the previous 720 quality-assured monitor operating hours; or
- The average of the hourly concentrations recorded by a pollutant concentration monitor for the hour before and the hour after the missing data period.

(iii) If the monitor data availability is less than 90.0%, the owner or operator shall obtain actual emission data by an alternate testing or monitoring method approved by the Department.

D. If requested by the Department, the owner/operator shall coordinate the quarterly cylinder gas audits with the Department to afford the Department the opportunity to observe these audits. The relative accuracy test audits shall be coordinated with the Department.

7. Department Review

This permit is issued under the authority of 567 Iowa Administrative Code (IAC) 22.3. The proposed equipment has been evaluated for conformance with Iowa Code Chapter 455B; 567 IAC Chapters 20 – 35; and 40 Code of Federal Regulations (CFR) Parts 51, 52, 60, 61, and 63 and has the potential to comply. This permit is issued based on information submitted by the applicant. Any misinformation, false statements or misrepresentations by the applicant or by the applicant's representative(s) shall cause this permit to be void.

No review has been undertaken on the engineering aspects of the equipment or control equipment other than the potential of that equipment for reducing air contaminant emissions. The Department assumes no liability, directly or indirectly, for any loss due to damage to persons or property caused by, resulting from, or arising out of the design, installation, maintenance or operation of the proposed equipment.

8. Owner and Operator Responsibility

This permit is for the construction and operation of specific emission unit(s), control equipment, and emission point as described in this permit and in the application for this permit. The permit holder, owner, and operator of the facility shall assure that the installation of the equipment listed in this permit conforms to the design in the application (i.e. type, maximum rated capacity, etc.). No person shall construct, install, reconstruct or alter this emission unit(s), control equipment, or emission point without the required amended permit.

Any owner or operator of the specified emission unit(s), control equipment, or emission point, including any person who becomes an owner or operator subsequent to the date on which this permit is issued, is responsible for assuring that the installation, operation, and maintenance of the equipment listed in this permit is in compliance with the provisions of this permit and all other applicable requirements and that adequate operation and maintenance is provided to ensure that no condition of air pollution is created.

9. Transferability

Unless the equipment is portable, this permit is not transferable from one location to another or from one piece of equipment to another. See Condition 12.A.(2) for notification requirements for relocating portable equipment (567 IAC 22.3(3)"f").

10. Construction

A. General Requirements:
It is the owner's responsibility to ensure that construction conforms to the final plans and specifications as submitted.

In permit amendments, all provisions of the original permit remain in full force and effect unless they are specifically changed by the permit amendment. If a proposed project is not timely completed, the owner or operator shall seek a permit amendment in order to revert back to the most recent previous version of the permit. The previous, unchanged permit provisions are included in the amendment for your convenience only and are unappealable.

This permit or amendment shall become void if any one of the following conditions occurs:
(1) The construction or implementation of the proposed project, as it affects the emission point permitted herein, is not initiated within eighteen (18) months after the permit issuance date; or
(2) The construction or implementation of the proposed project, as it affects the emission point permitted herein, is not completed within thirty-six (36) months after the permit issuance date; or
(3) The construction or implementation of the proposed project, as it affects the emission point permitted herein, is not completed within a time period specified elsewhere in this permit.

B. Changes to Plans and Specifications:
The owner or operator shall amend this permit or amendment prior to startup of the equipment if:
(1) Any changes are made to the final plans and specifications submitted for the proposed project; or
(2) This permit becomes void.

Changes to the final plans and specification shall include changes to plans and specifications for permitted equipment and control equipment and the specified operation thereof.

C. Amended Permits:
The owner or operator may continue to act under the provisions of the previous permit for the affected emission unit(s) and emission point, together with any previous amendment to the permit, until one of the following conditions occurs:
(1) The proposed project authorized by this amendment is completed as it affects the emission unit(s) and emission point permitted herein; or
(2) This current amendment becomes void.

11. Excess Emissions

Per 567 IAC 24.1(1), excess emissions during a period of startup, shutdown, or cleaning of control equipment are not a violation of the emission standard if it is accomplished expeditiously and in a manner consistent with good practice for minimizing emissions except when another regulation applicable to the unit or process provides otherwise. Cleaning of control equipment, which does not require the shutdown of process equipment, shall be limited to one (1) six-minute period per one (1) hour period.

An incident of excess emissions other than the above is a violation and may be subject to criminal penalties according to Iowa Code 455B.146A. If excess emissions are occurring, either the control equipment causing the excess shall be repaired in an expeditious manner, or the process generating the emissions shall be shut down within a reasonable period of time, as specified in 567 IAC 24.1.

An incident of excess emissions shall be orally reported by telephone, electronic mail or in person to the appropriate field office within eight (8) hours of, or at the start of, the first working day following the onset of the incident [See Permit Condition 12.B.(1)]. A written report of an incident of excess emissions shall be submitted as a follow-up to all required initial reports within seven (7) days of the onset of the upset condition [See Permit Condition 12.B.(2)].

12. Notification, Reporting, and Recordkeeping

A. The owner or operator shall furnish the Department the following written notifications:
   (1) Per 567 IAC 22.3(3)"b":
      (a) The date construction, installation, or alteration is initiated postmarked within thirty (30) days following initiation of construction, installation, or alteration.
      (b) The actual date of startup, postmarked within fifteen (15) days following the start of operation.
   (2) Per 567 IAC 22.3(3)"f," when portable equipment for which a permit has been issued is to be transferred from one location to another, the Department shall be notified:
      (a) At least fourteen (14) days before equipment relocation if the equipment will be located in a nonattainment area for the National Ambient Air Quality Standards (NAAQS) or a maintenance area for the NAAQS.
      (b) At least seven (7) days before equipment relocation.
   (3) Per 567 IAC 22.3(8), a new owner shall notify the Department of the transfer of equipment ownership within thirty (30) days of the occurrence. The notification shall include the following information:
      - The date of ownership change; the name, address, and telephone number of the responsible official, the contact person, and the owner of the equipment both before and after the ownership change; and the construction permit number(s) of the equipment changing ownership.
   (4) Unless specified per a federal regulation, the owner or the owner's authorized agent shall notify the Department in writing not less than thirty (30) days before a required test or performance evaluation of a continuous emission monitor [567 IAC 25.1(7)]. The notification shall include:
      - The time; the place; the name of the person who will conduct the tests; and other information as required by the Department.

      If the owner or operator does not provide timely notice to the Department, the Department shall not consider the test results or performance evaluation results to be a valid demonstration of compliance with the applicable rules or permit conditions. Upon written request, the Department may allow a notification period of less than thirty (30) days.

B. The owner or operator shall furnish the Department with the following reports:
   (1) Per 567 IAC 24.1(2), an incident of excess emissions as defined in 567 IAC 20.2 shall be reported within eight (8) hours or at the start of the first working day following the onset of the incident. The report may be made by electronic mail, in person or by telephone.
   (2) Per 567 IAC 24.1(3), a written report of an incident of excess emissions as defined in 567 IAC 20.2 shall be submitted as a follow-up to all required initial reports to the Department within seven (7) days of the onset of the upset condition.
   (3) Operation of this emission unit(s) or control equipment outside of those operating parameters specified in Permit Condition 5 in accordance to the schedule set forth in 567 IAC 24.1.
   (4) Per 567 IAC 25.1(6), the owner or operator of any facility required to install a continuous monitoring system or systems shall provide quarterly reports to the Director, no later than thirty (30) calendar days following the end of the calendar quarter, on forms provided by the Director.
   (5) Per 567 IAC 25.1(7), a written compliance demonstration report for each compliance testing event, whether successful or not, postmarked no later than six (6) weeks after the completion of the test period unless other regulations provide for other notification requirements. In that case, the more stringent reporting requirement shall be met.

C. All data, records, reports, documentation, construction plans, and calculations required under this permit shall be available at the plant during normal business hours for inspection and copying by federal, state, or local air pollution regulatory agencies and their authorized representatives, for a minimum of two (2) years from the date of recording unless otherwise required by another applicable law (i.e. NSPS, NESHAP, etc.)

D. Information regarding this permit should be sent to the attention of the following individuals based on the type of information being submitted: change in ownership (Air Quality Bureau Records Center), permit correspondence (Construction Permit Supervisor), stack testing correspondence (Stack Test Coordinator), and reports and notifications (Compliance Unit Supervisor and DNR Field Office). The addresses are:

Air Quality Bureau Iowa Department of Natural Resources 502 E. 9th St. Des Moines, IA 50319 Telephone: (515) 725-8200 Fax: (515) 725-9501	DNR Field Office 4 1401 Sunnyside Lane Atlantic, IA 50022 Phone: (712) 243-1934 Fax: (712) 243-6251

13. Appeal Rights

All conditions within an original permit may be appealed, subject to the appeal rights set forth in 561 IAC Chapter 7. Amended conditions within a permit amendment may be appealed, subject to the appeal rights set forth in 561 IAC Chapter 7. In permit amendments, all provisions of the original permit remain in full force and effect unless they are specifically changed by the permit amendment. The previous, unchanged permit provisions are included in the amendment for your convenience only and are unappealable.

14. Permit History

Permit No.	Project No.	Description	Date	Stack Testing
75-A-357	75-077	Original permit	12/17/75	No
75-A-357-S1		Converted ESP to "cold side" operation	3/3/93	No
75-A-357-S2		Corrected typos and averaging time error	5/9/95	No
75-A-357-S3	97-182	Corrected emission limit	5/7/97	No
75-A-357-P4	06-250	Original PSD permit with capacity increase and addition of FGD, LNB and baghouse	9/8/06	Yes
75-A-357-P5	08-151	Corrected operating limit	10/28/08	Yes
75-A-357-P6	11-349	Allowed combustion of treated coal	12/5/11	No
75-A-357-P7	13-466	Added Hg control and boiler projects	9/26/14	Yes
75-A-357-P8	22-002	Modify approved chemical list in Condition 5, modify temp and airflow	4/13/2022	No

END OF PERMIT

Iowa Department of Natural Resources
Air Quality Construction Permit

Permit Holder

Firm: MidAmerican Energy Company – Walter Scott, Jr. Energy Center

Contact:

Mark Podany
Manager, Environmental & Regulatory Compliance

(712) 366-5363

7215 Navajo Street
Council Bluffs, IA 51501

Responsible Party:

Matthew L. Finnegan
General Manager

7215 Navajo Street
Council Bluffs, IA 51501

Permitted Equipment

Emission Unit(s): WSEC 4 Boiler (EU 141; 7,675 MMBTU/hr) and Fugitive Emissions

Control Equipment:

Boiler controls:
Baghouse (CE 141A) for particulates, metals, and Hg; Low NO_x Burners (CE 141D), Overfire Air, and Selective Catalytic Reduction (SCR, CE 141B) for NO_x; Lime Spray Dryer Flue Gas Desulfurization (FGD, CE 141C) for SO_2, acid gases, and Hg; Activated Carbon Injection (ACI, CE 141E) for Hg; and Aqueous calcium bromide (optional) &
aqueous calcium chloride (optional) for Hg

Fugitive Emissions: See Condition 14

Emission Point: 141

Equipment Location: 7215 Navajo Street
Council Bluffs, IA 51501

Plant Number: 78-01-026

Permit No.	Proj. No.	Description	Date	Testing
03-A-425-P	02-528	Original PSD permit.	June 17, 2003	Yes
03-A-425-P1	06-250	Modified PM_{10} allowable for NAAQS.	September 8, 2006	Yes
03-A-425-P2	06-541	Removed 112(g) limits.	May 24, 2007	Yes
03-A-425-P3	08-516	Added 112(g) limits.	October 27, 2010	Yes
03-A-425-P4	11-349	Allow for combustion of treated coal	December 5, 2011	No

Under the Direction of the Director of
the Department of Natural Resources

PERMIT CONDITIONS

The permit holder, owner and operator of the facility shall assure that the installation, operation, and maintenance of this equipment is in compliance with all of the conditions of this permit and all other applicable requirements. This permit and its provisions are subject to the appeal rights set forth in Iowa Administrative Code (IAC), rule 561—7.5.

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1. Departmental Review

This permit is issued based on information submitted by the applicant. Any misinformation, false statements or misrepresentations by the applicant shall cause this permit to be void. In addition, the applicant may be subject to criminal penalties according to Iowa Code Section 455B.146A.

This permit is issued under the authority of 567 Iowa Administrative Code (IAC) 22.3. The proposed equipment has been evaluated for conformance with Iowa Code Chapter 455B; 567 IAC Chapters 20 – 34; and 40 CFR Parts 51, 52, 60, 61, and 63 and has the potential to comply.

No review has been undertaken on the engineering aspects of the equipment or control equipment other than the potential of that equipment for reducing air contaminant emissions. The DNR assumes no liability, directly or indirectly, for any loss due to damage to persons or property caused by, resulting from, or arising out of the design, installation, maintenance or operation of the proposed equipment.

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2. Transferability

As limited by 567 IAC 22.3(3)”f”, this permit is not transferable from one location to another or from one piece of equipment to another, unless the equipment is portable. When portable equipment for which a permit has been issued is to be transferred from one location to another, the DNR shall be notified in writing at least thirty (30) days prior to transferring to the new location (See Permit Condition 8.A.6). The owner will be notified at least ten (10) days prior to the scheduled relocation if the relocation will cause a violation of the National Ambient Air Quality Standards (NAAQS). In such case, a supplements permit shall be required prior to the initiation of construction of additional control equipment or equipments modifications needed to meet the standards.

The permit is for the construction and operation of specific emission unit(s), control equipment, and emission point as described in this permit and in the application for this permit. Any owner or operator of the specified emission unit(s), control equipment, or emission point, including any person who becomes an owner or operator subsequent to the date on which this permit is issued, is responsible for compliance with the provisions of this permit. No person shall construct, install, reconstruct or alter this emissions unit, control equipment or emission point without the required revisions to this permit.

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3. Construction

It is the owner's responsibility to ensure that construction conforms to the final plans and specifications as submitted, and that adequate operation and maintenance is provided to ensure that no condition of air pollution is created.

This permit shall become void if any one of the following conditions occur:

(1) the construction or modification of the proposed project, as it affects the emission point(s) permitted herein, is not initiated within eighteen (18) months after the permit issuance date; or

(2) the construction or modification of the proposed project, as it affects the emission point(s) permitted herein, is not completed within thirty-six (36) months after the permit issuance date; or

(3) the construction or modification of the proposed project, as it affects the emission point(s) permitted herein, is not completed within a time period specified elsewhere in this permit.

3. Construction (Continued)

3.a. Original Permits

The owner or operator shall obtain a new permit if any changes are made to the final plans and specifications submitted for the proposed project.

3.b. Modified or Supplemental Permits

This permit supersedes any and all previous permits issued for the emission point(s) or emission unit(s) permitted herein.

However, the permittee may continue to act under the provisions of the previous permit for the emission point(s) or emission unit(s) until one of the following conditions occurs:

(1) The proposed project authorized by this permit is completed as it affects the emission point(s) permitted herein; or
(2) The permit becomes void.

The owner or operator shall obtain a new permit if:

(1) Any changes are made to the final plans and specifications submitted for the proposed project; or
(2) This permit becomes void.

4. Credible Evidence

As stated in 567 IAC 21.5 and also in 40 CFR Part 60.11(g), where applicable, any credible evidence may be used for the purpose of establishing whether a person has violated or is in violation of any provisions specified in this permit or any provisions of 567 IAC Chapters 20 through 34.

5. Owner Responsibility

Issuance of this permit shall not relieve the owner or operator of the responsibility to comply fully with applicable provisions of the State Implementation Plan (SIP), and any other requirements of local, state, and federal law.

The owner or operator of any emission unit or control equipment shall maintain and operate the equipment and control equipment at all times in a manner consistent with good practice for minimizing emissions, as required by paragraph 567 IAC 24.2(1) *"Maintenance and Repair"*.

6. Excess Emissions

Excess emissions during a period of startup, shutdown, or cleaning of control equipment are not a violation of the emission standard if it is accomplished expeditiously and in a manner consistent with good practice for minimizing emissions except when another regulation applicable to the unit or process provides otherwise. Cleaning of control equipment, which does not require the shutdown of process equipment, shall be limited to one six-minute period per one-hour period. An incident of excess emissions other than the above is a violation and may be subject to criminal penalties according to Iowa Code 455B.146A. If excess emissions are occurring, either the control equipment causing the excess shall be repaired in an expeditious manner, or the process generating the emissions shall be shutdown within a reasonable period of time, as specified in 567 IAC 24.1.

An incident of excess emissions shall be orally reported to the appropriate DNR field office within eight (8) hours of, or at the start of, the first working day following the onset of the incident (See section 8.B.1). A written report of an incident of excess emissions shall be submitted as a follow-up to all required oral reports within seven (7) days of the onset of the upset condition.

7. Disposal of Contaminants

The disposal of materials collected by the control equipment shall meet all applicable rules.

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8. Notification, Reporting, and Recordkeeping

A. The owner shall furnish the DNR the following written notifications:
   1. The date construction, installation, or alteration is initiated postmarked within thirty (30) days following initiation of construction, installation, or alteration;
   2. The actual date of startup, postmarked within fifteen (15) days following the start of operation;
   3. The date of each compliance test required by Permit Condition 12, at least thirty (30) days before the anticipated compliance test date;
   4. The date of each pretest meeting, at least fifteen (15) days before the proposed meeting date. The owner shall request a proposed test plan protocol questionnaire at least sixty (60) days prior to each compliance test date. The completed questionnaire shall be received by the DNR at least fifteen (15) days before the pretest meeting date;
   5. Transfer of equipment ownership, within 30 days of the occurrence;
   6. Portable equipment relocation, at least thirty (30) days before equipment relocation.

B. The owner shall furnish the DNR with the following reports:
   1. Oral excess emissions reports, in accordance with 567 IAC 24.1;
   2. A written compliance demonstration report for each compliance testing event, whether successful or not, postmarked not later than six (6) weeks after the completion of the test period unless other regulations provide for other notification requirements. In that case, the more stringent reporting requirement shall be met;
   3. Operation of this emission unit(s) or control equipment outside of those limits specified in Permit Conditions 10 and 14 and according to the schedule set forth in 567 IAC 24.1.

C. The owner shall send correspondence regarding this permit to the following address:

Construction Permit Supervisor
Air Quality Bureau
Iowa Department of Natural Resources
7900 Hickman Road, Suite 1
Windsor Heights, IA 50324
Telephone: (515) 281-8189
Fax: (515) 242-5094

D. The owner shall send correspondence concerning stack testing to:

Stack Testing Coordinator
Air Quality Bureau
Iowa Department of Natural Resources
7900 Hickman Road, Suite 1
Windsor Heights, IA 50324
Telephone: (515) 242-6001
FAX: (515) 242-5127

E. The owner shall send reports and notifications to:

Compliance Unit Supervisor Air Quality Bureau Iowa Department of Natural Resources 7900 Hickman Road, Suite 1 Windsor Heights, IA 50324 Telephone: (515) 281-8448 Fax: (515) 242-5127	DNR Field Office 4 1401 Sunnyside Lane Atlantic, IA 50022 Telephone: (712) 243-1934 Fax: (712) 243-6251

8. Notification, Reporting, and Recordkeeping (Continued)

F. All data, records, reports, documentation, construction plans, and calculations required under this permit shall be available at the plant during normal business hours for inspection and copying by federal, state, or local air pollution regulatory agencies and their authorized representatives, for a minimum of two (2) years from the date of recording.

9. Permit Violations

Knowingly committing a violation of this permit may carry a criminal penalty of up to $10,000 per day fine and 2 years in jail according to Iowa Code Section 455B.146A.

10a. BACT Emission Limits

Pollutant	Tons/Yr[1]	Additional Limits
State Particulate Matter (PM)	NA	0.027 lb/MMBTU[2]
PM_{10}	NA	0.025 lb/MMBTU[2]
Opacity[3]	NA	5%[4]
Sulfur Dioxide (SO_2)[3]	3,362	0.1 lb/MMBTU[5]
Nitrogen Oxides (NO_X)[3]	2,353	0.07 lb/MMBTU[5]
Volatile Organic Compounds	121	0.0036 lb/MMBTU[2]
Carbon Monoxide (CO)[3]	5,177	0.154 lb/MMBTU[6]
Lead (Pb)	NA	0.000026 lb/MMBTU
Flourides (F)	NA	0.0009 lb/MMBTU
Total Reduced Sulfur (TRS)	NA	0.001 lb/MMBTU
Sulfuric Acid Mist (H_2SO_4)	NA	0.00421 lb/MMBTU

[1] Standard is a 12-month rolling total.
[2] Standard is expressed as the average of three (3) stack test runs.
[3] Compliance with the emission standards shall be demonstrated through the use of Continuous Emission Monitoring Systems (CEMS). See Condition 12 and Condition 16 for more information on compliance with the use of CEMS.
[4] Standard is a three (3) hour average.
[5] This standard is a 30-day rolling average not including periods of startup, shutdown, and malfunction.
[6] Standard is a one (1) calendar day average.

10b. 112(g) [Case-by-Case Maximum Achievable Control Technology (MACT)] Emission Limits

Pollutant	Lb/MMBTU (unless otherwise noted)
Mercury	0.013 lbs/hr[1]
Hydrogen Chloride (HCl)	0.0029 [2]
Total Selected Metals (TSM)[3]	0.000104[2]
Federal PM[4]	0.018[2]
Acetaldehyde[5]	0.0000058[2]
Benzene[5]	0.0000296[2]
Isophorone[5]	0.00000745[2]
Toluene[5]	0.000372[2]

[1] Prior to CEMS certification, the standard is expressed as the average of three (3) runs. Following the CEMS certification, the standard is expressed as a thirty (30) day rolling average. This limit is for total mercury emissions. Total mercury includes particulate bound mercury and both forms of vapor phase mercury (elemental and oxidized).
[2] Standard is expressed as the average of three (3) stack test runs.
[3] Total Selected Metals (TSM) means the combination of the following metallic HAP: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium.
[4] The federal particulate matter standard listed is a surrogate to show continual compliance with the total selected metals standard.
[5] The 112(g) emission limits will be reevaluated after actual test data has been gathered in order to determine if a new emission limit needs to be established whether that be higher or lower than the current emission limit. See permit Conditions 12 and 14.N. on testing requirements and the procedure for establishing the future limits.

10c. NSPS Limits

Pollutant	Emission Standard[1]	Reference (567 IAC)
Federal PM	13 ng/J heat input[2]	23.1(2)”z”[3]
Opacity[4]	20%[5]	23.1(2)”z”[3]
SO_2[4]	520 ng/J heat input[6]	23.1(2)”z”[3]
NO_X[4]	200 ng/J gross energy output[7]	23.1(2)”z”[3]

[1] Standard is expressed as the average of three (3) runs.
[2] 13 ng/J = 0.03 lb/MMBTU. See 40 CFR §60.42Da(a).
[3] IAC reference to New Source Performance Standards (NSPS) Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978; 40 CFR §60.40Da – 40 CFR §60.52Da).
[4] Compliance with the emission standards shall be demonstrated through the use of a CEMS. See Condition 12 and Condition 16 for more information on compliance with the use of CEMS.
[5] Opacity shall not exceed 20% (6-minute average), except for one (1) 6-minute period per hour of not more than 27% opacity. See 40 CFR §60.42Da(b).
[6] 520 ng/J = 1.20 lb/MMBTU. Compliance with this standard is determined on a 30-day rolling average basis. See permit Condition 14.D. See 40 CFR §60.43Da(a).
[7] 200 ng/J = 1.6 lb/megawatt-hour (gross). Compliance with this standard is determined on a 30-day rolling average basis. See 40 CFR §60.44Da(d)(1).

10d. Other Emission Limits

Pollutant	lb/hr	Reference (567 IAC)
PM_{10}	191.9[1, 2]	NAAQS
SO_2[3]	1,050.0[1, 4]	NAAQS
NO_X[3]	537.3[5, 6]	NAAQS
CO[3]	1,966.0[5, 7]	NAAQS
Pb	0.20[2, 5]	NAAQS

[1] Emission rate used in the computer aided dispersion model to demonstrate no exceedances of the National Ambient Air Quality Standards (NAAQS) or of the increment.
[2] Standard is expressed as the average of three (3) runs
[3] Compliance with the emission standards shall be demonstrated through the use of a CEMS. See Condition 12 and Condition 16 for more information on compliance with the use of CEMS.
[4] Standard is expressed as a three (3) hour rolling average.
[5] Emission rate used in the computer aided dispersion model to demonstrate no exceedances of the NAAQS.
[6] Standard is expressed as a calendar month average.
[7] This standard is expressed as a one (1) hour standard.

11. Emission Point Characteristics

This emission point shall conform to the specifications listed below:

Parameter	Value
Stack Height, (ft, from the ground)	551
Discharge Style	Unobstructed vertical
Stack Opening, (inches, dia.)	296
Exhaust Temperature (°F)	165
Exhaust Flowrate (scfm)	2,352,100

The temperature and flow rate are intended to be representative and characteristic of the design of the permitted emission point. The Department recognizes that the temperature and flow rate may vary with changes in the process and ambient conditions. If it is determined that any of the emission point design characteristics are different than the values stated above, the owner/operator must notify the Department and obtain a permit amendment, if required.

12. Compliance Demonstration(s) and Performance Testing

Pollutant	Initial	Subsequent	Methodology	Frequency
PM (federal)	Yes[1]	No	Stack test	One time
PM (state)	Yes	No	Stack test	One-time
PM_{10}	Yes	No	Stack test	One-time
Opacity	Yes[1]	Yes[2]	COMS[3]	Continuous
SO_2	Yes[1]	Yes[2]	CEMS	Continuous
NO_X	Yes[1]	Yes[2]	CEMS	Continuous
VOC	Yes	No	Stack test	One-time
CO	Yes	Yes[2, 4]	CEMS[5]	Continuous
Pb	Yes	No	Stack test	One-time
F	Yes	No	Stack test	One-time
TRS	Yes	No	Stack test	One-time
H_2SO_4	Yes	No	Stack test	One-time
Hg	Yes	Yes[6]	CEMS[7]	Continuous
HCl	Yes[8]	No	Stack test	One-time
TSM	Yes	No	Stack test	One-time
Acetaldehyde	Yes	Yes[4]	Stack test	Quarterly
Benzene	Yes	Yes[4]	Stack test	Quarterly
Isophorone	Yes	Yes[4]	Stack test	Quarterly
Toluene	Yes	Yes[4]	Stack test	Quarterly
Silt loading	Yes	Yes[9]	Performance Test	Monthly[10]

[1] See NSPS Subpart Da (40 CFR §60.40Da – 40 CFR §60.52Da) for initial performance testing requirements.

[2] Compliance shall be measured continuously through the use of Continuous Emission Monitoring Systems (CEMS).

[3] Per 40 CFR §60.48Da(p), the owner or operator can meet the compliance provisions by installing, certifying, and operating a CEMS measuring PM emissions discharged to the atmosphere and record the output of the system as specified in 40 CFR §60.48Da(p)(1) – 40 CFR §60.48Da(p)(8). The owner or operator is allowed to install a PM CEMS in lieu of a COMS for the NSPS, but the owner or operator is still required to install the COMS for measuring opacity to determine compliance with the BACT limit listed in Condition 10a.

[4] Testing shall be conducted once per quarter for the first year after the issuance date of the permit 03-A-425-P3. The tests shall be conducted with a minimum of forty-five (45) days between tests. The owner or operator shall operate and maintain a certified CO CEMS prior to the first test and during each subsequent test and shall maintain records to document having conducted the required quality assurance tests to demonstrate the continued certification and accuracy of the CO CEMS during the tests.

[5] If demonstrated, the CO CEMS data may also be used as a surrogate to demonstrate continual compliance with the organic HAP (acetaldehyde, benzene, Isophorone, and toluene) emission standards listed in Condition 10b. See Condition 14.N. for the requirements concerning CO and organic HAP emissions.

[6] Compliance shall be measured continuously through a combination of the use of Hg CEMS and stack test results. The CEMS shall be used to measure vapor phase mercury emissions continuously. Particulate bound mercury emissions shall be calculated through the use of the upper bound 95% confidence level of the particulate bound mercury fraction from the test results from all stack tests conducted on the unit. All runs shall be used unless otherwise approved by the Department. The formula for the upper bound 95% confidence level is:

$$95\% = \text{avg} + t\frac{S}{\sqrt{n}}$$

where: avg = average of the test runs
S = standard deviation of the test runs
t = percentage point of the *t* distribution with n-1 degrees of freedom
n = number of test runs

Total mercury shall then be calculated by adding the result of the upper bound 95% confidence level to the result of the mercury CEMS data.

12. Compliance Demonstration(s) and Performance Testing (Continued)

[7] Until such time that the owner or operator can certify its mercury CEMS per the EPA approved certification process, the owner or operator shall:

- Conduct Hg testing once per quarter for total mercury. The tests shall be conducted with a minimum of forty-five (45) days between tests and
- Conduct representative coal sampling of the fuel being fired during the test. The coal samples shall meet the following conditions:
  i. The sample shall be representative of the fuel fired on that day during the test.
  ii. Each composite sample shall meet the sampling requirements for special purpose sampling of ASTM D2234-76, any subsequent amendment to the ASTM procedure, or any future ASTM amendment approved by the Department.
  iii. The composite sample shall be collected as close to an "as-fired" condition as practicable.
  iv. The proposed location, sampling, and analytical collection methodology shall be submitted to and approved by the Department as part of the testing protocol.

[8] If the aqueous calcium chloride solution for additional Hg control is used, an additional compliance test shall be conducted within ninety (90) days of the initial use of the aqueous calcium chloride solution. The test shall be done with the maximum amount of aqueous calcium chloride solution intended to be used.

[9] Performance testing is required to be completed to demonstrate compliance with a silt content of 2.8 g/m^2.

[10] Performance testing on the haul road surface silt loading shall be completed once per month for the first year of operation. For each performance test, silt loading sampling shall be done for at least 3 different locations and immediately prior to the next cleaning cycle. After the first year of operation, the data shall be analyzed to determine whether or not further testing is required.

NOTES:

1. The initial compliance testing for all pollutants except for acetaldehyde, benzene, isophorone, and toluene was completed from May 8, 2007 – May 12, 2007. The testing requirements for acetaldehyde, benzene, isophorone, and toluene are new requirements.
2. The one (1) year of silt load testing was completed and the Department waived the requirement for the monthly silt load testing in a May 27, 2008 letter from Dennis Thielen of the Department to Donald Mohning of MidAmerican Energy.

<u>If an initial compliance demonstration specified above is testing</u>, the owner shall verify compliance with the emission limitations contained in Permit Condition 10 within sixty (60) days after achieving maximum production rate and no later than one hundred eighty (180) days after the initial startup date of the proposed equipment.

<u>If subsequent testing is specified above</u>, the owner shall verify compliance with the emission limitations contained in Permit Condition 10 according to the frequency noted above.

If testing is required, the owner shall use the test method and run time listed in the table below unless another testing methodology is approved by the Department prior to testing.

Pollutant	Test Run Time	Test Method
PM (federal)	2 hours	40 CFR 60, Appendix A, Method 5
PM (state)	2 hours	Iowa Compliance Sampling Manual Method 5
PM_{10}	3 hours	40 CFR 51, Appendix M, 201A with 202
Opacity	1 hour	40 CFR 60, Appendix A, Method 9
SO_2	1 hour	40 CFR 60, Appendix A, Method 6C
NO_X	1 hour	40 CFR 60, Appendix A, Method 7E
VOC	1 hour	40 CFR 60, Appendix A, Method 25A
CO	1 hour	40 CFR 60, Appendix A, Method 10
Pb	1 hour	40 CFR 60, Appendix A, Method 12
F	2 hours	40 CFR 60, Appendix A, Method 13B or Method 26A
TRS	1 hour	40 CFR 60, Appendix A, Method 16B
H_2SO_4	1 hour	40 CFR 60, Appendix A, Method 8
Hg	1 hour	40 CFR 60, Appendix A, Method 29
HCl	1 hour	40 CFR 60, Appendix A, Method 26
TSM	1 hour	40 CFR 60, Appendix A, Method 29
Acetaldehyde	1 hour	40 CFR 60, Appendix A, Method 18
Benzene	1 hour	40 CFR 60, Appendix A, Method 18
Isophorone	1 hour	40 CFR 60, Appendix A, Method 18
Toluene	1 hour	40 CFR 60, Appendix A, Method 18

12. Compliance Demonstration(s) and Performance Testing (Continued)

The unit(s) being sampled should be operated in a normal manner at its maximum continuous output as rated by the equipment manufacturer, or the rate specified by the owner as the maximum production rate at which this unit(s) will be operated. In cases where compliance is to be demonstrated at less than the maximum continuous output as rated by the manufacturer, and it is the owner's intent to limit the capacity to that rating, the owner may submit evidence to the Department that this unit(s) has been physically altered so that capacity cannot be exceeded, or the Department may require additional testing, continuous monitoring, reports of operating levels, or any other information deemed necessary by the Department to determine whether this unit(s) is in compliance.

Each emissions compliance test must be approved by the Department. Unless otherwise specified by the Department, each test shall consist of three (3) separate runs. The arithmetic mean of three (3) acceptable test runs shall apply for compliance, unless otherwise indicated by the Department.

A pretest meeting shall be held at a mutually agreeable site no less than fifteen (15) days prior to the date of each test. Representatives from the Department shall attend this meeting, along with the owner and the testing firm, if any. It shall be the responsibility of the owner to coordinate and schedule the pretest meeting. The owner shall be responsible for the installation and maintenance of test ports. The Department shall reserve the right to impose additional, different, or more detailed testing requirements.

13. NSPS and NESHAP Applicability

This emission unit is subject to Subparts A (General Provisions, 40 CFR §60.1 – 40 CFR §60.19) and Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, 40 CFR §60.40Da – 40 CFR §60.52Da) of the New Source Performance Standards (NSPS).

This emission unit is subject to Subparts A (General Provisions, 40 CFR §63.1 – 40 CFR §63.15) and B [Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act Sections, Sections 112(g) and 112(j), 40 CFR §63.40 – 40 CFR §63.56] of the National Emission Standard for Hazardous Air Pollutants (NESHAP). Consistent with the requirements of 40 CFR §63.44, if the EPA Administrator promulgates an applicable emission standard under Section 112(d) or Section 112(h) of the Act, or if the permitting authority issues a determination under Section 112(j) of the Act, this permit will be modified as necessary to make the terms of this permit consistent with the applicable standard. The owner or operator is required to submit a permit application requesting a change.

The facility (plant number 78-01-026) is considered an affected source under 40 CFR 72, 73, 75, 76, 77, and 78 definitions as emission units at this source are subject to the acid rain emission reduction requirements or the acid rain emission limitations, as adopted by the Department by reference (See 567 IAC 22.120 – 567 IAC 22.148). This emission unit will be subject to the SO_2 allowance allocation, NO_x emission limitations, and monitoring provisions of the federal acid rain program.

14. Operating Limits

Operating limits for this permit shall be:

A. This emission unit shall be limited to firing on coal and #2 fuel oil (for light off, startup, and flame stabilization).
B. The sulfur (S) content of the fuel used shall not exceed 0.625 lbs of S/MMBTU.
C. Per 40 CFR §60.42Da(a)(2), particulate matter (federal) emissions shall not exceed 1% of the potential combustion concentration (99% reduction) when combusting coal.
D. Per 40 CFR §60.43Da(a)(1) and 40 CFR §60.43Da(a)(2), sulfur dioxide emissions shall not exceed:
   (1) 520 ng/J (1.2 lb/MMBTU) heat input and 10% of the potential combustion concentration (90% reduction) when combusting coal, or
   (2) 30% of the potential combustion concentration (70% reduction), when emissions are less than 260 ng/J (0.60 lb/MMBTU) heat input. Compliance with this standard is determined on a 30-day rolling average basis.

14. Operating Limits (Continued)

E. Per 40 CFR §60.48a(d), during emergency conditions an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:
   (1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,
   (2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation, and
   (3) Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 million Btu/hr) heat input (approximately 125 MW electrical output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph (a), (b), (d), (e), and (h) under 60 CFR §60.43a for any period of operation lasting from 24 hours to 30 days when:
   (i) Any one flue gas desulfurization module is not operated,
   (ii) The affected facility is operating at the maximum heat input rate,
   (iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and
   (iv) The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.

F. The owner or operator shall submit the written reports required under NSPS Subparts A and Da to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

G. The minimum sorbent feed rate of the Flue Gas Desulfurization System shall be 0.40 lbs of lime/lb of inlet SO_2 based on 90% available CaO in the lime, expressed as a three (3) hour average except for eight (8) hours per calendar month in which the three (3) hour average minimum sorbent feed rate may be less than 0.40 lbs of lime/lb of inlet SO_2.

H. The minimum ammonia feed rate of the Selective Catalytic Reduction (SCR) system shall be 0.43 lbs of urea per pound of inlet SCR NO_x, expressed as a thirty (30) day rolling average.

I. The minimum halogenated activated carbon injection rate of the Activated Carbon Injection (ACI) system shall be 1.2 pounds of halogenated activated carbon per million standard cubic feet ($MMft^3$ or MMCF) of exhaust gas, expressed as a thirty (30) day rolling average.

J. The owner or operator may, but is not required to, treat the coal burned in this unit with chemicals containing additives including a mineral composite of calcium silicate components and other calcium compounds containing iron and aluminum.

K. The following conditions (except Condition 4) are required on the haul roads at the facility (plant number 78-01-026) in order for the roads to meet the BACT emission rates:
   (1) Haul truck loads shall be enclosed or covered
   (2) The maximum silt content shall not exceed 2.8 g/m^2. See Condition 12 for testing requirements.
   (3) In order to protect the NAAQS, the maximum number of trucks associated with ash and FGD hauling (all units) shall not exceed 80 trucks per day.
   (4) For paved roads:
      (i) Fugitive emissions of paved haul roads shall be controlled to an effective control efficiency of 80% by either water flushing followed by sweeping or using a street sweeper that is certified to achieve a pick-up efficiency of 80%. The control and record keeping requirements described in Condition 15.Q. shall begin at the same time as the startup of Boiler 4. The control efficiency of 80% shall be achieved by either using a certified sweeper once per day or by water flushing followed by sweeping of the paved haul roads once per day. The water spray rate shall be a minimum of 0.23 gallons per square yard.
      (ii) If water flushing followed by sweeping cannot be accomplished because the ambient air temperature (as measured at the facility during daylight operating hours) will be less than 35^0 F (1.7^0 C) or conditions due to weather, in combination with the application of the water, could create hazardous driving conditions, then the water flushing and sweeping shall be postponed and accomplished as soon after the scheduled date as the conditions preventing the application have abated.
      (iii) Water flushing and sweeping need not occur when a rain gage located at the site indicates that at least 0.2 inches of precipitation (water equivalent) has occurred within the preceding 24-hr time period or the paved road(s) will not be used on a given day.

14. Operating Limits (Continued)

(5) For unpaved roads:

(i) Fugitive emissions from unpaved haul roads shall be controlled by applying a chemical dust suppressant. Applications of the selected chemical dust suppressant and the record keeping requirements described in Condition 15.Q. shall begin at the same time as the startup of Boiler 4. A control efficiency of 95% shall be maintained on all haul roads. MidAmerican may elect to use any chemical dust suppressant that is capable of achieving the 95% control efficiency. In the event that the manufacturer or distributor of a chemical dust suppressant recommends different amounts of chemical dust suppressant or MidAmerican chooses to use a different chemical dust suppressant, MidAmerican shall notify DNR of the change in application rates and/or chemical dust suppressant and the manufacturer's/distributor's recommendations.

(ii) If the selected chemical dust suppressant cannot be applied because the ambient air temperature (as measured at the facility during daylight operating hours) will be less than 35^0 F (1.7^0 C) or conditions due to weather, in combination with the application of the chemical dust suppressant**,** could create hazardous driving conditions, then the chemical dust suppressant application shall be postponed and applied as soon after the scheduled application date as the conditions preventing the application have abated.

L. The following conditions are required on the following volume source fugitive emissions at the facility (plant number 78-01-026) for this project in order for these sources of emissions to meet the BACT emission rates:

(1) Stacker conveyor:

(i) Fugitive emissions shall be controlled by applying a chemical dust suppressant. Applications of the selected chemical dust suppressant and the record keeping requirements described in Condition 15.R. shall begin at the same time as the startup of Boiler 4. A control efficiency of 95% shall be maintained. MidAmerican may elect to use any chemical dust suppressant that is capable of achieving the 95% control efficiency. In the event that the manufacturer or distributor of a chemical dust suppressant recommends different amounts of chemical dust suppressant or MidAmerican chooses to use a different chemical dust suppressant, MidAmerican shall notify DNR of the change in application rates and/or chemical dust suppressant and the manufacturer's/distributor's recommendations.

(ii) If the selected chemical dust suppressant cannot be applied because the ambient air temperature (as measured at the facility during operating hours) will be less than 35^0 F (1.7^0 C) or other conditions due to weather cause the chemical dust suppressant to not be applied then the chemical dust suppressant application shall be postponed and applied as soon after the scheduled application date as the conditions preventing the application have abated.

(iii) The application of chemical dust suppressant is not required when rail unloading directly from the train to the plant silos without first depositing to a pile.

(2) Transfer to active pile:

(i) Fugitive emissions shall be controlled by applying a chemical dust suppressant. Applications of the selected chemical dust suppressant and the record keeping requirements described in Condition 15.R. shall begin at the same time as the startup of Boiler 4. A control efficiency of 95% shall be maintained. MidAmerican may elect to use any chemical dust suppressant that is capable of achieving the 95% control efficiency. In the event that the manufacturer or distributor of a chemical dust suppressant recommends different amounts of chemical dust suppressant or MidAmerican chooses to use a different chemical dust suppressant, MidAmerican shall notify DNR of the change in application rates and/or chemical dust suppressant and the manufacturer's/distributor's recommendations.

(ii) If the selected chemical dust suppressant cannot be applied because the ambient air temperature (as measured at the facility during operating hours) will be less than 35^0 F (1.7^0 C) or other conditions due to weather cause the chemical dust suppressant to not be applied then the chemical dust suppressant application shall be postponed and applied as soon after the scheduled application date as the conditions preventing the application have abated.

14. Operating Limits (Continued)

(3) Bucket reclaim:
(i) Fugitive emissions shall be controlled by applying a chemical dust suppressant. Applications of the selected chemical dust suppressant and the record keeping requirements described in Condition 15.R. shall begin at the same time as the startup of Boiler 4. A control efficiency of 95% shall be maintained. MidAmerican may elect to use any chemical dust suppressant that is capable of achieving the 95% control efficiency. In the event that the manufacturer or distributor of a chemical dust suppressant recommends different amounts of chemical dust suppressant or MidAmerican chooses to use a different chemical dust suppressant, MidAmerican shall notify DNR of the change in application rates and/or chemical dust suppressant and the manufacturer's/distributor's recommendations.
(ii) If the selected chemical dust suppressant cannot be applied because the ambient air temperature (as measured at the facility during operating hours) will be less than 35^0 F (1.7^0 C) or other conditions due to weather cause the chemical dust suppressant to not be applied then the chemical dust suppressant application shall be postponed and applied as soon after the scheduled application date as the conditions preventing the application have abated.

(4) Rail unloading:
(i) Fugitive emissions shall be controlled by applying a chemical dust suppressant. Applications of the selected chemical dust suppressant and the record keeping requirements described in Condition 15.R. shall begin at the same time as the startup of Boiler 4. A control efficiency of 95% shall be maintained. MidAmerican may elect to use any chemical dust suppressant that is capable of achieving the 95% control efficiency. In the event that the manufacturer or distributor of a chemical dust suppressant recommends different amounts of chemical dust suppressant or MidAmerican chooses to use a different chemical dust suppressant, MidAmerican shall notify DNR of the change in application rates and/or chemical dust suppressant and the manufacturer's/distributor's recommendations.
(ii) If the selected chemical dust suppressant cannot be applied because the ambient air temperature (as measured at the facility during operating hours) will be less than 35^0 F (1.7^0 C) or other conditions due to weather cause the chemical dust suppressant to not be applied then the chemical dust suppressant application shall be postponed and applied as soon after the scheduled application date as the conditions preventing the application have abated.
(iii) The application of chemical dust suppressant is not required when rail unloading is done directly from the train to the plant silos without first depositing to a pile.

M. The following conditions are required on the following area source fugitive emissions at the facility (plant number 78-01-026) for this project in order for these sources to meet the BACT emission rate:

(1) Active coal pile:
(i) The size of the active coal pile shall not exceed 311,155 square feet.
(ii) Fugitive emissions shall be controlled by applying a chemical dust suppressant. Applications of the selected chemical dust suppressant and the record keeping requirements described in Condition 15.S. shall begin at the same time as the startup of Boiler 4. A control efficiency of 95% shall be maintained. MidAmerican may elect to use any chemical dust suppressant that is capable of achieving the required control efficiencies. In the event that the manufacturer or distributor of a chemical dust suppressant recommends different amounts of chemical dust suppressant or MidAmerican chooses to use a different chemical dust suppressant, MidAmerican shall notify DNR of the change in application rates and/or chemical dust suppressant and the manufacturer's/distributor's recommendations.
(iii) If the selected chemical dust suppressant cannot be applied because the ambient air temperature (as measured at the facility during daylight operating hours) will be less than 35^0 F (1.7^0 C) or other conditions due to weather cause the chemical dust suppressant to not be applied then the chemical dust suppressant application shall be postponed and applied as soon after the scheduled application date as the conditions preventing the application have abated.

14. Operating Limits (Continued)

(2) Inactive coal storage pile:
   (i) The size of the inactive coal storage pile shall not exceed 1,196,459 square feet.
   (ii) Fugitive emissions shall be controlled by applying a chemical dust suppressant. Applications of the selected chemical dust suppressant and the record keeping requirements described in Condition 15.S. shall begin at the same time as the startup of Boiler 4. A control efficiency of 99% shall be maintained when the pile is inactive. A chemical dust suppressant shall be used to meet a control efficiency of 95% for maintenance of the inactive pile. MidAmerican may elect to use any chemical dust suppressant that is capable of achieving the required control efficiencies. In the event that the manufacturer or distributor of a chemical dust suppressant recommends different amounts of chemical dust suppressant or MidAmerican chooses to use a different chemical dust suppressant, MidAmerican shall notify DNR of the change in application rates and/or chemical dust suppressant and the manufacturer's/distributor's recommendations.
   (iii) If the selected chemical dust suppressant cannot be applied because the ambient air temperature (as measured at the facility during daylight operating hours) will be less than 35^0 F (1.7^0 C) or other conditions due to weather cause the chemical dust suppressant to not be applied then the chemical dust suppressant application shall be postponed and applied as soon after the scheduled application date as the conditions preventing the application have abated.

(3) Rail unloading coal stockout pile:
   (i) The size of the active coal storage pile shall not exceed 28,224 square feet.
   (ii) Fugitive emissions shall be controlled by applying a chemical dust suppressant. Applications of the selected chemical dust suppressant and the record keeping requirements described in Condition 15.S. shall begin at the same time as the startup of Boiler 4. A control efficiency of 95% shall be maintained. MidAmerican may elect to use any chemical dust suppressant that is capable of achieving the 95% control efficiency. In the event that the manufacturer or distributor of a chemical dust suppressant recommends different amounts of chemical dust suppressant or MidAmerican chooses to use a different chemical dust suppressant, MidAmerican shall notify DNR of the change in application rates and/or chemical dust suppressant and the manufacturer's/distributor's recommendations.
   (iii) If the selected chemical dust suppressant cannot be applied because the ambient air temperature (as measured at the facility during daylight operating hours) will be less than 35^0 F (1.7^0 C) or other conditions due to weather cause the chemical dust suppressant to not be applied then the chemical dust suppressant application shall be postponed and applied as soon after the scheduled application date as the conditions preventing the application have abated.

N. A bag leak detection system must be installed to meet the following criteria:
(1) At least one detector must be located in each compartment of the baghouse.
(2) The bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in "Fabric Filter Bag Leak Detection Guidance," EPA-454/R-98-015, September 1997.
(3) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.
(4) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.
(5) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensors.
(6) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel.
(7) The system's instrumentation and alarm may be shared among detectors.
(8) The system's alarm shall sound no more than 5% of the operating time during a 6-month period.

14. Operating Limits (Continued)

O. Within sixty (60) days of Departmental approval of the last required test results from Condition 12 of this permit for acetaldehyde, benzene, isophorone, and toluene the owner or operator shall submit the following to the Department:
   (1) An analysis for acetaldehyde, benzene, isophorone, and toluene to establish new 112(g) case-by-case MACT limits for those pollutants. This analysis shall include:
   - A summary of each test.
   - The result of each individual run.
   - All outliers in the data set and the methodology used to establish outliers.
   - The average of all runs conducted with the outliers removed.
   - The standard deviation of all runs conducted with the outliers removed.
   - The upper bound 95% confidence level of all runs conducted with the outliers removed. The formula used shall be:

$$95\% = \text{avg} + t\frac{S}{\sqrt{n}}$$

where: avg = average of the test runs
S = standard deviation of the test runs
t = percentage point of the *t* distribution with n-1 degrees of freedom
n = number of test runs

   (2) An analysis showing the correlation (or lack thereof) between CO and the organic HAPs that were tested.
   (3) A request to establish the 112(g) case-by-case limits for organic HAP emissions based on the testing conducted and the required analysis.

P. The waste material collected by the fabric filter and stored in the FGD waste silo system shall be processed through a pug-mill during loadout to increase the material moisture content to a minimum of 20%. The owner or operator shall conduct daily testing of the moisture content of the FGD waste material. Water wagons shall be used to wet the waste material during disposal site grading activities. These requirements do not apply to waste material being sold for beneficial use.

Q. The owner or operator is allowed, but not required, to add an aqueous calcium bromide chemical and/or an aqueous calcium chloride chemical to the coal prior to combustion for added mercury (Hg) control.

R. This emission unit is subject to all applicable operating limits set forth in NSPS Subparts A (40 CFR §60.1 – 40 CFR §63.19) and Da (40 CFR §60.40Da – 40 CFR §60.52Da) not specifically listed in this permit.

15. Operating Condition Monitoring

All records as required by this permit shall be kept on-site for a minimum of two (2) years and shall be available for inspection by the DNR. Records shall be legible and maintained in an orderly manner. These records shall show the following:

A. The date and an analysis showing the sulfur content and heat input representative of the coal burned for that day.

B. Per 40 CFR §60.51Da(a), the performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) for NO_x, SO_2, and PM emissions shall be submitted to the Administrator.

C. Per 40 CFR §60.51Da(b), the following information for NO_x and SO_2 shall be reported to the Administrator for each twenty-four (24) hour period:
   (1) Calendar date,
   (2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) for each thirty (30) successive boiler operating days, ending with the last thirty (30) day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.
   (3) Percent reduction of the potential combustion concentration of sulfur dioxide for each thirty (30) successive boiler operating days, ending with the last thirty (30) day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

15. Operating Condition Monitoring (Continued)

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least eighteen (18) hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.
(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_x only), emergency conditions (SO_2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.
(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.
(7) Identification of times when hourly averages have been obtained based on manual sampling methods.
(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.
(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3:

D. Per 40 CFR §60.51Da(c), if the minimum quantity of emission data as required by 40 CFR §60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of 40 CFR §60.48a(h) shall be reported to the Administrator for that thirty (30) day period:
(1) The number of hourly averages available for outlet emission rates (no) and inlet emission rates (n_i) as applicable.
(2) The standard deviation of hourly averages for outlet emission rates (so) and inlet emission rates (s_i) as applicable.
(3) The lower confidence limit for the mean outlet emission rate (E_o*) and the upper confidence limit for the mean inlet emission rate (E_i*) as applicable.
(4) The applicable potential combustion concentration.
(5) The ratio of the upper confidence limit for the mean outlet emission rate (E_o*) and the allowable emission rate (E_{std}) as applicable.

E. Per 40 CFR §60.51Da(d), if any standards under 40 CFR §60.43Da are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:
(1) Indicating if emergency conditions existed and requirements under § 60.48Da(d) were met during each period, and
(2) Listing the following information:
(i) Time periods the emergency condition existed;
(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;
(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;
(iv) Percent reduction in emissions achieved;
(v) Atmospheric emission rate (ng/J) of the pollutant discharged; and
(vi) Actions taken to correct control system malfunction

F. Per 40 CFR §60.51Da(e), if fuel pretreatment credit toward the sulfur dioxide emission standard under 40 CFR §60.43Da is claimed, the owner or operator of the affected facility shall submit a signed statement:
(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of 40 CFR §60.50Da and Method 19 (appendix A); and
(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

G. Per 40 CFR §60.51Da(f), any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

15. Operating Condition Monitoring (Continued)

H. Per 40 CFR §60.51Da(h), the owner or operator of the affected facility shall submit a signed statement indicating whether:
   (1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.
   (2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.
   (3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.
   (4) Compliance with the standards has or has not been achieved during the reporting period.

I. Per 40 CFR §60.51Da(i), for the purposes of the reports required under 40 CFR §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under 40 CFR §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

J. Per 40 CFR §60.51Da(j), owner or operator shall submit the written reports required under 40 CFR §60.51Da and 40 CFR 60, Subpart A to the Administrator semiannually for each six (6) month period. All semiannual reports shall be postmarked by the thirtieth day following the end of each six (6) month period

K. Per 40 CFR §60.51Da(k), the owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_x and/or opacity in lieu of submitting the written reports required under 40 CFR §60.51Da(b) and 40 CFR §60.51Da(i). The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative form.

L. This emission unit is subject to all applicable recordkeeping and reporting requirements set forth in NSPS Subparts A (40 CFR §60.1 – 40 CFR §63.19) and Da (40 CFR §60.40Da – 40 CFR §60.52Da) not specifically listed in this permit

M. The sorbent feed rate of the Flue Gas Desulfurization System (in lb/lb) expressed as a three (3) hour rolling average.

N. The urea feed rate of the SCR system (in lb/lb) expressed as a thirty (30) day rolling average.

O. The activated carbon feed rate of the ACI system (in lb/MMft^3) expressed as a thirty (30) day rolling average.

P. The following records must be maintained from the bag leak detection system:
   (1) The date, time and duration of each system alarm.
   (2) The time corrective action was initiated and completed.
   (3) A brief description of the cause of the alarm and the corrective action.
   (4) A record of the percent of operating time during each 6-month period that the alarm sounds. In calculating the operating time percentage,
      (i) if an inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted.
      (ii) if corrective action is required, each alarm shall be counted as a minimum of one (1) hour.
      (iii) if it takes longer than 1 hour to initiate corrective action, the alarm time shall be counted as the actual amount of time taken to initiate corrective action.

Q. A log showing the following for haul roads:
   (1) The date and number of trucks associated with Units 1, 2, 3 and 4.
   (2) Paved roads:
      (i) Records of either the use of a certified sweeper or the applications shall be maintained and shall include:
         - The dates of each application or use of certified sweeper,
         - The amount of water applied (if applicable),
         - The areas treated or swept by certified sweeper, and
         - The operator’s initials.
      (ii) If water is to be used and is not applied when scheduled then the records should so indicate and provide and an explanation.

15. Operating Condition Monitoring (Continued)

(3) Unpaved roads:
(i) Records of the applications shall be maintained and shall include:
- The dates of each application,
- The chemical dust suppressant used,
- The application intensity (gal/yd^2),
- Dilution ratio,
- The operator's initials, and
- Documentation of road and weather conditions, if necessary.

(ii) If the selected chemical dust suppressant is not applied as planned, then the records should so indicate and provide an explanation.

R. A log showing the following for the volume sources associated with this project:
(1) Stacker conveyor:
(i) Records of the applications shall be maintained and shall include:
- The dates of each application,
- The chemical dust suppressant used,
- The application intensity (gal/yd^2),
- Dilution ratio,
- The operator's initials, and
- Documentation of weather conditions, if necessary.

(ii) If the selected chemical dust suppressant is not applied as planned, then the records should so indicate and provide an explanation.

(2) Transfer to active pile:
(i) Records of the applications shall be maintained and shall include:
- The dates of each application,
- The chemical dust suppressant used,
- The application intensity (gal/yd^2),
- Dilution ratio,
- The operator's initials, and
- Documentation of weather conditions, if necessary.

(ii) If the selected chemical dust suppressant is not applied as planned, then the records should so indicate and provide an explanation.

(3) Bucket reclaim:
(i) Records of the applications shall be maintained and shall include:
- The dates of each application,
- The chemical dust suppressant used,
- The application intensity (gal/yd^2),
- Dilution ratio,
- The operator's initials, and
- Documentation of weather conditions, if necessary.

(ii) If the selected chemical dust suppressant is not applied as planned, then the records should so indicate and provide an explanation

(4) Rail unloading:
(i) Records of the applications shall be maintained and shall include:
- The dates of each application,
- The chemical dust suppressant used,
- The application intensity (gal/yd^2),
- Dilution ratio,
- The operator's initials, and
- Documentation of weather conditions, if necessary.

(ii) If the selected chemical dust suppressant is not applied as planned, then the records should so indicate and provide an explanation

15. Operating Condition Monitoring (Continued)

S. A log showing the following for the area sources in this project:
(1) Active coal pile:
(i) The date and size of the pile.
(ii) Records of the applications shall be maintained and shall include:
- The dates of each application,
- The chemical dust suppressant used,
- The application intensity (gal/yd^2),
- Dilution ratio,
- The operator's initials, and
- Documentation of weather conditions, if necessary.

(iii) If the selected chemical dust suppressant is not applied as planned, then the records should so indicate and provide an explanation.
(2) Inactive storage pile:
(i) The date and size of the pile.
(ii) Records of the applications shall be maintained and shall include:
- The dates of each application,
- The chemical dust suppressant used,
- The application intensity (gal/yd^2),
- Dilution ratio,
- The operator's initials, and
- Documentation of weather conditions, if necessary.

(iii) If the selected chemical dust suppressant is not applied as planned, then the records should so indicate and provide an explanation.
(3) Rail unloading coal stockout pile:
(i) The date and size of the pile.
(ii) Records of the applications shall be maintained and shall include:
- The dates of each application,
- The chemical dust suppressant used,
- The application intensity (gal/yd^2),
- Dilution ratio,
- The operator's initials, and
- Documentation of weather conditions, if necessary.

(iii) If the selected chemical dust suppressant is not applied as planned, then the records should so indicate and provide an explanation.

T. The results of all FGD waste material moisture content tests.
U. The date and the average hourly rate of aqueous calcium bromide and/or calcium chloride that is added to the coal.

16. Continuous Emission Monitoring

The following continuous emission monitoring requirements apply to this emission point and its associated emission unit(s) and control equipment:

A. The following monitoring systems are required:

- *Opacity:*

  In accordance with 40 CFR §60.49Da(a), the owner or operator shall install, calibrate, maintain, and operate a continuous monitoring system (CEMS) and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere.

  If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

  The system shall be designed to meet the 40 CFR 60, Appendix B, Performance Specification 1 (PS1).

  Per 40 CFR §60.48Da(p), the owner or operator may elect to install, certify, maintain and operate a CEMS measuring PM emissions discharged to the atmosphere and record the output of the system as specified in 40 CFR §60.48Da(p)(1) through 40 CFR §60.48Da(p)(8). If the owner or operator elects to use the PM CEMS in lieu of an opacity monitor to demonstrate compliance with the NSPS, the opacity monitor is still required as the monitor shall also be used to demonstrate compliance with the BACT emission standards in this permit.

- *SO_2:*

  In accordance with 40 CFR §60.49Da(b), the owner or operator shall install, calibrate, maintain, and operate a continuous monitoring system (CEMS) and record the output of the system, for measuring sulfur dioxide (SO_2) emissions, except where natural gas is the only fuel combusted, as follows:

  (1) Install, calibrate, maintain, and operate a CEMS and record the output of the system, for measuring sulfur dioxide (SO_2) emissions discharged to the atmosphere or
  (2) If the owner or operator has installed and certified a SO_2 CEMS according to the requirements of 40 CFR §75.21 and 40 CFR 75, Appendix B, that CEMS may be used to meet the SO_2 monitoring requirements provided:
    (i) A CO_2 or O_2 continuous monitoring system is installed, calibrated, maintained and operated at the same location in accordance with 40 CFR §60.49Da(d); and
    (ii) For sources subject to an SO_2 emission limit in lb/MMBTU under §60.43Da:
      (a) When relative accuracy testing is conducted, the SO_2 concentration data and the CO_2 (or O_2) data are collected simultaneously; and
      (b) In addition to meeting the applicable SO_2 and CO_2 (or O_2) relative accuracy specifications in Figure 2 of 40 CFR 75 Appendix B, the relative accuracy (RA) standard in 40 CFR 60, Appendix B, Performance Specification 2 (PS2), Section 13.2 is met when the RA is calculated on a lb/MMBTU basis and
    (iii) The reporting requirements of 40 CFR §60.51Da are met. The SO_2 and CO_2 (or O_2) data reported to meet the requirements of 40 CFR §60.51Da shall not include substitute data values derived from the missing data procedures in 40 CFR 75, Subpart D, nor shall the SO_2 data have been bias adjusted according to the procedures of 40 CFR 75.

16. Continuous Emission Monitoring (Continued)

The system shall be designed to meet the 40 CFR 60, Appendix B, Performance Specification 2 (PS2) and Performance Specification 6 (PS6) requirements. The specifications of 40 CFR 60, Appendix F (Quality Assurance/Quality Control) shall apply. Appendix F requirements shall be supplemented with a quarterly notice to the Department with the dates of the quarterly cylinder gas audits and annual relative accuracy test audit.

This monitor shall also be used to demonstrate compliance with the non-NSPS emission standards in this permit.

- *NO_x:*

In accordance with 40 CFR §60.49Da(c), the owner or operator shall either:

(1) Install, calibrate, maintain, and operate a CEMS and record the output of the system, for measuring nitrogen oxides (NO_x) emissions discharged to the atmosphere; or
(2) If the owner or operator has installed a NO_x emission rate CEMS to meet the requirements of 40 CFR 75 and is continuing to meet the ongoing requirements of 40 CFR 75, that CEMS may be used to meet the requirements of 40 CFR §60.49Da(c), except that the owner or operator shall also meet the requirements of 40 CFR §60.51Da. Data reported to meet the requirements of 40 CFR §60.51Da shall not include data substituted using the missing data procedures in 40 CFR 75, Subpart D, nor shall the data have been bias adjusted according to the procedures of 40 CFR 75.

The system shall be designed to meet the 40 CFR 60, Appendix B, Performance Specification 2 (PS2) and Performance Specification 6 (PS6) requirements. The specifications of 40 CFR Appendix F (Quality Assurance/Quality Control) shall apply. Appendix F requirements shall be supplemented with a quarterly notice to the Department with the dates of the quarterly cylinder gas audits and annual relative accuracy test audit.

This monitor shall also be used to demonstrate compliance with the non-NSPS emission standards in this permit.

- *O_2 or CO_2:*

In accordance with 40 CFR §60.49Da(d), the owner or operator shall install, calibrate, maintain, and operate a CEMS and record the output of the system, for measuring the oxygen (O_2) or carbon dioxide (CO_2) content of the flue gases at each location where SO_2 or NO_x emissions are monitored.

- *CO:*

Compliance with the carbon monoxide (CO) emission limits of this permit shall be continuously demonstrated by the owner or operator through the use of a CEMS. Therefore, the owner or operator shall install, calibrate, maintain, and operate a CEMS for measuring CO emissions discharged to the atmosphere and record the output of the system.

The system shall be designed to meet the 40 CFR 60, Appendix B, Performance Specification 4A (PS4A) and Performance Specification 6 (PS6) requirements. The specifications of 40 CFR 60, Appendix F (Quality Assurance/Quality Control) shall apply. Appendix F requirements shall be supplemented with a quarterly notice to the Department with the dates of the quarterly cylinder gas audits and annual relative accuracy test audit.

16. Continuous Emission Monitoring (Continued)

- *Hg:*

  Within one hundred twenty (120) days after final EPA approval of a mercury CEMS certification process the owner or operator shall continuously demonstrate compliance with the mercury (Hg) emission limits in this permit through the use of a combination of CEMS and stack testing as detailed in Condition 12, footnote 6 of the first table. Therefore, the owner or operator shall install, calibrate, maintain, and operate a CEMS for measuring Hg emissions discharged to the atmosphere and record the output of the system. Prior to final approval of the mercury CEMS certification process the owner or operator shall conduct quarterly Hg testing per the requirements of Condition 12.

  The system shall be designed to meet the final EPA approved mercury monitoring specification. The specifications of 40 CFR 60, Appendix F (Quality Assurance/Quality Control) shall apply. Appendix F requirements shall be supplemented with a quarterly notice to the Department with the dates of the quarterly cylinder gas audits and annual relative accuracy test audit.

- *Wattmeter:*

  Per 40 CFR §60.49Da(k)(1), the owner or operator shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in megawatt-hour on a continuous basis; and record the output of the monitor for demonstrating compliance with the output-based standard under 40 CFR §60.44Da(d)(1).

- *Flowmeter:*

  Per 40 CFR §60.49Da(l), the owner or operator demonstrating compliance with the output-based standard under 40 CFR §60.42Da, 40 CFR §60.43Da, 40 CFR §60.44Da, or 40 CFR §60.45Da shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of 40 CFR 60, Appendix B, Performance Specification 6 and 40 CFR 60, Appendix F, Procedure 1. In addition, the owner or operator shall record the output of the system, for measuring the volumetric flow of exhaust gases discharged to the atmosphere or

  Alternatively, per 40 CFR §60.49Da(m), data from a continuous flow monitoring system certified according to the requirements of 40 CFR §75.20(c) and 40 CFR 75, Appendix A, and continuing to meet the applicable quality control and quality assurance requirements of 40 CFR §75.21 and 40 CFR 75, Appendix B, may be used.

  Flow rate data reported to meet the requirements of 40 CFR §60.51Da shall not include substitute data values derived from the missing data procedures of 40 CFR 75.

B. In accordance with 40 CFR §60.49Da(e), the CEMS required in Condition 16.A. for SO_2, NO_x, and either O_2 or CO_2 shall be operated and the data recorded during all periods of operation including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

16. Continuous Emission Monitoring (Continued)

C. In accordance with 40 CFR §60.49Da(f)(1), the owner or operator shall obtain emission data for at least eighteen (18) hours in at least twenty-two (22) out of thirty (30) successive boiler operating days. If this minimum data cannot be met with a CEMS, the owner or operator shall supplement the emission data with other monitoring systems approved by the Administrator or the following reference methods and procedures:

(1) 40 CFR 60, Method 6 shall be used to determine the SO_2 concentration at the same location as the SO_2 monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.
(2) 40 CFR 60, Method 7 shall be used to determine the NO_x concentration at the same location as the NO_x monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.
(3) The emission rate correction factor, integrated bag sampling and analysis procedure of 40 CFR 60, Appendix A, Method 3B shall be used to determine the O_2 or CO_2 concentration at the same location as the O_2 or CO_2 monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.
(4) The procedures in 40 CFR 60, Appendix A, Method 19 shall be used to compute each 1-hour average concentration in ng/J (1b/million Btu) heat input.

Acceptable alternative methods and procedures are given in Condition 16.F.

D. The 1-hour averages required under 40 CFR §60.13(h) are expressed in ng/J (lb/million Btu) heat input and used to calculate the average emission rates under 40 CFR §60.48Da. The 1-hour averages are calculated using the data points required under 40 CFR §60.13(h)(2).

E. Per 40 CFR §60.49Da(i), the owner or operator shall use the following methods and procedures to conduct monitoring system performance evaluations under 40 CFR §60.13(c) and calibration checks under 40 CFR §60.13(d):

(1) Methods 3B, 6, and 7 shall be used to determine O_2, SO_2, and NO_x concentrations, respectively.
(2) SO_2 or NO_x (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N_2, as applicable) under 40 CFR 60, Appendix B, Performance Specification 2.
(3) The span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent.
(4) The span value for a continuous monitoring system measuring NO_x is either:
    (a) 1,000 ppm or
    (b) The owner or operator may elect to use the NO_x span values determined according to Section 2.1.2 in 40 CFR 75, Appendix A.
(5) The span value of the sulfur dioxide continuous monitoring system is either:
    (a) 125 percent of the maximum estimated hourly potential emissions of the fuel fired at the inlet to the sulfur dioxide control device and 50 percent of maximum estimated hourly potential emissions of the fuel fired at the outlet of the sulfur dioxide control device or
    (b) The owner or operator may elect to use the SO_2 span values determined according to Section 2.1.1 in 40 CFR 75, Appendix A.

Acceptable alternative methods and procedures are given in Condition 16.F.

16. Continuous Emission Monitoring (Continued)

F. The owner or operator may use the following as alternatives to the reference methods and procedures specified:

(1) For 40 CFR 60, Appendix A: 40 CFR 60, Appendix A, Method 6, Method 6A or Method 6B (whenever 40 CFR 60, Appendix A, Method 6 and Method 3 or Method 3B data are used) or 40 CFR 60, Appendix A, Method 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If either 40 CFR 60, Appendix A, Method 6A or 40 CFR 60, Appendix A, Method 6B is used under 40 CFR §60.49Da(i), the conditions under 40 CFR §60.49Da(d)(1) apply. These conditions do not apply under 40 CFR §60.49Da(h).
(2) For 40 CFR 60, Appendix A: 40 CFR 60, Appendix A, Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be 1 hour.
(3) For 40 CFR 60, Appendix A, Method 3: 40 CFR 60, Appendix A, Method 3A or 3B may be used if the sampling time is 1 hour.
(4) For 40 CFR 60, Appendix A, Method 3B: 40 CFR 60, Appendix A, Method 3A may be used.

G. The following data requirements shall apply to all CEMS for non-NSPS emission standards in this permit:

(1) The CEMS required by this permit shall be operated and data recorded during all periods of operation of the emission unit except for CEM breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.
(2) The 1-hour average PM, Hg, SO_2, NO_x, and CO emission rates measured by the CEMS required by this permit shall be used to calculate compliance with the emission standards of this permit. At least 2 data points must be used to calculate each 1-hour average.
(3) For each hour of missing emission data (Hg, NO_x, SO_2, or CO), the owner or operator shall substitute data by:
   (i) If the monitor data availability is equal to or greater than 95.0%, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:
      (a) For the missing data period less than or equal to 24 hours, substitute the average of the hourly concentrations recorded by a pollutant concentration monitor for the hour before and the hour after the missing data period.
      (b) For a missing data period greater than 24 hours, substitute the greater of:
         - The 90^{th} percentile hourly concentration recorded by a pollutant concentration monitor during the previous 720 quality-assured monitor operating hours; or
         - The average of the hourly concentrations recorded by a pollutant concentration monitor for the hour before and the hour after the missing data period.
   (ii) If the monitor data availability is at least 90.0% but less than 95.0%, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:
      (a) For a missing data period of less than or equal to 8 hours, substitute the average of the hourly concentrations recorded by a pollutant concentration monitor for the hour before and the hour after the missing data period.
      (b) For the missing data period of more than 8 hours, substitute the greater of:
         - The 95^{th} percentile hourly pollutant concentration recorded by a pollutant concentration monitor during the previous 720 quality-assured monitor operating hours; or
         - The average of the hourly concentrations recorded by a pollutant concentration monitor for the hour before and the hour after the missing data period.
   (iii) If the monitor data availability is less than 90.0%, the owner or operator shall obtain actual emission data by an alternate testing or monitoring method approved by the Department.

H. If requested by the Department, the owner/operator shall coordinate the quarterly cylinder gas audits with the Department to afford the Department the opportunity to observe these audits. The relative accuracy test audits shall be coordinated with the Department.

17. Description of Terms and Acronyms

acfm	Actual cubic feet per minute
Applicant	The owner, company official or authorized agent
CFR	Code of Federal Regulations
Department	Iowa Department of Natural Resources
DNR	Iowa Department of Natural Resources
gr/dscf	Grains per dry standard cubic foot
HAP	Hazardous Air Pollutant(s)
IAC	Iowa Administrative Code
Lb/bhp-hr	Pounds per brake horsepower hour
Lb/MWh (gross)	Pounds per gross megawatt hour
MMBTU	One million British thermal units
NA	Not Applicable
NAAQS	National Ambient Air Quality Standards
NO_X	Nitrogen Oxides
Owner	The owner or authorized representative
Permit	This document including permit conditions and all submitted application materials
PM_{10}	Particulate Matter equal to or less than 10 microns in aerodynamic diameter
scfm	Standard cubic feet per minute
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
VOC	Volatile Organic Compound

END OF PERMIT CONDITIONS

Iowa
State Implementation Plan

Regional Haze
Second Implementation Period (2019-2028)

Iowa Department of Natural Resources
Environmental Services Division
Air Quality Bureau
502 E 9th St
Des Moines, IA 50319
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Final
August 2023

Executive Summary

The purpose of this state implementation plan (SIP) revision is to satisfy Iowa's obligations for the second implementation period (2019-2028) of the federal Regional Haze Rule (RHR). The U.S. Environmental Protection Agency (EPA) promulgated the RHR in 1999 under the authority of Clean Act Action (CAA) section 169A. The goal of the RHR is to eliminate man-made visibility impairment in 156 mandatory Class I Federal areas (Class I areas) by 2064. States must periodically submit comprehensive 10-year plans that contain control measures necessary to make reasonable progress towards that goal. Progress reports are due every 5 years.

The RHR impacts all states, even those like Iowa that do not contain a Class I area. The Department of Natural Resources (DNR) submitted Iowa's plan for the first 10-year implementation period (2009-2018) in 2008 and submitted the initial 5-year progress report in 2013. This comprehensive plan addresses the second 10-year implementation period and includes the 5-year progress report for the second half of the first implementation period.

In the first implementation period, emissions from Iowa were potentially linked to visibility impairment in the Class I areas in Michigan (Isle Royale and Seney) and Minnesota (Boundary Waters Canoe Area and Voyageurs). Based on a review of source apportionment modeling conducted by the Lake Michigan Air Directors Consortium (LADCO) for the second implementation period, the DNR concludes that it is appropriate to retain those linkages and to also add Hercules-Glades in Missouri.

This plan includes new control measures to reduce emissions of sulfur dioxide (SO_2), a pollutant important to anthropogenic visibility impairment in those Class I areas. The new control measures require that MidAmerican Energy Company implement dry scrubber improvements at Louisa Generating Station (LGS) and Walter Scott Jr. Energy Center – Unit 3 (WSEC-3) by December 31, 2023. The scrubber improvements will reduce the actual SO_2 emissions from LGS and WSEC-3 by ~3,900 and ~5,800 tons per year, respectively, for a combined SO_2 reduction of ~9,700 tons per year.

The new SO_2 emission limits and compliance procedures associated with the required scrubber improvements are enforceable through two modified air construction permits issued by the DNR on July 20, 2023. Both permits are included with this SIP revision and are numbered 05-A-031-P6 for the main boiler at LGS and 75-A-357-P9 for WSEC-3.

The DNR concluded that the dry scrubber improvements were reasonable by considering the four statutory factors: 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 the source. As an optional fifth factor, the DNR evaluated visibility impacts.

In Iowa, only LGS and WSEC warranted selection for four-factor analysis. Results from an area of influence (AOI) study and its associated extinction weighted residence time data combined with emissions and distance information (EWRT*Q/d) supported that finding. No other Iowa sources contributed to the majority of the combined sulfate and nitrate EWRT*Q/d cumulative impacts in any Class I area.

The scrubber improvements at LGS and WSEC-3, in combination with existing state and federal programs, are sufficiently robust for downwind Class I areas to make reasonable progress. LADCO's regional modeling results predict that the average visibility conditions on the 20% most impaired days in 2028 will be better than the uniform rate of progress (URP) in each of the five downwind Class I areas linked to Iowa.

The DNR consulted with other states and with the Federal Land Managers (FLM) during the development of this plan. This SIP revision documents the consultation process and addresses the remaining obligations applicable to each 10-year comprehensive regional haze plan, including the emissions inventory, monitoring strategy, public participation, and administrative requirements.

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1. Background

In the 1977 amendments to the Clean Air Act (CAA), Congress added section 169A (42 U.S.C. §7491), setting forth the following national goal of restoring pristine visibility conditions in certain parks and wilderness areas of special national or cultural significance:

> "Congress hereby declares 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."

The mandatory Class I Federal areas include all the following, provided they were existence as of August 7, 1977 (the date of enactment of the 1977 CAA Amendments):[1]

- International parks,
- national wilderness areas and national memorial parks exceeding 5000 acres, and
- national parks exceeding 6000 acres.

Figure 1-1 identifies the resulting 158 areas designated as mandatory Class I Federal areas. The responsibility for managing each area falls to a Federal Land Manager (FLM) with either the National Park Service (NPS), the U.S. Fish and Wildlife Service (FWS), or the U.S. Department of Agriculture Forest Service (USDA FS, USFS, or simply FS).

Figure 1-1. Map (from EPA) showing the location of the 158 mandatory Class I Federal areas and the responsible FLM.

As required by CAA §169A(a)(2), the U.S. Environmental Protection Agency (EPA), in consultation with the Department of the Interior, developed a list of mandatory Class I Federal areas where visibility is an important factor. That list identified 156 areas that would benefit from EPA's subsequent efforts to protect visibility.[2] For simplicity, the term "Class I area" will be used in the remainder of this document to reference these 156 areas.

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[1] The term "mandatory Class I Federal areas" is defined in CAA §169A(g)(5) as "Federal areas which may not be designated as other than Class I [under Part C of the CAA]." The criteria in CAA §162(a) specify which areas "may not be designated as other than Class I."

[2] The list (44 FR 69122, November 30, 1979; 40 CFR 81 Subpart D) intentionally excluded Rainbow Lake (WI) and Bradwell Bay (FL).

In 1980, EPA issued its first regulations to improve visibility in the Class I areas. The reasonably attributable visibility impairment (RAVI) rules (45 FR 80084, December 2, 1980) addressed plume blight, which is visibility degradation caused by a coherent plume attributable to a single source or a small number of sources. The RAVI regulations did not impact Iowa because the transport distances, as can be inferred from Figure 1-1, are too great for a plume from an Iowa source to retain enough structure to directly impact visibility at a downwind Class I area. EPA explicitly deferred actions to address impairment from regional haze until some future date when sufficient improvements in monitoring techniques, regional scale modeling, and other scientific advances had occurred. In summary, only limited steps were taken to address visibility impairment in the mandatory Class I Federal areas in the years following the 1977 CAA Amendments.

In the 1990 CAA Amendments, Congress added section 169B (42 U.S.C. §7492), authorizing further research and regular assessments of the progress to improve visibility in the Class I areas. The National Academy of Sciences concluded in 1993 that "current scientific knowledge is adequate and control technologies are available for taking regulatory action to improve and protect visibility" (*Protecting Visibility in National Parks and Wilderness Areas*, National Research Council, Washington DC, 1993). In addition to authorizing the creation of visibility transport commissions and setting forth their duties, section 169B(f) of the CAA mandated the creation of the Grand Canyon Visibility Transport Commission (Commission) to make recommendations to EPA for the region affecting the visibility of the Grand Canyon National Park. After four years of research and policy development, the Commission submitted its report to EPA in June 1996. The Commission's report, as well as the many research reports prepared by the Commission, contributed invaluable information to EPA in its development of the science of visibility impairment and its regulations to address regional haze.

1.1. What is Regional Haze

Haze is an atmospheric phenomenon that obstructs the clarity, color, texture, and form of what is seen. Haze is caused when sunlight is absorbed or scattered by airborne particles and gases. Regional haze refers to visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Examples of emission sources include fossil-fuel fired power plants, industrial and commercial activities, on-road and off-road mobile sources, and institutional and residential heating. Natural events, such as dust storms and forest fires, can also reduce visibility. Emissions that contribute to regional haze can be transported hundreds, or even thousands, of miles.

Hazy conditions in the Midwest are primarily caused by particles composed of sulfates (SO_4), nitrates (NO_3), organic carbon, elemental carbon (soot), and crustal materials (*e.g.*, soil dust). Of these constituents, only elemental carbon impairs visibility by absorbing visible light. The other types of particles scatter light. Sulfate, nitrate, and organic carbon particles are largely "secondary" pollutants that form in the atmosphere from chemical reactions. Their key precursors are primarily SO_2, NO_X, and volatile organic compounds (VOC), respectively. By contrast, soot and crustal material are typically released directly into the atmosphere and are thus considered "primary" pollutants.

Particle constituents and sizes differ in their relative effectiveness at reducing visibility. Sulfate and nitrate-based particles can contribute disproportionately to haze because of their chemical affinity for water. This property allows them to grow rapidly in the presence of moisture, to the optimal particle size for scattering light (~0.1 to 1 microns). Most visibility impairment is attributable to particles that form in the "fine" range, having an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$). Coarse particles (those in the size range between PM_{10} and $PM_{2.5}$) are less effective at scattering light and are less important in the Midwest Class I areas. In general, the fine particles important to regional haze tend to form through chemical reactions. Coarse particles are typically emitted directly.

Three measures are commonly used to quantify visibility impairment:

- The deciview (dv) is a unitless haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to highly impaired (lower dv values represent clearer conditions). A change of one deciview is designed to represent the minimum amount of visibility change perceptible to an average human observer.
- Light extinction (beta extinction, b_{ext}) is a measure of light attenuation per unit distance (in inverse megameters, Mm^{-1}). Smaller values represent clearer conditions. Values for b_{ext} are commonly estimated from ambient concentrations of individual particle and gaseous constituents, considering their unique light-scattering or absorbing properties and making appropriate adjustments for relative humidity.
- Visual range (in miles) is how far one can see (larger values represent clearer conditions).

Under current conditions, average light extinction on the 20% most impaired days in more polluted years ranges from ~100 Mm^{-1} in the lower Midwest to ~50 Mm^{-1} in the upper Midwest. These values correspond to a visual range of 24 to 48 miles, or 23 to 16 dv, respectively. Natural conditions in the upper Midwest correspond to a light extinction of ~29 Mm^{-1}, equating to 11 dv, or a visual range of 84 miles. See the Haze Metrics Converter web page for related information.

1.2. Regional Haze Rule

Regional haze was first regulated when EPA published the Regional Haze Rule (RHR) on July 1, 1999 (64 FR 35714). Although EPA has since revised[3] various aspects of the RHR, its purpose has remained the same, to restore natural visibility conditions to each of the 156 Class I areas by 2064. Natural visibility conditions represent the long-term degree of visibility that is estimated to exist in a Class I area in the absence of human-caused impairment. Implementation of the RHR requires states to reduce their contributions to regional haze by developing comprehensive state implementation plan (SIP) revisions every 10 years to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, anthropogenic (manmade) visibility impairment in the Class I areas. No states are exempt from the RHR, but states with Class I areas are subject to additional requirements.

The RHR requires states to submit two types of planning documents, 10-year comprehensive regional haze SIP (RH SIP) revisions, and 5-year progress reports. Each 10-year comprehensive RH SIP must demonstrate how the state is or will achieve the goal of restoring natural visibility conditions to the Class I areas impacted by anthropogenic emissions from the state. Progress reports document the progress made towards visibility goals and are generally due at both the midpoint and conclusion of each 10-year period.

1.3. Review of the First Implementation Period (2009-2018)

Regional haze SIPs for the first 10-year implementation period (2009-2018) were due December 17, 2007. EPA encouraged states and Tribes to address visibility impairment from a regional perspective because the pollutants that lead to regional haze originate from sources located across broad geographic areas. To assist states with technical coordination, consultation, and SIP development efforts, EPA designated five regional planning organizations (RPOs). The Central Regional Air Planning Association (CENRAP) was designated as the RPO representing the central portion of the U.S., including the nine states of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Nebraska, Oklahoma, and Texas. Between 2000 and 2007, Iowa participated in the CENRAP workgroup process to develop technical analyses and control strategies for the first regional haze implementation period. While not an official member, Iowa also worked closely with and benefited from the technical and consultation efforts led by the Midwest Regional Planning Organization (MRPO). The five RPOs from the first implementation period are shown in Figure 1-2.

Figure 1-2. The five RPOs for the first regional haze implementation period.

[3] EPA maintains a web page listing regulatory actions related to visibility.

In 2008, the Iowa Department of Natural Resources (DNR) submitted Iowa's RH SIP for the first 10-year implementation period.[4] The DNR consulted with the FLMs and the states of Missouri, Arkansas, Oklahoma, Minnesota, and Michigan. Emissions sources in Iowa were not found to contribute to visibility impairment in the Class I areas in Missouri, Arkansas, or Oklahoma. Minnesota requested that Iowa review emissions and consider reductions that may affect the Minnesota Class I areas. The DNR relied upon the Clean Air Interstate Rule (CAIR), later replaced by the Cross-State Air Pollution Rule (CSAPR), to satisfy long-term strategy (LTS) obligations and Best Available Retrofit Technology (BART) requirements for electric generating units (EGUs). No other emissions reductions were needed in Iowa at that time to satisfy RHR obligations. Final actions taken by EPA on June 7, 2012 (77 FR 33642), June 26, 2012 (77 FR 38006), and December 3, 2019 (84 FR 66075), provide a history of EPA's full approval of Iowa's RH SIP for the first implementation period.

In the first 5-year progress report, submitted on June 16, 2013, the DNR concluded that Iowa's RH SIP remained sufficient. EPA concurred and approved the progress report on August 15, 2016 (81 FR 53924). The progress report requirements for the conclusion of the first regional implementation period are addressed here in Chapter 10.

1.4. Federal Rule Revisions for the Second Implementation Period (2019-2028)

On January 10, 2017 (82 FR 3078), EPA revised the RHR for the second implementation period (2019-2028). That final action did not change the rule's primary purpose, but it did include the following:

- A one-time extension of the submission deadline for the second implementation period from July 31, 2018, to July 31, 2021. (Subsequent revisions are still due July 31, 2028, and every ten years thereafter.)
- Clarifying (but not substantially revising) the relationship between the LTS and reasonable progress goals (RPGs).
- Modifying the set of days used to track progress towards natural visibility conditions to account for events such as wildfires. The 20% most anthropogenically impaired days are now evaluated, not simply the 20% worst visibility days.
- Providing states with additional flexibility to address visibility impacts from anthropogenic sources located outside the U.S. and from certain types of prescribed fires.
- Removing the requirement for progress reports to take the form of SIP revisions.
- Adjusting interim progress report submission deadlines so that subsequent progress reports will be due by January 31, 2025, July 31, 2033, and every 10 years thereafter. This means that one progress report will be required mid-way through each implementation period.
- Updating, simplifying, and extending to all states the RAVI provisions.
- Strengthening the FLM consultation requirements.

1.5. Regional Planning for the Second Implementation Period

Due to various changes in funding, structure, and membership, there are differences between the RPOs from the first implementation period and the regional organizations that supported SIP development efforts for the second period. Figure 1-3 depicts the five current planning organizations: the Central States Air Resource Agencies (CenSARA), the Lake Michigan Air Directors Consortium (LADCO), the Mid-Atlantic/Northeast Visibility Union (MANE-VU), the Southeastern Air Pollution Control Agencies (SESARM), and the Western Regional Air Partnership (WRAP).

Iowa relied on CenSARA to produce data for source impact analyses and to provide consultation venues. CenSARA includes the eight states of Arkansas, Iowa, Kansas, Louisiana, Missouri, Nebraska, Oklahoma, and Texas.[5] The DNR also benefited from LADCO and relied on their emissions modeling and photochemical modeling results and their consultation opportunities.

[4] Iowa's RH SIP documents for the first implementation period are available on the DNR's Implementation Plans web page.

[5] In 2012, Minnesota left CenSARA and joined LADCO.

Figure 1-3. The current five regional planning organizations (source: EPA).

1.6. Regional Haze SIP Requirements and Key Steps

In 40 CFR 51.308(f) EPA identifies the core requirements for periodic (10-year) comprehensive regional haze SIPs. To further assist states, EPA issued the August 20, 2019, "*Guidance on Regional Haze State Implementation Plans for the Second Implementation Period"* and the July 8, 2021, memo *"Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period.*" The 2019 guidance describes eight key process steps and offers recommendations for developing a RH SIP for the second implementation period. Table 1-1 (adapted from Table 1 in the 2019 guidance) summarizes the key steps and indicates which apply to Iowa. Step 1 (ambient data analysis), Step 6 (modeling the LTS and setting reasonable progress goals), and step 7A (conducting various progress and glidepath checks) are not applicable because Iowa does not contain a Class I area.[6]

Table 1-1. Key steps to develop a regional haze SIP for the second implementation period.

Key Step	Summary	Applicable to Iowa
Step 1	Conduct ambient data analysis for each Class I area in the state	No
Step 2	Determine which Class I areas in other states may be affected by the state's own emissions	Yes
Step 3	Select sources for four-factor analysis	Yes
Step 4	Identify potential emission control measures for the selected sources, develop data on the four statutory factors	Yes
Step 5	Decide what control measures are necessary to make reasonable progress and establish the long-term strategy	Yes
Step 6	Regional scale modeling of the LTS to set the RPG for 2028	No
Step 7A	Conduct progress, degradation, and Uniform Rate of Progress (URP) glidepath checks	No
Step 7B	This step is only applicable if the RPG for the 20 percent most anthropogenically impaired days for a Class I area identified in Step 2 is above its URP glidepath. If so, demonstrate that there are no additional emission reduction measures that would be reasonable to include in the LTS	Conditionally
Step 8	Additional SIP requirements, such as: state and FLM consultation; emission inventories; and progress reports	Yes

[6] However, a synopsis of the ambient data analysis and visibility tracking steps is provided in Chapter 3 for informational purposes and glidepath data are reviewed in Chapter 8 to help demonstrate the robustness of Iowa's LTS.

2. Determination of Affected Class I Areas in Other States

Iowa is unique among all states because no portion of any Class I area is within 300 km of Iowa's border (Figure 2-1). This reduces but does not eliminate Iowa's potential to contribute to visibility impairment in downwind Class I areas. It also complicates determining which downwind Class I areas may be affected by Iowa's emissions. The techniques used must be capable of reasonably incorporating long-range transport patterns and assessing contributions to visibility impairment across distances that always exceed 300 km.

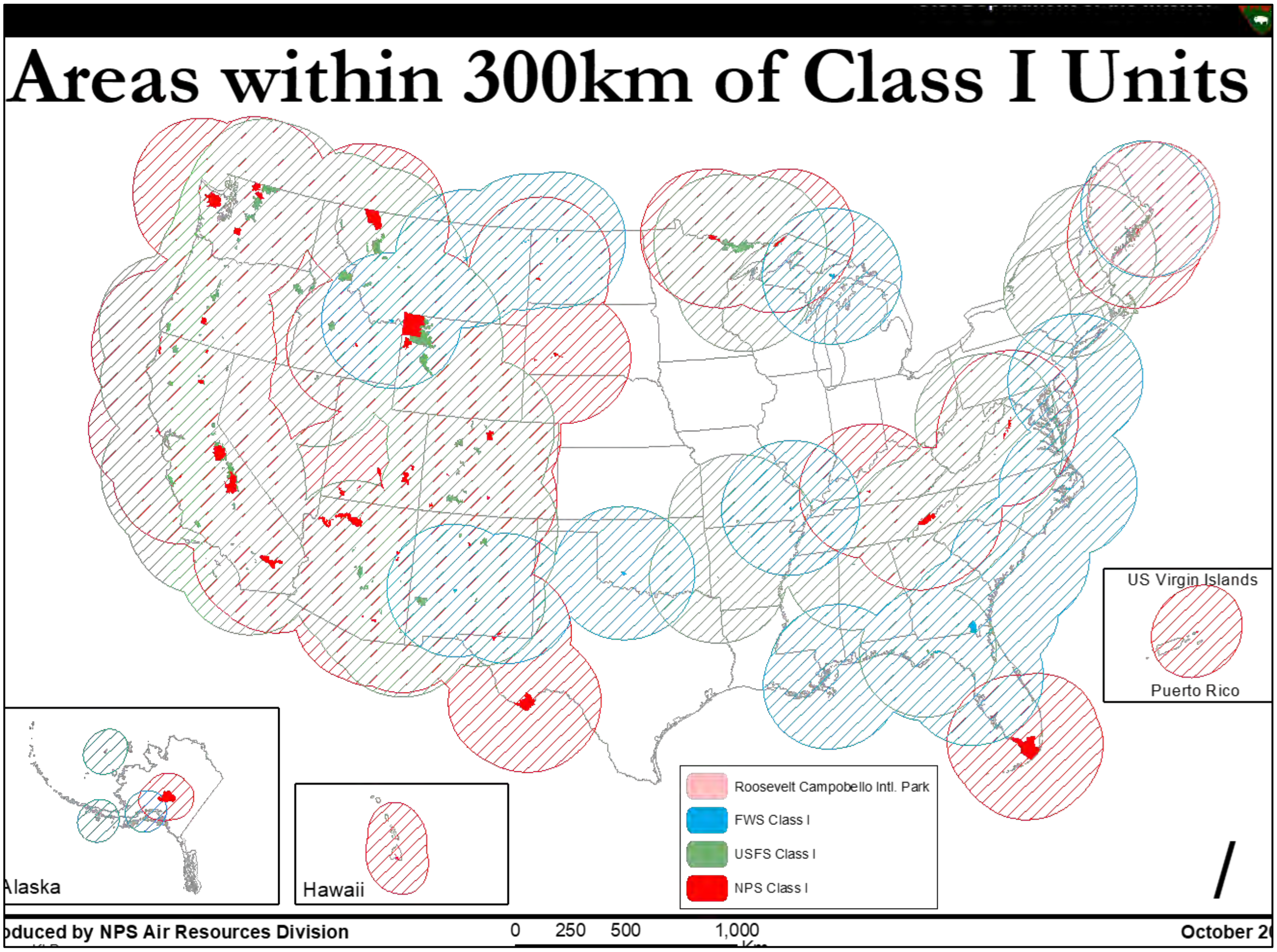

Figure 2-1. Map identifying locations within 300 km of the 158 mandatory Class I Federal areas.

Photochemical source apportionment modeling is generally the most sophisticated and scientifically sound technique for tracking state contributions to distant downwind locations. The DNR relied upon this method during the first implementation period by using Particulate Matter Source Apportionment Technology (PSAT) results from the Comprehensive Air Quality Model with extensions (CAMx) to conclude that emissions from sources in Iowa could contribute to visibility impairment in the Class I areas in Michigan and Minnesota (Table 2-1).

Table 2-1. Class I areas likely impacted by Iowa's emissions, as determined in the first implementation period.

State	Class I Area	Abbreviation
Michigan	Isle Royale	ISLE
Michigan	Seney	SENE
Minnesota	Boundary Waters Canoe Area	BOWA
Minnesota	Voyageurs	VOYA

The DNR believes it is reasonable to retain these linkages for the second implementation period. EPA's 2019 guidance encourages states that retain such linkages to consider whether the assumptions about source-receptor relationships have changed since the first implementation period. The validity of these linkages can be assessed directly using LADCO's most recent CAMx PSAT results, documented in Appendix A-1 and Appendix A-2. The DNR only used the 2028 PSAT results associated with the 2016 base year (the 2028_{2016} modeling platform), and not the older 2011 base year (the 2028_{2011} modeling platform).

For the 2028_{2016} PSAT simulation, LADCO used a combination of a geographic spatial mask to tag individual states in and near LADCO and regional groupings for more distant states. Contributions were tracked for primary and secondary sulfates and nitrates and (the remaining) primary particulates (*i.e.* elemental carbon, primary organic aerosols, fine soil, and coarse mass). The use of two source groups distinguished anthropogenic and biogenic sources within each of the tags. LADCO did not use the CAMx PSAT secondary organic aerosol (SOA) tracers, which was a reasonable decision given the high computational demand and greater interest in the sulfate and nitrate results.

Table 2-2 provides the total of Iowa's anthropogenic sulfate, nitrate, and primary particulate source contributions to visibility impairment, in inverse megameters, on the 20% most (anthropogenically) impaired days at each of the 12 listed Class I areas. The DNR extracted these results from the June 5, 2021, version of LADCO's analytical spreadsheet for its 2028_{2016} CAMx PSAT simulation. For simplicity, the DNR summed the anthropogenic contributions from all other states and state groupings outside Iowa into a single value. For Table 2-2, the DNR also grouped the non-anthropogenic source contributions into one of the following categories: initial conditions & boundary conditions (ICBC); natural sources and fires (wildfires, prescribed fires, and agricultural fires); sources in Canada, Mexico (CanMex), and other locations (such as offshore); and secondary organic aerosols, referred to as the organic carbon estimate (OC Est.). The organic carbon estimate includes both natural and anthropogenic contributions and is a calculated value determined as the difference between the total beta extinction from the core CAMx model and the sum of all the PSAT tracers. The Rayleigh and sea salt contributions are site-specific constants needed only to produce a total b_{ext} value. These results are shown as a percentage of the total modeled impact (excludes Rayleigh and sea salt) in Table 2-3.

Table 2-2. Modeled contributions (Mm^{-1}) for the 20% most impaired days from LADCO's 2028_{2016} CAMx PSAT analysis.

State	Class I Area	Anthropogenic[7]		Mostly Non-Anthropogenic			OC Est.	Constants: Rayleigh +SeaSalt	Total b_{ext}
		Iowa	All Other States	ICBC	Natural + Fire[8]	CanMex + Other			
Arkansas	Caney Creek	0.59	23.58	6.93	2.48	1.57	7.81	11.45	**54.40**
Arkansas	Upper Buffalo	0.90	21.46	7.94	2.92	2.36	7.38	11.39	**54.35**
Kentucky	Mammoth Cave	1.81	42.72	6.80	2.54	2.02	7.00	11.29	**74.18**
Michigan	Isle Royale	1.42	16.09	10.47	2.30	1.91	4.17	12.26	**48.62**
Michigan	Seney	1.49	23.00	9.89	2.67	2.96	5.11	12.24	**57.36**
Minnesota	Boundary Waters	0.94	11.22	9.69	2.02	1.81	3.63	11.20	**40.51**
Minnesota	Voyageurs	0.87	10.34	10.03	1.61	2.38	3.52	12.29	**41.03**
Missouri	Hercules-Glades	1.86	25.67	5.84	5.12	2.03	7.62	11.30	**59.43**
Missouri	Mingo	1.34	35.87	6.40	3.74	2.01	7.98	12.32	**69.67**
Oklahoma	Wichita Mtns.	0.56	24.39	7.90	3.38	3.39	5.19	11.34	**56.16**
S. Dakota	Badlands	0.25	7.70	8.05	1.26	1.82	3.40	11.06	**33.53**
S. Dakota	Wind Cave	0.18	5.76	6.24	1.54	1.07	3.32	10.08	**28.18**

[7] The anthropogenic contributions account for sulfates, nitrates, and primary particulates. Secondary organic aerosol contributions were not tracked in PSAT and are instead represented by the OC Est., a calculated value that includes both anthropogenic and natural contributions. Also note, for this table the DNR shifted the commercial marine and other anthropogenic source contributions not attributable to a specific state/state group (*e.g.* offshore sources) into the "CanMex + Other" column.

[8] The fire category tracked the total impacts from wildfires, prescribed fires, and agricultural (ag) fires. Although agricultural fire (crop reside burning) is an anthropogenic activity, its contributions were not isolated from the wildfire and prescribed fire impacts. Labeling the fire contributions as a non-anthropogenic activity is reasonable here because: 1) wildfire is not an anthropogenic source for RHR purposes; 2) adjustments can be made to the 2064 endpoints for certain prescribed fires; and 3) emissions from agricultural fires are minimal in Iowa as crop residue burning is not a common practice within the state.

Table 2-3. Percentage contributions on the 20% most impaired days from LADCO's 2028_{2016} CAMx PSAT results.

State	Class I Area	Anthropogenic[7]		Mostly Non-Anthropogenic			OC Est.	Total Modeled
		Iowa	All Other States	ICBC	Natural + Fire[8]	CanMex + Other		
Arkansas	Caney Creek	1.4%	54.9%	16.1%	5.8%	3.7%	18.2%	100%
Arkansas	Upper Buffalo	2.1%	49.9%	18.5%	6.8%	5.5%	17.2%	100%
Kentucky	Mammoth Cave	2.9%	67.9%	10.8%	4.0%	3.2%	11.1%	100%
Michigan	Isle Royale	3.9%	44.3%	28.8%	6.3%	5.3%	11.5%	100%
Michigan	Seney	3.3%	51.0%	21.9%	5.9%	6.6%	11.3%	100%
Minnesota	Boundary Waters	3.2%	38.3%	33.1%	6.9%	6.2%	12.4%	100%
Minnesota	Voyageurs	3.0%	36.0%	34.9%	5.6%	8.3%	12.3%	100%
Missouri	Hercules-Glades	3.9%	53.3%	12.1%	10.6%	4.2%	15.8%	100%
Missouri	Mingo	2.3%	62.5%	11.2%	6.5%	3.5%	13.9%	100%
Oklahoma	Wichita Mtns.	1.3%	54.4%	17.6%	7.5%	7.6%	11.6%	100%
S. Dakota	Badlands	1.1%	34.3%	35.8%	5.6%	8.1%	15.1%	100%
S. Dakota	Wind Cave	1.0%	31.8%	34.5%	8.5%	5.9%	18.3%	100%

Neither EPA rule nor guidance prescribe a specific contribution threshold for establishing linkages between a state and a downwind Class I area. However, the use of the linkages Iowa considered during the first implementation (see Table 2-1) can inform the current review of contribution data. According to the recent LADCO CAMx PSAT results provided in Table 2-3, Iowa's projected 2028 anthropogenic contributions to visibility impairment in the LADCO Class I areas (those in Minnesota and Michigan) ranges from 3.0% (Voyageurs) to 3.9% (Isle Royale). For consistency with the first implementation period and its SIP-approved conclusions, this suggests that linkages should also be established for any other Class I areas where Iowa's contributions fall within or exceed that range. Under this reasonable approach, Iowa also contributes to visibility impairment in Hercules-Glades, Missouri (3.9%), but no other additional linkages are needed at this time as all other contributions are below the minimum value from among the LADCO Class I area contributions (3.0% in this case). Table 2-4 summarizes the resulting list of five Class I areas now linked to Iowa's emissions.

Table 2-4. Class I areas linked to Iowa's emissions, as determined for the second implementation period.

State	Class I Area	Abbreviation	Type	Acreage	FLM
Michigan	Isle Royale	ISLE	National Park	542,428	NPS
Michigan	Seney	SENE	Wilderness Area	25,150	FWS
Minnesota	Boundary Waters Canoe Area	BOWA	Wilderness Area	747,840	FS
Minnesota	Voyageurs	VOYA	National Park	114,964	NPS
Missouri	Hercules-Glades	HEGL	Wilderness Area	12,315	FS

Additionally, while Iowa is not establishing any formal linkages, potential impacts on the seven other Class I areas listed in Table 2-5 were factored into the source selection analysis (Chapter 4). This approach ensured the analysis was both thorough and reasonable. No states have requested that Iowa further reduce its emissions for the second implementation period.

Table 2-5. Other Class I areas typically considered by the DNR for the second implementation period.

State	Class I Area	Abbreviation	Type	Acreage	FLM
Arkansas	Caney Creek	CACR	Wilderness Area	14,344	FS
Arkansas	Upper Buffalo	UPBU	Wilderness Area	9,912	FS
Kentucky	Mammoth Cave	MACA	National Park	51,303	NPS
Missouri	Mingo	MING	Wilderness Area	8,000	FWS
Oklahoma	Wichita Mountains	WIMO	Wilderness Area	8,900	FWS
South Dakota	Badlands	BADL	Wilderness Area	64,250	NPS
South Dakota	Wind Cave	WICA	National Park	28,060	NPS

3. Visibility Metrics

While Iowa is not subject to the visibility analysis and tracking requirements of the RHR, a review of the related background information and associated data is informative. Under 40 CFR 51.308(f)(1), states with Class I areas must include the following in their comprehensive RH SIPs:

- Baseline, current, and natural visibility conditions for the most impaired and clearest days.
- Actual progress to date for the most impaired and clearest days:
  - since the baseline period, and
  - during the previous implementation period up to and including the period for calculating current visibility conditions.
- Differences between current and natural visibility conditions.
- The URP that would need to be maintained in order to attain natural visibility conditions for the most impaired days by the end of 2064.

3.1. Deciview Haze Index

The above mandatory visibility metrics must be reported using the deciview (dv) haze index. The deciview haze index is calculated from total atmospheric light extinction (b_{ext}) using the following logarithmic equation:

$$\mathrm{dv} = 10 \cdot \ln(\mathrm{b_{ext}}/10\mathrm{Mm}^{-1})$$

3.2. IMPROVE Equation

Values for total atmospheric light extinction (b_{ext}) are constructed using speciated data collected and analyzed from the Interagency Monitoring of Protected Visual Environments (IMPROVE) program.[9] The IMPROVE samplers provide 24-hour duration mass concentrations, in micrograms per cubic meter (μg/m^3) for the sulfate (assumed to be ammonium sulfate), nitrate (assumed to be ammonium nitrate), organic mass, elemental carbon, fine soil, sea salt, and coarse mass ($PM_{10\text{-}2.5}$) particulate components, on a 1-day-in-3 schedule.[10] The data are used in the following algorithm, known as the "second" IMPROVE equation, to calculate b_{ext}.

b_{ext} ≈ 2.2 × f_S(RH) × [Small Sulfate] + 4.8 × f_L(RH) × [Large Sulfate]
+ 2.4 × f_S(RH) × [Small Nitrate] + 5.1 × f_L(RH) × [Large Nitrate]
+ 2.8 × [Small Organic Mass] + 6.1 × [Large Organic Mass]
+ 10 × [Elemental Carbon]
+ 1 × [Fine Soil]
+ 1.7 × f_{SS}(RH) × [Sea Salt] (sea salt is a natural source of haze and can be important in some coastal areas)
+ 0.6 × [Coarse Mass]
+ Rayleigh Scattering (site specific)
+ 0.33 × [NO_2 (in parts per billion (ppb)), if available]

[Large Sulfate] = [Total Sulfate] / 20 μg/m^3 × [Total Sulfate], for [Total Sulfate] < 20 μg/m^3
[Large Sulfate] = [Total Sulfate], for [Total Sulfate] ≥ 20 μg/m^3
[Small Sulfate] = [Total Sulfate] - [Large Sulfate]

[9] The IMPROVE program is managed by a steering committee consisting of representatives from federal agencies and regional (or multi-jurisdictional) planning organizations, as well as state and international agencies. It operates 110 sites, representing the 156 Class I areas. Each IMPROVE site is located to obtain representative data, but may not be located within the actual boundary of its Class I area due to both practical requirements (such as power, security, and access) as well as legal restrictions (such as the 1964 Wilderness Act, which restricts the siting of man-made items, including environmental monitoring equipment). A single IMPROVE site may represent more than one Class I area.

[10] 2007, Marc Pitchford, William Malm, Bret Schichtel, Naresh Kumar, Douglas Lowenthal & Jenny Hand. R*evised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data,* **Journal of the Air & Waste Management Association**, 57:11, 1326-1336, DOI: 10.3155/1047-3289.57.11.1326.

The IMPROVE equation's various coefficients account for the given pollutant's effectiveness at scattering or absorbing light. The sulfate, nitrate, and organic components are split into small and large modes, based on their concentrations.[11] The small and large modes of sulfate and nitrate have associated hygroscopicities, $f_S(RH)$ and $f_L(RH)$, respectively, while $f_{SS}(RH)$ is a hygroscopic coefficient for sea salt.[12] Rayleigh scattering is a natural occurrence and accounts for light scattering attributable to air molecules, and is typically around 8 to 12 Mm^{-1}. While generally unimportant for RHR purposes, NO_2 gas concentrations (ppb) can be incorporated if available.

3.3. Visibility Conditions

The baseline, current, and natural conditions for each Class I area are computed for the 20% most impaired days and 20% clearest days, using 5-year averages to smooth interannual variability and reduce the impacts of extreme events. The 5-year baseline period is fixed and uses the 2000-2004 timeframe. The current conditions timeframe varies with the implementation period to capture the most recent 5-year period with available data. EPA typically estimates the 2064 natural conditions for state use.

In the first implementation period, the most impaired days were simply the monitored days with the 20% highest actual deciview values, regardless of the source of the visibility impairment. In the 2017 revisions to the RHR, the definition for the most visibly impaired days was revised to focus on days with the most anthropogenic impairment, to help minimize the impacts of largely uncontrollable sources, such as wildfires and dust storms, which could be particularly impactful in the Western U.S. To assist states with this revision, EPA developed a methodology to identify the 20% most impaired days, described in EPA's December 20, 2018, memo: "*Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program.*" EPA also suggested using a new estimate for the natural visibility condition for the 20% most impaired days, with the new estimate linked to the determination of the 20% most impaired days.

In the June 3, 2020 technical addendum memo,[13] EPA provides a summary of baseline, current, and natural visibility conditions for the 20% most impaired and 20% clearest days for all Class I areas. Table 3-1 includes those conditions for the LADCO and HEGL Class I areas and shows the calculated differences between current and 2064 natural visibility conditions. The current conditions represent five-year averages across the 2014-2018 timeframe, the most recent data available to EPA at that time. The DNR will generally maintain that timeframe for defining current conditions but may include more recent data when examining information on a purely annual (and not a 5-year average) basis.

Table 3-1. Comparison of baseline, current, and natural visibility conditions for the 20% most impaired and 20% clearest days in the LADCO and HEGL Class I areas. All values are in deciviews (dv).

State	Class I Area	Baseline Visibility (2000-2004)		Current Visibility (2014-2018)		Natural Visibility (2064)		Difference in Current – Natural Visibility	
		Most Impaired	Clearest	Most Impaired	Clearest	Most Impaired	Clearest	Most Impaired	Clearest
MI	ISLE	19.63	6.77	15.54	5.30	10.17	3.72	5.37	1.58
MI	SENE	23.58	7.14	17.57	5.27	11.11	3.74	6.46	1.53
MN	BOWA	18.43	6.50	13.96	4.48	9.09	3.48	4.87	1.00
MN	VOYA	17.88	7.15	14.18	5.31	9.37	4.27	4.81	1.04
MO	HEGL	25.17	12.84	18.72	9.71	9.30	4.69	9.42	5.02

[11] Sulfate, nitrate, and total organic carbon are split using the same basic equation. For concentrations less than 20 μg/m^3, the fraction in the large mode is estimated by dividing the total concentration of the component by 20 μg/m^3. For example, if the total fine component concentration is 4 μg/m^3, the fraction in the large mode is calculated as 4/20 x 4 μg/m^3 = 0.8 μg/m^3; the remaining 3.2 μg/m^3 is in the small mode. If the total component concentration exceeds 20 μg/m^3, all of it is assumed to be in the large mode.
[12] Monthly values for the three f(RH) terms for each Class I area (and other information, including equation development and history) are available on the IMPROVE Algorithm web page.
[13] June 3, 2020, EPA Technical Addendum Memorandum from Richard A. Wayland: "*Technical addendum including updated visibility data through 2018 for the memo titled 'Recommendation for the Use of Patched and Substituted Data and Clarification of Data Completeness for Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program.'*"

Summaries of the annual visibility data from 2000 through 2019 for the LADCO and HEGL Class I areas are provided in Table 3-2 and Table 3-3. Table 3-2 provides the annual average deciview haze index for the 20% most impaired days, *i.e.*, the 20% of monitored days in a calendar year with the highest values of the deciview index attributed to anthropogenic sources. Table 3-3 provides the annual average haze index for the 20% clearest days, *i.e.* the 20% of monitored days in a calendar year with the lowest values of the deciview index (no adjustments needed). The source for the data in Table 3-2 is the 1988-2019 *"*Means for Impairment Metric" file (posted December 2020) from the IMPROVE Regional Haze Rule Summary Data web page (now likely found on the archived data page). The 20% most impaired values correspond to the G90 impairment group. The data source for Table 3-3 is the associated "Means for Best, Middle, and Worst 20% Visibility Days" file, with the 20% clearest values corresponding to the G10 impairment group. Both datasets are plotted in Figure 3-1. A clear overall trend towards improved visibility conditions is evident at all five sites for both the 20% most impaired days and the 20% clearest days.

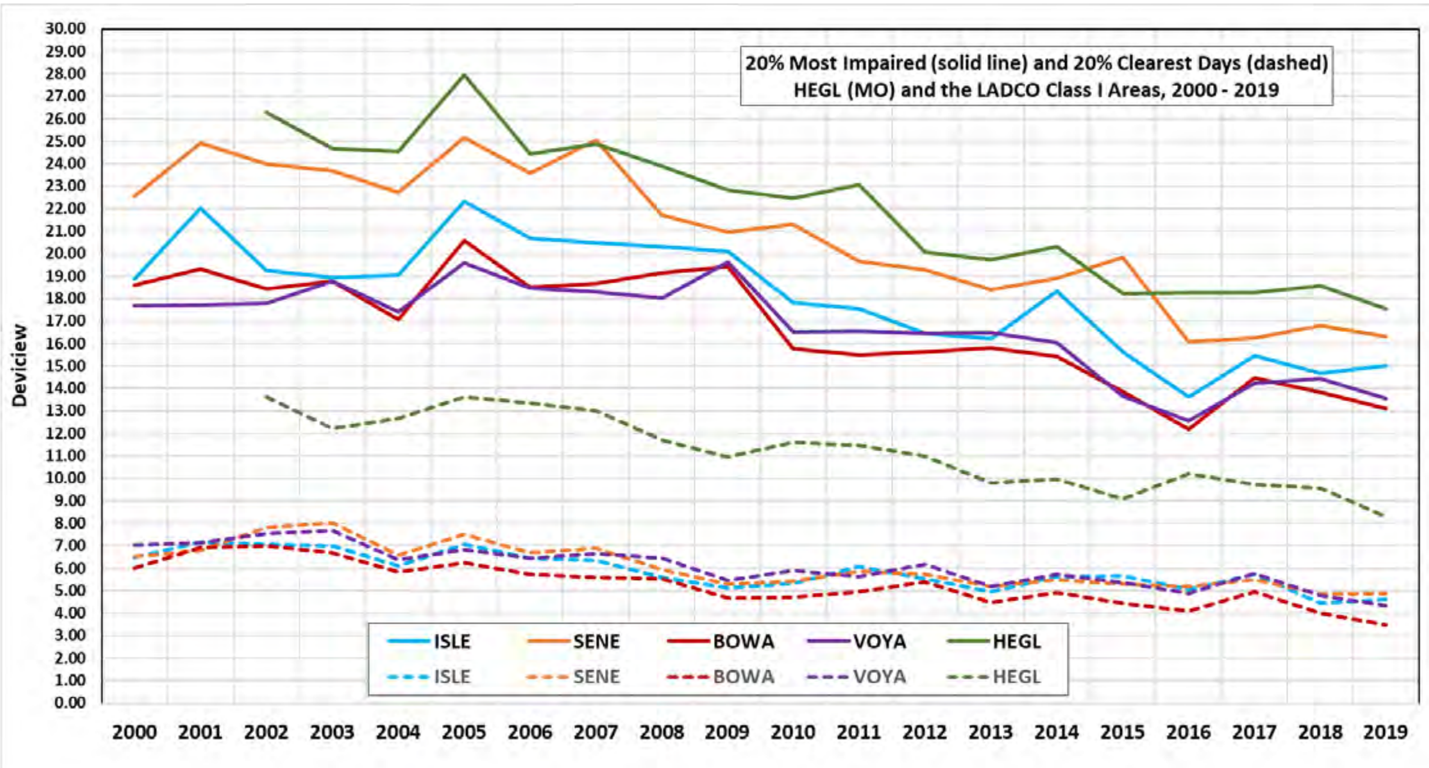

Figure 3-1. Observed visibility trends in the LADCO and HEGL Class I areas, 2000-2019.

The individual PM component (constituent) contributions for the 20% most impaired days for each year in the 2000-2019 timeframe for the LADCO and HEGL Class I areas are examined in Figure 3-2 through Figure 3-6. The composition data, converted from concentrations to inverse megameters (Mm^{-1}) using the second IMPROVE equation, include the contributions from sulfates, nitrates, coarse mass, fine soil, elemental carbon (light-absorbing carbon), organic carbon mass, and sea salt (which is negligible in these areas). Rayleigh scattering is appropriately excluded from the speciated analysis but, as required, is incorporated in the total deciview values plotted on the second vertical axis. The component contribution data was also sourced from the "Means for Impairment Metric*"* file mentioned above.

Sulfates and nitrates contributed the majority of the anthropogenic visibility impairment in the LADCO and HEGL Class I areas throughout the 2000-2019 timeframe. In much of that period, the sulfate contributions generally exceeded those from nitrates. While the reverse has often been true in more recent years, it remains logical to continue evaluating both pollutants for the second implementation period by focusing on precursor emissions of SO_2 and NO_X.

Table 3-2. Annual average conditions, in deciviews, for the 20% most impaired days (G90).

Class I Area	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
ISLE	18.87	22.03	19.25	18.96	19.04	22.34	20.70	20.49	20.31	20.12	17.81	17.56	16.46	16.22	18.32	15.63	13.61	15.45	14.68	15.03
SENE	22.57	24.91	24.01	23.69	22.73	25.14	23.58	25.04	21.71	20.96	21.30	19.67	19.29	18.40	18.89	19.81	16.09	16.23	16.81	16.32
BOWA	18.59	19.32	18.43	18.77	17.05	20.58	18.49	18.68	19.16	19.41	15.76	15.48	15.63	15.80	15.42	13.86	12.20	14.48	13.83	13.12
VOYA	17.70	17.70	17.80	18.77	17.41	19.58	18.45	18.29	18.01	19.61	16.51	16.57	16.44	16.49	16.04	13.64	12.56	14.24	14.43	13.56
HEGL			26.28	24.67	24.55	27.96	24.44	24.90	23.88	22.84	22.47	23.07	20.08	19.73	20.31	18.23	18.25	18.25	18.55	17.56

Table 3-3. Annual average conditions, in deciviews, for the 20% clearest days (G10).

Class I Area	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
ISLE	6.50	7.17	7.07	6.99	6.13	7.08	6.44	6.36	5.61	5.13	5.32	6.06	5.53	4.94	5.64	5.66	5.06	5.72	4.44	4.60
SENE	6.51	6.79	7.83	8.01	6.58	7.51	6.68	6.88	5.94	5.30	5.44	5.86	5.74	5.18	5.51	5.30	5.18	5.50	4.84	4.89
BOWA	6.01	6.92	7.01	6.70	5.84	6.25	5.73	5.59	5.52	4.67	4.71	4.94	5.39	4.46	4.92	4.45	4.08	4.96	3.98	3.49
VOYA	7.02	7.12	7.54	7.68	6.37	6.83	6.45	6.67	6.46	5.47	5.92	5.63	6.17	5.20	5.75	5.35	4.89	5.78	4.79	4.33
HEGL			13.64	12.22	12.66	13.62	13.34	12.99	11.71	10.96	11.61	11.48	10.99	9.78	9.97	9.06	10.20	9.74	9.58	8.29

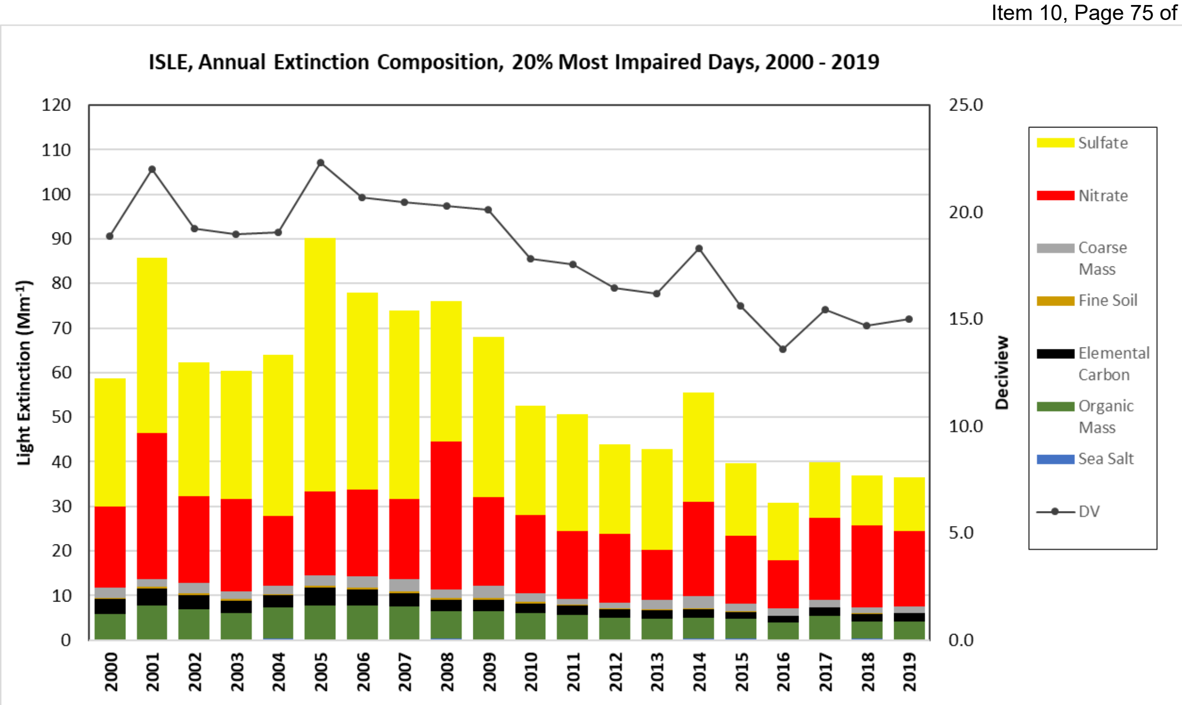

Figure 3-2. Isle Royale: Annual extinction composition for the 20% most impaired days, 2000-2019.

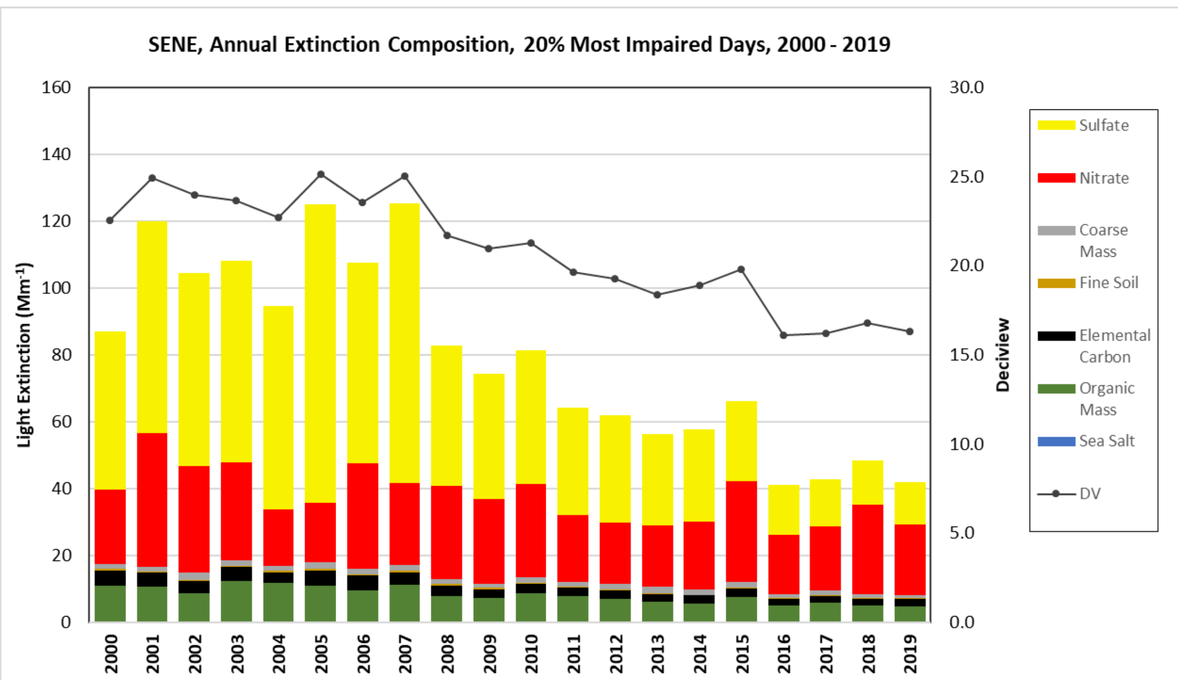

Figure 3-3. Seney: Annual extinction composition for the 20% most impaired days, 2000-2019.

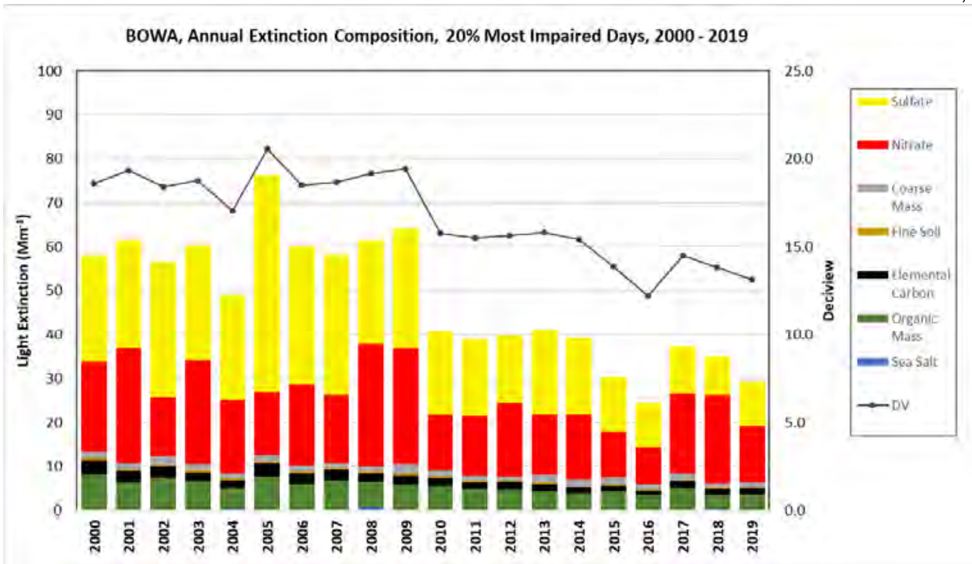

Figure 3-4. Boundary Waters: Annual extinction composition for the 20% most impaired days, 2000-2019.

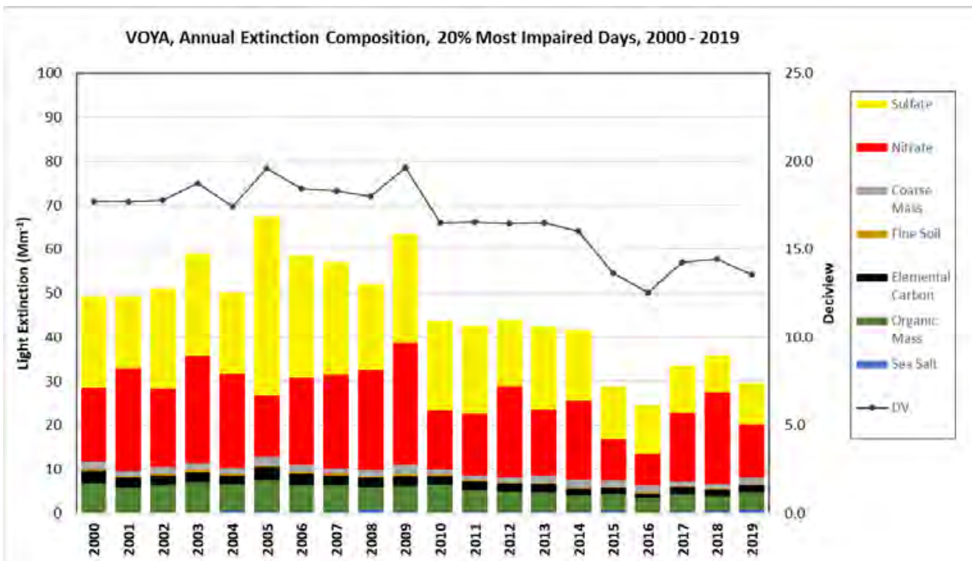

Figure 3-5. Voyageurs: Annual extinction composition for the 20% most impaired days, 2000-2019.

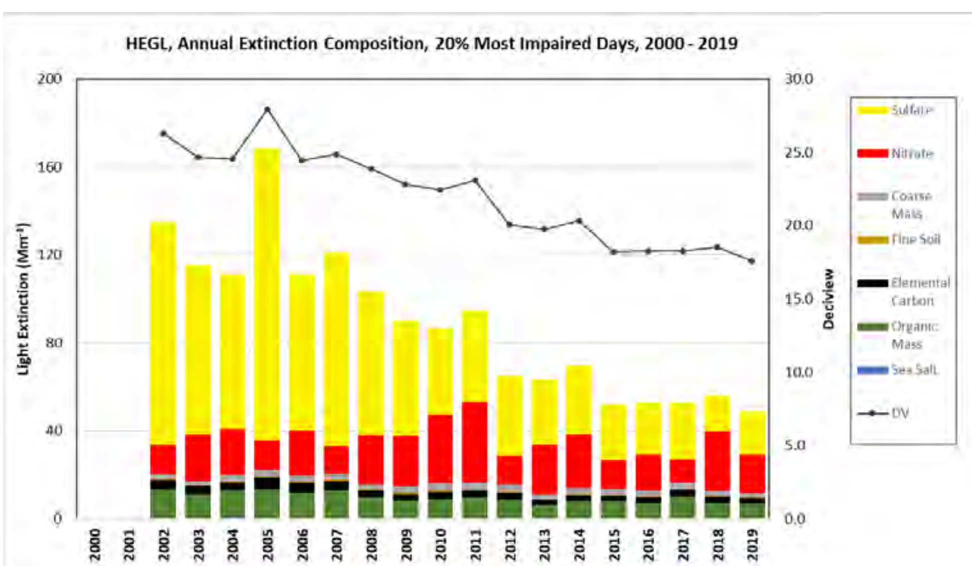

Figure 3-6. Hercules-Glades: Annual extinction composition for the 20% most impaired days, 2000-2019.

3.4. Uniform Rate of Progress

Under 40 CFR 51.308(f)(1)(vi), states with Class I areas are required to report the URP for each area. The URP is calculated for the 20% most impaired days and represents the annual rate of visibility improvement (in deciviews per year) needed to stay on a linear path to reach natural conditions by 2064, given the 2000-2004 baseline starting point. The URP is calculated as follows:

$$\text{URP} = [(2000 - 2004\ \text{visibility})_{20\%\text{most impaired}} - (\text{natural visibility})_{20\%\text{most impaired}}]/60$$

An example of a URP line, also known as a "glidepath," is shown in Figure 3-7 (sourced from EPA's December 20, 2018, "*Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program*"). The URP graph typically includes metrics about baseline and current conditions, and conditions for the 20% clearest days. Although not shown in this example, an actual URP analysis would also include predicted visibility conditions for the implementation period endpoint, *e.g*. 2028. Ideally, predicted visibility in the endpoint year is on or below the URP line for the 20% most impaired days and no degradation occurs on the 20% clearest days.

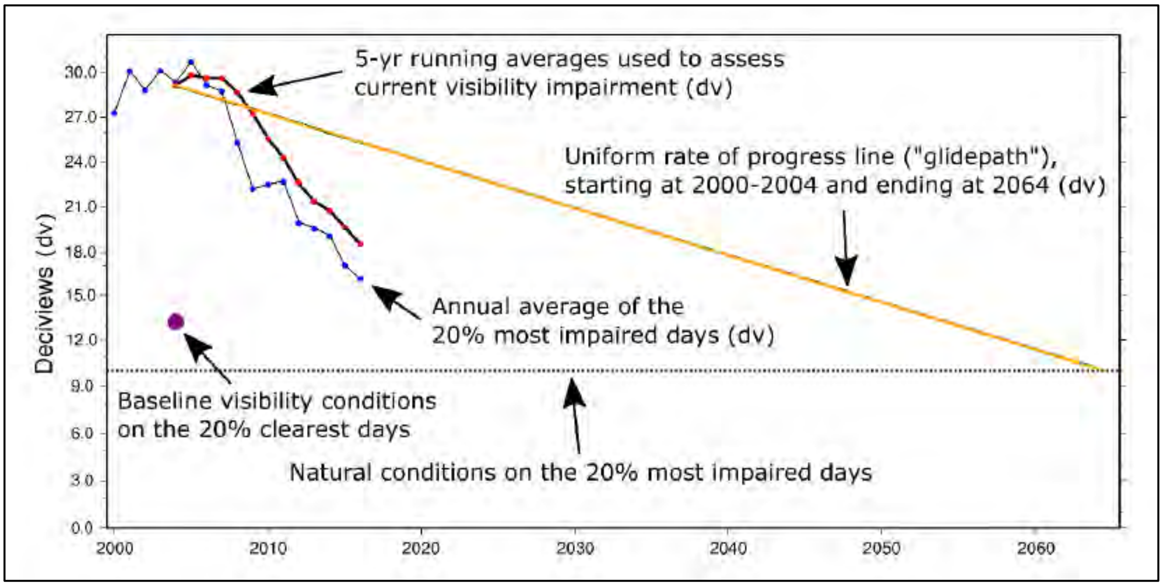

Figure 3-7. Example diagram of the URP and related visibility tracking metrics.

The RHR allows states to adjust the URP by increasing the 2064 natural visibility condition for the 20% most impaired days to account for impacts from anthropogenic sources outside the United States (and certain wildland prescribed fires). EPA's September 19, 2019, memo "*Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility*" provides (in its Table E-1) adjusted natural conditions that account for international anthropogenic contributions.[14] The "default adjusted" natural conditions values for the 20% most impaired days for the LADCO and HEGL Class I areas are provided in Table 3-4, along with the unadjusted values, and the resulting URPs. This data is provided for informational purposes only. The authority to determine URPs is limited to states with a Class I area.

Table 3-4. Uniform rate of progress values (20% most impaired) for the LADCO and HEGL Class I areas.

Class I Area	Baseline (2000-2004) (dv)	2064 Natural Visibility (dv)	2064 Default Adjusted Natural Visibility (dv)	URP (dv/yr)	Adjusted URP (dv/yr)
ISLE	19.63	10.17	12.99	0.16	0.11
SENE	23.58	11.11	14.07	0.21	0.16
BOWA	18.43	9.09	12.12	0.16	0.11
VOYA	17.88	9.37	12.49	0.14	0.09
HEGL	25.17	9.30	11.32	0.26	0.23

[14] EPA's default adjustments only include the international anthropogenic contributions (and not wildland prescribed fires).

4. Selecting Sources for Four-Factor Analysis

A key step in the current RH SIP development process is determining which sources should conduct a four-factor analysis to evaluate feasible SO_2 and NO_X control measures. CenSARA contracted with Ramboll in 2018 to perform an area of influence (AOI) study for Class I areas throughout and near the CenSARA region. The CenSARA AOI study combined a residence time analysis using back-trajectory modeling with IMPROVE data to produce sulfate and nitrate extinction weighted residence times (EWRT). The EWRT data were augmented with SO_2 and NO_X emissions (Q) and inverse distance weighting (1/d) to produce EWRT*Q/d metrics for sulfates and nitrates. These metrics were used to identify emission sources with a higher probability of contributing to anthropogenically impaired visibility in Class I areas.

Of the following four source selection methods highlighted in EPA's 2019 guidance document, the CenSARA AOI study and the DNR's analysis of the associated EWRT*Q/d metrics are exceeded in complexity and sophistication only by photochemical modeling:

1) Emissions divided by distance (Q/d)
2) Trajectory analyses
3) Residence time analyses
4) Photochemical modeling (zero-out or source apportionment)

4.1. CenSARA AOI Analysis

The data and methods of the CenSARA AOI study are reviewed below and documented in Appendix B, Ramboll's November 2018 final report "*Determining Areas of Influence – CenSARA Round Two Regional Haze*." The DNR's analysis of the EWRT*Q/d metrics and the associated threshold decisions are discussed in Section 4.2. The Iowa sources selected for four-factor analysis are identified in Section 4.3.

4.1.1. Residence Time (RT)

The Hybrid-Single Particle Lagrangian Integrated Trajectory (HYSPLIT) model was used to generate 72-hour back-trajectories arriving at IMPROVE sites at 06:00, 12:00, 18:00, and 24:00 local time for trajectory ending altitudes of 100 m, 200 m, 500 m, and 1000 m for each site's 20% most anthropogenically impaired days during the 5-year period from 2012 to 2016. HYSPLIT was configured to use hourly gridded meteorological data from the 12 km North American Model (NAM) sigma-pressure hybrid dataset (NAMS).

The 20% most anthropogenically impaired days from each year in the 2012-2016 timeframe (the most recent 5 years available at the time) for each Class I area were identified (flagged) in the "Daily Impairment Values Including Patched Values" data file from the IMPROVE RHR Summary Data web page. The daily file also included IMPROVE $PM_{2.5}$ component and coarse PM concentration measurements, light extinction values, visibility impairment parameters, and "patched" values (historical seasonal median values used to fill in missing values following procedures described in EPA's December 20, 2018, "*Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program"*) so that data were available for each day of interest during the 2012-2016 period.

The number of back trajectories needed for each Class I area (using the location of the IMPROVE monitor to represent the location of that Class I area) grew quickly. For example, the IMPROVE monitors utilize a 1 in 3-day sampling frequency, yielding approximately 121 scheduled sampling days per year, meaning the 20% most impaired days in a given year are generally comprised of measurements from about 24 days. The CenSARA AOI analysis used 5 years of data, with HYSPLIT run four times per day with four different ending heights per run. For one Class I area this yields:

5 years x ~**24** (20% most impaired days/year) x **4** start-times/day x **4** end heights $\cong$ **1,920** back-trajectories/Class I area

Residence time is the cumulative time that a trajectory spends in a specific geographical area. The geographical areas were defined using EPA's 12 km continental U.S. (CONUS) domain,[15] with the results aggregated to 36 km x 36 km

[15] The "12US2" domain has a lower-left corner at (-2412000 m, -1620000 m) and 396x246 grid cells. The projection is Lambert-Conformal, with Alpha = 33°, Beta = 45° and Gamma = -97°, with a center of X = -97° and Y = 40°.

resolution. The residence times for each grid cell were normalized by the total trajectory time for each Class I area, yielding a percentage value.

By normalizing the results, the data from all back trajectories for one Class I area (~1,920 trajectories) can be combined into a single useful product, an example of which is shown in Figure 4-1 (smoothing[16] was applied to reduce image noise). Alternatively, it may be informative to examine the residence times separately by ending height (100 m, 200 m, 500 m, or 1000 m). However, this has two primary drawbacks. First, it raises questions about which ending height is the most important, and second, it quadruples the data review. The DNR chose to focus on the residence time analyses that incorporated all trajectory ending heights. This approach incorporates all available information while weighting each trajectory equally, making this a reasonable choice.

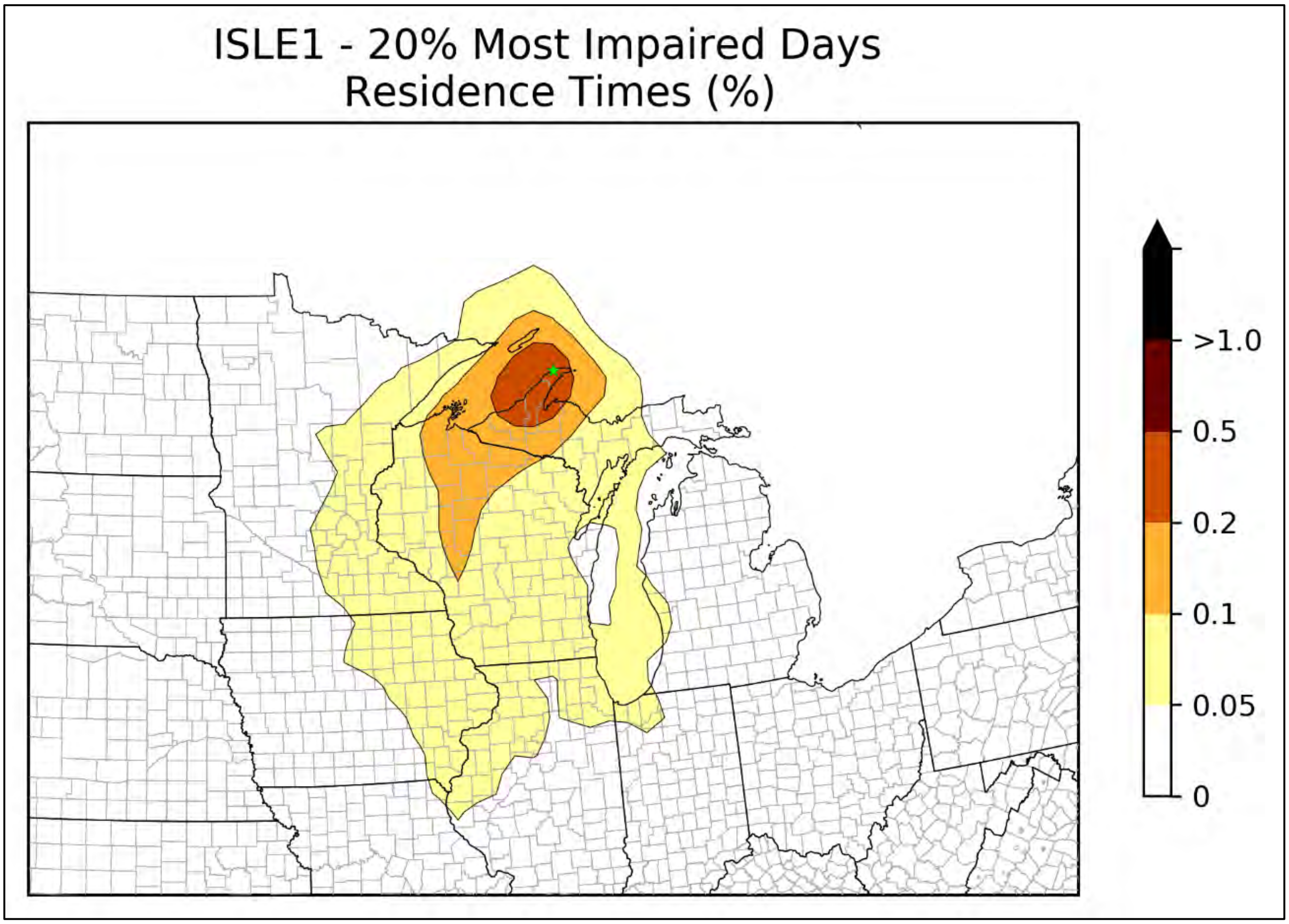

Figure 4-1. Example normalized residence time plot for the 20% most impaired visibility days in 2012-2016 for Isle Royale using all ending height trajectories (100, 200, 500, and 1000 meters combined).

The absolute values of the normalized residence times (percentages) in Figure 4-1 are generally small. This is expected. Using a single 72-hour back trajectory as an example, if the trajectory spent one hour in a given grid cell, the normalized residence time value for that grid cell would be just 1.39% (1/72). This small number is meaningful, especially when compared against grid cells that have a zero value (*i.e.* the trajectory did not traverse that area). It should be noted that graphical depictions of residence time (such as in Figure 4-1) are sensitive to the scale/breakpoints chosen for plotting purposes. Unshaded areas may thus have non-zero values and could contain important sources.

4.1.2. Extinction Weighted Residence Time (EWRT)

Incorporating additional data, such as measurements from the IMPROVE network, enhances the residence time analysis by weighting geographical areas with a higher probability of influencing visibility at each of the IMPROVE sites. Previous analyses of contributions of individual PM components to total extinction on the 20% most anthropogenically impaired

[16] Based on a Gaussian filter.

days show that sulfate and nitrate are the two major PM components that account for a large fraction of the anthropogenic visibility impairment in the Class I areas analyzed. Extinction weighted residence time (EWRT) plots were therefore generated for SO_4 and NO_3 (separately) using:

$$\mathrm{EWRT_{ij}} = \sum_{k=1}^{N} \mathrm{b_{ext_k}} \tau_{\mathrm{ijk}}$$

where $\mathrm{b_{ext_k}}$ is the extinction coefficient attributed to the pollutant (SO_4 or NO_3) measured upon arrival of the k^{th} trajectory at the IMPROVE site, τ_{ijk} is the residence time of the k^{th} trajectory at the grid cell (i,j), and N is the total number of trajectories.

The gridded EWRT values were normalized to display the percentage of the domain total EWRT for the given pollutant. An example of a normalized EWRT plot for sulfate is shown in Figure 4-2. Similar to the residence time plots, the geographical extent of the shaded areas is dependent upon the scale/break-points chosen for plotting and shading does not necessarily delineate the only areas of interest.

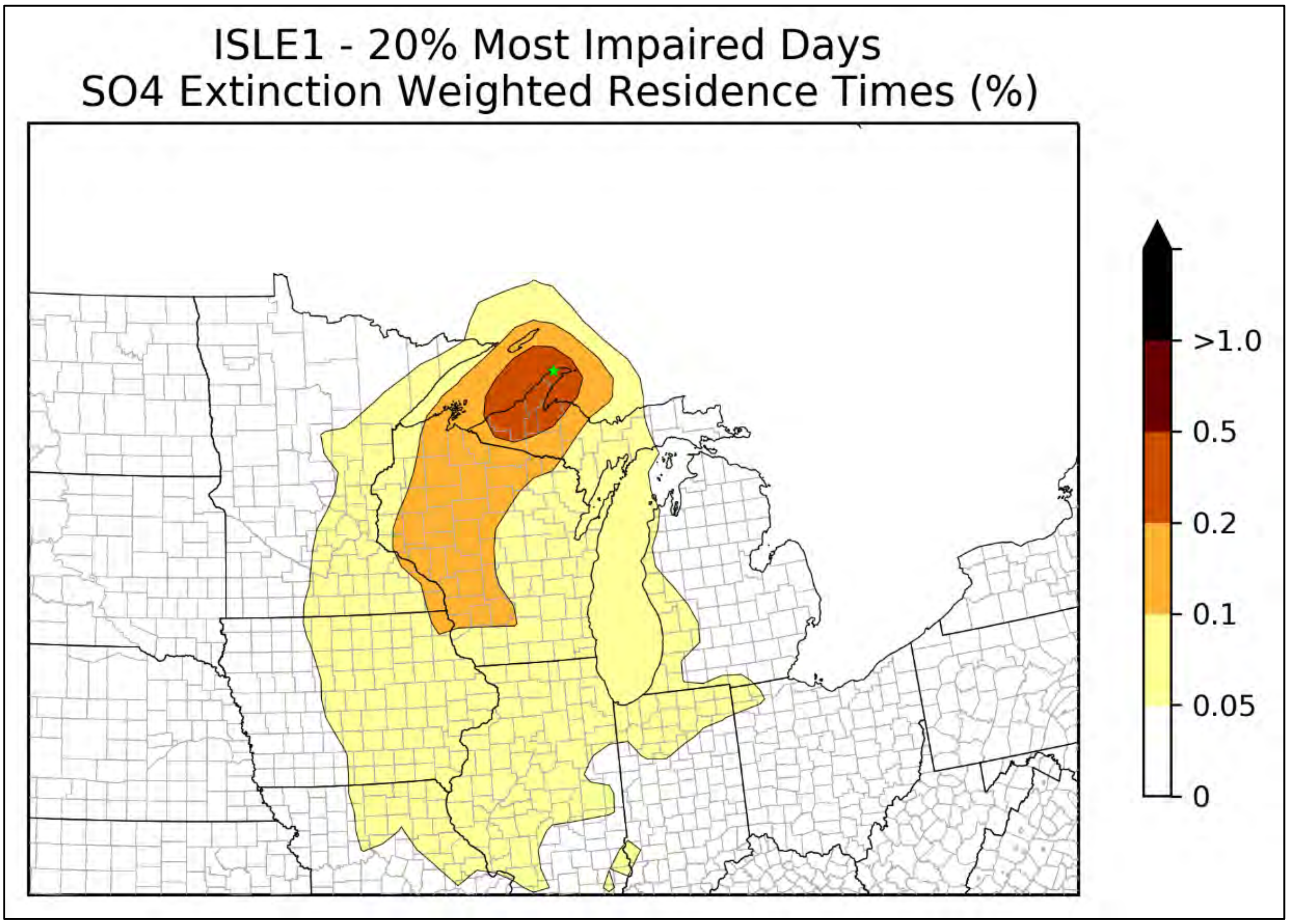

Figure 4-2. Example normalized EWRT plot for sulfates (EWRT-SO_4) on the 20% most impaired visibility days in 2012-2016 for Isle Royale (using all trajectory ending heights combined).

4.1.3. EWRT Combined with Emissions and Distance Weighting (EWRT*Q/d)

The EWRT values for SO_4 and NO_3 were combined with SO_2 and NO_X emissions (*Q*) data, respectively, to evaluate the possible impacts from point[17] sources. The point source category is important because emissions released at elevated

[17] Point sources include the "major" point sources (those subject to Title V), such as power-plants, industrial sources, larger manufacturing operations, and some (typically larger) institutional, non-industrial, and commercial activities. The point sources are often split into two classes: EGU and nonEGU. The EGUs include only the power plants. All other point sources are classified as

stack heights can more easily be transported far downwind. Inverse distance weighting was applied to incorporate the effects of dispersion, deposition, and chemical transformation along the path of the trajectories. The distance (d) in the (1/d) weighting factor represents the distance between the centers of the grid cell containing the emitting source and the grid cell containing the IMPROVE site (each grid cell has a horizontal resolution of 36 km x 36 km). If the IMPROVE monitor's grid cell also contained emissions (*i.e.*, d is zero), the distance was set to half of the grid cell size (*i.e.*, 18 km).

Ramboll compiled facility-level actual 2016 emissions data and 2028 emissions forecasts (in tons per year) to produce two different sets of EWRT*Q/d metrics for the point sources. The 2028 emissions projections were obtained from EPA's 2011v6.3 modeling case 2028el. The DNR chose not to use the EWRT*Q/d datasets calculated from the 2028 emissions estimates because confidence in the reasonableness of those projections was low.

The DNR instead used Ramboll's EWRT*Q/d metrics calculated using emissions data extracted from EPA's 2016 "alpha" platform. For EGUs, the "alpha" platform utilized 2016 data from EPA's Clean Air Markets Division (CAMD). For Iowa's nonEGU point sources, the "alpha" platform included 2016-specific emissions data uploaded by the DNR to EPA's Emissions Inventory System (EIS). The EWRT*Q/d results also incorporate aircraft and airport ground support emissions and some rail yard emissions that EPA categorizes as point sources.[18]

Ramboll calculated the EWRT*Q/d values for both nitrates (EWRT*Q/d-NO_3) and sulfates (EWRT*Q/d-SO_4) for each Class I area by multiplying the pollutant-specific EWRT for the grid cell containing the facility by the facility's 2016 "alpha" emissions (using NO_X emissions for the EWRT*Q/d-NO_3 metric and SO_2 emissions for the EWRT*Q/d-SO_4 metric), divided by the distance to the given Class I area.

4.2. EWRT*Q/d Data Evaluation

Using the EWRT*Q/d-NO_3 and EWRT*Q/d-SO_4 data to evaluate, rank, and select sources for four-factor analysis requires additional processing steps and decision making.[19] For example, the potential importance of a source may be evaluated using the EWRT*Q/d-NO_3 and EWRT*Q/d-SO_4 data for a given Class I area independently,[20] or those values may first be summed for each source and the resulting totals evaluated. While both approaches are potentially reasonable, the DNR chose to combine (sum) the EWRT*Q/d-NO_3 and EWRT*Q/d-SO_4 values for each facility. This simplified the analysis and offered a degree of consistency with one-atmosphere principles such as the interdependence between nitrate and sulfate chemistry and the resultant partitioning of their concentrations.

Ramboll's AOI study and their associated spreadsheets also made it possible to limit the sources considered for four-factor analysis to only those facilities within the grid cells that have, for example, an extinction weighted residence time for either nitrate or sulfate (EWRT-NO_3 and EWRT-SO_4, respectively) greater than a given percentage of the total EWRT-NO_3 or total EWRT-SO_2 summed across all grid cells in the CONUS domain.[21] Conceptually, this EWRT-filtering process can be thought of as creating subregions of emphasis (consisting of only those grid cells with an EWRT-NO_3 or EWRT-SO_4 value greater than a given percentage of the CONUS domain total), and only sources within those subregions would be further evaluated for source selection purposes. This is a potentially reasonable approach that limits the geographical

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nonEGU. The emissions from smaller stationary sources are inventoried in the nonpoint category and were reasonably excluded from this AOI analysis. All other nonpoint, and all onroad, offroad, and other source types were also excluded (some airport and rail sources classified by EPA as point sources were included in the AOI analysis by default, but were unimportant for Iowa). At this time, the exclusion of these sources is reasonable and supported by EPA's 2028 source apportionment modeling, which generally indicates that the majority of the U.S. anthropogenic visibility impairment in the central and upper Midwest Class I areas is attributable to the point sources. For example, see Figure 39 in Appendix B of EPA's September 19, 2019, Updated 2028 Regional Haze Modeling TSD.

[18] For Iowa and other states, EPA estimates the emissions from aircraft/airport and rail yard sources. For these sources, the 2016 "alpha" platform carried forward EPA's estimates from the 2014NEIv2. The EWRT*Q/d values for Iowa's aircraft/airport and rail yard sources were small, as expected, and would remain so even with the use of 2016-specific data.

[19] The DNR acknowledges the Arkansas Division of Environmental Quality (DEQ) for its development, refinement, and distribution of a source screening methodology using Ramboll's EWRT*Q/d data. The DNR's analysis, while slightly different, is derived from Arkansas' work.

[20] Using the independent approach, the EWRT*Q/d-NO_3 data would be analyzed to select sources for NO_X controls and the analysis then repeated using the EWRT*Q/d-SO_4 data to select sources for SO_2 controls.

[21] Similar filtering was also available using the EWRT*Q or the EWRT*Q/d data, but filtering by these metrics is not common.

scope of the analysis and it may help to focus on those areas containing sources with a higher likelihood of impacting visibility in a given Class I area. Alternatively, it may potentially exclude important sources and careful consideration is required when selecting an EWERT-NO_3 or EWRT-SO_4 threshold. The DNR choose not to implement this optional screening technique, thus ensuring no sources would be excluded from subsequent stages of this analysis of the EWRT*Q/d data.

To use the combined EWRT*Q/d metric, the DNR first modified Ramboll's spreadsheet to calculate the combined EWRT*Q/d value for each facility, accomplished by simple addition (EWRT*Q/d-NO_3 + EWRT*Q/d-SO_4).[22] Those results were then sorted from largest to smallest. In theory, it is possible to use just this information to select sources for four-factor analysis by merely identifying all facilities in the state that have a combined EWRT*Q/d value above a chosen threshold. In practice, this approach is complex and impractical. Identifying a reasonable threshold is difficult and a single combined EWRT*Q/d threshold value would most likely not be appropriate for all Class I areas of interest. Attempting to identify multiple thresholds (*e.g.* one for each Class I area) only compounds the problem.

An appropriate solution is to use the combined EWRT*Q/d data in a normalized sense. The normalization is computed by dividing each facility's combined EWRT*Q/d value by the sum of all the combined EWRT*Q/d values for that Class I area across all grid cells in the CONUS domain.[23] This normalization simply converts each facility's EWRT*Q/d value into a percentage contribution to the total EWRT*Q/d for the given Class I area. This normalization process is conceptually identical to that used to normalize the residence time (and EWRT) analyses for plotting purposes.

One potentially reasonable approach to select sources for four-factor analysis is to identify all sources with an individual impact greater than a given percentage contribution threshold, such as 1%. Another option, and the one selected by the DNR, is to first use the per-facility percentage contributions (ranked from largest to smallest)[24] to compute a cumulative (rolling total) percentage. Using a cumulative percentage approach treats each Class I area equally. It guarantees that those sources contributing to a given percentage of the total visibility impairment for a Class I area, as represented by the combined (sulfate plus nitrate) EWRT*Q/d metric, will be considered for four-factor analysis.

Using the rolling total approach incurs one additional decision, selecting an appropriate cumulative percentage threshold. The DNR designed its threshold so that all Iowa sources that contribute to the majority of the combined (sulfate plus nitrate) EWRT*Q/d impacts in any given Class I area would be selected for four-factor analysis. The threshold is identified in a given Class I area as the rolling total that traverses, and thus exceeds, fifty percent.[25] The DNR first examined the results for the ISLE, SENE, BOWA, VOYA, and HEGL Class I areas, but then extended the review to include the seven additional Class I areas listed previously in Table 2-5.

The AOI analytical spreadsheet tool is included in Appendix C-1 and a copy of the results for each of the 12 Class I areas evaluated by the DNR is provided in Appendix C-2. As an example, results from the Isle Royale analysis are provided in Table 4-1. The "Combined EWRT*Q/d" contributions are sorted in descending order and the listed facilities are those that account for the majority of the total impact.[26]

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[22] The DNR further modified Ramboll's spreadsheet to increase the number of rows included in the calculations to ensure no sources were inadvertently omitted. Other refinements and data additions were also made and corrections were applied to address two emission inventory errors identified by the Wisconsin DNR. See the README tab of Appendix C-1 for additional information.

[23] Had the DNR used an EWRT-filtering process, the combined EWRT*Q/d total for that Class I area would include only those values from sources within the grid cells meeting the EWRT-NO_3 and/or EWRT-SO_4 filtering threshold (the "subregion(s)").

[24] Sorting the individual source percentage contributions from largest to smallest before computing the cumulative percentages (rolling totals) is an important, logical, and necessary step. To select the most impactful sources, the per-facility AOI impacts must be ranked from highest to lowest.

[25] The exact value of this threshold varies slightly from one Class I area to another. For the 12 Class I areas evaluated by the DNR, the specific threshold values ranged from no less than 50.15% (at ISLE) up to 51.43% (at VOYA).

[26] Because the combined EWRT*Q/d metric is sorted in descending order (from largest to smallest), the sources with the largest impacts are listed first. The resulting cumulative totals (%) are rolling values (where the value in a given row is added to all the values from those above it) and are therefore naturally listed from smallest to largest.

Table 4-1. Cumulative rankings for the majority of the combined (NO_3 plus SO_4) EWRT*Q/d AOI metrics for Isle Royale.

Facility (*Iowa sources)	State	FIPS	2016 NO_X (tpy)	2016 SO_2 (tpy)	d (km)	EWRT - NO_3	EWRT - SO_4	Combined EWRT*Q/d	Percent Total EWRT*Q/d	Cumulative Total (%)
Tilden Mining Company LC	MI	26103	12,676	245	120	12051	13933	1300313	8.22%	8.22%
Wisconsin Electric Power Company	MI	26103	3,758	5,885	114	8294	11111	848113	5.36%	13.59%
Arcelormittal Burns Harbor LLC	IN	18127	8,599	12,831	653	10845	10394	347053	2.20%	15.78%
St. Clair / Belle River Power Plant	MI	26147	13,293	37,160	685	1427	5819	343276	2.17%	17.96%
JH Campbell Plant	MI	26139	2,354	12,850	528	5290	12775	334157	2.11%	20.07%
Xcel Energy - Sherburne Generating Plant	MN	27141	8,471	8,504	499	10186	7040	292959	1.85%	21.92%
Empire Iron Mining Partnership	MI	26103	4,389	373	120	6416	9407	263596	1.67%	23.59%
Expera Specialty Solutions	WI	55085	1,168	1,596	225	13648	19236	206927	1.31%	24.90%
Expera Specialty Solutions LLC	WI	55087	1,577	6,532	354	6278	9660	206142	1.30%	26.20%
Ameren Missouri Labadie Plant	MO	29071	6,576	31,113	1011	3399	4972	175175	1.11%	27.31%
L Anse Warden Electric Company LLC	MI	26013	214	284	82	20783	34249	172794	1.09%	28.40%
WPL - Edgewater Generating Station	WI	55117	1,307	5,981	418	6631	10245	167428	1.06%	29.46%
Northshore Mining Co - Silver Bay	MN	27075	1,581	933	236	14271	15289	155809	0.99%	30.45%
Thomas Hill Energy Center Power Division Thomas Hill	MO	29175	12,456	14,411	949	5013	5574	150450	0.95%	31.40%
Duke Energy Indiana LLC - Gibson Genera	IN	18051	13,190	14,963	1009	3233	7044	146763	0.93%	32.33%
WPL - Columbia Energy Center	WI	55021	3,482	1,393	453	12500	14467	140510	0.89%	33.22%
US Steel Corp - Minntac	MN	27137	6,366	1,149	339	6265	6323	139224	0.88%	34.10%
***MidAmerican Energy Co - Louisa Station**	**IA**	**19115**	**3,120**	**5,129**	**721**	**10739**	**12587**	**135957**	**0.86%**	**34.96%**
Verso Escanaba LLC	MI	26041	1,700	727	202	10479	13087	135445	0.86%	35.81%
Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	KY	21145	11,002	23,808	1144	2223	5425	134239	0.85%	36.66%
Catalyst Paper - Biron Mill	WI	55141	1,436	2,506	360	11830	12155	131670	0.83%	37.50%
Duke Energy Indiana LLC - Cayuga Genera	IN	18165	12,379	2,819	839	6725	7804	125499	0.79%	38.29%
Chicago O Hare International Airport	IL	17031	4,984	491	610	13471	10531	118603	0.75%	39.04%
Wisconsin Rapids Paper Mill	WI	55141	1,875	1,622	365	11830	12155	114810	0.73%	39.77%
Minnesota Power Inc - Boswell Energy Ctr	MN	27061	4,314	3,644	417	6395	5553	114611	0.72%	40.49%
Arcelormittal USA LLC	IN	18089	4,132	2,392	646	10633	11147	109241	0.69%	41.18%
Cokenergy LLC - contractor of ArcelorMi	IN	18089	0	6,298	645	10633	11147	108839	0.69%	41.87%
Will County Generating Station	IL	17197	1,053	4,507	648	11077	11947	101155	0.64%	42.51%
Entergy Arkansas Inc - Independence Plant	AR	5063	9,867	22,570	1333	1834	4933	97072	0.61%	43.12%
Midwest Generation LLC	IL	17179	2,959	8,209	777	4798	7235	94660	0.60%	43.72%
US Steel Gary Work	IN	18089	3,143	2,590	653	10845	10394	93468	0.59%	44.31%
Waukegan Electric Generating Station	IL	17097	1,031	2,734	565	14975	12912	89782	0.57%	44.88%

Facility (*Iowa sources)	State	FIPS	2016 NO_X (tpy)	2016 SO_2 (tpy)	d (km)	EWRT - NO_3	EWRT - SO_4	Combined EWRT*Q/d	Percent Total EWRT*Q/d	Cumulative Total (%)
Wisconsin Public Service Corporation - Weston Plant	WI	55073	1,087	1,337	312	11062	11428	87453	0.55%	45.44%
***Walter Scott Jr Energy Center**	**IA**	**19155**	**5,474**	**8,975**	**927**	**4570**	**6240**	**87432**	**0.55%**	**45.99%**
WI Electric Power, dba WE Energies - Pleasant Prairie	WI	55059	2,227	1,087	548	14975	12912	86507	0.55%	46.54%
Archer Daniels Midland Co	IL	17115	2,078	7,363	845	6881	7836	85228	0.54%	47.07%
NIPSCO RM Schahfer Generating Station	IN	18073	4,397	1,441	699	9713	11540	84838	0.54%	47.61%
Avon Lake Power Plant (0247030013)	OH	39093	2,062	9,021	819	3896	6668	83261	0.53%	48.14%
Xcel Energy - Allen S King Generating Plant	MN	27163	1,395	1,515	448	12963	12669	83206	0.53%	48.66%
Dynegy Midwest Generation LLC	IL	17155	1,208	4,082	690	8289	11413	81989	0.52%	49.18%
Midwest Generation LLC	IL	17197	962	3,202	663	10220	12920	77248	0.49%	49.67%
Expera Specialty Solutions LLC	WI	55073	640	1,469	321	11724	11441	75855	0.48%	50.15%

4.3. Sources Selected for Four-Factor Analysis

The DNR's evaluation of the AOI data produced two Iowa facilities to select for four-factor analysis: Louisa Generating Station (LGS) and Walter Scott Jr. Energy Center (WSEC). As indicated in Table 4-2, both are coal-fired EGUs (power plants) operated by MidAmerican Energy Company (MidAmerican). LGS is located along the Mississippi River in the northeastern corner of Louisa County in eastern Iowa and WSEC is located along the Missouri River in southwestern Pottawattamie County in western Iowa (see Figure 4-3). LGS and WSEC each contributed to the majority of the combined EWRT*Q/d visibility impacts at Isle Royale. No other Iowa source contributed above that threshold in any of the 11 other Class I areas evaluated (SENE, BOWA, VOYA, HEGL, CACR, UPBU, MACA, MING, WIMO, BADL, and WICA).

Table 4-2. Iowa sources selected for four-factor analysis.

Company	Facility Name	Facility Type	Unit Descriptions	Pollutants	DNR Facility ID	County	Latitude Longitude
MidAmerican Energy Co.	Louisa Generating Station (LGS)	EGU (power plant)	One (1) coal-fired boiler (main boiler)	SO_2 and NO_X	58-07-001	Louisa	41.3181 -91.0933
MidAmerican Energy Co.	Walter Scott Jr Energy Center (WSEC)	EGU (power plant)	Two (2) coal-fired boilers (Units 3 & 4)	SO_2 and NO_X	78-01-026	Pottawattamie	41.1806 -95.8390

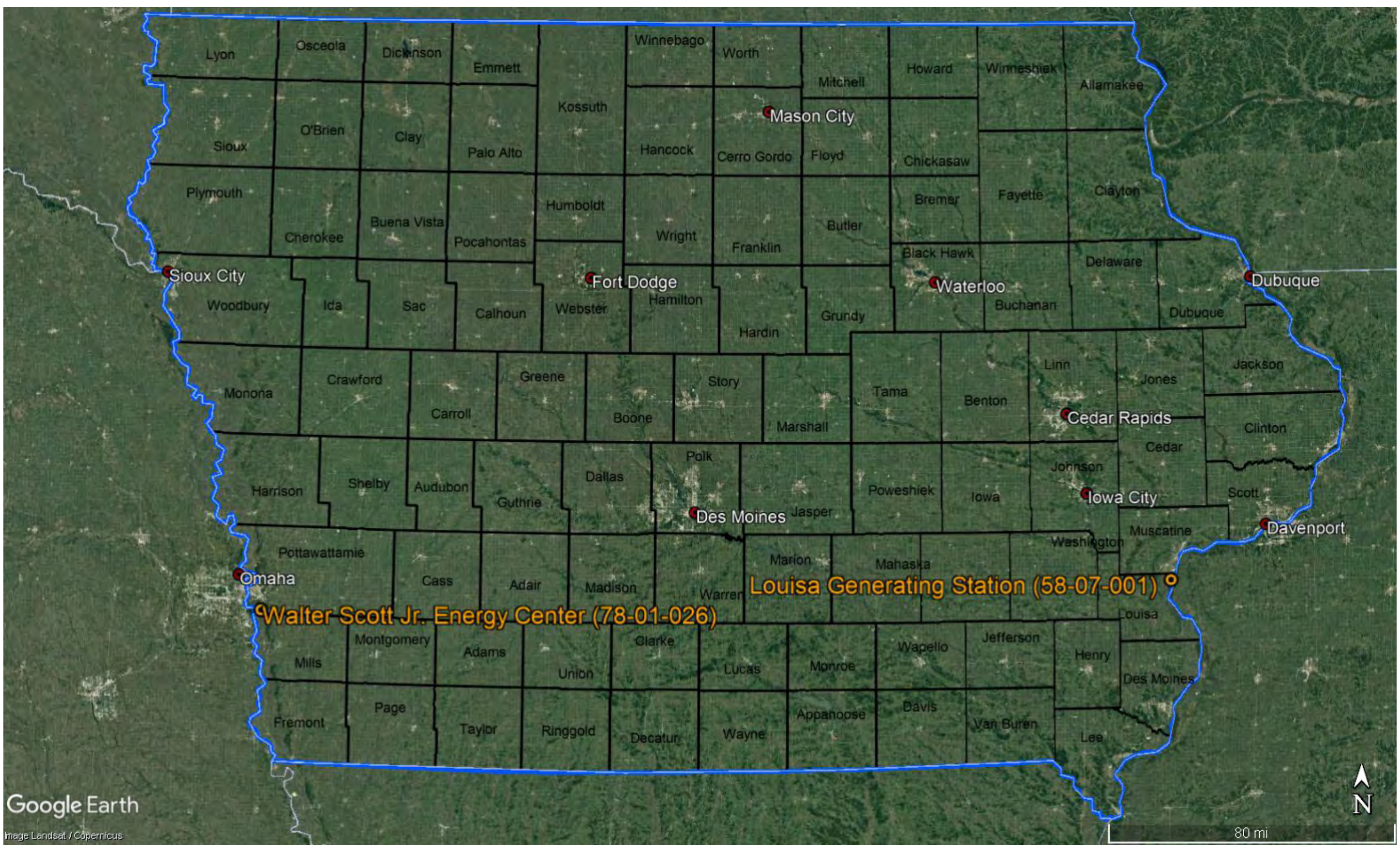

Figure 4-3. Locations of LGS and WSEC.

5. Four-Factor Analysis

On July 15, 2020, the DNR requested that MidAmerican Energy Company (MidAmerican) submit a four-factor analysis for Louisa Generating Station (LGS) and Walter Scott Jr. Energy Center (WSEC). An analysis of the four statutory factors begins with the identification of potential control measures that reduce emissions of visibility impairing pollutants. The four statutory factors evaluated for each measure 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 the source.

In 40 CFR 51.308(f)(2)(i) EPA requires that these four statutory factors be evaluated to determine the emission reduction measures that are necessary to make reasonable progress. EPA guidance also permits consideration of an optional fifth factor, visibility benefits, when determining which control measures are necessary to make reasonable progress towards natural visibility conditions.

MidAmerican submitted the requested four-factor analysis on December 14, 2020, and later provided a superseding version, dated August 9, 2021. In this SIP revision, the DNR relies solely on the newer analysis, included here as Appendix D-1. The newer version improves the calculated cost estimates by using a firm-specific interest rate. Additionally, MidAmerican updated its visibility benefits analysis to incorporate recent CAMx PSAT results from LADCO's new (at the time) 2028_{2016} photochemical modeling platform.

5.1. Source Characteristics

LGS produces steam for electricity generation by combusting subbituminous low-sulfur coal in a dry bottom wall-fired boiler with a maximum rated heat capacity of 8,000 MMBtu/hr. The high-pressure steam spins a generator with a nameplate capacity of 811.9 megawatts (MW). Commercial operation began in 1983. The boiler is equipped with a dry lime flue gas desulfurization (FGD) system to reduce SO_2 emissions and low NO_X burners (LNB) with overfire air (OFA) to reduce NO_X emissions.

WSEC includes two dry bottom wall-fired boilers that both combust subbituminous low-sulfur coal to produce steam for electricity generation. The two boilers, identified as Unit 3 (WSEC-3) and Unit 4 (WSEC-4),[27] are rated at 7,700 MMBtu/hr and 7,675 MMBtu/hr, respectively. WSEC-3 began commercial operation in 1978 and serves a generator with a nameplate capacity of 725.8 MW. WSEC-4 began commercial operation in 2007 and serves a generator with a nameplate capacity of 922.5 MW. Both units are equipped with dry lime FGD to reduce SO_2 emissions and LNB with OFA to reduce NO_X. Unit 4 additionally includes a selective catalytic reduction (SCR) system to further control NO_X emissions. Table 5-1 summarizes characteristics associated with the main boilers at LGS and WSEC.

Table 5-1. Unit characteristics for MidAmerican's Louisa Generating Station and Walter Scott Jr. Energy Center.

Facility Name	Unit ID	Maximum Rated Heat Input	Nameplate Capacity	Online Year	Existing SO_2 Controls	Existing NO_X Controls
Louisa Generating Station	101	8,000 MMBtu/hr	811.9 MW	1983	Dry Lime FGD	LNB+OFA
Walter Scott Jr Energy Center	3	7,700 MMBtu/hr	725.8 MW	1978	Dry Lime FGD	LNB+OFA
	4	7,675 MMBtu/hr	922.5 MW	2007	Dry Lime FGD	LNB+OFA, SCR

In 2003, WSEC-4 was subject to the prevention of significant deterioration (PSD) preconstruction permitting process for its SO_2 and NO_X emissions. As part of the PSD review process, Best Available Control Technology (BACT) for SO_2 was determined to be an FGD system with an emission limit of 0.1 lb/MMBtu (30-day rolling average) and an annual emission restriction of 3,362 tons per rolling 12-month period. For NO_X, the BACT emission limit was established at 0.07 lb/MMBtu (30-day rolling average) based on the best available control option of low NO_X burners, overfire air, and SCR, with an annual emission restriction of 2,353 tons per rolling 12-month period. The BACT emission limits are established

[27] Units 1 and 2 at WSEC retired in 2015 and are permanently prohibited from operating. On September 18, 2015, the Iowa DNR rescinded their air construction permits: 72-A-162-S4 (Unit 1) and 72-A-173-P3 (Unit 2) .

as enforceable restrictions in Iowa DNR air construction permit 03-A-425-P4, available in Appendix E or DNR's construction permit search. Compliance must be demonstrated using continuous emission monitoring systems (CEMS).

5.2. Emissions and Operations Review

Table 5-2 provides the 2009-2021 annual unit-level emissions and heat input data from CAMD[28] for LGS, WSEC-3, and WSEC-4. Table 5-3 contains the calculated annual emission rates, in lb/MMBtu. The selected 2009-2021 timeframe includes the most recent complete year available in CAMD (at the time) and all prior years back to the beginning of the first 10-year implementation period (2009-2018). The use of recent emissions information is preferred for evaluation purposes but due to the impacts of the COVID-19 pandemic the 2020 emissions and operations data is not representative of normal conditions and the representativity of 2021, while appearing more typical, is still uncertain. To establish representative baseline emissions, the four-factor analysis will use three-year averages calculated using the 2017-2019 data. For these units, the 2017-2019 timeframe is considered to be a recent and representative period.

Table 5-2. Annual 2009-2021 SO_2 and NO_X emissions and heat input data[29] from CAMD for LGS and WSEC.

Year	SO_2 (tpy)			NO_X (tpy)			Heat Input (MMBtu)		
	LGS	WSEC-3	WSEC-4	LGS	WSEC-3	WSEC-4	LGS	WSEC-3	WSEC-4
2009	2,250	7,983	1,913	4,136	4,579	1,625	46,174,909	46,124,800	53,469,751
2010	7,075	8,723	2,129	4,745	5,411	1,405	51,089,371	56,787,742	53,870,361
2011	7,306	9,642	2,246	3,721	5,311	1,635	42,889,900	54,717,238	55,587,681
2012	8,743	9,335	2,244	4,691	5,360	1,684	51,933,353	50,382,792	54,538,957
2013	8,206	9,043	2,134	4,348	6,066	1,519	47,963,080	48,892,424	50,497,488
2014	9,365	9,119	2,045	4,630	5,388	1,378	52,557,962	50,318,160	48,701,307
2015	6,098	6,630	2,113	3,416	4,240	1,425	39,730,725	38,180,672	53,696,657
2016	5,156	7,365	1,601	3,131	4,326	1,141	35,208,861	42,314,661	41,119,547
2017	5,237	8,486	1,291	3,490	5,437	1,044	36,681,145	48,261,687	36,887,210
2018	7,332	8,118	1,835	4,871	5,186	1,548	51,727,847	45,240,043	56,396,028
2019	5,286	7,520	1,375	2,960	4,466	1,126	34,547,040	41,855,533	41,913,267
2020	2,870	5,113	847	1,687	2,839	584	19,483,009	27,238,459	24,994,030
2021	6,722	7,236	1,125	3,700	4,701	827	42,884,100	38,440,324	28,699,266

Table 5-3. Annual emission rates, in lb/MMBtu, calculated using the CAMD data.

Year	SO_2 Rate (lb/MMBtu)			NO_X Rate (lb/MMBtu)		
	LGS	WSEC-3	WSEC-4	LGS	WSEC-3	WSEC-4
2009	0.097	0.346	0.072	0.179	0.199	0.061
2010	0.277	0.307	0.079	0.186	0.191	0.052
2011	0.341	0.352	0.081	0.174	0.194	0.059
2012	0.337	0.371	0.082	0.181	0.213	0.062
2013	0.342	0.370	0.085	0.181	0.248	0.060
2014	0.356	0.362	0.084	0.176	0.214	0.057
2015	0.307	0.347	0.079	0.172	0.222	0.053
2016	0.293	0.348	0.078	0.178	0.204	0.056
2017	0.286	0.352	0.070	0.190	0.225	0.057
2018	0.283	0.359	0.065	0.188	0.229	0.055
2019	0.306	0.359	0.066	0.171	0.213	0.054
2020	0.295	0.375	0.068	0.173	0.208	0.047
2021	0.314	0.376	0.078	0.173	0.245	0.058

[28] In July 2022, CAMD replaced the Air Markets Program Data (AMPD) tool with the Clean Air Markets Program Data (CAMPD) tool. The DNR simply refers to the underlying EGU emissions information, which should be unchanged, as "CAMD" data.
[29] Note, the 2016 emissions data for LGS and WSEC shown in Table 4-1 predate revisions made to the CAMD data that are reflected in this table. The differences are relatively small (27 tons or less) and do not impact results or conclusions.

The data in Table 5-2 are plotted in Figure 5-1 through Figure 5-3. Throughout the 2009-2021 timeframe, the variability in each unit's annual tons of actual emissions is likely most attributable to changes in heat input. This assumption is based on the relatively small interannual variability in each unit's annualized lb/MMBtu emission rates. The largest exceptions occur within the 2009 through 2011 timeframe for LGS where its SO_2 emission rates increase from 0.097 to 0.341 lb/MMBtu.

Across the 2009-2021 timeframe, the annual tons of SO_2 emissions from LGS and WSEC-3 generally peaked within the years from 2011-2014. Variability is less pronounced in their 2009-2021 annual NO_X emissions. WSEC-4 is subject to more stringent emission limits and this is reflected in its emissions data.

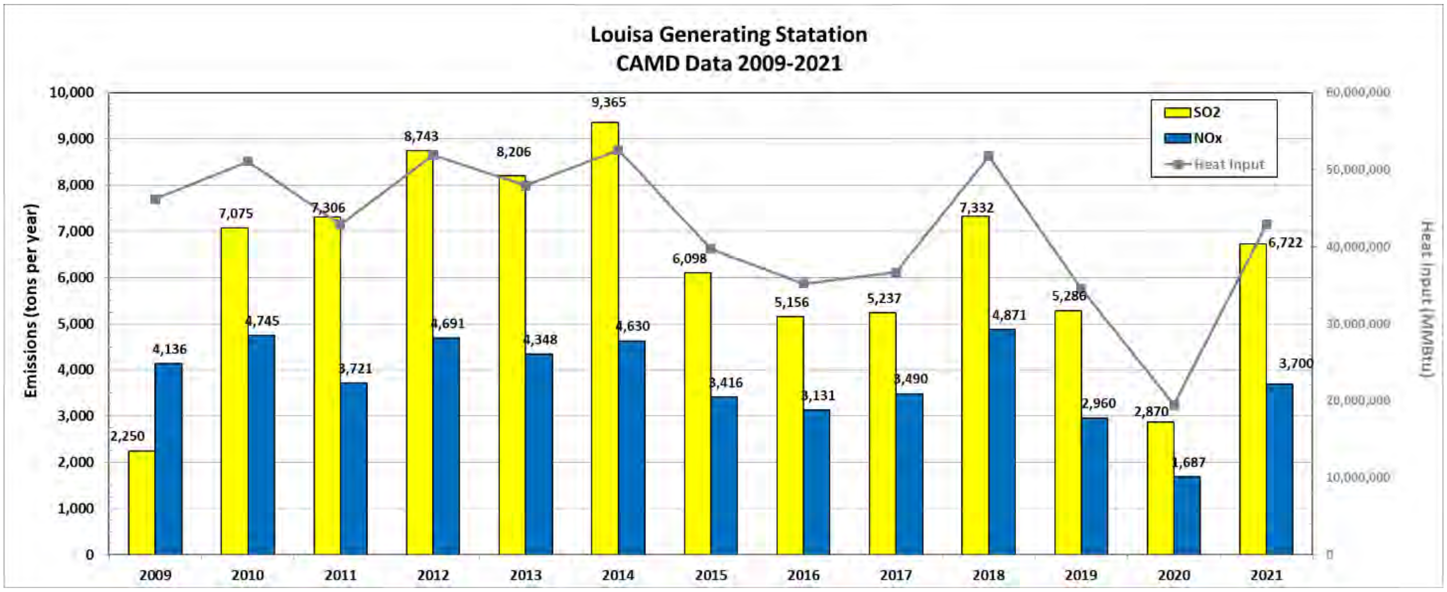

Figure 5-1. Annual 2009-2021 SO_2, NO_X, and heat input data from CAMD for LGS.

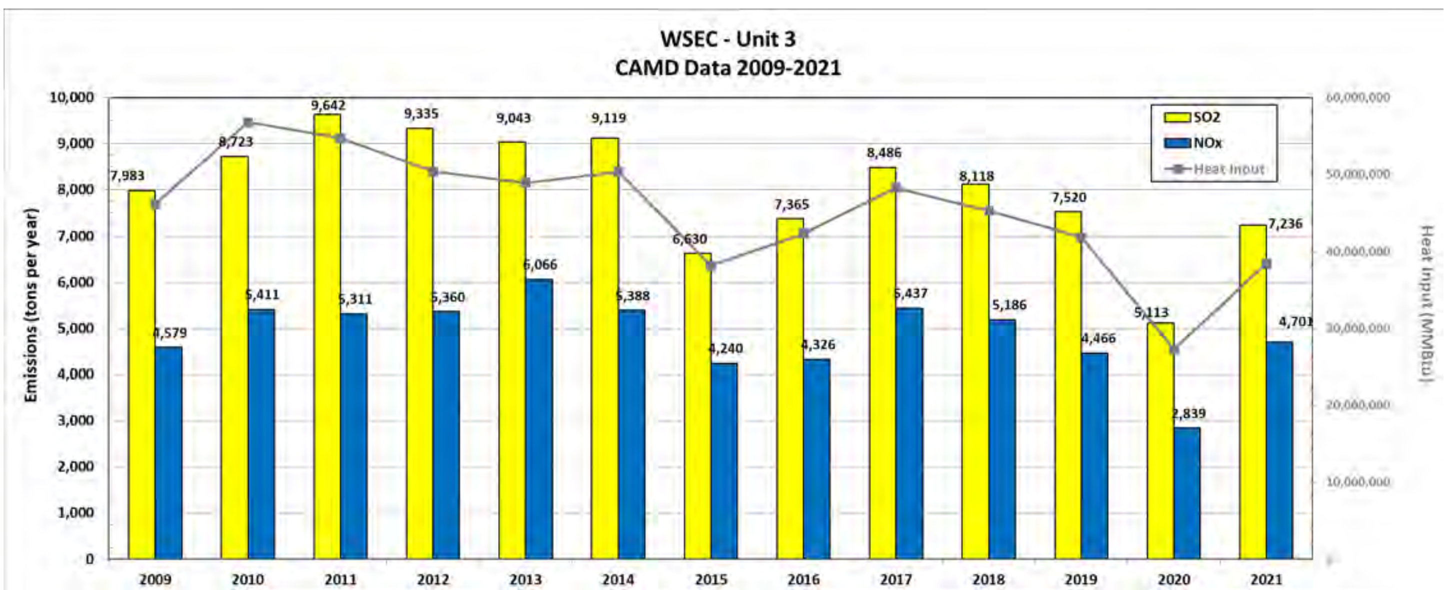

Figure 5-2. Annual 2009-2021 SO_2, NO_X, and heat input data from CAMD for WSEC-3.

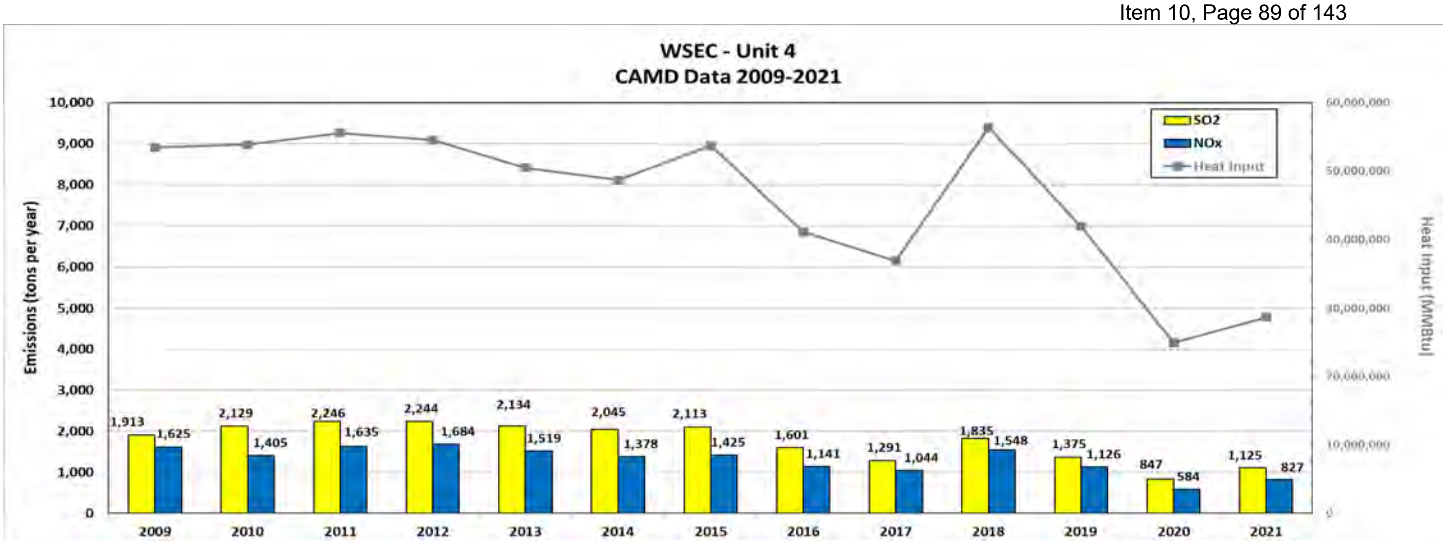

Figure 5-3. Annual 2009-2021 SO_2, NO_X, and heat input data from CAMD for WSEC-4.

5.2.1. Projected Boiler Operation for the Second Implementation Period

MidAmerican anticipates that the utilization of LGS, WSEC-3, and WSEC-4 will decrease through 2028 due to the increased integration of renewable energy. However, for purposes of the four-factor analysis, MidAmerican assumed that future boiler utilization, and thus future emissions, will remain unchanged from the baseline. Therefore, MidAmerican did not project that actual emissions will decrease and the four statutory factors were evaluated using the representative baseline emissions.

5.3. Identification of Technically Feasible Control Measures

To begin the analysis of the four statutory factors, MidAmerican first identified the technically feasible SO_2 and NO_X emissions control options for LGS, WSEC-3, and WSEC-4. For SO_2, MidAmerican identified the following three technologies: wet flue gas desulfurization (wet FGD), dry flue gas desulfurization (dry FGD), and dry sorbent injection (DSI). The DSI control option was not evaluated further because, as a stand-alone control technology, it is less effective at reducing SO_2 emissions than the existing dry FGD systems that are already installed on these units. While adding DSI might provide additional benefits to boilers equipped with dry FGD systems that burn high-sulfur coal, these units burn low-sulfur coal and the addition of DSI would not improve their overall performance. Therefore, DSI is not considered a feasible control measure for these three boilers.

For NO_X, MidAmerican identified the following controls as technically feasible for all three units: SNCR and SCR. Each boiler is already equipped with LNB and OFA, so these needed no further consideration.

The Iowa DNR required that MidAmerican characterize the four statutory factors for all technically feasible SO_2 and NO_X control options identified.

5.3.1. WSEC-4

WSEC-4 is currently equipped with all feasible control options identified by MidAmerican and no additional technically feasible control measures were identified to further reduce NO_X and SO_2 emissions. WSEC-4's 2017-2019 actual average SO_2 emission rate of 0.067 lb/MMBtu provides the same level of performance as a wet FGD system. The system of NO_X controls on WSEC-4 achieves a 2017-2019 average NO_X emission rate of 0.055 lb/MMBtu, consistent with the lowest limits in EPA's RACT/BACT/LAER Clearinghouse (RBLC) database.

Permit 03-A-425-P4 restricts WSEC-4 to an enforceable BACT SO_2 emission limit of 0.1 lb/MMBtu. According to EPA's 2019 guidance, the stringency of that limit is twice the level considered reasonable for purposes of regional haze, as:

> "…an EGU that has add-on flue gas desulfurization (FGD) and that meets the applicable alternative SO_2 emission limit of the 2012 Mercury Air Toxics Standards (MATS) rule for power plants…0.2 lb/MMBtu for coal-fired EGUs...is low enough that it is unlikely that an analysis of control measures for a source already equipped with a scrubber and meeting one of these limits would conclude that even more stringent control of SO_2 is necessary to make reasonable progress."

WSEC-4 is restricted to a NO_X emission limit of 0.07 lb/MMBtu. In review of the RBLC to compare WSEC-4's NO_X limit to BACT limits established since 2012, WSEC-4 remains in the top percentage of the lowest emission limits established on coal-fired EGUs.

Based on the available information, no additional technically feasible control options are identified for WSEC-4. The existing emission limits represent a level of control that is considered reasonable for regional haze purposes and the Iowa DNR has determined that no further review of WSEC-4 is required at this time.

5.3.2. LGS and WSEC-3

Four potential control measures were identified for both LGS and WSEC-3, two measures reduce SO_2 and two reduce NO_X, as shown in Table 5-4. The candidate SO_2 measures are operational improvements to the existing dry FGD systems and replacement with new wet FGDs. The candidate NO_X measures include the addition of either SNCR or SCR systems.

Table 5-4. Candidate control measures for both LGS and WSEC-3.

SO_2	NO_X
Improve Operation of Existing Dry FGD	SNCR
New Wet FGD	SCR

5.4. Factor 1 – Cost of Controls

Control costs are frequently evaluated in dollars per ton of pollutant reduced. The total annualized costs for a given technically feasible control technology are divided by the estimated annual actual emission reductions provided by that option. One-time capital costs, such as equipment and installation, are annualized in the annual capital recovery cost. The capital recovery cost is added to the operation and maintenance (O&M) costs to produce total annualized costs.

Table 5-5 summarizes the cost estimates provided by MidAmerican, in 2019 dollars (2019$), for the two SO_2 control options at LGS and WSEC-3. Table 5-6 provides the NO_X control measures costs for SNCR and SCR. Operational improvements to the existing dry FGD systems incur no capital costs because both LGS and WSEC-3 have existing dry FGD systems. The total annual costs for improving the existing dry FGD systems are attributable to the costs of increased lime reagent usage and commensurate increased waste disposal costs, which are incorporated in the annual O&M costs.

Table 5-5. SO_2 control measure costs estimated by MidAmerican for LGS and WSEC-3.

SO_2 Control Measures		LGS (Unit 101)		WSEC-3	
		Improve Existing Dry FGD	Wet FGD	Improve Existing Dry FGD	Wet FGD
Capital Cost (2019$)		-	$398,140,000	-	$370,150,000
Capital Recovery Cost (2019$/yr)		-	$40,136,000	-	$37,314,000
Annual O&M Cost (2019$/yr)		$1,102,000	$1,986,000	$1,248,000	$3,849,000
Total Annualized Cost (2019$/yr)		$1,102,000	$42,122,000	$1,248,000	$41,163,000
Emissions with Controls	tpy	2,049	1,230	2,256	1,354
	lb/MMBtu	0.1	0.06	0.1	0.06
Baseline Emissions (2017-2019 avg)	tpy	5,952		8,041	
	lb/MMBtu	0.292		0.357	
Emission Change vs Baseline	tpy	-3,903	-4,722	-5,785	-6,687
	%	-66%	-79%	-72%	-83%
Cost Effectiveness (2019$/Ton)		**$282**	**$8,920**	**$216**	**$6,160**
Incremental Cost (2019$/Ton)		n/a	$50,090	n/a	$44,250

Table 5-6. NO_X control measure costs estimated by MidAmerican for LGS and WSEC-3.

NO_X Control Measures		LGS (Unit 101)		WSEC-3	
		SNCR	SCR	SNCR	SCR
Capital Cost (2019$)		$14,175,300	$236,140,160	$13,851,200	$238,436,408
Capital Recovery Cost (2019$/yr)		$1,429,000	$20,709,492	$1,396,300	$20,910,873
Annual O&M Cost (2019$/yr)		$2,192,000	$3,562,450	$2,844,000	$3,860,815
Total Annualized Cost (2019$/yr)		$3,621,000	$24,271,942	$4,240,300	$24,771,688
Emissions with Controls	tpy	3,208	1,035	4,275	1,181
	lb/MMBtu	0.157	0.05	0.181	0.05
Baseline Emissions (2017-2019 avg)	tpy	3,774		5,030	
	lb/MMBtu	0.183		0.223	
Emission Change vs Baseline	tpy	-566	-2,739	-755	-3,849
	%	-15%	-73%	-15%	-77%
Cost Effectiveness (2019$/Ton)		**$6,398**	**$8,862**	**$5,616**	**$6,436**
Incremental Cost (2019$/Ton)		n/a	$9,500	n/a	$6,640

The Iowa DNR evaluated the cost estimates for each technically feasible control option provided by MidAmerican.[30] No restrictions on operations were evaluated or considered as part of the control cost analysis because MidAmerican assumed LGS and WSEC-3 will continue to operate at baseline levels. The Iowa DNR determined that MidAmerican followed the procedures specified in EPA's Control Cost Manual to estimate control option costs, such as considering the full useful life of the control equipment (30 years for SCR and 20 years for the other control options), labor costs, interest rate, and operation and maintenance costs. MidAmerican utilized a firm-specific interest rate approved by the Iowa Utilities Board of 7.862% to estimate annual capital recovery costs for new control equipment estimates. In accordance with EPA's Control Cost Manual, the Iowa DNR requested, and MidAmerican provided, additional justification to support the firm-specific interest rate of 7.862%.[31] The Iowa DNR determined that the firm-specific interest rate is appropriate in this case. No additional costs were considered for equipment removal, additional water treatment systems, or any cost related to compliance such as unit shutdowns due to new control equipment installation.

5.5. Factor 2 – Time Necessary for Compliance

Improve Existing Dry FGD Systems

MidAmerican estimates that the implementation of operational improvements to the existing dry FGD systems at both LGS and WSEC-3 could be implemented relatively quickly, within approximately six months, to allow for testing and FGD system optimization.

New Wet FGD Systems

MidAmerican estimates it would take approximately five years to install a new wet FGD system. This time is needed to design, permit, procure, install, and startup the new system. Additionally, the installation of a wet FGD system requires the given unit to be out of service and a unit's planned outage must accommodate regional electricity demands and be coordinated with the maintenance shutdowns of other regionally affected utilities.

[30] The specific control cost analysis conducted by the Iowa DNR for SNCR and SCR is provided in Appendix D-2.
[31] The firm-specific interest rate justification document is provided in Appendix D-3.

SNCR and SCR

MidAmerican estimates that SNCR could be implemented within three years and SCR could be implemented within five years. This time is needed to design, permit, procure, install, and startup the new system. Additionally, the installation of either SNCR or SCR requires the given unit to be out of service and a unit's planned outage must accommodate regional electricity demands and be coordinated with the maintenance shutdowns of other regionally affected utilities.

The Iowa DNR reviewed MidAmerican's estimates for the time necessary for compliance for each technically feasible control option to determine if they were reasonable. This factor was not used to eliminate technically feasible control options but was considered to determine the appropriate enforceable timeframes for implementing control improvements or installing new control equipment.

5.6. Factor 3 – Energy and Non-Air Quality Environmental Impacts

Improve Existing Dry FGD Systems

MidAmerican estimates that implementing operational improvements to the existing dry FGD systems would increase the use of lime injection which will result in a small increase in material handling and solid waste disposal costs.

New Wet FGD Systems

According to MidAmerican, the use of a wet FGD system has several environmental impacts compared to the existing dry system. Wet FGD systems create significantly greater volumes of waste that must be dewatered and disposed. A wet system uses significantly more water than a dry system. They also generate a wastewater stream that must be treated and discharged. MidAmerican considered the additional waste water generation costs in the control measure costs for new wet FGD systems.

SNCR and SCR

SNCR and SCR systems both utilize some form of ammonia as a reagent to promote the conversion of NO_X to elemental nitrogen and water. Due to imperfect mixing between the flue gas and the reagent, a greater amount of reagent, *i.e.* ammonia, must be injected to achieve the desired NO_X reduction. The excess ammonia remains unreacted in the process and is emitted from the stack to the atmosphere as ammonia "slip." According to MidAmerican, the excess ammonia emissions associated with SCR are typically between 2 to 10 ppm and SNCR are between 10 to 20 ppm. The excess ammonia emissions can combine with other pollutants such as sulfur compounds to form fine particulate matter. The additional fine particulate formation has the potential to adversely impact the surrounding area and the environment.

Ammonia for these processes can be provided using either anhydrous ammonia, aqueous ammonia, or urea. Storage and the use of these forms of ammonia, especially anhydrous ammonia, can raise significant safety concerns. However, with proper system design and operation, these safety issues are manageable.

Retrofitting SCR would also increase the parasitic electrical load of the station as the ancillary systems that support the SCR require auxiliary power. Additionally, placement of the SCR catalyst grid in the exhaust flow path of the boiler causes backpressure, which must be overcome by supplying additional power to the existing flue gas systems. An SNCR system would incur some smaller auxiliary power consumption loads as well.

The Iowa DNR reviewed MidAmerican's energy and non-air quality environmental impacts for each technically feasible control option to determine if the proposed control measures will cause a negative effect on the environment. The energy and non-air quality environmental impacts are considered but do not eliminate any technically feasible control options identified by MidAmerican.

5.7. Factor 4 – Remaining Useful Life

MidAmerican did not request to restrict or limit the operation of LGS or WSEC-3 and neither unit has a scheduled retirement date. Therefore, this factor does not affect annualized costs since LGS and WSEC-3 are both projected to operate at levels equivalent to the 2017-2019 baseline, and the costs of controls (Factor 1) consider the full life of the controls. The Iowa DNR determined that this statutory factor does not weigh for or against a particular control option.

5.8. Optional 5th Factor – Visibility Impacts

EPA's 2019 and 2021 guidance documents both permit the consideration of visibility benefits when determining which controls are necessary to make reasonable progress towards natural visibility conditions. MidAmerican did provide a visibility impact assessment, however, the Iowa DNR conducted an independent analysis, as discussed below.

Using LADCO's 2028_{2016} CAMx PSAT modeling results, the Iowa DNR quantified, in Mm^{-1}, Iowa's predicted anthropogenic ("Anthro.") sulfate and nitrate contributions to the total modeled visibility impairment for the 20% most impaired days at the LADCO and HEGL Class I areas, as shown in Table 5-7. The sulfate and nitrate contributions from every other state in the continental U.S. (all 47 other states plus Washington D.C. and tribal areas) were summed in the "All Other States Anthro." column. The "All Else Modeled" column provides the sulfate and nitrate contributions from all other modeled sources, which encompasses initial conditions & boundary conditions; natural sources; fires; and sources in Canada, Mexico, and other locations (*e.g.* offshore).

For simplicity, the DNR summed the PSAT results for the primary particulate contributions from the elemental carbon (EC), the fine crustal (FC), and the coarse mass (CM) components across all sources (anthropogenic and natural) and across all regions/locations in the model domain. The contributions from secondary organic aerosols are represented by the "OC Est." (which are calculated values and not direct PSAT results, as discussed previously).

The summation of all the aforementioned component contributions produces the total predicted modeled visibility impairment in 2028 for each area. The totals should not be converted to deciviews because they exclude site-specific Rayleigh scattering values (and sea salt constants).

Table 5-7. Modeled 2028 contributions for the 20% most impaired days at the LADCO and HEGL Class I areas.

Class I Area	Iowa Anthro.† (Mm^{-1})		All Other States Anthro. (Mm^{-1})		All Else Modeled[32] (Mm^{-1})		EC+FC+CM (Mm^{-1})	OC Est. (Mm^{-1})	Total Modeled (Mm^{-1})
	Sulfate	Nitrate	Sulfate	Nitrate	Sulfate	Nitrate			
ISLE	0.648	0.653	5.514	8.674	7.98	5.511	3.221	4.169	36.36
SENE	0.593	0.798	8.380	12.331	8.02	6.625	3.268	5.105	45.12
BOWA	0.395	0.463	3.869	5.908	6.89	5.439	2.721	3.626	29.31
VOYA	0.439	0.325	3.992	4.769	5.97	6.946	2.778	3.523	28.74
HEGL	1.000	0.792	13.267	9.198	6.11	4.877	5.278	7.617	48.13

†Iowa's maximum sulfate and maximum nitrate impacts are highlighted.

Among the five Class I areas linked to Iowa, the maximum predicted sulfate and nitrate contributions attributable to Iowa's anthropogenic emissions are 1.000 Mm^{-1} and 0.798 Mm^{-1}, respectively. The maximum sulfate impact is linked to HEGL and the maximum nitrate impact is linked to SENE, as highlighted in Table 5-7. Those impacts equate to contributions representing 2.1% and 1.8% of the total modeled visibility impairment in those areas, shown in Table 5-8.

Table 5-8. Percentage contributions to the 2028 total modeled visibility impairment on the 20% most impaired days.

Class I Area	Iowa Anthro. (%)		All Other States Anthro. (%)		All Else Modeled[32] (%)		EC+FC+CM (%)	OC Est (%)	Total Modeled (%)
	Sulfate	Nitrate	Sulfate	Nitrate	Sulfate	Nitrate			
ISLE	1.8%	1.8%	15.2%	23.9%	21.9%	15.2%	8.9%	11.5%	100%
SENE	1.3%	1.8%	18.6%	27.3%	17.8%	14.7%	7.2%	11.3%	100%
BOWA	1.3%	1.6%	13.2%	20.2%	23.5%	18.6%	9.3%	12.4%	100%
VOYA	1.5%	1.1%	13.9%	16.6%	20.8%	24.2%	9.7%	12.3%	100%
HEGL	2.1%	1.6%	27.6%	19.1%	12.7%	10.1%	11.0%	15.8%	100%

[32] The DNR placed contributions from fires in the "All Else Modeled" category. See footnotes 7 and 8 for additional information.

The "Iowa Anthro." contributions above represent the contributions from all anthropogenic SO_2 and NO_X sources in the state, including LGS and WSEC. Obtaining the modeled impacts attributable to just LGS and WSEC would require a new PSAT simulation configured to provide that additional detail, or zero-out runs. Absent those demanding modeling exercises, an emissions proportionality assessment using the source-specific emissions for LGS and WSEC ratioed to the state-wide totals offers an objective and manageable means of investigating possible individual contributions from LGS and WSEC-3.

The Iowa DNR performed the emissions proportionality calculations using LADCO's 2028 emissions projections and not the 2016 base year emissions data, for consistency with the 2028 PSAT results. At the facility level, LGS and WSEC are predicted (by ERTAC v16.1) to remain the largest SO_2 and NO_X sources in Iowa in 2028, a result consistent with the 2016 actual emissions data. Table 5-9 provides the 2028 ERTAC v16.1 emissions projections for LGS, WSEC, and the remainder of Iowa's EGUs. The emissions totals for each anthropogenic data category are also included. Iowa's non-anthropogenic emissions (biogenics and fires[33]) are appropriately excluded from this analysis. The proportionalities of the sulfate and nitrate emissions by category are charted in Figure 5-4.

Table 5-9. Predicted 2028 anthropogenic emissions proportionality and conservative LGS and WSEC apportionments.

Category	SO_2			NO_X		
	tpy	% Total	Total EGU Apportionment	tpy	% Total	Total EGU Apportionment
LGS	5,605	15.8%	28.5%	3,403	3.5%	8.0%
WSEC (3 & 4)	9,897	27.8%	50.3%	6,025	6.3%	14.2%
All other IA EGUs	12,501	35.2%		12,013	12.5%	
Point-EGU	28,002	78.8%	78.8%	21,442	22.2%	22.2%
Point-nonEGU	6,784	19.1%		19,210	19.9%	
Nonpoint	576	1.6%		22,667	23.5%	
Nonroad	39	0.1%		14,163	14.7%	
Onroad	137	0.4%		18,917	19.6%	
Total	35,538	100%		96,398	100%	

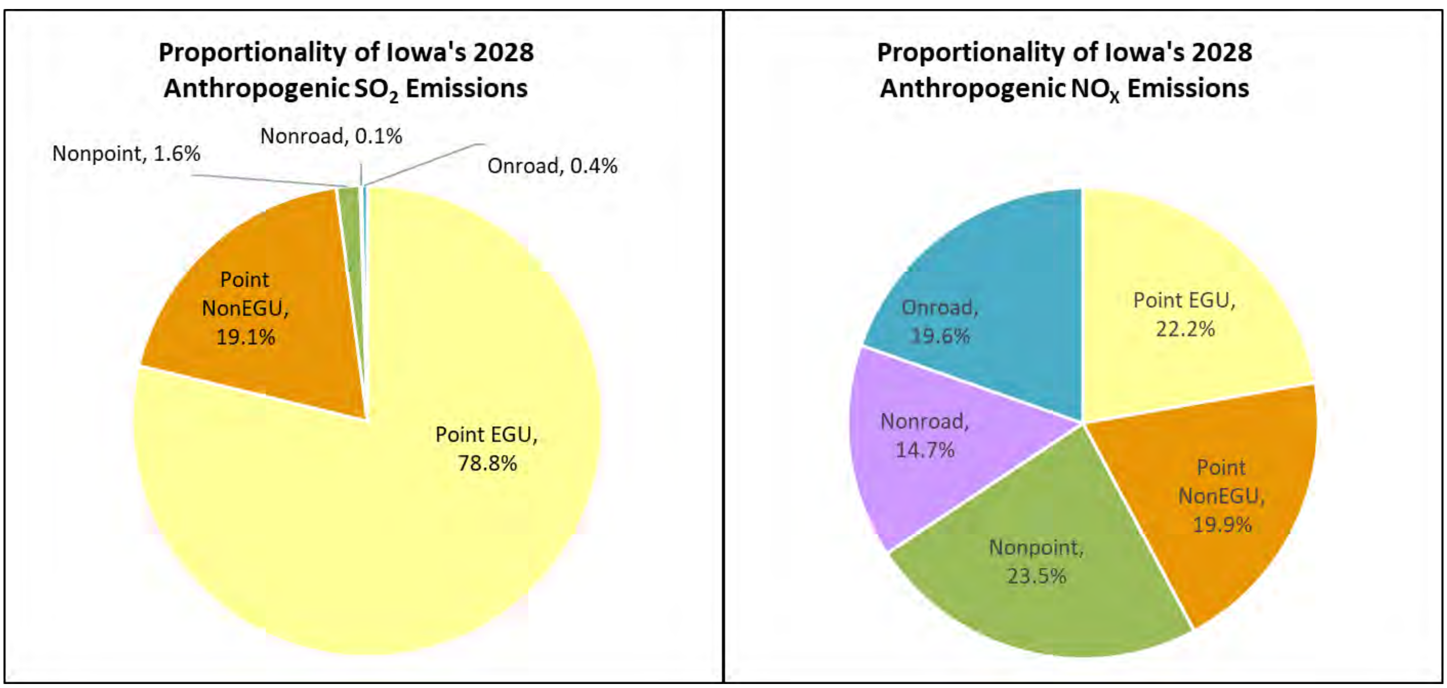

Figure 5-4. Source category percentages for Iowa's projected 2028 SO_2 and NO_X anthropogenic emissions.

[33] For consistency with the PSAT results, ag fires were considered a non-anthropogenic source (ag burning is uncommon in Iowa).

Point sources are projected to emit nearly 98% of all Iowa's 2028 SO_2 emissions, with EGUs accounting for 78.8% of the state total. The categorical differences in the 2028 NO_X emissions are far less pronounced, with each of the five categories responsible for similar shares, from 14.7% to 23.5%. Table 5-9 also shows that LGS and WSEC account for 15.8% and 27.8% of Iowa's total 2028 anthropogenic SO_2 emissions, respectively, and 3.5% and 6.3% of Iowa's total 2028 anthropogenic NO_X emissions. Multiplying those percentages by Iowa's modeled visibility impact (in Mm^{-1}, from Table 5-7) for the given pollutant for a given Class I area would yield an estimate of the visibility impairment attributable to LGS and WSEC at a given Class I area. This is a potentially reasonable methodology when lacking facility-level source apportion modeling or zero-out runs. However, the DNR is modifying this approach in two ways to produce a more conservative assessment.

First, all forecasted EGU emissions in Iowa will be apportioned between LGS and WSEC. This is analogous to assuming that LGS and WSEC are the only EGUs in Iowa but that they emit the entirety of the state's projected 2028 EGU SO_2 and NO_X emissions totals. This total apportionment is split between LGS and WSEC based on the per-pollutant ratio of each facility's emissions to the sum of their emissions.[34] This increases LGS's SO_2 apportionment from 15.8% to 28.5% and WSEC's apportionment from 27.8% to 50.3%, as provided above in Table 5-9. Using the same methodology, the resulting NO_X apportionments for LGS and WSEC are 8.0% and 14.2%, respectively. As designed, the apportioned percentages still sum to the point-EGU category totals, 78.8% for SO_2 and 22.2% for NO_X. For WSEC, the apportionment is based on the total emissions from Units 3 and 4 combined, this is analogous to assuming that Unit 3 is also responsible for the emissions from Unit 4. This simplifying assumption is reasonable as Unit 3 currently emits the majority of WSEC's total SO_2 and NO_X emissions.

The second conservative assumption is to use the maximum sulfate and nitrate impacts identified in Table 5-7 to calculate estimated visibility impacts (and not values specific to each Class I area). Table 5-10 provides the resulting maximum estimated sulfate and nitrate visibility impacts attributable to LGS and WSEC on the 20% most impaired days in 2028 that may be assumed to impact any of the LADCO or HEGL Class I areas. LGS's estimated sulfate contribution is 0.285 Mm^{-1} (1.000 Mm^{-1} * 28.5%) and its nitrate contribution is 0.064 Mm^{-1} (0.798 Mm^{-1} * 8.0%). The corresponding sulfate and nitrate impacts for WSEC are 0.503 Mm^{-1} and 0.133 Mm^{-1}, respectively. In both cases, the sulfate impacts are 4.4 times the nitrate impacts.

Table 5-10. Conservative visibility impairment estimates attributed to LGS and WSEC on the 20% most impaired days.

Source	Sulfate Impacts (Mm^{-1})	Nitrate Impacts (Mm^{-1})	Sulfate vs Nitrate Impacts Ratio
Louisa Generating Station	0.285	0.064	4.4
Walter Scott Jr Energy Center	0.503	0.113	4.4

5.9. Control Measure Decisions

Louisa Generating Station

After considering all the statutory factors, the Iowa DNR determined that implementing operational improvements to the existing dry FGD system at LGS to reduce SO_2 emissions is a reasonable control option. In comparison, the estimated cost effectiveness of installing a new wet FGD system is not considered reasonable due to the high cost coupled with the estimated incremental decrease in SO_2 emissions being relatively small (less than ~14% versus baseline conditions). A wet FGD system would also incur estimated incremental costs that exceed $50,000/ton. In contrast to wet FGD, the required operational improvements to the existing dry FGD system will not require a capital expenditure, the estimated cost effectiveness is less than $300/ton, and the SO_2 emissions reductions will occur expeditiously (versus the 5 years needed for wet FGD). The operational improvements to the existing dry FGD system at LGS is a cost-effective SO_2 control option that provides for reasonable progress.

After considering all the statutory factors and the optional visibility impacts data, the Iowa DNR determined that the addition of SNCR or SCR systems on LGS to further control NO_X emissions is not cost effective or reasonable at this time.

[34] For example, the SO_2 apportionment for LGS is calculated as follows: 78.8% * (5,605 / (5,605 + 9,897)) = 28.5%. The NO_X apportionment for LGS is: 22.2% * (3,403 / (3,403 + 6,025)) = 8.0%.

The estimated cost effectiveness of both options exceeds approximately $6,000/ton[35] while at the same time NO_X reductions from Iowa's EGUs are less effective at improving visibility versus SO_2 reductions. The requirement to install additional NO_X controls (SNCR or SCR) at LGS is not considered cost effective based on the high capital control costs, projected boiler operation, and the estimated visibility benefits from SO_2 reductions at Iowa EGU sources exceeding those of NO_X by greater than a factor of 4.

Walter Scott Jr Energy Center – Unit 3

After considering all the statutory factors, the Iowa DNR determined that implementing operational improvements to the existing dry FGD system at WSEC-3 to reduce SO_2 emissions is a reasonable control option. In comparison, the estimated cost effectiveness of installing a new wet FGD system is not considered reasonable due to the high cost coupled with the estimated incremental decrease in SO_2 emissions being relatively small (less than ~11% versus baseline conditions). A wet FGD system would also incur estimated incremental costs that exceed $44,000/ton. In contrast to wet FGD, the required operational improvements to the existing dry FGD system will not require a capital expenditure, the estimated cost effectiveness is less than $300/ton, and the SO_2 emissions reductions will occur expeditiously (versus the 5 years needed for wet FGD). The operational improvements to the existing dry FGD system at WSEC-3 is a cost-effective SO_2 control option that provides for reasonable progress.

After considering all the statutory factors and the optional visibility impacts data, the Iowa DNR determined that the addition of SNCR or SCR systems on WSEC-3 to further control NO_X emissions is not cost effective or reasonable at this time. The estimated cost effectiveness of both options exceeds approximately $5,000/ton[35] while at the same time NO_X reductions from Iowa's EGUs are less effective at improving visibility versus SO_2 reductions. The requirement to install additional NO_X controls (SNCR or SCR) at WSEC-3 is not considered cost effective based on the high capital control costs, projected boiler operation, and the estimated visibility benefits from SO_2 reductions at Iowa EGU sources exceeding those of NO_X by greater than a factor of 4.

Summary

In conclusion, the implementation of operational improvements to the existing dry FGD systems at both LGS and WSEC-3 will satisfy Iowa's reasonable progress requirements for the second implementation period of the RHR. This control option is the most cost effective and the DNR's analysis shows that the visibility benefits of reducing SO_2 emissions from LGS and WSEC-3 significantly exceed those of reducing NO_X emissions. Improvements to the existing FGD systems at both LGS and WSEC-3 are expected to cost less than $300/ton (2019$) and will reduce actual SO_2 emissions by an estimated 9,688 tons per year, as summarized in Table 5-11.

Table 5-11. Actual SO_2 emission reduction estimates from operational improvements to the existing dry FGD systems.

Source	Baseline SO_2 Emissions [2017-2019 Average] (tpy)	SO_2 Emissions after Dry FGD Improvements (tpy)	Estimated Change in Actual SO_2 Emissions (tpy)
Louisa Generating Station (main boiler)	5,952	2,049	-3,903
Walter Scott Jr. Energy Center – Unit 3	8,041	2,256	-5,785
Total	**13,993**	**4,305**	**-9,688**

[35] The estimated cost effectiveness assumes an SNCR control efficiency of 15%, based on boiler type, size, age, and load-variability. MidAmerican and the Iowa DNR also investigated the impact of achieving a higher NO_X control efficiency of 20%. This evaluation had a marginal impact on the cost effectiveness and did not change the Iowa DNR's conclusion that SNCR is not a cost-effective control option for regional haze at this time.

6. Long-Term Strategy

In 40 CFR 51.308(f)(2) EPA requires that a state's long-term strategy (LTS) include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress, as determined pursuant to (f)(2)(i) through (iv). Based on the conclusions from the four-factor analysis, Iowa's LTS must include the requirements that LGS and WSEC-3 implement operational improvements to their existing dry FGD systems.

6.1. Emission Limits and Compliance Schedules

To establish enforceable emissions limits and compliance schedules for the LTS, the DNR modified the air construction permits for the main boiler at LGS and WSEC-3. Table 6-1 identifies the modified permit numbers and summarizes the new SO_2 permit conditions associated with the LTS. Both permits include a new SO_2 emission limit expressed in terms of a lb/hr mass rate. Each new SO_2 limit is comparable to a 0.10 lb/MMBtu load-varying limit because the modified permits further require that MidAmerican develop minimum additive injection rates to maintain high SO_2 control efficiencies at all operating loads. Compliance with the new limits must begin by December 31, 2023 (and is not tied SIP approval).

All air construction permits issued by the DNR are federally enforceable by their issuance under Iowa's SIP-approved preconstruction permitting program. Including the permits with this SIP makes the conditions permanent (meaning they cannot be subsequently revised without an EPA-approved SIP revision). The DNR issued both permits on July 20,2023, and both are included in Appendix E. Appendix E also includes the current permit for WSEC-4, 03-A-425-P4, to incorporate its existing SO_2 and NO_X limits into Iowa's SIP for the purpose of preventing future visibility impairment.

Table 6-1. Emission limit and compliance summary for the scrubber improvements at LGS and WSEC-3.

Facility – Unit	DNR Facility ID	Construction Permit Number	New SO_2 Limit (30 Day-Rolling Average)[a]	Compliance Date	Compliance Measures
Louisa Generating Station – Main Boiler	58-07-001	05-A-031-P6	800 lb/hr	12/31/2023	CEMS
Walter Scott Jr Energy Center – Unit 3	78-01-026	75-A-357-P9	770 lb/hr	12/31/2023	CEMS

[a]Both permits also include new requirements (in Conditions 5.Q and 5.R) to reduce SO_2 emissions at varying boiler operating loads.

Both LGS and WSEC-3 have existing low-NO_X burners and overfire air control systems that are utilized to maintain NO_X emissions at current performance levels. These controls provide consistent short-term NO_X performance and are an inherent function of each boiler's current combustion control equipment design. The control equipment cannot be altered, removed, or replaced without Iowa DNR approval, per 567 IAC 22.1. Additionally, 567 IAC 24.2(1)"a" requires that MidAmerican maintain and operate the control equipment at all times in a manner consistent with good practice for minimizing emissions.

In forecasting future boiler operations, MidAmerican anticipates that the use of LGS and WSEC-3 will decrease through 2028 due to the increased integration of renewable energy. However, for purposes of the four-factor analysis, MidAmerican conservatively assumed that future boiler utilization, and thus future emissions, will not decrease but will instead remain unchanged from the 2017-2019 baseline period. Based on each boiler's inherent control system and anticipated operation, the Iowa DNR projects that actual NO_X emissions from these units will not significantly increase above the baseline average. Therefore, no additional NO_X permit restrictions are needed at this time for LGS or WSEC-3.

6.2. Additional LTS Obligations

Iowa's LTS also considers the following additional factors, as required by 51.308(f)(2)(iv):

A. Emission reductions due to ongoing air pollution control programs, including measures to address RAVI;
B. Measures to mitigate the impacts of construction activities;
C. Source retirement and replacement schedules;
D. Basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs; and
E. The anticipated net effect on visibility due to projected changes in point, area [nonpoint], and mobile source emissions over the period addressed by the LTS. (This is addressed in Chapter 8.)

6.2.1. Emission Reductions Due to Ongoing Programs

Numerous ongoing federal and state air pollution control programs will continue to contribute to emissions reductions in Iowa and associated visibility improvements in the LADCO and HEGL Class I areas. Iowa's LTS for the second implementation period (2019-2028) builds on the success of the programs considered during the first implementation period and incorporates additional reductions from new regulations and control measures, as discussed below.

6.2.1.1. Federal Programs Summary Tables

The two tables below identify the federal programs likely to provide the most visibility co-benefits. Table 6-2 summarizes the federal control programs incorporated in the first implementation period of the RHR and Table 6-3 includes more recent federal programs that will further improve visibility for the second implementation period. As a practical matter, neither table represents a comprehensive list of all federal programs that could theoretically benefit visibility.

Table 6-2. Federal control programs considered in the first implementation period.

Source Category	Control Program	Rule Published	Federal Register	Initial Implementation Year(s)
Onroad	Tier 2 Vehicle and Gasoline Sulfur Standards	2/10/2000	65 FR 6697	2004-2009
	2004 and Later Model Year Heavy-Duty Highway Engines and Vehicles Rule	10/6/2000	65 FR 59895	2004
	2007 Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements	1/18/2001	66 FR 5001	2006 (diesel fuel) 2007-2010 (engines)
Nonroad	Large Spark-Ignition Engines and Recreational (Marine and Land-Based) Engine Standards	11/8/2002	67 FR 68241	2004-2012
	Tier 4 Nonroad Diesel Engines and Diesel Fuel Rule [Clean Air Nonroad Diesel Rule]	6/29/2004	69 FR 38957	2007-2010 (diesel fuel) 2008-2014 (engines)
Point-EGU	Clean Air Interstate Rule (CAIR); remanded in 2008	5/12/2005	70 FR 25161	2009-2010
	Cross-State Air Pollution Rule (CSAPR); replaced CAIR	8/8/2011	76 FR 48207	2015-2017
Point - nonEGU	Reciprocating Internal Combustion Engines (RICE) Standards for Hazardous Air Pollutants	6/15/2004	69 FR 33473	2013

Table 6-3. Federal control programs considered in the second implementation period.

Source Category	Control Program	Rule Published	Federal Register	Initial Implementation Year(s)
Onroad	Greenhouse Gas & Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles (Phase 1)	9/15/2011	76 FR 57105	2014-2018
	Tier 3 Vehicle and Gasoline Sulfur Standards	4/28/2014	79 FR 23413	2017-2025
Nonroad	Standards for Locomotive Engines and Marine Compression-Ignition Engines <30 Liters per Cylinder	6/30/2008	73 FR 37095	2008-2015
	Emissions Standards for New Nonroad [Small] Spark-Ignition Engines, Equipment, and Vessels	10/8/2008	73 FR 59033	2010-2012
	Category 3 Marine Diesel Engine Standards	4/30/2010	75 FR 22895	2016
Point-EGU	Mercury and Air Toxics Standard (MATS)	2/16/2012	77 FR 9303	2015-2017
	CSAPR Update	10/26/2016	81 FR 74504	2017
Point-nonEGU	Major Source Industrial, Commercial, and Institutional (ICI) Boiler MACT	1/31/2013	78 FR 7137	2013 (new) 2016 (existing)

6.2.1.2. Federal Control Programs for the First Implementation Period (2009-2018)

The federal programs considered in the LTS for the first implementation period will maintain or provide additional visibility benefits through the second implementation period. Reductions beyond those achieved during the first implementation period are expected from the onroad and nonroad engine and equipment standards because of ongoing fleet-vehicle and equipment turnover (*i.e*., replacement of older vehicles or equipment with newer vehicles or equipment). In the summaries that follow, the order is not an indicator of importance.

Onroad: Tier 2 Vehicle and Gasoline Sulfur Standards

The Tier 2 vehicle standards phase-in began in 2004 for new passenger cars and light light-duty trucks, with full implementation in the 2007 model year. These standards, published on February 10, 2000, required passenger vehicles in each manufacturer's fleet to meet an average standard of 0.07 grams of NO_X per mile by 2007. The Tier 2 standards also covered passenger vehicles over 8,500 pounds gross vehicle weight rating (*i.e.*, larger pickup trucks and sport utility vehicles). For these vehicles, the standards were phased in beginning in 2008, with full compliance required by 2009. The Tier 2 standards required vehicles to be 77% to 95% cleaner than previous models. Beginning in 2004, fuel standards required that most refiners and importers meet a corporate average gasoline sulfur standard of 120 parts per million (ppm), and a cap of 300 ppm. In January 2006, the sulfur content of gasoline was required to average 30 ppm. Lower sulfur content gasoline assists in lowering NO_X emissions by increasing the efficiency of the catalytic converter.

Onroad: 2004 and Later Model Year Heavy-Duty Highway Engines and Vehicles Rule

On October 6, 2000, EPA published a final rule for a major new program to reduce emissions from on-highway heavy-duty engines and vehicles. It was the first of a multi-phase program designed to provide cleaner air. In this first phase, EPA finalized new diesel engine standards beginning with model year 2004 for all diesel vehicles over 8,500 pounds and heavy-duty gasoline engine standards beginning with model year 2005. The standards required diesel trucks to be more than 40% cleaner than the current models available at that time and gasoline trucks to be 78% cleaner. The rule also phased in on-board diagnostic (OBD) systems for gas and diesel engines for vehicles between 8,500 and 14,000 pounds.

Onroad: 2007 Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements

On January 18, 2001, EPA promulgated the second phase of the on-highway heavy-duty engines and vehicles program. A new PM emission standard for new heavy-duty diesel engines took full effect in the 2007 model year. Standards for NO_X and non-methane hydrocarbons (NMHC) were phased in together between 2007 and 2010 for diesel engines. The standards were based on the use of high-efficiency catalytic exhaust control devices or comparably effective advanced technologies. Because these devices are damaged by sulfur, EPA reduced the level of sulfur in highway diesel fuel by 97% by mid-2006, permitting a maximum sulfur content of 15 ppm. This diesel fuel is commonly referred to as ultra-low sulfur diesel (ULSD). The sulfur content of diesel fuel used on highways before 2006 was typically 500 ppm. Heavy-duty gasoline engines were subject to new standards based on a phase-in requiring 50% compliance in the 2008 model year and 100% compliance in the 2009 model year. Under the combined effects of the first phase and this second phase rule, EPA projected NO_X reductions of 2,570,000 tons, PM reductions of 109,000 tons, and NMHC reductions of 115,000 tons by 2030 (when the then-current heavy-duty vehicle fleet is replaced with newer heavy-duty vehicles). These emissions reductions were on par with those for passenger vehicles and low sulfur gasoline requirements under the Tier 2 rule.

Nonroad: Large Spark-Ignition Engines and Recreational (Marine and Land-Based) Engine Standards

On November 8, 2002, EPA adopted emission standards for engines in three types of nonroad equipment:

- Large Industrial Spark-Ignition Engines: Spark-ignition nonroad engines powered by gasoline, liquid propane gas, or compressed natural gas rated over 19 kilowatts (kW) (25 horsepower). These engines are used in commercial and industrial applications, including forklifts, electric generators, airport baggage transport vehicles, and a variety of farm and construction applications.
- Diesel Marine Engines: Diesel engines over 37 kW (50 horsepower) used in recreational boats.
- Recreational Vehicles: Snowmobiles, off-highway motorcycles, and all-terrain vehicles.

These emission standards were phased in from model years 2004 through 2012. By 2020, EPA anticipated the impacts of this rule to include a 72% reduction in VOC emissions and an 80% reduction in NO_X emissions from these engines.

Nonroad: Tier 4 Nonroad Diesel Engines and Diesel Fuel Rule

The Clean Air Nonroad Diesel Rule, finalized by EPA on June 29, 2004, established the Tier 4 emission standards for nonroad diesel engines and sulfur reductions in nonroad diesel fuel. The new emission standards applied to diesel engines used in most construction, agricultural, industrial, and airport equipment. The standards took effect for new engines beginning in 2008 and were fully phased in for most engines by 2014. Exhaust emissions from these engines were to decrease by more than 90%. This rule also included a two-step process limiting the sulfur content of nonroad diesel fuel from then-current levels of about 3,000 ppm to 15 ppm (a reduction greater than 99%). First, starting in 2007, fuel sulfur levels in nonroad diesel fuel were limited to 500 ppm. That limit also covered fuels used in locomotive and marine applications (though not the marine residual fuel used by very large engines in ocean-going vessels). Second, starting in 2010, the sulfur level in most nonroad diesel fuel was reduced to 15 ppm. In the case of locomotive and marine diesel fuel, this second step occurred in 2012.

Point-EGU: CAIR and CSAPR

On May 12, 2005, EPA promulgated the Clean Air Interstate Rule (CAIR) to help downwind nonattainment and maintenance areas attain and maintain the 1997 $PM_{2.5}$ and ozone national ambient air quality standards (NAAQS) by reducing SO_2 and NO_X emissions. CAIR established federal trading programs involving 28 eastern states. EGUs in Iowa participated in all three CAIR trading programs, capping annual SO_2 emissions, annual NO_X emissions, and ozone season (OS) NO_X emissions. The NO_X and SO_2 emissions budgets for CAIR's first phase were implemented in 2009 and 2010, respectively. The DNR relied on participation in CAIR to satisfy Best Available Retrofit Technology (BART) requirements for Iowa's BART-eligible EGUs and to satisfy LTS obligations for the first implementation period.

The D.C. Circuit Court remanded CAIR in 2008 and on August 8, 2011, EPA replaced CAIR with the Cross-State Air Pollution Rule (CSAPR). The DNR later revised Iowa's RH SIP to replace reliance on CAIR with reliance on CSAPR.[36] CSAPR implemented its first-phase of NO_X and SO_2 emission budgets in 2015 and 2016, respectively.

Point-nonEGU: RICE NESHAP

On June 15, 2004, EPA finalized the first regulation for stationary reciprocating internal combustion engines (RICE) greater than 500 horsepower located at major sources of hazardous air pollutants (HAPs). While focused on HAPs, the RICE NESHAP (National Emissions Standards for Hazardous Air Pollutants) provided co-benefits through reductions in NO_X, PM, SO_2, and VOC. RICE owners and operators were required to comply with the NESHAP by May 3, 2013.

6.2.1.3. Federal Control Programs for the Second Implementation Period (2019-2028)

The federal programs reviewed below were finalized after the development of the RH SIP for the first implementation period. Rules not incorporated into LADCO's 2028_{2016} modeling platform are excluded. The LADCO 2028_{2016} emissions modeling inventory is largely based[37] on EPA's "2016fh" emissions modeling platform, which EPA documents in its March 2021 TSD: "*Preparation of Emissions Inventories for the 2016v1 North American Emissions Modeling Platform.*" [38]

Onroad: Greenhouse Gas and Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles (Phase 1)

Although this September 15, 2011, rule regulates greenhouse gas (GHG) pollutants, EPA expects reductions in downstream emissions of non-GHG pollutants, such as NO_X and SO_2. These reductions are expected due to reduced fuel use from improvements in road load (aerodynamics and tire rolling resistance) and increased use of auxiliary power units (APU) during extended idling. By 2030, these Phase 1 standards are expected to reduce NO_X by over 245,000 tons and SO_2 by over 6,800 tons.[39]

Onroad: Tier 3 Vehicle and Gasoline Sulfur Standards

On April 28, 2014, EPA set Tier 3 standards for new vehicle emissions starting in 2017 and lowered the sulfur content of gasoline, based on the vehicle and its fuel as an integrated system. The vehicle standards reduce both tailpipe and

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[36] A copy of this SIP revision is available under the Regional Haze section of the DNR's Implementation Plans web page.

[37] The exceptions are documented in LADCO's TSD (Appendix A-1) and include, for example, utilizing ERTAC results instead of IPM.

[38] EPA's TSD notes that onroad regulations finalized after the year 2014 were not incorporated into the MOVES201b model run for 2028. Thus, the onroad forecast does not include the Safer Affordable Fuel Efficient (SAFE) Vehicles Final Rule for Model Years 2021-2026 or the Phase 2 GHG Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles.

[39] These emissions reductions estimates were adapted from TABLE VII–5 in 76 FR 57105 (published September 15, 2011).

evaporative emissions from passenger cars, light-duty trucks, medium-duty passenger vehicles, and some heavy-duty vehicles. Full implementation will occur by 2025. Starting on January 1, 2017, Tier 3 limited the annual average gasoline sulfur content to 10 ppm. By 2030, it is anticipated that the Tier 3 program will reduce NO_X emissions by over 300,000 tons and SO_2 emissions by over 12,000 tons.

Nonroad: Standards for Locomotive Engines and Marine Compression-Ignition Engines Less Than 30 Liters per Cylinder
On June 30, 2008, EPA adopted a three-part program to: (1) tighten emission standards for existing locomotives and large marine diesel engines when they are remanufactured; (2) set near-term engine-out emissions standards, referred to as Tier 3 standards, for newly-built locomotives and marine diesel engines; and (3) set longer-term standards, referred to as Tier 4 standards, for newly-built locomotives and marine diesel engines. Sources impacted include:

- Locomotives: With some limited exceptions, the regulations apply to all diesel line-haul, passenger, and switch locomotives that operate extensively within the United States including newly manufactured locomotives and remanufactured locomotives that were originally manufactured after 1972.
- Marine Diesel Engines: The regulations apply to both newly manufactured marine diesel engines and remanufactured commercial marine diesel engines above 600 kW or 800 horsepower with displacement less than 30 liters per cylinder installed on vessels flagged or registered in the U.S.

These standards were phased in between 2008 and 2015 and were enabled by ULSD fuel availability. EPA estimates that by 2030 this program will reduce annual emissions of NO_X and PM by ~800,000 and ~27,000 tons, respectively.

Nonroad: Emissions Standards for New [Small] Nonroad Spark-Ignition Engines, Equipment, and Vessels
On October 8, 2008, EPA established new exhaust and evaporative emission standards for:

- Small nonroad spark-ignition engines and equipment. Spark-ignition nonroad engines rated below 25 horsepower (19 kW) used in household and commercial applications, including lawn and garden equipment, utility vehicles, generators, and a variety of other construction, farm, and industrial equipment.
- Marine Spark-Ignition Engines and Vessels: Spark-ignition engines used in marine vessels, including outboard engines, personal watercraft, and sterndrive/inboard engines.

This rule also included a wide range of amendments to other highway and nonroad programs. EPA estimated that by 2030, the new standards will reduce VOC emissions by ~600,000 tons, NO_X emissions by ~130,000 tons, and $PM_{2.5}$ emissions by ~5,500 tons.

Nonroad: Category 3 Marine Diesel Engine Standards
On April 30, 2010, EPA finalized two additional tiers (Tiers 2 and 3) of NO_X standards for new marine diesel engines with per-cylinder displacement at or above 30 liters (called Category 3 marine diesel engines). The Tier 2 emission standards were applied beginning in 2011 and the Tier 3 emission standards were applied beginning in 2016. By 2030, this rule is expected to reduce annual NO_X emissions in the U.S. by ~1,200,000 tons and PM emissions by ~143,000 tons. While these large engines typically power ocean-going vessels and aren't in use in or near Iowa, they may propel large cargo ships operating in the Great Lakes and thus these rules could be of benefit to Class I areas in the upper Midwest.

Point-EGU: Mercury and Air Toxics Standard (MATS)
On February 16, 2012, EPA promulgated MATS to reduce mercury and other toxics from new and existing coal and oil-fired EGUs. MATS established numerical emission limits for mercury, PM (a surrogate for toxic non-mercury metals), and HCl (a surrogate for all toxic acid gases). Controls to reduce HCl often have the co-benefit of reducing SO_2 emissions. Sources had until April 16, 2015, to comply with the rule, unless granted a one-year extension for control installation or an additional extension for reliability reasons, with all sources required to comply by April 2017. Reductions in EGU SO_2 emissions occurred as a co-benefit of limiting acid gas emissions or by direct compliance with the MATS alternative SO_2 emission limit. Units that converted from burning coal to combusting only natural gas eliminated nearly all their SO_2 emissions and a significant portion of their NO_X emissions.

Point-EGU: CSAPR Update

On October 26, 2016, EPA published the CSAPR Update rule, establishing the new Group 2 ozone season NO_X trading program to partially[40] address CAA 110(a)(2)(D)(i)(I) "good neighbor" requirements for the 2008 ozone NAAQS. This rule established more stringent ozone season NO_X budgets for 22 states in the eastern U.S. Starting in 2017, it reduced Iowa's ozone season NO_X budget from 16,207 tons to 11,272 tons.

Point-nonEGU: Major Source Industrial, Commercial, and Institutional (ICI) Boiler NESHAP (Boiler MACT)

On September 13, 2004, EPA promulgated the NESHAP for Industrial, Commercial, and Institutional (ICI) Boilers and Process Heaters, requiring major sources of HAPs to meet emissions standards reflecting the application of the maximum achievable control technology (MACT). This rule is often referred to as the Boiler MACT. While its impacts were considered during the first implementation period, the rule was vacated and remanded by the D.C. Circuit Court on July 30, 2007. EPA addressed the court decision in a March 21, 2011, rulemaking, but simultaneously announced plans to reconsider certain issues. On January 31, 2013, EPA finalized the reconsideration and established the 2013 and 2016 compliance dates for new and existing affected sources, respectively. The compliance deadlines for new and existing sources have passed and the measures implemented to reduce HAP emissions have yielded NO_X and SO_2 co-benefits. The largest reductions occurred at affected sources that converted (for various reasons) from coal to natural gas.

6.2.1.4. State Programs

The DNR implements major and minor new source review (NSR) programs and issues prevention of significant deterioration (PSD)permits, major and minor source air construction permits, and permits by rule. These and other actions yield visibility co-benefits. The control measures in the DNR's May 2016 attainment plan for the Muscatine 1-hour SO_2 nonattainment area reduced SO_2 emissions in the area by over 10,000 tons per year.

The DNR's compliance and enforcement actions also benefit visibility. For example, the September 2, 2015, Consent Decree between Interstate Power and Light Co. (IPL) and plaintiffs EPA, Iowa, Linn County, and Sierra Club (Case 1:15-cv-00061-EJM) required the installation of SCR at Ottumwa Generating Station and the refueling or retiring of units at the Burlington, Dubuque, Prairie Creek, and Sutherland facilities.

6.2.2. Measures to Mitigate the Impacts of Construction Activities

The Iowa DNR's rules on fugitive dust (567 IAC 23.3(2)"c") require that reasonable precautions be taken to prevent the discharge of visible emissions of airborne dust beyond the lot line of the property from which the emissions originated. The Iowa DNR also requires minor NSR permits for aggregate processing plants, concrete batch plants, and asphalt plants. Portable aggregate, concrete, or asphalt plants must notify the Iowa DNR at least 7 days (14 in some cases) before transferring the equipment to a new location to allow for review of the emissions impacts. The DNR would notify the portable plant if there are potential adverse NAAQS impacts. A more stringent emission standard and the installation of additional control equipment would be required if the relocation would prevent attainment or maintenance of the NAAQS. The DNR has determined that no additional measures are needed to mitigate the impacts of construction activities for purposes of the RHR. General construction activities in Iowa will not impact visibility impairment in Class I areas due to the extensive transport distances in combination with their relatively low emissions and release heights.

6.2.3. Source Retirement and Replacement Schedules

The Iowa DNR regularly updates the ERTAC input files, and the National Electric Energy Data System (NEEDS) database for the Integrated Planning Model (IPM), to incorporate publicly known Iowa EGU source retirement, replacement, and refueling (repowering) schedules. LADCO's 2018_{2016} modeling platform includes schedules known to the DNR as of the September 2020 outreach window for the LADCO-modified ERTAC v16.1 run, as summarized in Table 6-4. By default, all EGU modifications completed before 2016 are fully incorporated into the base year and need not be listed in this table. For reference, in the 2002 base year for the first implementation period, Iowa contained 37 active coal-fired units reporting emissions to CAMD. As of May 2022, that number was 10, a nearly four-fold reduction.

[40] EPA published the "Revised CSAPR Update" on April 30, 2021, in response to the D.C. Circuit remanding the CSAPR Update for failing to eliminate all significant contributions related to the 2008 O_3 NAAQS. In the Revised rule, EPA found that Iowa and 8 other states had eliminated their significant contributions and were not included in the new Group 3 ozone season NO_X trading program.

Table 6-4. Iowa EGU source retirements, refuelings, or replacements that occurred during or after the 2016 base year.

CAMD Facility Name	Unit(s)	ORIS ID	DNR Facility ID	Nameplate Capacity (MW)	Description of Change [source type, if not a coal-fired boiler]	Year
Ames	7, 8	1122	85-01-006	108.8 (total)	Refueled from coal to natural gas	2016
Burlington	1	1104	29-01-013	212.0	Ceased burning coal	2021
Centerville	1, 2	1105	04-01-003	27.0 (each)	Retired [diesel combustion turbines (CT)]	2017
Dubuque	1, 5, 6	1046	31-01-017	81.2 (total)	Retired [refueled (coal to gas) boiler]	2017
George Neal North	1, 2	1091	97-04-010	496.2 (total)	Retired	2016
Grinnell	1, 2	7137	79-01-022	~25 (each)	Retired [natural gas CTs]	2017
Marshalltown CTs	1A-3B	1068	64-01-012	189.0 (total)	Refueled from diesel to natural gas [6 CTs]	2017
Marshalltown Generating Station	CT1, CT2	58236	64-01-012	705.9 (total)	New natural gas combined cycle combustion turbines	2017
ML Kapp	2	1048	23-01-014	218.5	Retired [refueled (coal to gas) boiler]	2018
Prairie Creek[41]	4	1073	57-01-042	148.8	Refueled from coal to natural gas	2017
Sutherland	1, 3	1077	64-01-012	75.0 (total)	Retired [refueled (coal to gas) boiler] and replaced by Marshalltown Generating Station	2017

The DNR expects additional changes will occur in Iowa's EGU sector. For example, the ERTAC v16.1 results predate IPL's decision to retire Lansing Unit 4 by the end of 2022. Additionally, Muscatine Power and Water (MPW) plans to retire two of its three coal-fired boilers (Units 7 and 8) prior to December 31, 2028, and is conducting a power supply study to evaluate future options regarding Unit 9. Although these anticipated actions are not incorporated into or relied upon to meet Iowa's LTS obligations, they will further reduce SO_2 and NO_X emissions when implemented.

6.2.4. Smoke Management

In 40 CFR 51.308(f)(2)(iv)(D) EPA requires that the state's LTS consider basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs. Iowa typically burns less than a combined ~30,000 acres per year for prescribed fire and agricultural burning purposes,[42] which is considerably less than most other states.

The DNR has not adopted a statewide smoke management program at this time, but it does have a Prescribed Fire Policy[43] for departmental use. Source apportionment modeling conducted by CENRAP for the first implementation period demonstrated that fires in Iowa do not significantly contribute to visibility impairment in Class I areas. This conclusion is still valid, as discussed below. There is no need to include a smoke management plan (SMP) in this SIP revision.

Growth in Iowa's prescribed fire activities over the last 20 years has been minimal and agricultural fires (crop reside burning) in Iowa remain uncommon. LADCO's 2028_{2016} PSAT results indicate that all U.S. fires (the combined impacts from wildfire (which is a natural source), prescribed fires, and agricultural fires from all states) contribute only approximately 1 to 2% of the total visibility impact on the 20% most impaired days at the LADCO Class I areas and approximately 5% at HEGL. Iowa's total prescribed fire and agricultural fire emissions represent less than 1% of the 2017 U.S. totals, as shown in Table 6-5 and Table 6-6.

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[41] By Consent Decree, Prairie Creek Unit 3 must either retire or refuel by the end of 2025. To be conservative, the DNR updated the ERTAC files assuming this unit would convert to natural gas, rather than shutdown.

[42] Additional Iowa acres may be burned in events categorized by EPA as wildfires, but wildfire emissions are considered a natural source pursuant to the regional haze rule and do not contribute to (manmade) visibility impairment.

[43] The DNR's Fire Policy guides the effective and safe use of fire as a tool for ecological restoration and maintenance of Iowa's natural areas on state owned, leased, or managed lands, other public lands, and private lands for which landowners seek the advice and consult of the DNR and declare their intention to use fire as a management tool. The DNR's Fire Policy includes a smoke management plan that must be followed for all DNR prescribed burns to minimize smoke impacts.

Table 6-5. 2017 NEI prescribed fire emissions, in tons per year.

	VOC	NO_X	SO_2	PM_{10}-PRI	$PM_{2.5}$-PRI	NH_3
Iowa	4,138	266	140	1,805	1,530	288
U.S. Total	2,042,075	164,697	78,191	948,309	805,307	144,913
% U.S. Total	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%

Table 6-6. 2017 NEI agricultural field burning emissions, in tons per year.

	VOC	NO_X	SO_2	PM_{10}-PRI	$PM_{2.5}$-PRI	NH_3
Iowa	141	33	6	231	169	106
U.S. Total	38,061	12,706	4,237	42,933	30,776	63,460
% U.S. Total	0.4%	0.3%	0.1%	0.5%	0.5%	0.2%

7. Emissions Inventory

In 40 CFR 51.308(f)(6)(v) EPA requires states to provide for an emissions inventory of visibility impairing pollutants for a current and future year. Iowa's compliance with the Air Emissions Reporting Requirements (AERR) in 40 CFR Part 51 Subpart A and Iowa's engagement in regional activities related to emissions growth and forecasting satisfy these requirements. While EPA's 2019 guidance explains that the inventories themselves are not required RH SIP elements pursuant to (f)(6)(v), reviewing the inventories for the modeled years is a common practice and can inform other required elements, such as §51.308(f)(2)(iii) and (f)(2)(iv)(A).

7.1. 2016 Base Year and 2028 Future Year Modeled Emissions

Figure 7-1 charts Iowa's emissions by sector and pollutant from LADCO's 2016 base and 2028 future year modeled inventory summaries. The use of LADCO's summary data is ideal because it provides consistency with their 2028_{2016} CAMx results (discussed in previous chapters). PM_{10} emissions are omitted here to avoid confusion caused by the application of fugitive dust transport fraction adjustments used to offset modeled overpredictions. In practical terms, Iowa's PM_{10} emissions are unimportant for RHR purposes, but they are reviewed in Chapter 10 for completeness.

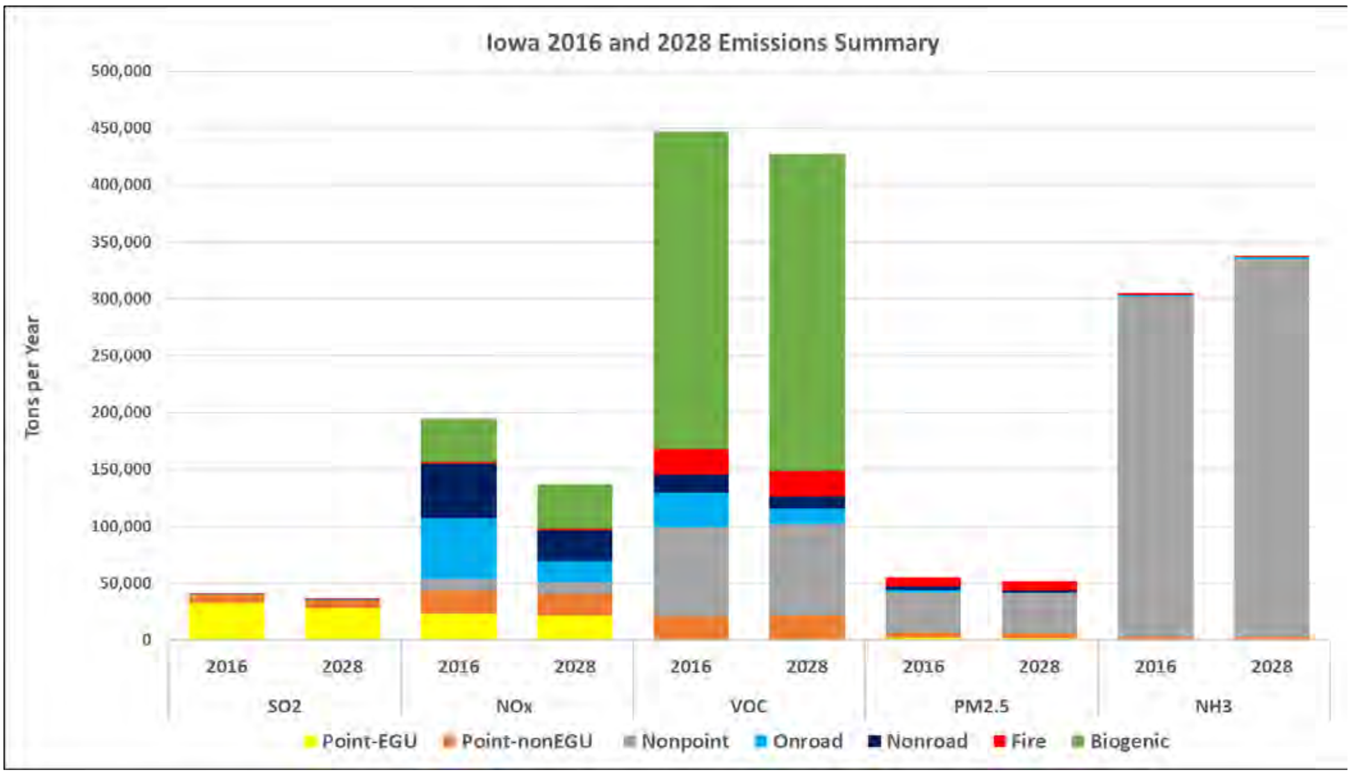

Figure 7-1. Comparison of Iowa's 2016 base year and 2028 projected emissions as modeled by LADCO.

The LADCO 2016 modeling inventory (discussed in Appendix A-1) is based mostly on EPA's 2016fh_16 ("fh") emissions modeling platform. The 2016fh platform incorporates point source emissions data reported by the DNR through the State and Local Emissions Inventory System (SLEIS). EPA documents the 2016fh inventory in its March 2021 TSD "*Preparation of Emissions Inventories for the 2016v1 North American Emissions Modeling Platform*." LADCO largely sourced its 2028 projections from EPA's 2028fh inventory (see Table 3-4 in Appendix A-1). The most notable exception for Iowa was the replacement of the IPM EGU projections with the LADCO-modified ERTAC v16.1 results.

Table 7-1 and Table 7-2 detail Iowa's 2016 and 2028 modeled emissions inventories, respectively, and provide each sector's percentage contribution to the given pollutant's total. In this 2016 inventory, Iowa's point-EGU sources emitted 32,542 tons of SO_2, or 79% of the state SO_2 total. The point-nonEGU sources contributed 6,941 tons of SO_2, or 17% of the total. The NO_X emissions are more evenly distributed, primarily among the point (EGU plus nonEGU), onroad, nonroad, and biogenic sectors. Biogenic sources are the largest contributors to the VOC total, with the nonpoint category the largest of the anthropogenic VOC sources. Over 64% of the $PM_{2.5}$ emissions and over 98% of the ammonia emissions are associated with nonpoint sources. Note, the sector percentages as shown may not always sum to 100% due to rounding.

Table 7-1. 2016 Iowa emissions summary (LADCO 2028_{2016} platform), in tpy and sector contributions (%) per pollutant.

Category[44]	SO_2 (tpy)	NO_X (tpy)	VOC (tpy)	$PM_{2.5}$ (tpy)	NH_3 (tpy)		SO_2 (%)	NO_X (%)	VOC (%)	$PM_{2.5}$ (%)	NH_3 (%)
Point-EGU	32,542	22,739	367	1,815	154		79%	12%	0%	3%	0%
Point-nonEGU	6,941	20,521	20,186	4,690	2,342		17%	11%	5%	9%	1%
Nonpoint	593	10,123	78,722	35,549	299,643		1%	5%	18%	64%	98%
Onroad	305	53,803	29,868	1,639	1,112		1%	28%	7%	3%	0%
Nonroad	62	47,634	16,247	3,193	53		0%	24%	4%	6%	0%
Fire	750	1,426	22,309	8,275	1,576		2%	1%	5%	15%	1%
Biogenic		38,820	278,977					20%	62%		
Total	**41,194**	**195,065**	**446,675**	**55,161**	**304,881**		**100%**	**100%**	**100%**	**100%**	**100%**

Table 7-2. 2028 Iowa projected emissions (LADCO 2028_{2016} platform), in tpy and sector contributions (%) per pollutant.

Category[44]	SO_2 (tpy)	NO_X (tpy)	VOC (tpy)	$PM_{2.5}$ (tpy)	NH_3 (tpy)		SO_2 (%)	NO_X (%)	VOC (%)	$PM_{2.5}$ (%)	NH_3 (%)
Point-EGU	28,002	21,442	405	1,284	225		77%	16%	0%	2%	0%
Point-nonEGU	6,784	19,210	21,170	4,771	2,354		19%	14%	5%	9%	1%
Nonpoint	562	9,943	80,315	35,100	332,615		2%	7%	19%	68%	98%
Onroad	137	18,917	13,481	700	936		0%	14%	3%	1%	0%
Nonroad	51	26,878	10,910	1,440	57		0%	20%	3%	3%	0%
Fire*	750	1,426	22,309	8,275	1,576		2%	1%	5%	16%	0%
Biogenic*		38,820	278,977					28%	65%		
Projected Total	**36,287**	**136,635**	**427,566**	**51,571**	**337,763**		**100%**	**100%**	**100%**	**100%**	**100%**

*Note: the 2028 fire and biogenic emissions were kept constant to their 2016 values (a common practice).

Between 2016 and 2028 reductions are forecast across most pollutants and sectors (ignoring the fire and biogenic emissions, which were held constant). Table 7-3 reveals that the NO_X emissions exhibit the largest overall projected decrease, with a total reduction of 58,430 tons, or 30%. This is primarily attributable to decreases in the onroad and nonroad sectors. The second largest overall change, from a percentage basis, is the 12% projected reduction in the total SO_2 emissions. The overall SO_2 emissions decrease of 4,908 tons is mainly attributable to the 14% reduction in the point-EGU emissions. However, this forecast predates the decision to require scrubber improvements at LGS and WSEC-3, which will further reduce SO_2 emissions by an estimated 9,688 tpy. The projected overall VOC and $PM_{2.5}$ reductions are a modest 4% and 7%, respectively. In absolute terms, the 4% VOC reduction equates to a noteworthy 19,109 tons, driven by significant decreases in the onroad and nonroad sectors of 55% and 33%, respectively. The ammonia emissions are projected to increase by 32,882 tons, or 11%. This change is largely associated with agricultural activities.

Table 7-3. Projected changes in Iowa's emissions between 2016 and 2028, in tpy and as sector-specific percentages.

Category[44]	SO_2 (tpy)	NO_X (tpy)	VOC (tpy)	$PM_{2.5}$ (tpy)	NH_3 (tpy)		SO_2 (%)	NO_X (%)	VOC (%)	$PM_{2.5}$ (%)	NH_3 (%)
Point-EGU	-4,540	-1,297	38	-530	71		-14%	-6%	10%	-29%	46%
Point-nonEGU	-157	-1,312	984	82	11		-2%	-6%	5%	2%	0%
Nonpoint	-31	-179	1,593	-449	32,972		-5%	-2%	2%	-1%	11%
Onroad	-168	-34,886	-16,387	-939	-175		-55%	-65%	-55%	-57%	-16%
Nonroad	-11	-20,756	-5,337	-1,753	4		-18%	-44%	-33%	-55%	7%
Fire	n/a						n/a				
Biogenic	n/a						n/a				
Overall Change	**-4,908**	**-58,430**	**-19,109**	**-3,590**	**32,882**		**-12%**	**-30%**	**-4%**	**-7%**	**11%**

[44] The point-nonEGU category includes aircraft and airport emissions. Residential wood combustion and agriculture emissions from livestock and crops are included in the nonpoint category. Marine and rail emissions are included in the nonroad category. The fire category includes wildfires, prescribed fires, and agricultural fires. Note, in this document the terms 'category' and 'sector' are generally used interchangeably.

7.2. Inventory Commitment

To address the final component of 40 CFR 51.308(f)(6)(v), the DNR commits to periodically updating Iowa's emissions inventory as needed. Currently, the DNR updates Iowa's point source inventory on an annual basis and complies with the triennial reporting requirements of the AERR by providing data or accepting EPA emission estimates for the event, nonpoint, onroad, and nonroad categories.

Iowa's point sources report their emissions electronically to the DNR through SLEIS. The DNR reviews the information and submits the required data to EPA. For the nonpoint and event (fire) source categories, the DNR either provides activity data, accepts the default values, or works with EPA if problems are identified in the calculated emissions estimates. The DNR typically accepts EPA's default emissions estimates for the onroad and nonroad sectors.

The DNR will continue providing periodic reviews of Iowa EGU source data and will update, as appropriate, input files to EGU emissions forecasting tools, such as the National Electric Energy Data System (NEEDS) database for IPM and the unit availability and control files for the ERTAC model. The DNR will also continue coordinating, as resources allow, with regional organizations and EPA to review growth and control forecasts for nonEGU point sources and emissions from other anthropogenic data categories.

8. Visibility Projections

In 40 CFR 51.308(f)(2)(iv)(E) EPA requires the consideration of the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the LTS. Table 8-1 summarizes the visibility improvements expected during the second implementation period (2019-2028) in the LADCO and HEGL Class I areas, as predicted using LADCO's 2028_{2016} modeling platform. The expected improvements on the 20% most impaired days range from 0.71 to 1.24 deciviews. No visibility degradation occurs on the 20% clearest days. These results should be conservative because they do not incorporate the required scrubber improvements at LGS and WSEC-3.[45]

Table 8-1. LADCO's projected visibility improvements for the 20% most impaired days and 20% clearest days.

Class I Area	20% Most Impaired Days				20% Clearest Days			
	Baseline 2000-2004 (dv)	Current 2014-2018 (dv)	LADCO 2028 (dv)	Projected Improvement (dv)	Baseline 2000-2004 (dv)	Current 2014-2018 (dv)	LADCO 2028 (dv)	Projected Improvement (dv)
ISLE	19.63	15.54	14.83	0.71	6.77	5.30	5.23	0.07
SENE	23.58	17.57	16.67	0.90	7.14	5.27	5.17	0.10
BOWA	18.43	13.96	13.17	0.79	6.50	4.48	4.41	0.07
VOYA	17.88	14.18	13.36	0.82	7.15	5.31	5.25	0.06
HEGL	25.17	18.72	17.48	1.24	12.84	9.71	9.14	0.57

8.1. Glidepath Check

For each Class I area within its border, a state must establish a reasonable progress goal (RPG), in deciviews. Each RPG must reflect emission reductions from the long-term strategy and other CAA requirements for the end of the implementation period (2028). The RPGs are typically calculated using regional photochemical modeling results. The RPGs themselves are not enforceable, but glidepath checks are a required component of their development.

Iowa does not establish RPGs, but if Michigan, Minnesota, or Missouri (for HEGL) were to establish an RPG that is set above the URP for the given Class I area, then Iowa, and all other contributing states, must produce a robust demonstration showing that no other reasonable emission control measures are available. Based on LADCO's 2028_{2016} modeling results, the DNR anticipates that the RPGs that EPA will approve for these five Class I areas will be below their URP. This is true for both the adjusted URP (based on a 2064 endpoint that incorporates international contributions) and the more stringent unadjusted URP, as shown in Table 8-2. The glidepath analyses are represented visually and augmented with additional data in Figure 8-1 through Figure 8-5, generated using LADCO's regional haze Microsoft Excel spreadsheet tool (version dated June 5, 2021).

Table 8-2. URP values and visibility progress for the 20% most impaired days, all values are in deciviews (dv).

Class I Area	2028 Unadjusted URP	2028 Adjusted URP	LADCO 2028 Modeled Conditions	Amount Below 2028 URP	Amount Below 2028 Adjusted URP
ISLE	15.85	16.97	14.83	1.02	2.14
SENE	18.59	19.78	16.67	1.92	3.11
BOWA	14.69	15.91	13.17	1.52	2.74
VOYA	14.48	15.72	13.36	1.12	2.36
HEGL	18.82	19.63	17.48	1.34	2.15

[45] These new reductions were not yet identifiable during LADCO's ERTAC v16.1 outreach timeframe (September 2020).

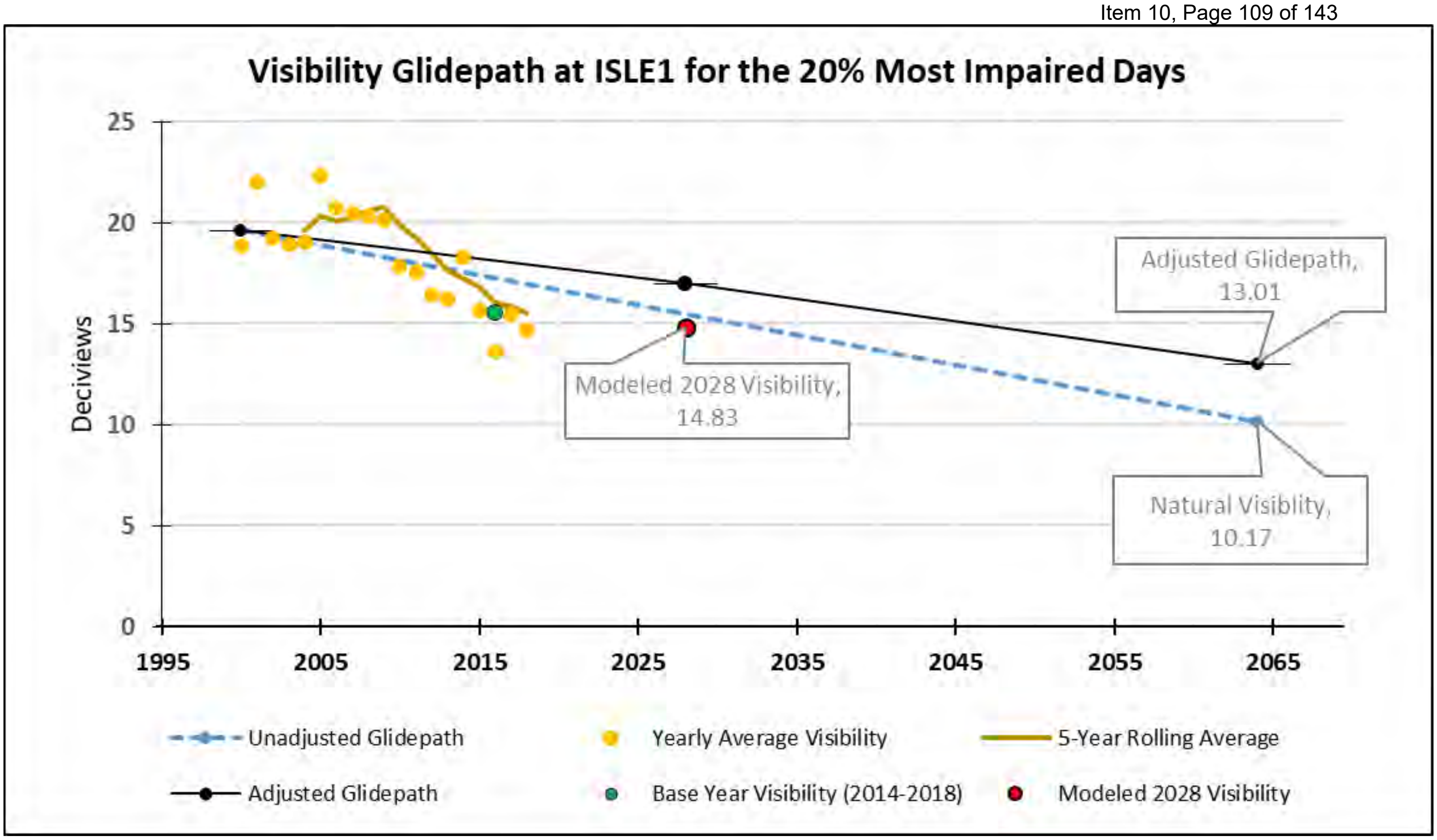

Figure 8-1. Uniform rate of progress analysis on the 20% most impaired days for ISLE.

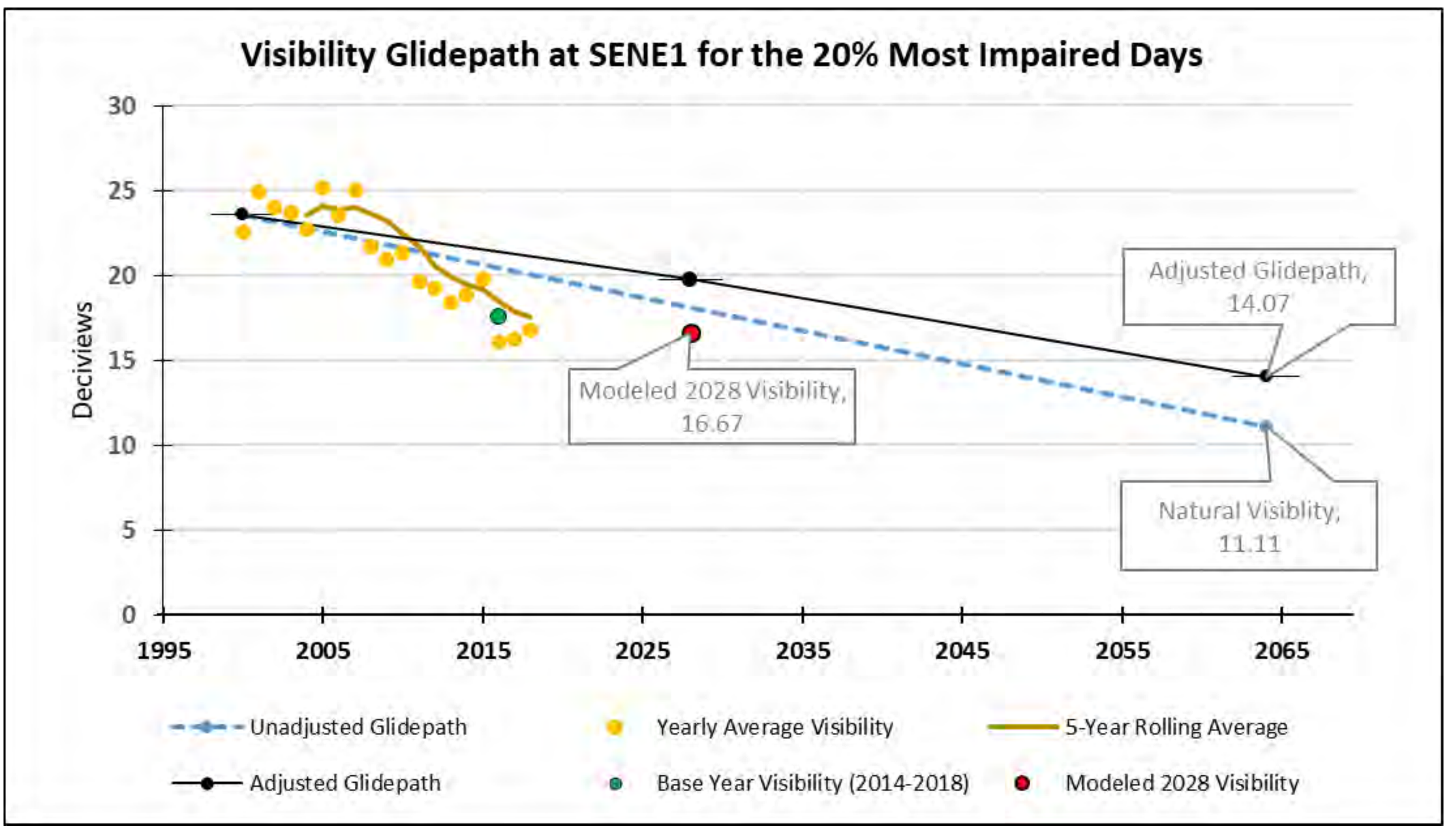

Figure 8-2. Uniform rate of progress analysis on the 20% most impaired days for SENE.

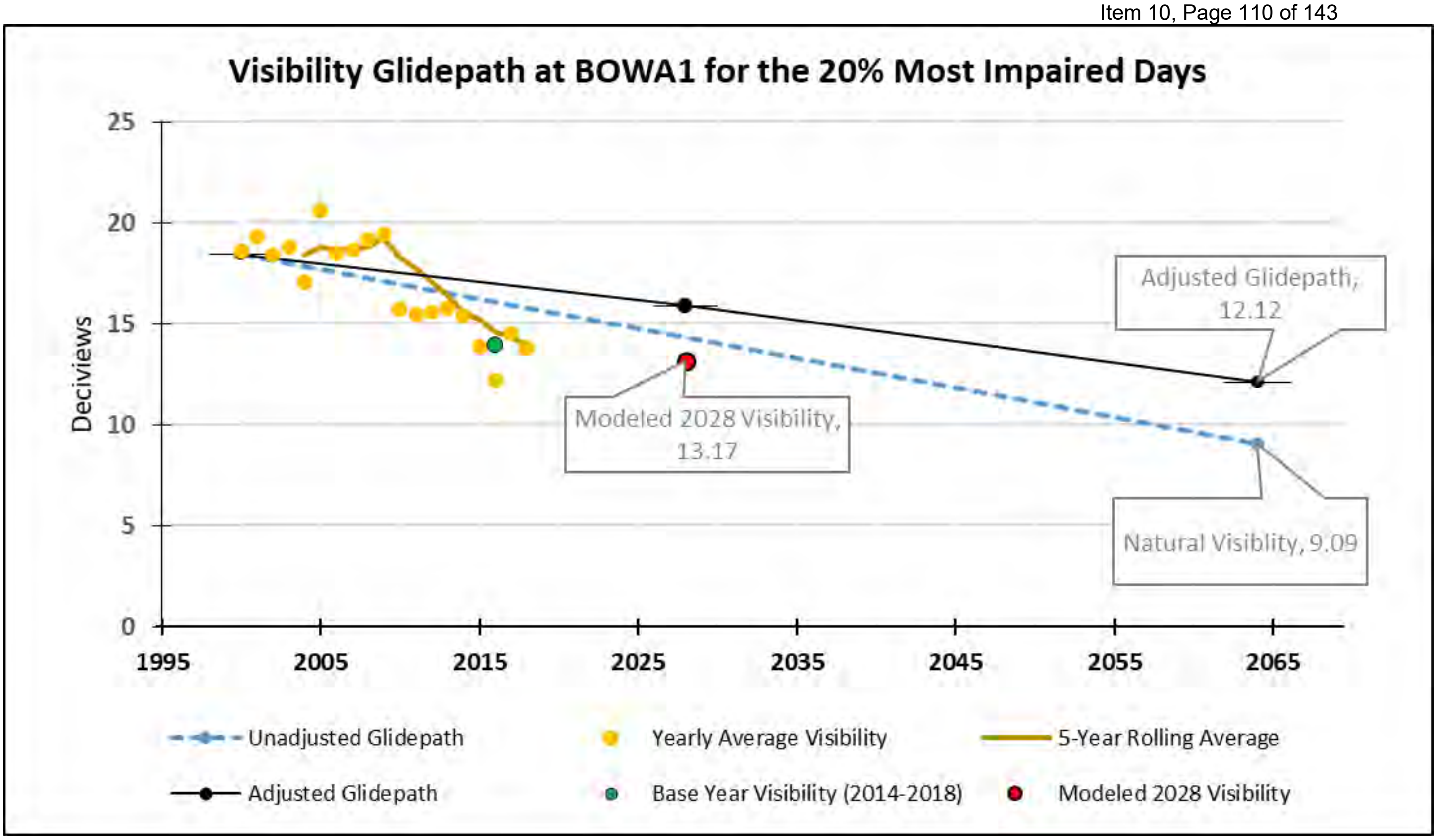

Figure 8-3. Uniform rate of progress analysis on the 20% most impaired days for BOWA.

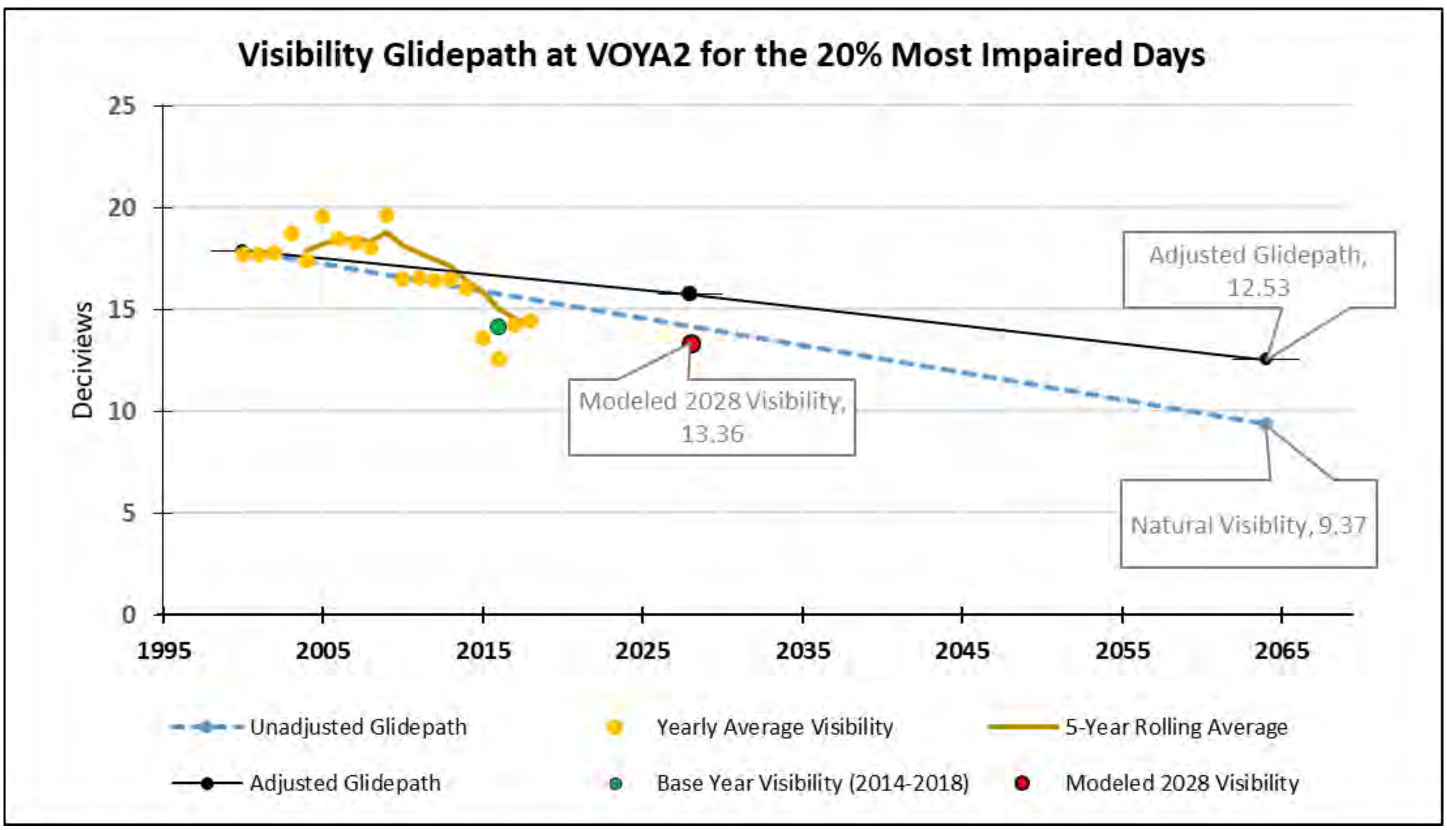

Figure 8-4. Uniform rate of progress analysis on the 20% most impaired days for VOYA.

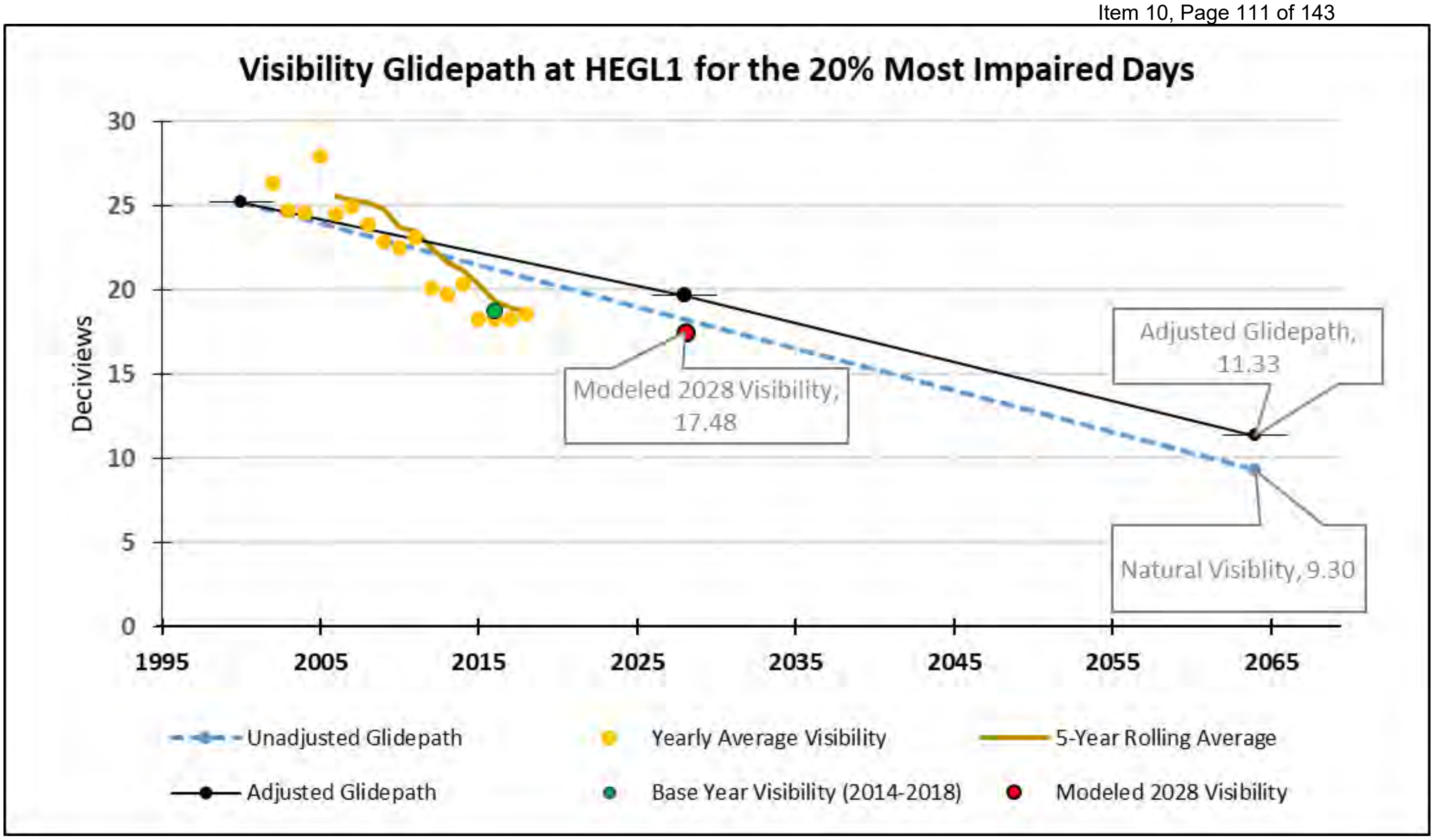

Figure 8-5. Uniform rate of progress analysis on the 20% most impaired days for HEGL.

9. Monitoring Strategy

In 40 CFR 51.308(f)(6) EPA requires a monitoring strategy for measuring, characterizing, and reporting regional haze visibility impairment that is representative of all mandatory Class I areas within the state. While those provisions are not applicable in Iowa, §51.308(f)(6)(iii) does require that states with no Class I areas provide for "procedures by which monitoring data and other information are used in determining the contribution of emissions from within the State to regional haze visibility impairment at mandatory Class I Federal areas in other States."

Between 2000 and 2003, five new IMPROVE sites and fifteen new IMPROVE Protocol sites were installed in the CENRAP region (as it existed at that time) to fill data voids in southern Arkansas, Iowa, Kansas, southern Minnesota, Nebraska, and Oklahoma. The network of IMPROVE and IMPROVE Protocol sites, active as of October 1, 2020, is shown in Figure 9-1.

The Iowa DNR operates two IMPROVE Protocol sites, one at Viking Lake State Park in southwestern Iowa and the other at the Lake Sugema Wildlife Management Area in southeastern Iowa. The monitors began operation in June 2002. Additional monitoring equipment at these two locations provides supplemental information on $PM_{2.5}$ and its precursors. The data from the IMPROVE and IMPROVE protocol monitors are analyzed by a national laboratory (funded via an interagency agreement between EPA and the National Park Service) and uploaded by the laboratory to the [IMPROVE] website. The supplemental monitoring data is publicly available through [EPA]. The DNR intends to continue to operate the two IMPROVE Protocol monitors as long as the interagency agreement is in place and funding is available. The IMPROVE measurements are utilized in data analysis, photochemical modeling studies, and other visibility-related assessments.

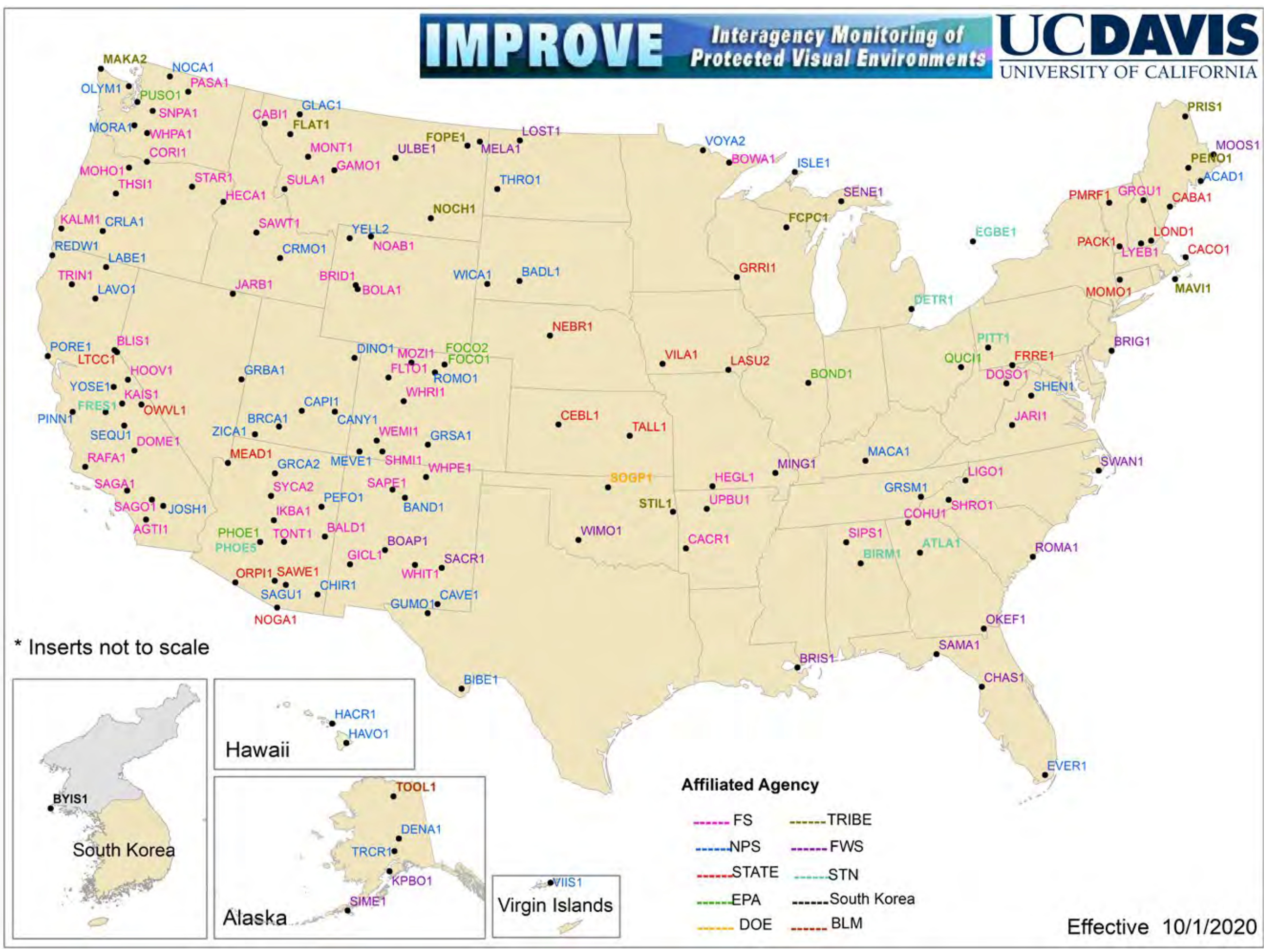

Figure 9-1. Locations of the IMPROVE (including Protocol) sites (source: [2021 IMPROVE Calendar]).

10. Five-Year Progress Report

In 40 CFR 51.308(f)(5) EPA requires each 10-year comprehensive RH SIP to address paragraphs 51.308(g)(1) through (5) so that the plan also serves as a progress report that addresses the period since submission of the progress report for the prior implementation period. In July 2013, the DNR submitted Iowa's 5-year progress report for the prior (first) implementation period (2009-2018). This chapter will close out the progress report requirements for the remainder of the first implementation period.

10.1. Control Measure Status and Emissions Reductions

In 40 CFR 51.308(g)(1) and (2) EPA requires "a description of the status of implementation of all measures included in the implementation plan [for the first implementation period] for achieving reasonable progress goals…and a summary of the emissions reductions achieved throughout the State through implementation of [those] measures."

No source-specific or unit-specific emissions limits or compliance schedules were developed for Iowa's RH SIP for the first implementation period, nor were any needed to satisfy BART requirements for nonEGUs. For the affected EGUs, Iowa initially relied on participation in CAIR to satisfy applicable BART obligations and to fulfill elements of Iowa's LTS. The DNR later revised the RH SIP to replace reliance on CAIR with reliance on CSAPR.[36]

Using CAMD data, Figure 10-1 charts Iowa's annual total EGU SO_2 and NO_X emissions, and heat input, from the 2002 base year of the initial RH SIPs through 2021.[46] Figure 10-1 also includes the IPM v2.1.9 EGU projections for the then-future year 2018 (2018FY) extracted from Table 7.2 (using the "Modified" SO_2 value) of Iowa's first RH SIP.

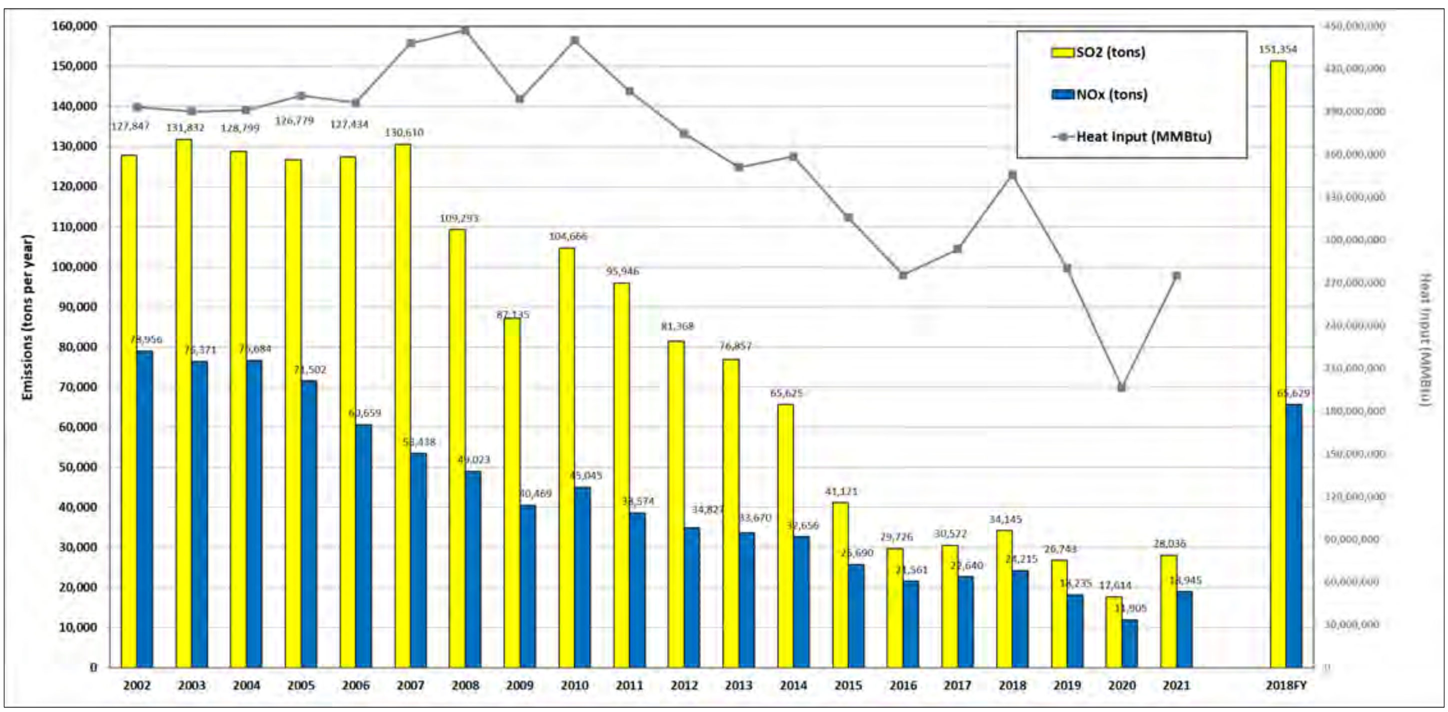

Figure 10-1. Annual 2002-2021 total Iowa EGU SO_2, NO_X, and heat input data from CAMD.

Iowa's EGU SO_2 and NO_X emissions have decreased substantially since 2008, the year preceding CAIR implementation. Between 2008 and 2021, SO_2 and NO_X emissions declined by 81,258 and 30,078 tons, respectively, decreases of 74% and 61%. Prior to CAIR implementation, the SO_2 emissions variability was relatively limited. However, across the 2002-2007 timeframe, NO_X emissions declined by 25,517 tons, a 32% reduction. Installations of low NO_X burners and overfire air systems in the later portion of that period may explain the differences, but the DNR did not investigate the cause(s). Substantial disparities exist between Iowa's 2018 actual EGU emissions and the 2018FY projections made during the first implementation period. IPM v2.1.9 overpredicted Iowa's SO_2 and NO_X EGU emissions by 117,209 and 41,414 tons,

[46] Including the 2021 CAMD data satisfies the requirement in 40 CFR 51.308(g)(4) regarding the use of recent data for sources that report directly to a centralized emissions data system operated by EPA.

respectively, deviations of 343% and 171%. While the IPM results incorporate additional sources that do not report to CAMD (units serving generators between 1 and 25 megawatts), this discrepancy is a relatively minor issue. Forecasting EGU emissions well into the future is certainly a difficult task, and the DNR was not surprised that the IPM v2.1.9 results overpredicted Iowa's EGU emissions. For emissions forecasting purposes, the use of IPM is not necessarily preferable to other tools, such as the ERTAC model.

10.2. Visibility Progress

Because Iowa does not contain a Class I area, the visibility analyses required by 40 CFR 51.308(g)(3) do not apply. However, it is informative to review the visibility progress made in the LADCO Class I areas (Iowa was not linked to HEGL in the first implementation period). Table 10-1 includes the 2000-2004 baseline visibility conditions and compares the more stringent unadjusted URP values to current (2014-2018) conditions, using the 20% most impaired days, and not the 20% worst days, as was the practice during the first implementation period (before EPA's 2017 rule revisions). Even without adjustment for international contributions, the observed visibility progress is far better than the URP glidepath, by up to 3.10 deciviews (Seney) and no less than 1.71 deciviews for any other area. Table 3-3 and Figure 3-1 both previously demonstrated that on the 20% clearest (best) days no overall degradation in visibility occurred.

Table 10-1. Visibility progress during the first implementation period, 20% most (anthropogenically) impaired days.

LADCO Class I Area	Baseline Visibility (2000-2004) (dv)	Unadjusted URP (dv/yr)	Unadjusted 2018 URP (dv)	Current Visibility (2014-2018) (dv)	Amount Below 2018 URP (dv)
Isle Royale	19.63	0.16	17.42	15.54	1.88
Seney	23.58	0.21	20.67	17.57	3.10
Boundary Waters	18.43	0.16	16.25	13.96	2.29
Voyageurs	17.88	0.14	15.89	14.18	1.71

10.3. Emissions Inventory and Tracking Analysis

40 CFR 51.308(g)(4) requires an analysis tracking changes in emissions over time. EPA's August 20, 2019, guidance recommends that this progress report "cover a period approximately from the first full year that was not actually incorporated in the previous progress report through a year that is as close as possible to the submission date of the 2021 SIP." Iowa's 2013 progress report incorporated the second version of the 2008 NEI (2008NEIv2, dated April 10, 2012), the most recent available at that time. EPA guidance would thus suggest using 2009 data in this progress report, but comprehensive emissions data are not available for 2009. The Iowa DNR is instead overlapping the review by using 2008 data, but from an updated version of the NEI for that year.

Table 10-2 summarizes Iowa's 2008 emissions using the third (and final) version of the 2008 NEI (2008NEIv3, updated September 2013). The anthropogenic emissions are represented by the point-EGU, point-nonEGU, nonpoint, onroad, and nonroad categories. The fire category includes wildfire, prescribed fire, and agricultural fire.[47] The biogenic category contains only natural emissions from vegetation and soils. Unlike the CAMD data, the point-EGU data includes units serving generators with a nameplate capacity of 25 MW or less. Iowa's primary PM_{10} emissions (filterable + condensable) are included in the tables below for completeness purposes but do not reflect the application of fugitive dust transport factors to reduce overprediction biases of coarse PM in photochemical modeling analyses. The magnitude of Iowa's nonpoint PM_{10} emissions is not a good indicator of visibility impacts in Class I areas.

Table 10-3 summarizes Iowa's 2017 emissions using data from the January 2021 version of the 2017 NEI. This is the most current comprehensive dataset available.[48] The development of the 2017 NEI is documented in EPA's February 2021 TSD "*2017 National Emissions Inventory: January 2021 Updated Release*."

[47] The 2008NEIv3 reported no wildfire emissions in Iowa. Agricultural fires are normally categorized as an anthropogenic nonpoint source but are summed here into the fire category for consistency with the LADCO PSAT categorizations. The intentional burning of agricultural land is an uncommon practice in Iowa and thus emissions in Iowa from this sector are generally small.

[48] The 2020 NEI is currently under development and no versions have yet been released.

Table 10-2. 2008NEIv3 Iowa emissions summary, in tpy and sector contributions (%) per pollutant.

Category[44]	SO_2 (tpy)	NO_X (tpy)	VOC (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	NH_3 (tpy)		SO_2 (%)	NO_X (%)	VOC (%)	PM_{10} (%)	$PM_{2.5}$ (%)	NH_3 (%)
Point-EGU	117,393	51,283	684	8,583	6,006	31		71%	17%	0%	2%	5%	0%
Point-nonEGU	43,224	38,403	21,639	8,452	5,412	3,388		26%	13%	5%	2%	5%	1%
Nonpoint	2,141	5,151	68,898	521,027	94,747	297,049		1%	2%	14%	95%	80%	98%
Onroad	691	87,898	39,424	3,761	3,192	1,463		0%	29%	8%	1%	3%	0%
Nonroad	1,345	82,051	38,537	6,059	5,799	63		1%	27%	8%	1%	5%	0%
Fire	189	758	4,361	3,099	2,865	237		0%	0%	1%	1%	2%	0%
Biogenic		35,620	304,416						12%	64%			
Total	**164,983**	**301,164**	**477,959**	**550,982**	**118,021**	**302,232**		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Table 10-3. 2017NEI (Jan 2021 version) Iowa emissions summary, in tpy and sector contributions (%) per pollutant.

Category[44]	SO_2 (tpy)	NO_X (tpy)	VOC (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	NH_3 (tpy)		SO_2 (%)	NO_X (%)	VOC (%)	PM_{10} (%)	$PM_{2.5}$ (%)	NH_3 (%)
Point-EGU	31,302	23,274	296	1,383	1,054	123		79%	12%	0%	0%	1%	0%
Point-nonEGU	7,274	20,542	19,942	5,917	4,538	2,657		18%	10%	7%	2%	6%	1%
Nonpoint†	441	14,428	85,780	332,379	57,732	329,769		1%	7%	29%	95%	81%	99%
Onroad	279	50,202	27,222	2,795	1,529	1,100		1%	25%	9%	1%	2%	0%
Nonroad	63	46,632	15,241	3,161	3,044	55		0%	24%	5%	1%	4%	0%
Fire	277	542	8,275	3,769	3,167	672		1%	0%	3%	1%	4%	0%
Biogenic		42,465	141,289						21%	47%			
Total	**39,635**	**198,084**	**298,046**	**349,404**	**71,065**	**334,377**		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

† The 2017 NEI contains a double-counting error in Iowa's inventory that produces emissions in the nonpoint sector from coal-fired industrial combustion sources. All Iowa's industrial coal combustion emissions are already accounted for in the point source category. The DNR manually corrected this error here by resetting all industrial nonpoint coal-fired emissions to zero.

Table 10-4 shows the changes in Iowa's emissions between the 2008NEIv3 and the 2017NEI (January 2021 version). For each pollutant, the differences are expressed in tons per year and as sector-specific percentages. Between 2008 and 2017, the SO_2 and NO_X emissions from the point-EGU sector decreased by 86,091 and 28,009 tons, respectively. These equate to sector reductions of 73% and 55%. Overall, the SO_2 emissions declined by 125,347 tons, or 76%. Total NO_X emissions decreased by 103,080 tons, or 34%, driven by reductions in point sources (both EGUs and nonEGUs), onroad sources, and offroad sources. While the overall VOC reduction was 179,913 tons, it was largely driven by changes in biogenics (the cause of the biogenic reduction was not investigated). Excluding both biogenics and fire, the overall VOC decrease becomes 20,701 tons, a 12% decline. While Iowa's PM_{10} emissions decreased by more than 200,000 tons, or 37%, the impacts on visibility in the Class I areas would be negligible as Iowa's PM_{10} emissions are generally inconsequential for regional haze purposes. Iowa's primary $PM_{2.5}$ emissions declined by 40%, but their importance to regional haze is also minimal. Overall, only the ammonia emissions increased, with the 11% change largely associated with an estimated emissions increase from agricultural sources.

Table 10-4. Changes in Iowa's emissions between 2008 and 2017, in tpy and as sector-specific percentages.

Category[44]	SO_2 (tpy)	NO_X (tpy)	VOC (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	NH_3 (tpy)		SO_2 (%)	NO_X (%)	VOC (%)	PM_{10} (%)	$PM_{2.5}$ (%)	NH_3 (%)
Point-EGU	-86,091	-28,009	-388	-7,200	-4,952	92		-73%	-55%	-57%	-84%	-82%	296%
Point-nonEGU	-35,950	-17,862	-1,698	-2,535	-874	-731		-83%	-47%	-8%	-30%	-16%	-22%
Nonpoint	-1,700	9,277	16,883	-188,648	-37,014	32,720		-79%	180%	25%	-36%	-39%	11%
Onroad	-412	-37,697	-12,202	-966	-1,663	-363		-60%	-43%	-31%	-26%	-52%	-25%
Nonroad	-1,283	-35,418	-23,296	-2,899	-2,755	-8		-95%	-43%	-60%	-48%	-48%	-13%
Fire	88	-216	3,914	670	302	435		47%	-29%	90%	22%	11%	183%
Biogenic		6,846	-163,127						19%	-54%			
Overall Change	**-125,347**	**-103,080**	**-179,913**	**-201,578**	**-46,956**	**32,145**		**-76%**	**-34%**	**-38%**	**-37%**	**-40%**	**11%**

10.4. Emissions Changes Assessment

In 40 CFR 51.308(g)(5) EPA requires an "assessment of any significant changes in anthropogenic emissions within or outside the state…and whether or not these changes in anthropogenic emissions were anticipated...and whether they have limited or impeded progress in reducing pollutant emissions and improving visibility." This assessment is best accomplished by comparing the emissions projections from the first RH SIP for the then-future year 2018 (2018FY) to actual 2018 emissions. Since 2018 is not an NEI year, the 2017 NEI data discussed above provide a suitable surrogate.

Table 10-5 provides the 2018FY emissions projections. The data were extracted from Table 7.2 of Iowa's RH SIP for the first implementation period. Various sectors were combined, as needed,[49] to best match the data categories used above. The emissions differences between the 2017 NEI (Table 10-3) and the 2018FY projections are provided in Table 10-6 in tons per year and as sector-specific percentages of the 2018FY forecasts. Some emissions differences are expected due to changes in sector assignments and emissions estimation procedures. For example, in the first RH SIP, the aircraft and airport emissions were included in the nonroad, and not the point-nonEGU, sector. Under §51.308(g)(4) Iowa is not required to backcast previously reported emissions for consistency with more recent emissions estimation procedures.

Table 10-5. Iowa's 2018FY forecast emissions (from the first RH SIP), in tpy and sector contributions (%) per pollutant.

Category	SO_2 (tpy)	NO_X (tpy)	VOC (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	NH_3 (tpy)	SO_2 (%)	NO_X (%)	VOC (%)	PM_{10} (%)	$PM_{2.5}$ (%)	NH_3 (%)
Point-EGU	151,354*	65,629	1,802	11,232	9,578	713	76%	28%	0%	3%	10%	0%
Point-nonEGU	42,862	40,964	56,714	21,737	10,151	5,763	22%	17%	8%	6%	10%	2%
Nonpoint	3,224	7,476	127,849	329,443	68,997	315,316	2%	3%	19%	88%	69%	97%
Onroad	400	33,975	36,404	708	708	4,225	0%	15%	5%	0%	1%	1%
Nonroad	220	60,210	37,143	6,088	5,582	101	0%	26%	6%	2%	6%	0%
Fire	204	200	1,672	5,819	5,495	49	0%	0%	0%	2%	5%	0%
Biogenic		25,732	408,291				0%	11%	61%	0%	0%	0%
Projected Total	**198,264**	**234,186**	**669,875**	**375,027**	**100,511**	**326,167**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

*Reflects use of the "Modified" SO_2 value from Table 7.2 of Iowa's regional haze SIP for the first implementation period.

Table 10-6. Differences between the 2017NEI and the 2018FY forecast, in tpy and as sector-specific percentages.

Category	SO_2 (tpy)	NO_X (tpy)	VOC (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	NH_3 (tpy)	SO_2 (%)	NO_X (%)	VOC (%)	PM_{10} (%)	$PM_{2.5}$ (%)	NH_3 (%)
Point-EGU	-120,052	-42,355	-1,506	-9,849	-8,524	-590	-79%	-65%	-84%	-88%	-89%	-83%
Point-nonEGU	-35,588	-20,422	-36,772	-15,820	-5,613	-3,106	-83%	-50%	-65%	-73%	-55%	-54%
Nonpoint	-2,783	6,952	-42,069	2,936	-11,265	14,453	-86%	93%	-33%	1%	-16%	5%
Onroad	-121	16,227	-9,182	2,087	821	-3,125	-30%	48%	-25%	295%	116%	-74%
Nonroad	-157	-13,578	-21,902	-2,927	-2,538	-46	-71%	-23%	-59%	-48%	-45%	-45%
Fire	73	342	6,603	-2,050	-2,328	623	36%	171%	395%	-35%	-42%	1272%
Biogenic		16,733	-267,002					65%	-65%			
Total Difference	**-158,629**	**-36,102**	**-371,829**	**-25,623**	**-29,446**	**8,210**	**-80%**	**-15%**	**-56%**	**-7%**	**-29%**	**3%**

Iowa's total SO_2 emissions in 2017 were 158,629 tons less than the 2018FY projection, an 80% difference driven largely by unforeseen decreases in the EGU and nonEGU point source categories of 79% and 83%, respectively. Total NO_X emissions were 36,102 tons less than forecast, a 15% difference, again largely driven by unexpected point source reductions. If the NO_X increases from fires and biogenics were excluded, the NO_X reductions would total 53,177 tons.

The 2017 VOC, PM_{10}, and $PM_{2.5}$ emissions were less than forecast for the 2018FY, by 56%, 7%, and 29%, respectively. The total ammonia emissions forecasts were, by contrast, relatively accurate, differing by just 3%. This small

[49] Consolidation was as follows: Nonpoint = Ammonia + Area + Fugitive Dust + Road Dust; Fire = Area Fire + Point Fire + Wildfire

discrepancy, largely attributable to more growth in the nonpoint sector, has not impeded visibility progress. Neither has the unanticipated increases in the nonpoint and onroad NO_X emissions, as they are more than offset by decreases in the point and nonroad categories.

The bar charts in Figure 10-2 depict Iowa's emissions from the 2008NEIv3, the 2017NEI, and the forecast 2018FY data from Iowa's first RH SIP. The SO_2, NO_X, VOC, and primary particulate emissions all decreased, rather substantially, between 2008 and 2017. Overall, Iowa's 2017 emissions were well below the 2018FY projections from the first implementation period. The one exception, the increase in ammonia, did not hinder visibility progress in the LADCO Class I areas.

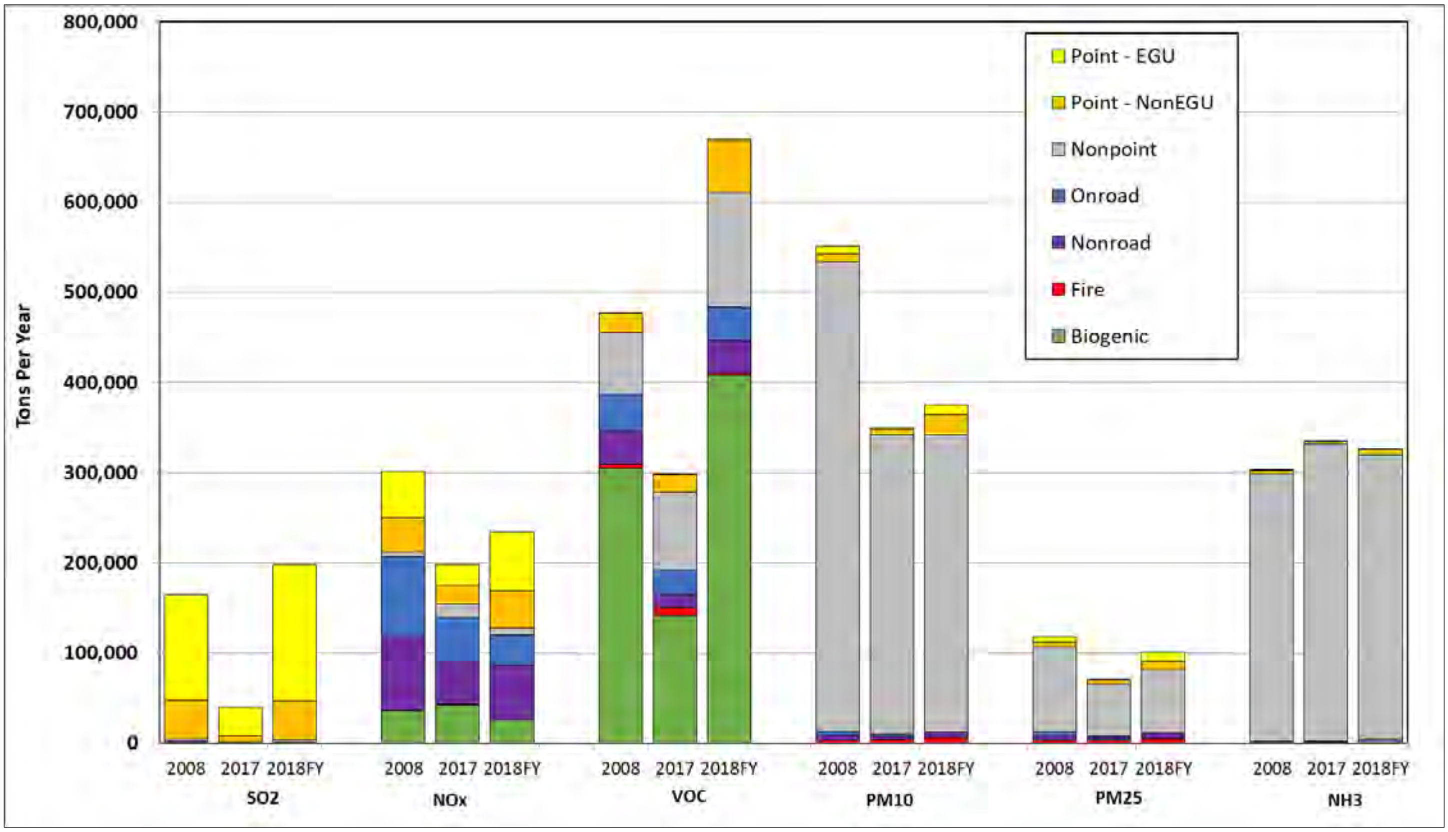

Figure 10-2. Iowa emissions by sector and pollutant from the 2008NEIv3, the 2017NEI, and the 2018 "future year" (the 2018FY projections were extracted from Iowa's RH SIP for the first implementation period).

10.5. Future Progress Report Commitment

As required by §51.308(f), Iowa commits to periodically submitting reports to EPA evaluating progress towards the reasonable progress goal for each Class I area located outside the state that may be affected by emissions from within the state. Subsequent progress reports are due by January 31, 2025, July 31, 2033, and every 10 years thereafter. Progress reports need not be submitted in the form of a SIP revision but will be made available for public comment for at least 30 days before submission to EPA and all comments received from the public will be submitted to EPA along with the subsequent progress report and an explanation of any changes to the progress report made in response to those comments.

11. Consultation

Pursuant to 40 CFR 51.308(f)(2)(ii) and 51.308((i)(2), states must consult with other states and with the Federal Land Managers (FLMs)[50] regarding their long-term strategy for regional haze. Iowa fulfilled its consultation obligations through a combination of regularly scheduled regional calls, individual state meetings, informal FLM discussions, and a formal 60-day FLM review period.

11.1. Regional Discussions

Iowa participated in monthly regional haze conference calls between the CenSARA member states and FLM, EPA, and tribal representatives. The monthly CenSARA calls began in 2017 and transitioned to quarterly calls in 2023. Starting in November 2019, Iowa also participated in LADCO's monthly regional haze calls (bimonthly after October 2021). The DNR provided updates on these calls regarding Iowa's progress in selecting sources for four-factor analysis and Iowa's intent to require SO_2 emissions reductions from LGS and WSEC-3. Call notes are available upon request. Iowa will continue to engage in regional planning activities and will consult with the FLMs through such activities or by separate calls as requested by the FLMs to address 40 CFR 51.308(i)(4).

11.2. Individual State Consultation

In response to a request from Minnesota for direct consultation, the Iowa DNR met virtually with the Minnesota Pollution Control Agency (MPCA) on June 30, 2022. During the meeting, the MPCA overviewed its regional haze planning efforts and related technical data, including its own CAMx PSAT results and the outcomes of its source selection and four-factor analyses. Minnesota shared that it is on track to meet the 2064 goal and had no formal "asks" for Iowa, but did identify Iowa as a state that contributes to visibility impairment in both of its Class I areas (Boundary Waters and Voyageurs). The DNR noted that it found those conclusions reasonable and consistent with LADCO's 2028_{2016} CAMx PSAT modeling results. The DNR then summarized Iowa's planning efforts and Iowa's decision to require dry scrubber improvements at both LGS and WSEC-3 to address regional haze obligations for the second implementation period.[51]

At the request of the DNR, virtual consultation meetings were held with Missouri (Department of Natural Resources) and with Michigan (Department of Environment, Great Lakes, and Energy – Air Quality Division) on November 1, and November 4, 2022, respectively. In both meetings, the Iowa DNR reviewed its use of the LADCO 2028_{2016} CAMx PSAT data and the resulting conclusions that Iowa contributes to visibility impairment at HEGL in Missouri and at ISLE and SENE in Michigan (and BOWA and VOYA in Minnesota). The DNR also summarized Iowa's source selection methodology, four-factor analyses, visibility assessments (the optional fifth-factor), and its decision for the long-term strategy to require SO_2 reductions from dry scrubber improvements at LGS and WSEC-3. The meetings generally ended with a brief review of the proposed emission limits and implementation timeframes in the draft air construction permits for those units, followed by a question and answer opportunity. Additional meetings were unneeded. No states requested that Iowa reduce its emissions for this implementation period of the regional haze program and no measures were identified for Iowa by an upwind state pursuant to 40 CFR 51.308(f)(2)(ii)(B).

11.3. Informal FLM Source Selection and LTS Discussions

In March 2020 the USDA FS provided a recommendation to the DNR that identified three Iowa sources, listed below, as candidates for potential further analysis. The FS identified these sources and the pollutant(s) of interest based on its review of emission rate data (lb/MMBtu) and results from a LADCO Q/d analysis.

- University of Northern Iowa (SO_2)
- Burlington Generating Station (SO_2)
- Muscatine Power and Water, Unit 8 (SO_2 and NO_X)

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[50] The FLM consultation process includes one or more designees from each of three federal agencies, the National Park Service (NPS), the U.S. Fish and Wildlife Service (FWS), and the U.S. Department of Agriculture (USDA) Forest Service (USDA FS, USFS, or simply FS). The DNR typically communicated with the FLMs collectively, but individual agency discussions occurred when warranted.

[51] Iowa's measures were not established or needed pursuant to an official agreement through a regional planning process under 40 CFR 51.308(f)(2)(ii)(A).

In June 2020 the NPS provided a recommendation to the DNR that identified eleven Iowa sources, listed below, as potential candidates for a four-factor analysis.[52] The NPS identified these sources using a Q/d (SO_2 + NO_X) threshold of 1.2 based on 2017 NEI emissions data for the nonEGUs and 2019 CAMD data for the EGUs.

- Walter Scott Jr. Energy Center [EGU]
- Louisa [EGU]
- George Neal North [EGU]
- George Neal South [EGU]
- Burlington (IA) [EGU]
- Muscatine [EGU]
- Ottumwa [EGU]
- ADM Corn Processing - Cedar Rapids [nonEGU]
- Continental Cement Company - Davenport [nonEGU]
- Natural Gas Pipeline Co. Of America - Station 107 [nonEGU]
- Northern Natural Gas Co. - Ogden [nonEGU]

The DNR appreciated the recommendations and considered the information provided by the FS and NPS but choose to select sources using more sophisticated data from CenSARA's area of influence (AOI) analysis, as documented in Chapter 4. The DNR reviewed its source selection methods and results with the FLMs on June 3, 2020. The DNR does agree with the inclusion of Louisa and Walter Scott Jr. Energy Center, as suggested by the NPS, but found no compelling reason to expand the source selection process to include any other sources identified using less technical methods.

On January 20, 2022, the DNR met with the FLMs to informally discuss Iowa's four-factor analyses. The discussion included the DNR's preliminary decision to require LGS and WSEC-3 to implement dry scrubber improvements to satisfy Iowa's emissions reduction obligations for its long-term strategy (LTS) for the second planning period of the RHR.

11.4. Formal FLM Consultation

To address the formal consultation requirements of 40 CFR 51.308(i)(2), the DNR provided a draft of this regional haze SIP to the FLMs on October 11, 2022, and held a 60-day review period that ended on December 9, 2022. The notification announcing the formal consultation opportunity (provided in Appendix F) included the opportunity for the FLMs to discuss their: 1) assessment of impairment of visibility in any mandatory Class I Federal area; and 2) recommendations on the development and implementation of strategies to address visibility impairment. The FLM review period preceded the public comment process as a prerequisite to addressing CAA 169A(d), which requires that the public notice for the public comment opportunity (discussed in Chapter 12) include a summary of the FLM's conclusions and recommendations.

On November 3, 2022, the DNR held a virtual consultation meeting with the FLMs (FS, FWS, and NPS attended, as did EPA) to overview Iowa's draft SIP and to provide an opportunity for questions. The NPS presented their preliminary comments to the DNR during a consultation meeting they held virtually on November 29, 2022 (FS and EPA also attended).

11.5. Response to FLM Comments Received During Formal FLM Consultation

The FS and NPS both provided written comments to the DNR on December 8, 2022 (their comment letters are provided in Appendix F[53]). A summary of their comments, and the DNR's responses, are provided below to address 40 CFR 51.308(i)(3). The DNR has added comment numbering for ease of reference. The FWS did not provide written comments.

Both FLM comment letters provided generally positive comments on the state's FLM consultation efforts and the SIP's organizational structure, content, analytical techniques, and the meaningful SO_2 reductions required from LGS and WSEC-3. No additional summary or response is necessary for those remarks, but the DNR appreciates the complimentary statements.

[52] The NPS provided an initial list of Iowa sources in 2019 and revised its recommendations in 2020 using updated emissions data.
[53] The calculation (cost) workbooks that accompanied the NPS's comment letter are available upon request.

11.5.1. Comments from the Forest Service

FS Comment 1

The FS believes that two other sources, George Neal North (GNN) and George Neal South (GNS), should also have conducted a four-factor analysis. If GNN and GNS were treated as one source and all their sulfate and nitrate EWRT*Q/d impacts combined, the impacts would rank between WSEC and LGS at BOWA and VOYA. The FS further notes that GNN and GNS are owned by the same company, located only about 1.5 miles apart, and served by a common rail line.

DNR Response

The DNR and EPA have always treated GNN and GNS as separate stationary sources for all air quality permitting purposes. Therefore, the GNN and GNS facilities were evaluated in the same manner here because the RHR does not establish different criteria for combining emissions from these two sources.

FS Comment 2

Even if GNN and GNS were not grouped together, the impacts of the units individually are in the range of units selected by Minnesota for four-factor analysis.

DNR Response

Neither EPA rule nor guidance prescribe or identify a universal source selection methodology or threshold. EPA guidance instead recognizes the availability of multiple analytical methods and clearly allows each state to identify an approach it considers reasonable.

In Minnesota, facilities with a Q/d > ~4.6 were generally asked to conduct a four-factor analysis. The DNR utilized sulfate and nitrate EWRT*Q/d data to additionally incorporate both transport and impairment (IMPROVE) data to help identify a reasonable set of facilities for four-factor analysis. Since Minnesota is home to two Class I areas and all sources in Minnesota are closer to those Class I areas than either GNN or GNS, it is reasonable that differences exist between Iowa's and Minnesota's methodologies and decisions regarding which sources to select for four-factor analysis. The DNR does not believe it necessary to select either GNN or GNS for four-factor analysis at this time based on the AOI analysis and Iowa's use of a 50% cumulative impact threshold, as discussed in Chapter 4.

FS Comment 3

GNN and GNS are similar to LGS and WSEC-3. The following boiler features are the same, or nearly the same: size, fuel, firing configuration, age, and existing SO_2 controls. Due to their similarity, it seems highly likely that the SO_2 controls that are being proposed at LGS and WSEC-3 could also be applied at GNN and GNS at the same extremely low cost documented in Iowa's plan.

DNR Response

The similarities and differences between LGS, WSEC-3, GNN, and GNS have not been fully evaluated. Using the four-factor analyses for LGS and WSEC-3 to identify potential control options and possible related control costs for GNN or GNS is therefore speculative. An examination of the feasibility of control options at GNN and GNS is further not supported by the results of the DNR's source selection methodology, which concluded that neither GNN nor GNS warrant selection for four-factor analysis at this time. Additionally, the Class I areas impacted by Iowa are projected by LADCO's modeling to be better than required for URP purposes, thus a more "robust demonstration" as might otherwise be required under 40 CFR 51.308(f)(3)(ii)(B) is not applicable.

11.5.2. Comments from the National Park Service

NPS Comment 1

The NPS supports the use of the cumulative AOI approach but recommends that Iowa consider broadening its source selection criteria by using a higher threshold, such as 80% [rather than 50%], to ensure that the sources with the most significant impacts to NPS Class I areas are selected for analysis and that a reasonable number of sources are evaluated. The NPS specifically recommends that Iowa additionally select GNN and GNS for four-factor analysis of SO_2 and NO_X. The NPS's review found that both facilities rank in the top 60% at Badlands National Park, 66% at Wind Cave and Isle Royale National Parks, and 75% at Voyageurs National Park.

DNR Response

As mentioned in response to *FS Comment 2*, neither EPA rule nor final guidance prescribe or identify a universal source selection methodology or threshold. While EPA proposed an 80% threshold in its draft regional haze guidance (dated July 2016) the final guidance (dated August 20, 2019) contains no such threshold recommendation. The DNR identified the 50% cumulative AOI impact threshold as a reasonable approach because it captures the majority of the assessed visibility impact and focuses on those sources with the greatest potential visibility impacts. The DNR agrees that the use of a more stringent threshold would identify additional sources, but believes the methods used in this round are reasonable and satisfy the requirements of the RHR.

With respect to the facility contributions to the various Class I areas, the AOI results indicate that just nine facilities (none of which area in Iowa) are responsible for the majority (top 50%) of the AOI impacts in Badlands National Park. The individual contributions from those nine sources range from 11.43% down to 2.52%. The contributions from GNN and GNS are each less than 2%. Similarly, the majority of the cumulative AOI impacts at Wind Cave can be traced to just eight facilities, with their individual contributions ranging from 13.87% down to 2.58%, with GNN and GNS each contributing less than 1.50%. Unlike situations where visibility impairment is attributable to a relatively large number of sources (such as at ISLE), the AOI results indicate that visibility impacts at BADL and WICA are dominated by a small number of facilities, and none are in Iowa. The DNR believes its current source selection decisions are reasonable, need not be expanded, and are consistent with EPA guidance, which recognizes: *"In setting a threshold, a state may consider the number of emissions sources affecting the Class I areas at issue, the magnitude of the individual sources' impacts, and the amount of anthropogenic visibility impairment at the Class I area."*

<u>*NPS Comment 2*</u>
The NPS recommends that states identify the criteria used when evaluating controls, including those for costs, as required under the RHR. The NPS specifically recommends that Iowa establish cost thresholds to aid in documenting the rationale behind final reasonable progress determinations and that Iowa establish a cost threshold in line with other states.
<u>*DNR Response*</u>
In accordance with the RHR, the DNR considered the costs of controls in developing its control decisions for Iowa's long-term strategy for making reasonable progress. However, neither the RHR nor EPA's regional haze guidance include a bright-line cost effectiveness threshold for states to use in making this consideration. Nor does the rule or guidance provide a prescriptive process for establishing cost effectiveness thresholds when considering control costs to organize and guide its decision-making.

Rather than selecting an arbitrary dollar per ton cost threshold, the DNR's decisions balance the costs of controls with the other three required factors (time necessary for compliance, energy & non-air quality environmental impacts, and remaining useful life) and further incorporate visibility impacts information (the optional fifth factor).

The DNR concluded that SO_2 emissions controls from LGS and WSEC-3 are currently the most cost-effective means to improve visibility in downwind Class I areas. The DNR determined that the costs of NO_X controls are not reasonable, given they are of much greater expense, more than an order of magnitude, than the SO_2 controls, and the regional modeling and emissions analysis (the optional fifth factor visibility analysis) indicates that control of Iowa's EGU SO_2 emissions will provide greater visibility benefits than NO_X controls, perhaps by a factor of 4.4. The DNR believes its conclusions to require SO_2 reductions from LGS and WSEC-3 of ~9,700 tons per year is sufficient to satisfy the control decision requirements for the second round of the RHR and that this decision is supported and documented by the information provided in Chapter 5.

<u>*NPS Comment 3*</u>
Some of the controls evaluated by the DNR and recommended by the NPS for Iowa sources are within cost-effectiveness ranges selected by other states. The NPS encourages Iowa to establish a cost threshold in line with other states, and require installation of all technically feasible, cost-effective controls. In support of its comment, the NPS produced its own SCR and SNCR control cost estimates for LGS and WSEC-3.
<u>*DNR Response*</u>
The NPS provided cost effectiveness threshold examples for seven states (Arizona, Arkansas, Colorado, Idaho, Nevada, Oregon, and Texas) which range from $4,000/ton to $10,000/ton. Each of these states contain at least one Class I area. The examples from those seven states do not establish a representative sample given that the RHR applies to 52 "states" (all 50 states, the District of Columbia, and the Virgin Islands) and no threshold examples are identified for states in the Midwest or any states without Class I areas. The DNR appreciates the NPS's facility-specific control-cost analyses and

related information, but that information does not substitute for the DNR's results nor does it alter the DNR's conclusions that additional NO_X controls are unnecessary for LGS and WSEC-3 at this time.

NPS Comment 4

The NPS recommends that Iowa address both GNN and GNS by conducting four-factor analyses and implementing cost-effective control options in this planning period. The NPS estimated the cost effectiveness for improving the efficiency of the SO_2 scrubbers at both George Neal units at $280/ton SO_2, with emissions reductions estimated at 2,639 tons/year at GNN and 3,271 tons/year at GNS. (The estimated cost effectiveness for improving the efficiency of the SO_2 scrubbers at the George Neal units is very similar to the four-factor analysis estimates for LGS and WSEC-3.)

DNR Response

The DNR appreciates the information provided, but concludes that neither GNN or GNS require a four-factor analysis at this time. Therefore, the estimated cost-effectiveness of SO_2 reductions need not be evaluated for either GNN or GNS.

NPS Comment 5

The NPS estimated the cost of reducing NO_X emissions at GNN by adding SNCR. SNCR would reduce NO_X emissions by an estimated 487 tons/year at a cost of $5,546/ton. This would be found cost effective under thresholds established by other states. The NPS encourages Iowa to establish a cost threshold in line with other states, and require installation of all technically feasible, cost-effective controls.

DNR Response

The DNR appreciates the information provided, but concludes that GNN does not require a four-factor analysis at this time. Therefore, the estimated cost-effectiveness of NO_X reductions need not be evaluated.[54]

[54] Note, at the time of the NPS's analyses, the CAMD database erroneously excluded SNCR from the list of NO_X controls installed on GNN. This has since been corrected. Iowa DNR air construction permit number 95-A-313-P8 identifies SNCR as an existing control technology installed at GNN. Additionally, the direct testimony of William R. Whitney (the General Manager – Engineering Services for MidAmerican Energy Company) filed with the Iowa Utilities Board on April 1, 2022 (Docket EPB-2022-0156) confirms the SNCR system at GNN (Neal Unit 3) became operational August 14, 2014.

12. Public Participation

The public comment period for this proposed SIP revision began on February 13, 2023, and ended March 16, 2023, with a public hearing held virtually on March 16, 2023. The DNR's public participation process followed procedures meeting the applicable requirements in 40 CFR 51.102 and Appendix V to 40 CFR 51.

12.1. Response to Public Comments

The DNR received the following 59 written comment letters during the public comment period (a copy of each letter is provided in Appendix G):

- 4 letters (emails) from individual citizens (Fuller, Jones, Klein, and Leners);
- 1 letter from the National Park Service;
- 1 joint letter[55] from Sierra Club, National Parks Conservation Association, Coalition to Protect America's National Parks, and Iowa Interfaith Power & Light, self-identified collectively as the "Conservation Organizations" (CO). This letter includes the March 14, 2023, *Review and Comments on Reasonable Progress Controls for the Iowa Regional Haze Plan for the Second Implementation Period,* by Victoria R. Stamper (the "Stamper Report");
- 1 letter from the Iowa Environmental Council (IEC); and
- 52 letters (all nearly identical) from individual Sierra Club members.

During the public hearing, the DNR received two verbal comments. The responsiveness summary below includes a summary of all the written and verbal comments received during the 32-day public comment period and the DNR's responses. Where needed, DNR uses its own comment numbering system for ease of reference. Comment numbering and order are not indicative of importance.

12.1.1. Supportive and Citizen Comments

Supportive Comments

The NPS and three citizen commenters (Fuller, Jones, and Klein) supported the plan's requirements to reduce SO_2 emissions.

DNR Response

DNR appreciates the supportive comments and has finalized the construction permit modifications for LGS and WSEC-3 that make the SO_2 emissions reductions permanent and enforceable.

Citizen Comment (Leners)

The commenter inquired of the plan's impact on MidAmerican Energy Company, the budgetary implications, the degree to which costs will be passed on to consumers, and the cost-benefit ratio of the intended new regulations.

DNR Response

According to MidAmerican's four-factor analysis, the dry FGD scrubber improvements required by this plan represent the most cost-effective option of all the technically feasible SO_2 or NO_X control measures available for either LGS or WSEC-3 (see Table 5-5 and Table 5-6). The FGD improvements require no capital expenditures, incur annual operation and maintenance (O&M) costs of no more than $1,248,000 per year, and yield cost effectiveness values less than or equal to $282 per ton of SO_2 removed (2019$). As a control measure for the power-sector, total costs are relatively inexpensive and the dollar per ton cost-effectiveness is high. The scrubber improvements will benefit visibility and can be implemented quickly with only minor energy and non-air impacts. This information represents the mandatory factors that DNR must consider to comply with CAA 169A and the federal regional haze rule. Other budgetary or cost-benefit considerations could not be used to modify the DNR's SO_2 control decisions for LGS and WSEC-3.

12.1.2. Comments from the National Park Service

NPS Comment 1

Iowa could improve the draft SIP and further reduce haze causing emissions from LGS and WSEC by requiring cost-effective NO_X emission controls, as the NPS previously described in its consultation feedback [see Section 11.5.2].

[55] The letter's numerous attachments are available upon request.

DNR Response

Neither the RHR nor EPA guidance establish cost-effectiveness thresholds, therefore cost consideration decisions are made on a state-by-state basis. Cost threshold selections by an individual state are likely, at least in part, influenced by current and projected visibility impairment values and the degree of anticipated progress. The decision by other individual states to use a given threshold does not automatically imply that Iowa should select the same or a similar cost threshold.

The Class I areas impacted by Iowa's emissions are all projected to be better than required by the URP. In accordance with EPA guidance, the DNR does not treat this as providing a "safe harbor," but it does negate the need for a more rigorous analysis or consideration of more expensive control options. The DNR does not agree that requiring NO_X controls on LGS or WSEC-3 is reasonable at this time. Cost-effectiveness values (dollars per ton) for the SNCR and SCR options are substantially more expensive than the scrubber improvements at LGS and WSEC-3. Regional modeling indicates, that for Iowa's EGUs, SO_2 emissions reductions are more than four times as effective at improving visibly than NO_X reductions. Requiring SNCR or SCR on either LGS or WSEC-3 fails to provide reasonably cost-effective or meaningful reductions for purposes of regional haze and thus neither is currently appropriate.

NPS Comment 2

The NPS continues to recommend that Iowa DNR evaluate opportunities to reduce haze causing SO_2 and NO_X emissions from George Neal North (GNN) and George Neal South (GNS). The NPS's preliminary assessment found that SO_2 improvements, similar to those identified for LGS and WSEC-3, are likely feasible and extremely cost effective for these power plants. The NPS encourages Iowa to take advantage of the opportunity this SIP provides to obtain further emissions reductions.

DNR Response

The DNR concluded that neither GNN nor GNS merit selection for four-factor analysis by using relatively sophisticated area of influence (AOI) metrics. EPA's 2019 guidance supports DNR's decisions by clarifying that "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." The DNR's methods capture each Iowa source that contributes to the majority of the visibility impacts from point sources at any of the 12 downwind Class I areas listed in Table 2-4 and Table 2-5. In fact, no state is further removed from Class I areas than Iowa, yet the DNR's regional haze plan requires nearly 9,700 tons of SO_2 reductions per year (versus 2017-2019 average baseline conditions). Additionally, the associated emission limits are not tied to future EPA actions but instead require compliance no later than December 31, 2023. The DNR believes this plan fulfils Iowa's obligations for the second implementation period of the regional haze rule.

12.1.3. Comments from the Conservation Organizations (CO)

CO Comment 1

DNR allows for use of an unreasonably high interest rate (7.862%) and, unless sufficient documentation is provided, must adjust the interest rate in the cost-effectiveness analyses to reflect the current prime bank rate (7.75%).

- It is unreasonable for DNR to determine that MidAmerican Energy's use of a firm-specific interest rate is appropriate based on approval by the Iowa Utilities Board and supplemental information. MidAmerican Energy has not explained the details of how its cost of capital is calculated, other than to refer to utility commission docket numbers in which the cost of capital was approved.
- DNR must collect more information on MidAmerican Energy's calculations and must ensure that the methods used are consistent with EPA's Control Cost Manual.

DNR Response

The 7.862% firm-specific interest rate utilized in the four-factor analyses was the result of DNR's in-depth review and associated discussions with MidAmerican to determine the appropriate interest rate consistent with EPA's Control Cost Manual. MidAmerican initially based their four-factor analyses on a 7% interest rate, but documentation supporting the use of that interest rate was not available. In response to the DNR's request for additional information, MidAmerican provided sufficient justification for use of a 7.862% firm-specific interest rate, and subsequently revised its four-factor analyses to use that rate. Furthermore, differences in costs calculations between those based on a 7.75% bank prime rate versus those using the justified firm specific interest rate of 7.862% are inconsequential.

CO Comment 2

DNR allows for use of truncated life of emission control equipment and must revise the cost-effectiveness analyses to use a 30-year useful life for all the pollution control equipment.

- MidAmerican and DNR erroneously assume the following for LGS and WSEC-3:
  - 20-year useful life in determining annualized costs of the SO_2 controls evaluated.
  - 20-year useful life for controlling NO_X emissions with SNCR systems.
- There was no justification for only assuming a useful life of 20 years for a new wet FGD system or for the operational upgrades to the existing dry FGD system. EPA has found that FGD systems can last 30 years or longer.
- Given that EPA has assumed a 30-year life of SNCR in control cost calculations for coal-fired EGUs in the context of the regional haze program,[56] it is reasonable to assume a 30-year life of SNCR for application to LGS and WSEC-3. EPA's Control Cost Manual (CCM) provides, for example, that "Based on data EPA collected from electric utility manufacturers, at least 11 of approximately 190 SNCR systems on utility boilers in the U.S. were installed before January 1993."
- MidAmerican Energy did not identify any limitations on the remaining useful life of either LGS or WSEC-3, and the draft SIP fails to contain any enforceable limitations on their remaining useful life, thus the life of controls should be 30 years or longer.

DNR Response

After evaluating the examples provided by the commenter to support longer control equipment lifetimes, the DNR concludes that the cost-effectiveness analyses presented in this SIP revision are based on the appropriate control equipment lifetimes and need no revision. Control costs are evaluated on a case-by-case basis and the assumptions made for other states by other EPA regions are unique to their given situation. They do not require Iowa to evaluate longer useful lifetimes for the SNCR or FGD control systems. Both MidAmerican Energy and DNR utilized the nationally applicable tools provided by EPA and followed the recommendations in EPA's CCM in determining the appropriate control equipment lifetimes. Costs were therefore evaluated using the typical lifetimes presented in the CCM, which are 30-years for SCR and 20-years for SNCR,[57] dry FGD, and wet FGD control systems. Limitations on the remaining useful life of either LGS or WSEC-3 are thus unnecessary.

CO Comment 3

DNR failed to evaluate reasonable SO_2 emission rates that could be achieved with better optimization of the existing dry FGD systems at LGS and WSEC-3, and also with new retrofit wet FGD systems.

- MidAmerican evaluated improvements to the dry FGD systems at these plants that would achieve an SO_2 rate of 0.10 lb/MMBtu. This reflects an SO_2 control efficiency of approximately 78%. This SO_2 control efficiency is unreasonably low. DNR must evaluate FGD upgrades to meet a 90% reduction level or an annual average emission rate of 0.05 lb/MMBtu at LGS and at WSEC-3. Further, DNR must impose an SO_2 emission limit of 0.06 lb/MMBtu on a 30-day rolling average basis.
- DNR must also evaluate eliminating the FGD bypass installed at LGS in 2007.
- DNR must also require an evaluation of a wet FGD retrofit to achieve an annual average SO_2 rate of 0.03 lb/MMBtu at LGS and at WSEC-3. A new wet FGD could be considered cost-effective at LGS, at a cost effectiveness of $6,968/ton (2021$). A new wet FGD should also be considered as a cost-effective option at WSEC-3, as it could reduce SO_2 emissions by 7,365 tons per year from 2017-2019 baseline emissions at a cost

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[56] The commenter provided the following reference: "See, *e.g.*, 80 Fed. Reg. 18944 at 18968 (April 8, 2015)." Note, this references a proposal, not a final rule.

[57] EPA's CCM does provide that: "Based on data EPA collected from electric utility manufacturers, at least 11 of approximately 190 SNCR systems on utility boilers in the U.S. were installed before January 1993. [10]" (see page 1-53 of *Chapter 1 - Selective Non-Catalytic Reduction*" (as revised on 4/25/2019) in *Section 4 – NO_X Controls*). Reference "[10]" for that statement identifies the associated data source as the: "*U.S. Environmental Protection Agency. Electric Generating Unit Database. EGU_ICR_Part I_and_Part II. Based on EGU information collection request. December 16, 2011.* [Currently] *Available at* [the Air Toxics Standards for Utilities web page]*."* That "*EGU information collection request*" (ICR No. 2362.01, OMB Control Number 2060-0631) was conducted by EPA in support of the Mercury and Air Toxics Rule (MATS), and is also known as the "MATS ICR," or the "2010 ICR" in reference to the year the data were collected. Any associated equipment ages based on that data are thus relative to 2010, not a more current year. Further examination of the data reveals that for the 11 SNCRs installed before 1993, most (7) were installed in 1992, making their age at that time approximately 18 years, which is consistent with a 20-year recommended SNCR lifetime.

effectiveness of $4,907/ton (2021$). Colorado and Nevada use a cost effectiveness threshold of $10,000/ton and New Mexico uses a threshold of $7,000/ton.

DNR Response

The regional haze rule does not establish a presumptive level of control that must be implemented in order for a control measure to be considered reasonable. The DNR determined, based on site-specific considerations, that the 800 lb/hr and 770 lb/hr limits and associated conditions established for LGS and WSEC-3, respectively, are comparable to a 0.10 lb/MMBtu limit. The estimated uncontrolled emission rate and purported 78% control efficiency, as presented by the commenter, are not applicable to the four-factor analysis and do not impact the determination of the emission limits that are both achievable in practice and reasonable for regional haze purposes. Additionally, the emission limits apply at all times, thus the presence or absence of FGD bypass at LGS is irrelevant. Furthermore, according to data collected by the U.S. Energy Information Administration (EIA) for 2021 and previous years (via Schedule 6, Part F of the Form EIA-860 data), LGS is not equipped with FGD bypass.

Regarding the cost-effectiveness values considered by other states, see the DNR's responses to NPS Comments 2 and 3 in Section 11.5.2 and NPS Comment 1 in Section 12.1.2. Furthermore, that other states established costs thresholds at various levels demonstrates the inherent flexibility within the regional haze program. There are no criteria set by EPA on the appropriateness of a lower range or upper range of the thresholds that states determine appropriate for use in their Regional Haze SIPs. Without a sound methodology or a universally accepted and applied approach, it is unreasonable for Iowa to just pick another state's threshold simply because it will result in the imposition of new controls. In accordance with regulatory requirements and informative data, the DNR determined the appropriate control measures for Iowa sources by identifying cost effective controls through consideration of the four statutory factors and visibility impacts information. With respect to the commenter's claim that new wet FGD should be considered cost effective, this option is clearly unreasonable when considered in the context of its incremental costs, which are approximately $50,090/ton for LGS and $44,250/ton for WSEC-3 (2019$), as shown in Table 5-5.

CO Comment 4

DNR's proposed lb/hr SO_2 emission limits for LGS and WSEC-3 must be revised to be in units of lb/MMBtu.

- A lb/hr SO_2 emissions limit will result in exceedances of a lb/MMBtu SO_2 rate and so cannot be used.
- A lb/MMBtu limit will be much more effective at ensuring SO_2 emission reductions across all levels of operation and will result in greater SO_2 emission reductions per year.
- A review of the new draft permit conditions shows that the new conditions are not sufficiently clear, lack enforceability, and do not mandate the same reduction in SO_2 emission rates at all boiler loads.

DNR Response

Among other obligations, the regional haze rule requires enforceable emissions limitations that are necessary to make reasonable progress. However, the rule does not prescribe or restrict the form that such emission limits must take. A pound per hour limit with additional control equipment operating requirements will provide stringency comparable to a pound per MMBtu limit while also providing operational flexibility to the source.

The DNR includes enforceable conditions in the air construction permits for LGS and WSEC-3 that require MidAmerican to study, develop, and comply with reagent injection rates to maintain SO_2 emission reductions across varying boiler operating loads.[58] Those conditions ensure the new lb/hour SO_2 limits for LGS and WSEC-3 achieve the actual emissions reductions determined in the four-factor analysis and also ensure the reductions will be maintained for the life of the equipment. The DNR disagrees that the conditions are not sufficiently clear, lack enforceability, and do not mandate the same reduction at all boiler loads.

To maintain SO_2 reductions during varying boiler operating loads, the new permit conditions provide a limited degree of flexibility to enable data collection efforts to evaluate the reagent injection rates. This study is necessary because the injection rates cannot be determined prior to implementation of the scrubber improvements. The DNR requires MidAmerican to conduct the study expeditiously, within 60 days of scrubber improvement implementation. The DNR will evaluate and approve the study only if the actual SO_2 emissions reductions are maintained pursuant to permit conditions 1c and 5.Q (see permits 05-A-031-P6 and 75-A-357-P9 for LGS and WSEC-3, respectively). The DNR has

[58] See Conditions 5.Q and 5.R in permit 05-A-031-P6 for LGS or permit 75-A-357-P9 for WSEC-3.

established federally enforceable limits that apply at all times to satisfy regional haze requirements and has determined that additional permit conditions are unnecessary at this time.

CO Comment 5

DNR allows for unreasonably high cost estimates and low cost threshold to screen out cost-effective NO_X controls at LGS and WSEC-3.

- DNR relied on flawed assumptions for the level of NO_X control that could be achieved for LGS and WSEC-3, and therefore its cost effectiveness analysis requires correction. SNCR at LGS and WSEC-3 should have achievable NO_X removal efficiencies of 20.9% and 21.7%, respectively, not 15%. Additionally, DNR and MidAmerican evaluated SCR to achieve a NO_X rate of 0.05 lb/MMBtu, but it is more reasonable to evaluate 0.04 lb/MMBtu on an annual basis.
- Even without correction, the DNR's and MidAmerican Energy's cost effectiveness analyses still show that both SNCR and SCR must be considered as cost effective controls for LGS and WSEC-3. Their costs[59] are within the range of the cost effectiveness thresholds used by other states.[60]
- Based on the analyses presented in the Stamper Report, SCR at WSEC-3 is cost effective at $6,377/ton and at least SNCR is cost effective at LGS at a cost of $4,598/ton [both values are in 2021$]. SCR at LGS ($9,371/ton, 2021$) would be considered cost effective under several states' cost effectiveness thresholds for their regional haze plans.

DNR Response

The DNR disagrees that the NO_X control cost estimates for LGS and WSEC-3 are unreasonably high, based on flawed assumptions, or otherwise require correction. Consistent with EPA's Control Cost Manual, MidAmerican assumed, based on site-specific considerations for LGS and WSEC-3, that SNCR could achieve NO_X reductions of 15% in practice. However, the DNR's evaluation of the cost-effectiveness of SNCR controls at LGS and WSEC-3 did not rely solely on the results provided by MidAmerican. The DNR conducted its own assessments as part of the review process. Two scenarios were evaluated during that review. The first assumed a NO_X control efficiency of 15% and the second assumed a control efficiency of 20%. The results of those assessments are included in Appendix D-2, just as they were in the draft materials. Under the 15% control scenario, the DNR's resulting cost-effectiveness values were not significantly different than those provided by MidAmerican. Assuming an SNCR NO_X control efficiency of 20%, the DNR's estimated cost-effectiveness for LGS and WSEC-3 were $5,011/ton and $4,423/ton, respectively (2019$).

Regarding SCR, the DNR disagrees that the cost-effectiveness evaluations should assume a control rate of 0.04 lb/MMBtu. The RACT/BACT/LAER Clearinghouse, which remains the best source of data regarding the degree of emissions reductions best achieved in practice, identifies 0.05 lb/MMBtu as the best rate of control for short-term averages.

The DNR does not agree that the cost-effectiveness values presented in the Stamper Report for either SNCR or SCR are appropriate, but the values provided are not significantly different[61] than those estimated by the DNR and as such do not impact the DNR's decision that neither SNCR nor SCR are reasonable at this time for LGS or WSEC-3. While the cost-effectiveness values may be similar to those considered by other states, that does not alter the DNR's conclusions, as previously discussed in the responses to NPS Comments 2 and 3 in Section 11.5.2, NPS Comment 1 in Section 12.1.2, and CO Comment 3 above. The DNR finds that the SNCR and SCR cost-effectiveness values for LGS and WSEC-3 are unreasonable in comparison to the SO_2 control costs and that SO_2 emission reductions from Iowa's EGUs provide greater visibility protections than NO_X reductions. In summary, this plan does not require modification in response to this comment.

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[59] As shown in Table 5-6, MidAmerican's cost effectiveness estimates for SNCR for LGS and WSEC-3 are $6,398/ton and $5,616/ton, respectively, with SCR costs for LGS and WSEC-3 being $8,862/ton and $6,436/ton, respectively. The DNR's values are provided in Appendix D-2. All associated costs are in 2019$.

[60] The commenter provides the following examples: Colorado and Nevada are using a cost effectiveness threshold of $10,000/ton; Minnesota is using a $7,600/ton cost threshold; New Mexico's threshold is $7,000 per ton; Arizona is using a cost threshold of $6,500/ton; and Washington is using $6,300/ton for Kraft pulp and paper power boilers.

[61] For example, the Stamper Report estimated the cost-effectiveness of SNCR at Louisa at $4,598/ton (2021$) and the DNR's estimate (assuming 20% control efficiency) was $5,011/ton (2019$), a difference of only $413/ton.

CO Comment 6

DNR must require WSEC-4 to upgrade its dry FGD system and impose an annual average SO_2 limit of 0.05 lb/MMBtu and a 30-day rolling average limit of 0.06 lb/MMBtu.

- DNR must require that MidAmerican investigate the optimization of the existing dry FGD system at WSEC-4 for SO_2 removal because such upgrades are cost effective at $281/ton (2021$) and would, on average, remove 379 tons per year of SO_2 from WSEC-4.
- MidAmerican and DNR also suggest that since WSEC-4's BACT determination from 2003 is still consistent with recent BACT determinations, no further analysis of emission controls are needed. However, only considering controls if they are in the RACT/BACT/LAER Clearinghouse is inadequate given that the data it hosts is incomplete because states do not generally upload determinations and therefore the information is out of date.
- Contrary to the RHR's requirements, neither MidAmerican nor DNR support the proposed "do nothing" emission control approach for WSEC-4 with a robust technical analysis or reasoned analysis. Instead, DNR merely suggests one of the examples [the alternative MATS limit] from EPA's 2019 Guidance applies.

<u>DNR Response</u>

The DNR disagrees that a more stringent SO_2 limit on WSEC-4 is needed to satisfy Iowa's reasonable progress obligations. Consistent with best practice for evaluating available control technologies and associated limits for minimizing emissions of air pollutants, the DNR consulted the information in the RACT/BACT/LAER Clearinghouse to assess the reasonableness of WSEC-4's current SO_2 BACT limit and recent actual performance. No other repository for better data exists and based on the DNR's experience using the repository for coal-fired EGUs, the DNR does not agree with the commenters claim that the data is incomplete or out of date. The commenter's assertions that DNR's approach and conclusions regarding WSEC-4 are inconsistent with the RHR and EPA guidance are incorrect. While neither the regional haze rule nor EPA guidance establish levels of control necessary to satisfy reasonable progress requirements, EPA's 2019 guidance does present relevant examples, such as the 0.2 lb/MMBtu alternative[62] MATS SO_2 limit, that may provide a suitable basis for excluding sources from four-factor analysis. However, the DNR did not exclude WSEC-4 from four-factor analysis, and only referenced the MATS limits for context. The resulting evaluation identified no additional technically feasible control options for WSEC-4.

The DNR agrees that the RHR requires reasonable progress toward natural visibility conditions, but that does not require the imposition of a more stringent SO_2 emission limit on WSEC-4 at this time. Requiring additional reductions from WSEC-4, a unit that achieved a controlled SO_2 emission rate of 0.067 lb/MMBtu across the 2017-2019 baseline period, is not currently reasonable.

CO Comment 7

DNR's highly convoluted screening method contains a fatal flaw which arbitrarily results in DNR ignoring GNN and GNS, two sources with visibility impacts greater than the sources DNR selected.

- The fatal flaw in the DNR's multi-step source selection analysis was the last step, which only looked at the first Iowa source that contributed to 50% or more of the cumulative EWRT*Q/d at each of the 12 Class I areas. This methodology results in DNR ignoring GNN and GNS.
- EPA's 2021 guidance clarifies that states should focus on their in-state sources and that a source selection method that excludes a state's largest visibility impairing sources is likely to be unreasonable. Both GNN and GNS are among the list of sources contributing at least 1% to the cumulative EWRT*Q/d at BADL and WICA.
- As the NPS pointed out, the George Neal units both have dry FGD systems with relatively high SO_2 emissions, given their SO_2 controls. Thus, at the minimum, these units must be evaluated for FGD upgrades such as those evaluated for LGS and WSEC-3, otherwise, DNR's exclusion of the George Neal units is arbitrary.
- DNR's selection of only two sources [LGS and WSEC] does not consist of a set of sources and pollutants which has the potential to meaningfully reduce their contributions to visibility impairment.

<u>DNR Response</u>

The DNR disagrees that its source selection methodology is arbitrary, suffers from a fatal flaw, is convoluted, or is otherwise inadequate to address the requirements of the regional haze rule. The logical approach to ensuring meaningful and reasonable progress towards natural visibility conditions begins with a source selection method that is scientific, equitable, and manageable. The DNR's use of the AOI data, following a method similar to that developed by

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[62] The alternative MATS limit is available only to coal-fired EGUs with FGD systems. WSEC-4 meets those criteria.

the Arkansas Division of Environmental Quality (DEQ), in combination with a cumulative threshold that not just meets, but always exceeds a 50% cumulative impact (rolling total), fulfills these criteria. Regional modeling is the only option that is more sophisticated, but it incurs extensive personnel and computational resources and is not known to the DNR to have been used as a stand-alone source selection method (VISTAS states did use facility-specific CAMx PSAT results in their source selection process, but first conducted an AOI analysis to identify which sources to tag).

The DNR's methods and thresholds ensured the most important and meaningful sources were evaluated. All Iowa sources, and not just the first source as the commenter claims, were selected for four-factor analysis if they contributed to the majority of the AOI impact at any of the 12 Class I areas evaluated (those listed in Table 2-4 and Table 2-5). In response to this misunderstanding, the DNR modified language on page 25 to help clarify its methods.

The commenter also claims that Iowa ignored sources with greater visibility impacts, GNN and GNS, versus the sources Iowa selected (LGS and WSEC). That statement is invalid because it relies on an inaccurate interpretation of the AOI results. The commenter compares the normalized percentage contributions of individual sources from different Class I areas but treats them as absolute values. Such a comparison is not meaningful because a larger percentage of a small number can easily be less than a smaller percentage of a larger value. For example, 1% of 100 is smaller than 0.5% of 300, just as the absolute combined (SO4 +NO3) EWRT*Q/d values (AOI impacts) for GNN and GNS at BADL (where their relative impacts are highest, at 1.38% and 1.97%, respectively) are less than those of LGS and WSEC at ISLE (in which LGS and WSEC contribute to the majority of the cumulative visibility impact).[63] These results do not support the commenter's statements that GNN and GNS have higher visibility impacts than LGS and WSEC. Additionally, the importance of GNN and GNS to the BADL (and WICA) are likely overstated by the AOI data as the LADCO CAMx PSAT modeling indicates that Iowa's total anthropogenic contributions to BADL are considerably less than Iowa's contributions to ISLE (see Table 2-2 and Table 2-3).[64]

Using a cumulative impacts threshold, rather than individual source-based threshold such as 1%, is a solution to these issues and it provides the important added benefit of treating all Class I areas equally. Regardless of the visibly progress at the given Class I area, or the number of contributing sources, the majority of the AOI visibility impact will always be reviewed by Iowa using the cumulative impacts approach. Individual facility-based thresholds offer no such guarantees.

EPA's 2021 Clarifications Memo, like the RHR itself, preserves state flexibility by avoiding the establishment of specific criteria or thresholds. Most importantly, the methods and conclusions reached by a state must produce a reasonable outcome supported by a reasonable explanation. The DNR's decisions and explanations meet those requirements. LGS and WSEC are the two largest SO_2 sources in the state and are the most important sources to visibility impacts in the 12 Class I areas evaluated. In comparison, GNN and GNS are smaller units, their AOI contributions are likely overstated, and they remain less important than LGS and WSEC. Further review of either GNN or GNS is not required at this time.

CO Comment 8

DNR must ensure four-factor analyses are conducted and must adopt reasonable progress measures for GNN and GNS to reduce SO_2 emissions based on the additional use of lime in the units' dry FGD systems.

- The 2017-2019 GNN and GNS actual SO_2 removal rates are estimated at 28.5% and 23.3%, respectively, yet the upgrades to those plants' dry FGD systems are presumed to be capable of achieving 90% SO_2 removal. The use of additional lime would reduce SO_2 emissions by 3,318 tons per year at GNN and by 3,618 tons per year at GNS below 2017-2019 emissions.
- The dry FGD improvements would be highly cost effective, about $280/ton (2021$), similar to those for LGS and WSEC-3, which the DNR has proposed to find reasonable.
- DNR must ensure the dry FGD systems at GNN and GNS meet annual SO_2 rates at or below 0.05 lb/MMBtu while achieving 30-day average SO_2 emission rates of 0.06 lb/MMBtu.

<u>DNR Response</u>

See the DNR's response to NPS Comment 2 (in Section 12.1.2).

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[63] The absolute AOI combined (sulfate plus nitrate) impacts for GNN and GNS at BADL are 55527 and 79289, respectively, of the total 4,026,191, while those values for LGS and WSEC at ISLE are 135957 and 87432, respectively, of the total 15,809,693.

[64] The DNR would expect the same result if the PSAT analysis were to use the 2016 base year and not forecasted 2028_{2016} emissions.

CO Comment 9

DNR improperly relied on and must eliminate the consideration of visibility impacts as a basis to conclude that SNCR and SCR are not reasonable controls for LGS and WSEC-3.

- Assertions that reductions from one pollutant are less effective than another are not a reasonable basis for rejecting controls.
- States may not give visibility impacts the same weight as the four statutory factors and states may not purport a lack of perceptible or sufficient visibility improvements to excuse selecting emission controls.
- DNR only requires emission controls on the dominant pollutant, SO_2, and its assertions that reductions from NO_X are less effective than SO_2 is not a reasonable basis for rejecting controls.
- DNR must reconsider its determination of NO_X controls at LGS and WSEC 3, must correct the four-factor analyses to ensure that it comports with the legal requirements, must require SCR installation at WSEC-3, and at least require SNCR installation, if not SCR installation, at the LGS facility as cost-effective NO_X controls.

DNR Response

The DNR disagrees with the commenter's assertions that the DNR gave visibility the same weight as the four statutory factors, that visibility impacts were improperly relied upon, or that imperceptible visibility improvements were used to excuse the installation of NO_X control at either LGS or WSEC-3. In accordance with the RHR and EPA guidance, the DNR considered the four-statutory factors when evaluating NO_X controls at LGS and WSEC-3. The costs of compliance are given the most weight, as it generally incorporates data from the other three factors. The NO_X control costs far exceeded the cost-effectiveness of the SO_2 controls and were not considered reasonable for regional haze purposes at this time. The DNR only considered visibility impacts as part of a weight of evidence analysis and concluded that Iowa's obligations to satisfy reasonable progress requirements would be met by requiring the implementation of scrubber improvements at LGS and WSEC-3.

CO Comment 10

Uniform Rate of Progress (URP) is not a "safe harbor" and DNR must not rely on it to avoid robust four-factor analyses and emission controls.

- DNR wrongfully exempts GNN and GNS from controls based on purported compliance by other states with URP.
- It is inappropriate for DNR to use the status of the glideslope in other states to justify inaction in this plan and in doing so fail to make reasonable progress to continue cleaning up haze pollution incrementally. DNR's assertion that the modeling predictions in Class I areas are better than required for URP purposes, thus a more "robust demonstration" as might otherwise be required under 40 CFR 51.308(f)(3)(ii)(B) is not applicable – is not an excuse for avoiding emission reductions at Iowa sources.
- The state is urged to modify the draft SIP by requiring measures of pollution reduction to satisfy the requirement to make reasonable progress, and not lean improperly on the URPs in the other states to justify doing nothing.

DNR Response

The DNR did not use the glideslope to avoid four-factor analyses or emissions controls and no "safe harbor" was assumed. The DNR based its control decisions on the four statutory factors and the weight of evidence information provided by the visibility impact assessment. In accordance with EPA guidance, after the control decisions were made the DNR evaluated the URP planning metric of the Class I areas linked to Iowa. Since ISLE, SENE, BOWA, VOYA, and HEGL were all projected, based on the LADCO modeling, to be better than URP, no revisions to the control decisions were warranted because the need for a more robust evaluation was not triggered.

CO Comment 11

DNR failed to meaningfully address and incorporate comments from the Federal Land Managers.

- While DNR engages in some type of consultation process with the FS and NPS, DNR disregards the FLM consultation/asks and proceeds as DNR initially intended. DNR's responses are generally terse and fail to engage with the FLM comments and fail to provide any meaningful explanation on why they ignore and/or disagree with the FLM comments.
- DNR must meaningfully consider and adapt its selection of sources and SIP measures to reflect comments and suggestions from the FLMs. For example, by using a higher screening threshold, such as 80%; establishing cost thresholds to aid in documenting the rationale behind its final reasonable progress determinations; and establishing a cost threshold in line with other states.

- It is unreasonable for DNR to assert that it can ignore the NPS comment to consider costs in line with other states because the examples provided were from states that have at least one Class I area (and Iowa has none) and none were in the Midwest. All states are responsible for the requirements of the Act, Iowa cannot ignore determinations made by states with Class I areas because the State lacks a Class I area. DNR provides no justification as to why the lack of Midwestern states is meaningful, and it was unreasonable for DNR to suggest that only cost- effectiveness determinations from states in close geographic proximity to Iowa are relevant.
- The State must not ignore, as it has done, NPS Comments 4 and 5 [in Section 11.5.2], where the NPS provided a detailed cost-effective analysis for SO_2 controls at GNN and GNS (as well as the cost of reducing NO_X emissions at GNN). Despite comments from the FS pointing out the similarities between the sources covered by the draft SIP and those excluded, DNR arbitrarily excludes GNN and GNS from consideration.

DNR Response

The DNR disagrees that it failed to consider the FLM comments or that its consultation efforts were otherwise inadequate. In their December 8th comment letters, both the FS and the NPS acknowledged the DNR's consultation and communication efforts. The FS noted that "*We are especially grateful for your sustained, continuous efforts to communicate with us and solicit our input over the years.*" *The NPS wrote "We sincerely appreciate the early engagement and substantive consultation that Iowa and the NPS have had during SIP development and look forward to continuing to work together for clean air and clear views into the future.*"

The DNR understands the FLMs encouraged Iowa to employ more stringent thresholds to select more sources, recommended additional control measures, and suggested that Iowa select cost thresholds that would result in NO_X reductions. The DNR disagrees that such actions are necessary at this time to satisfy the requirements of the regional haze rule. The DNR's responses to the FLMs are factual and it has not ignored the FLM comments, but the department is under no obligation to undertake a complete reanalysis of the technical details supporting the comments provided by the NPS or FS. Disagreements do not equate to failures to satisfy the FLM consultation requirements.

The original list of sources recommended by the NPS for source selection consideration was based on the top 80% of Q/d impacts to NPS Class I areas. When more sophisticated data (the AOI results) became available, the DNR recognized that complete reliance on a Q/d method was an inferior approach for evaluating Iowa sources, which are always more than 300 km away from any Class I area. While the AOI methodology does contain a Q/d calculation, it benefits from back trajectory data and IMPROVE measurements. Using only a simple Q/d method fails to give any consideration to the complex nature of long-distance transport or the meteorological conditions on the most impaired days. It simply, and incorrectly, assumes impacts share a linear relationship with emissions and distance. An 80% threshold may be reasonable when used with an approach that contains such flaws, but it does not justify an 80% threshold for use with the AOI data and the DNR's methods. The DNR's evaluation brought the most important sources to the forefront and a greater than 50% threshold captured a reasonable number of Iowa sources for four factor-analysis.

The RHR requires the consideration of the cost of controls, but does not mandate that states identify a cost-effectiveness threshold. The DNR considered costs in a manner where the selection and justification of an arbitrary dollar per ton cost-effectiveness threshold was unnecessary. Regarding costs and decisions made by other states for purposes of the regional haze rule, it is logical to place greater emphasis upon conclusions from air quality agencies in neighboring or nearby states. The atmospheric conditions, chemistry, sources, pollutants, degree of degradation, and emissions reductions responses pertaining to visibility impairment will exhibit similarities based on proximity (notwithstanding significant geographical or other anomalous features). As a result, more expensive cost thresholds may be appropriate in some states but not others, and it is relevant that examples from Midwestern states would be most beneficial to help inform the selection of cost-thresholds for Iowa, if they had been needed.

CO Comment 12

DNR's interstate consultations consists of meeting to share updates rather than engaging in the joint planning process, failing to satisfy the 40 CFR §51.308(f)(2)(ii) requirement that states develop coordinated emission management strategies.

- DNR fails to demonstrate that its SIP includes all measures agreed to during state-to-state consultations or a regional planning process. DNR provides no information to document that the measures it intended to propose were agreed to during the regional conference calls. DNR's characterizations of these conference calls does not indicate that the states engaged in any discussion about whether and how the sources would be controlled.

- DNR's consultation with Minnesota appears to be an implicit agreement that neither state would ask anything of the other state. There was no engagement between states to develop coordinated emission management strategies. DNR's virtual consultation meetings with Missouri and Michigan followed the same format.
- The draft SIP fails to demonstrate compliance with RHR requirements for interstate consultation. DNR must provide more substantive information about its consultations and include it in the SIP for the public to review.

<u>DNR Response</u>

Throughout the regional haze SIP development process, the DNR engaged extensively with Michigan, Minnesota, and Missouri, as well as other states in the CenSARA and LADCO regional organizations. The RHR does not mandate that every instance of interstate communication be detailed, which would be impractical, thus SIPs should focus on the most valuable information. As such, the DNR summarized the monthly consultation process and made the numerous call notes available upon request. The DNR agrees that the RHR does require documentation of the substantive discussions. In response to the commenter's belief that the consultation process was not sufficiently documented, the DNR has created a new attachment, Appendix H, which further documents direct communications between Iowa and the states of Minnesota, Michigan, and Missouri. This addition does not represent a substantive change requiring additional public notice. The DNR's materials in Appendix H contain the same data, concepts, and conclusions as provided in the draft SIP, essentially only the medium/format is different.

The absence in Appendix H of any specific requests, or "asks" by downwind states simply reflects the fact that none were received. To conclude that this constitutes an implicit agreement that no state would ask anything of the other state is erroneous. Minnesota, Michigan, and Missouri were all informed of the DNR's intent to reduce SO_2 emissions by nearly 9,700 tons per year and no state sought additional measures from Iowa. The materials shared, as documented in Appendix H, include information on the four-factor analysis. In summary, Iowa engaged in discussions that address the requirement to develop coordinated emissions management strategies and the DNR has sufficiently documented the interstate consultation process.

<u>CO Comment 13</u>

DNR completely ignored the environmental justice communities impacted by Iowa's polluting sources, entirely failing to evaluate environmental justice impacts and issue a plan that reduces emissions and minimizes harms to disproportionately impacted communities, as EPA's regulations and guidance urge it to do.

- As EPA must consider environmental justice, so must DNR and all other entities that accept federal funding, per Title VI of the Civil Rights Act of 1964.
- DNR must conduct a thorough analysis of the current and potential effects to impacted communities from sources considered in the SIP as well as those sources identified by commenters and other stakeholders but not reviewed by DNR. By not conducting this analysis and including the benefits of projected decline in emissions to these communities, DNR is not fulfilling its obligations under the law. In establishing emission limits in its SIP, DNR must reduce impacts at *both* the Class I areas and the environmental justice communities.
- DNR has an obligation to ensure meaningful involvement and fair treatment of impacted communities. EPA's EJScreen tool shows that the socioeconomic indicator for limited English-speaking households for communities surrounding LGS, WSEC, and GNN, ranges from 76 to 88 percent, yet there is no evidence in the draft SIP package that DNR ensured meaningful access to review and comment on the draft SIP for persons with limited English proficiency.
- DNR must revise the SIP to analyze environmental justice impacts, reduce emissions, and minimize harms to disproportionately impacted communities.

<u>DNR Response</u>

The purpose of this SIP revision is to satisfy Iowa's obligations for the second implementation period (2019-2028) of the federal RHR. The goal of the RHR is to eliminate man-made visibility impairment in 156 mandatory Class I Federal areas by 2064, not the visibility in the communities surrounding LGS and WSEC. The DNR's analysis of the AOI metrics did not support including GNN, GNS, or any other Iowa source, in the draft SIP. Federal law, including the CAA, does not require any specific actions or mitigation measures in addressing environmental justice concerns in this SIP revision.

However, the DNR recognizes the importance of complying with civil rights law and considering environmental justice in the administration of its programs, services, and activities and provides opportunities for meaningful engagement. The DNR does not discriminate on the basis of race, color, creed, religion, sex, sexual orientation, gender identity, national origin, English-language proficiency, disability, or age in the administration of its programs, services, or activities in accordance with applicable laws and regulations. DNR will not tolerate discrimination, intimidation, threats, coercion, or retaliation against any individual or group because they have exercised their rights protected by federal or state law.

The DNR has two nondiscrimination coordinators on staff and has developed a Civil Rights and Environmental Justice web page. The DNR's Notice of Nondiscrimination and Language Access Plan (LAP) are posted on the web page in both English and Spanish, and the DNR offers language assistance services free of charge. The LAP reflects DNR's commitment to serving Iowans of all backgrounds and cultures, including individuals with limited English proficiency. By adopting the LAP, DNR recognizes its obligation to provide meaningful access to programs, services, and activities by removing language-based barriers to public interaction. Additionally, the LAP provides the procedures DNR follows in responding to requests for interpretation, translation, and other language services and in assessing need for language services.

DNR provided meaningful access to review and comment on the draft SIP and the proposed construction permit modifications for LGS and WSEC-3 by taking the following steps:[65]

- Providing public notice of the opportunity to comment and notice of the public hearing. This notice included information on how to request reasonable accommodation and language services, as well as a link to DNR's Language Access and Disability Nondiscrimination plans. The notice was published in the *Des Moines Register* on February 13, 2023, electronically delivered to over 27,000 subscribers of the DNR's Air Quality News listserve, and posted on the DNR's Public Participation web page.
- Advertising the public hearing on the DNR's Event Calendar and website.
- Holding a virtual public hearing with the option to participate using video conference and telephone options.
- Providing at least 30 days public notice in advance of the hearing.

The SO_2 emissions reductions of nearly 9,700 tons per year resulting from the new requirements for LGS and WSEC-3 will contribute to reduced environmental and health impacts on all populations impacted by emissions from these sources. Short-term exposures to SO_2 can harm the human respiratory system and make breathing difficult. People with asthma, particularly children, are sensitive to these effects of SO_2.

The DNR reviews and approves all pre-construction air permits in Iowa, with the exception of Linn and Polk counties, where local air programs are present. Facilities and equipment must be designed to meet emission standards and not result in a violation of any national ambient air quality standard. Facilities meeting state and federal requirements are issued construction permits which include operating requirements to assure continued compliance. All pre-construction permits issued for LGS, WSEC, GNN, and GNS have undergone this detailed analysis.

Each of these four facilities also has a Title V operating permit. A Title V permit is a single document that incorporates all of the state and federal air quality regulations for the given facility and it must be renewed every five years. Title V permits include all of the enforceable record keeping and monitoring requirements and ensure continuous compliance with the air quality regulations designed to protect public health and the quality of life in Iowa. The four Title V permits for the aforementioned facilities have been placed on public comment and renewed three times.

DNR works diligently to ensure our work is transparent to the public. This transparency is accomplished in a variety of ways that not only inform the public of the applications currently under review, but also assists them in engaging with the DNR and providing meaningful comments that could impact the decisions made during the review of an application.

DNR has several ways a member of the public can stay informed about proposed construction or Title V permit applications in their area. Iowa EASY Air provides a public inquiry portal that allows anyone to search for and view active applications, permits seeking public comment, and previously issued construction and Title V permits. DNR's construction permit search web page provides an alternative to Iowa EASY Air and allows the public to search by varied

[65] Section 12.2 includes additional information on the public participation process.

criteria such as city or county to access issued permits and applications that are currently under review. The public may also view Title V permits on public notice and completed Title V permits on the Title V permit web page. On these sites the DNR encourages the public to review the applications and emissions information and submit comments or questions to the DNR by providing the direct contact information for the staff member assigned review.

12.1.4. Comments from the Iowa Environmental Council (IEC)

IEC Comment 1

DNR's use of the 50% threshold in the source selection process is arbitrary, by definition is not a majority, is inconsistent with other states, and is inconsistent with EPA guidance.

- By choosing 50% as the threshold, DNR purposely excludes GNN and GNS from its four-factor analysis, which undermines the RHR and results in a draft SIP that fails to meaningfully reduce contributions to visibility impairment. South Dakota found that GNN and GNS contributed more to the visibility impairment at Badlands National Park than some in-state sources.
- DNR's 50% screening threshold is inconsistent with comprehensive and meaningful thresholds in use by other states. Iowa should use a threshold that screens additional sources.
- The 50% threshold is inconsistent with EPA's July 8, 2021, Clarifications memo, as states should "focus on the in-state contribution to visibility impairment" and should "not decline to select sources based on the fact that there are larger out-of-state contributors." DNR is doing exactly that by pointing at nine facilities outside Iowa responsible "for the majority (top 50%) of the AOI Impacts" rather than considering the ability of Iowa sources to meaningfully reduce contributions to visibility impairment at Badlands National Park and Wind Cave.

DNR Response

See the DNR's responses to NPS Comment 2 (in Section 12.1.2) and CO Comments 7 and 11. The DNR will further add that its source selection method does not purposefully exclude GNN or GNS. It's simply designed to be reasonable by focusing on the largest sources that contribute to cumulative thresholds that always exceeded (and did not just meet) 50%, thus encompassing the mathematical majority of the AOI impacts. That one or more South Dakota facilities may have less AOI impact on WICA or BADL than GNN or GNS is irrelevant. The reverse is also true. These factors do not undermine Iowa's use of a greater than 50% cumulative AOI contribution threshold or mean that Iowa's source selection method is deficient.

States are commonly using source selection methods customized for their needs. The DNR's method is based on an analytical approach developed by the Arkansas DEQ for evaluating the AOI data. Other states within CenSARA have also employed the AOI data in their source selection process. The LADCO states typically utilized a Q/d method, but individual state thresholds varied from ~4 (*e.g.* Minnesota and Michigan) to ~10 (*e.g.* Wisconsin). South Dakota's source selection process also included a Q/d evaluation, but it only considered sources within 400 km of a Class I area. Had the DNR followed that approach, no Iowa sources would be selected for four-factor analysis, even using South Dakota's Q/d threshold of 2.[66]

The DNR's source selection method identifies a reasonable set of Iowa sources for four-factor analysis and ultimately leads to nearly 9,700 tons of SO_2 emissions reductions that provide for reasonable progress in downwind Class I areas, consistent with the requirements of the RHR. EPA's 2021 Clarification memo does not change, substitute, or add any regulatory provisions or requirements.

IEC Comment 2

DNR must remedy its failure to select GNN and GNS for four-factor analysis.

- DNR used the LADCO CAMx PSAT results showing Iowa's projected 2028 anthropogenic contributions to visibility impairment in the LADCO Class I areas ranges from 3.0% (Voyageurs) to 3.9% (Isle Royale). DNR then used consistency with the first implementation period and its SIP-approved conclusions as a basis to only look at

[66] South Dakota also utilized the WRAP's Weighted Emissions Potential/Area Of Influence (WEP/AOI) analysis for source selection purposes. The WEP/AOI data is free from the 400 km limitation and was similar, but not identical, to the CenSARA AOI data (EWRT*Q/d) utilized by the DNR. (A notable exception being the WEP/AOI's use of 2028 emissions projections, and not 2016 actual emissions data.) South Dakota's evaluation of the WEP/AOI results identified the same two in-state sources as their Q/d method.

sources where Iowa's contributions fall within or exceed that range. This method ignores significant sources, namely GNN and GNS.

- Had DNR evaluated sources based on a 1% contribution, the LADCO modeling shows that GNS (1.97%) and GNN (1.38%) meaningfully contribute to the visibility impairment at the Badlands National Park and should have been selected for four- factor analysis.

DNR Response

The 2028_{2016} LADCO CAMx PSAT results do not provide visibility impairment contribution data for individual Iowa facilities and played no role in the DNR's source selection process. Iowa's contributions from the LADCO PSAT modeling represent the total impact from all in-state anthropogenic emissions, *i.e.* all of Iowa's point, onroad, nonroad, and nonpoint anthropogenic sources. This information was useful for reassessing general linkages between Iowa and downwind Class I areas, and the DNR added HEGL as a newly linked Class I area as a result of that review.[67] However, the source selection process requires assessments on an individual facility basis. The AOI data fulfilled that need without the significant resource burdens required of source-specific CAMx PSAT modeling.

Regarding the use a 1% contribution threshold in the AOI analysis, see the DNR's response to CO Comment 7 for a discussion on the drawbacks to that approach and additional support for Iowa's source selection decisions.

IEC Comment 3

Instead of providing a well-reasoned explanation for excluding GNN and GNS, DNR provided an explanation of flawed-reasoning.

- Each state has an obligation to submit a long-term strategy that addresses the regional haze visibility impairment resulting from emissions from within that state. EPA has specified that this obligation is not discharged simply because another state's contributions to visibility impairment may be greater. Yet that is exactly what DNR is doing in refusing to include GNN and GNS.
- In the DNR's FLM responsiveness summary [in Section 11.5.2], DNR states that "(u)nlike situations where visibility impairment is attributable to a relatively large number of sources (such as at ISLE), the AOI results indicate that visibility impacts at BADL and WICA are dominated by a small number of facilities, and none are in Iowa." This is clearly contrary to the South Dakota Regional Haze SIP that concluded that emissions from Washington, New Mexico, Colorado, Montana, Wyoming, North Dakota, and all non-WRAP states, which includes the neighboring states of Iowa and Nebraska, produce significantly more visibility impairment at Badlands National Park than South Dakota's own sources.

DNR Response

The DNR does not assume that Iowa's obligations under the regional haze rule are discharged simply because another state's contributions are greater. In fact, Iowa sources are not the leading contributors in the AOI analysis to any Class I area, but this has no bearing on the DNR's source selection process. The DNR's method treats all sources and all Class I areas fairly, equitable, and consistently, thereby ensuring source importance is neither artificially elevated nor demoted. The selection of LGS and WSEC and the decisions stemming from Iowa's four-factor analyses produced a reasonable outcome, consistent with the requirements of the RHR.

The DNR's analysis of the AOI data indicated that the majority of the AOI visibility impacts at BADL and WICA are dominated by a relatively short list of sources, few of those sources are in South Dakota, and none are in Iowa. South Dakota showed, using CAMx PSAT modeling conducted by WRAP, that visibility impairment in their Class I areas is largely attributable to interstate transport.[68] Both conclusions are valid, but comparing or contrasting the AOI impacts with CAMx PSAT results requires great care given the extensive differences in their design, sophistication, and purpose.

[67] LADCO's CAMx PSAT results indicate that Iowa's total anthropogenic contributions to visibility impairment at BADL and WICA on the 20% most impaired days are only 1.0% and 1.1%, respectively, significantly less than 3.0% to 3.9% range for the LADCO and HEGL Class I areas (see Table 2-3).

[68] For example, according to Figure 3-4 in South Dakota's regional haze SIP for the second planning period, in 2028 the states of Washington, New Mexico, Colorado, Montana, Wyoming, and North Dakota are each projected to contribute more to visibility impairment (from ammonium sulfate) at BADL than South Dakota's own sources. Additionally, the predicted contributions from the "USnonWRAP" grouping were also projected to exceeded South Dakota's impacts. However, that grouping encompasses all anthropogenic sources within each of the 35 non-WRAP states in the continental U.S. (of which Iowa is a small part). It also includes commercial marine vessels (CMV) operating within 200 nautical miles of the U.S. coast (the Emission Control Area (ECA) zone).

The AOI metric is a non-physical amalgamation of back trajectories, IMPROVE data, separation distance, and 2016 point-source emissions information. Its sole function for the DNR was in use of selecting individual Iowa facilities for four-factor analysis, not quantifying state contributions to visibility impairment under a 2028 projected emissions scenario or assessing the importance of various anthropogenic emissions source types (such as point EGU, point-nonEGU, mobile, oil & gas, and remaining[69] sources). For those questions, the CAMx PSAT results produced by WRAP and used by South Dakota provided a one-atmosphere, state-of-the science approach for modeling projected visibility contributions by pollutant, state, and emissions sector.

However, Iowa's anthropogenic contributions to visibility impairment were not tracked individually in WRAP's CAMx PSAT modeling, but were grouped with all other non-WRAP states in the continental U.S., as indicated in Figure 12-1. This grouping saves significant computational time versus tracking all states individually, but provides no information regarding the relative importance or unimportance of Iowa's sources to visibility impairment in any Class I area. The WRAP's CAMx PSAT results thus do not refute the DNR's source selection conclusions. The AOI analysis and the WRAP CAMX PSAT modeling simply focus on different sources, consider different years, use vastly different methods, and serve different purposes.

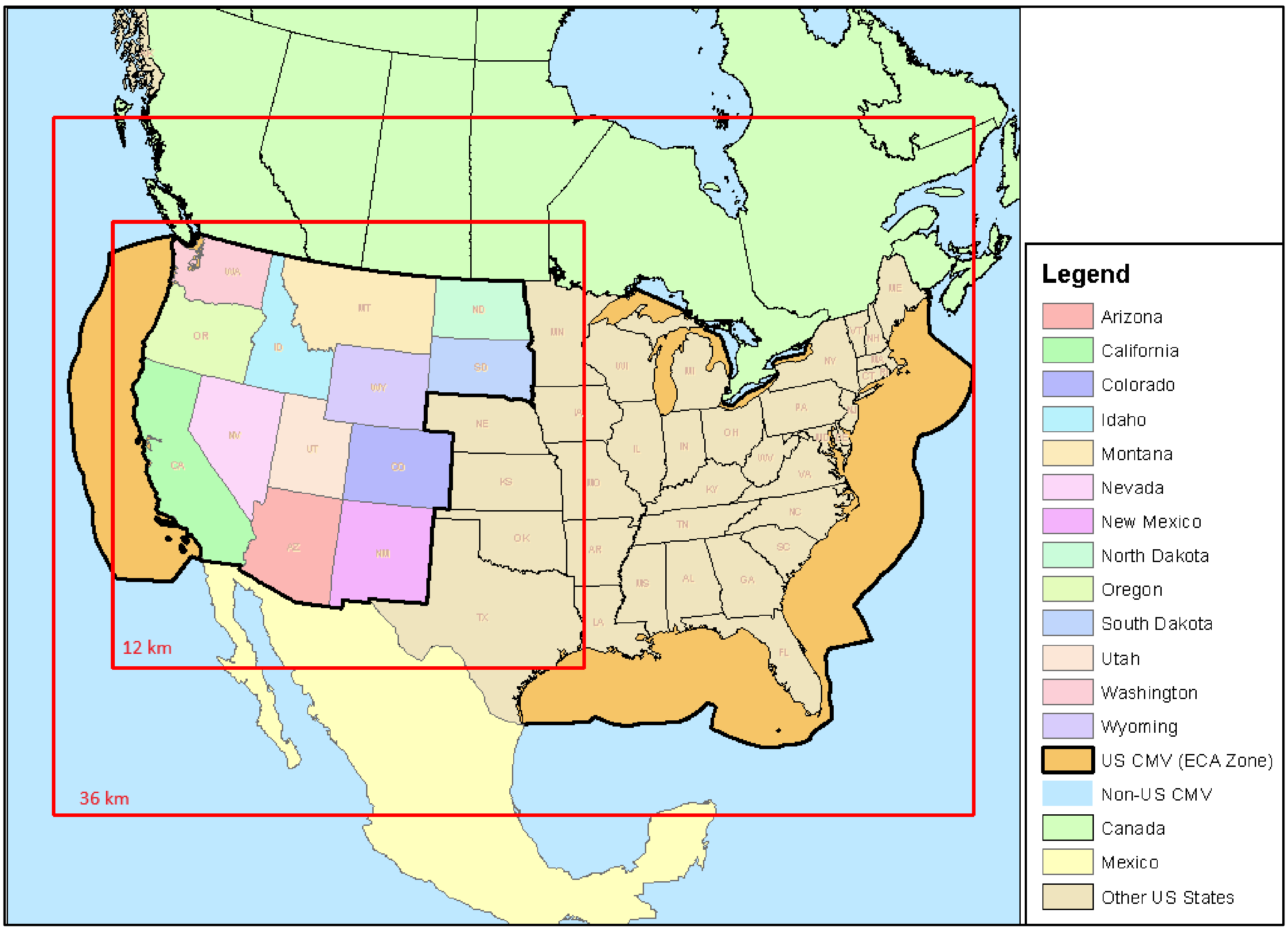

Figure 12-1. Depiction of the 36 and 12 km WRAP modeling domains (two innermost boxes) and the geographic source regions. Image sourced from the Ramboll/WRAP Regional Haze Modeling Run Specification Sheet, Revised September 29, 2020.

[69] Examples (non-exhaustive) of remaining anthropogenic sources include residential wood combustion, fugitive dust, and agriculture.

IEC Comment 4

DNR is determining the best available retrofit technology (BART) on the absolute mandatory minimum of powerplants, required under 42 USC §7491(b).

- A state plan must include a BART determination for any plant that may reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area. By establishing its source selection threshold at 50%, DNR ignores GNN and GNS.

DNR Response

As a one-time requirement, the RHR directed states to evaluate BART eligibility and BART controls during the first implementation period. While states are not determining BART in this or subsequent planning periods, the DNR did not exclude any source from possible selection and subsequent four-factor analysis based on prior BART eligibility or previous BART determinations. As discussed in response to CO Comments 7 and 11, and IEC Comments 1 and 3, the DNR's cumulative impacts thresholds provided a reasonable basis for source selection.

IEC Comment 5

The uniform rate of progress (URP) goals do not justify ignoring cost-effective actions.

- DNR noted that LADCO's regional modeling results predict that the average visibility conditions on the 20% most impaired days in 2028 will be better than the URP in each of the five downwind Class I areas linked to Iowa. However, as EPA clarified in the July 8, 2021 memorandum, URP cannot be used as a "safe harbor" to otherwise avoid potentially cost-effective and otherwise reasonable controls.
- The URP is a planning metric used to gauge the amount of progress made thus far and the amount left to make. It is not based on consideration of the four statutory factors and, therefore, cannot answer the question of whether the amount of progress made in any particular implementation period is "reasonable progress."

DNR Response

The DNR did not use the URP to avoid four-factor analyses and no "safe harbor" was assumed. The DNR based its control decisions on the four statutory factors and a weight of evidence analysis using the visibility impact assessment information in Section 5.8. The better-than-URP visibility progress projected by LADCO in each of the Class I areas linked to Iowa (ISLE, SENE, BOWA, VOYA, and HEGL) simply negated the need to conduct a more rigorous analysis. Additionally, see the DNR's response to CO Comment 10.

IEC Comment 6

DNR ignored the FLM recommendations to broaden the source selection criteria and conduct four-factor analyses of GNN and GNS.

- The DNR did not use the information and recommendations provided by the FLMs to meaningfully inform the State's decisions on the long-term strategy. DNR clearly did not perform a four-factor analysis for GNN and GNS, and it is clear from the responsiveness summary that DNR chose to summarily dismiss the FLM comments, failing to provide a well-reasoned explanation of why it chose not to do a four-factor analysis.

DNR Response

The DNR has not ignored any formal FLM comments. See the DNR's responses to NPS Comment 2 (in Section 12.1.2) and CO Comment 11.

IEC Comment 7

There are ancillary air quality benefits beyond regional haze for reducing SO_2 emissions from GNN and GNS.

- Cost effective measures implemented as a part of addressing regional haze will improve ambient air quality and additionally may allow the state to remain in attainment as other ambient air standards are lowered, including $PM_{2.5}$.

DNR Response

The DNR takes its responsibility to protect public health seriously. Currently, all regulatory ambient air quality monitors in Iowa are measuring pollutant concentrations that are better than required by the federal national ambient air quality standards (NAAQS). The purpose of the regional haze rule is to restore natural visibility conditions to 156 mandatory Class I Federal areas. There are no Class I areas in Iowa and the regulatory requirements in 40 CFR 51.308 do not apply to the NAAQS nor include the consideration of other related ancillary benefits.

IEC Comment 8
DNR should consider the environmental justice issues associated with GNN and GNS when evaluating whether to include the facilities in its screening.

- Like several executive orders, EPA's July 8, 2021, memorandum encouraged states to be aware of where sources of visibility impairing air pollutants are located and impacts they may have on environmental justice communities.
- Based on EJScreen results, the census tract in which GNN and GNS are located is at or above the 90th percentile in the state for ozone and traffic, as well as factors not directly related to air quality such as superfund proximity. Demographically, it is at the 95th percentile in the state for socioeconomic indicators, including at least the 90th percentile for people of color, limited English speaking households, and less than high school education. The surrounding community has similarly high environmental justice indicators.

DNR Response
As discussed in the DNR's response to CO Comment 13, the purpose of this SIP revision is to satisfy Iowa's obligations for the second implementation period (2019-2028) of the federal RHR. The goal of the RHR is to eliminate man-made visibility impairment in 156 mandatory Class I Federal areas by 2064, not the visibility in the communities surrounding GNN and GNS. Federal law, including the CAA, does not require any specific actions or mitigation measures in addressing environmental justice concerns in this SIP revision. However, the DNR recognizes the importance of complying with civil rights law and considering environmental justice in the administration of its programs, services, and activities. Please refer to DNR's Civil Rights and Environmental Justice web page for more information.

12.1.5. Individual Sierra Club Member Comments

The 52 comment letters received from individual Sierra Club members were each nearly identical. They all expressed concerns, for both visibility and public health reasons, that the state is not taking adequate steps to control air pollution from LGS, WSEC 3 & 4, GNN, and GNS. The commenters urged the DNR to revise the draft SIP to:

- Require an evaluation of FGD upgrades to meet a 90% reduction level or an annual average emission rate of 0.05 lb/MMBtu at LGS and at WSEC-3. Further, DNR should impose an SO_2 emission limit of 0.06 lb/MMBtu on a 30-day rolling average basis at these coal plants.
- Require an evaluation of a wet FGD retrofit to achieve an annual average SO_2 rate of 0.03 lb/MMBtu at LGS and at WSEC-3.
- Require SCR at WSEC-3 and at least SNCR at LGS.
- Require dry FGD upgrades at WSEC-4.
- Evaluate GNN and GNS for controls, including cost-effective upgrades to their FGD systems, which are currently not achieving the level of control that such systems are designed to control.

DNR Response
See the DNR's response to: NPS Comments 1 and 2 (in Section 12.1.2); CO Comments 3, 4, 5, 6, and 7; IEC Comment 7; and the verbal comments below.

12.1.6. Verbal Comments Received During the Public Hearing

Two speakers provided comments to the DNR during the public hearing that was held virtually on March 16, 2023.

Emma Coleman, Sierra Club, Des Moines, IA:
The commenter spoke for a stronger regional haze plan that goes much further to reduce pollution to protect our parks and our local public health.
DNR Response
The DNR's plan provides for nearly 9,700 tons of SO_2 reductions per year with implementation of the associated new emission limits on LGS and WSEC-3 beginning no later than December 31, 2023. This ensures Iowa has a sufficiently robust SIP to further improve visibility in downwind Class I areas. The regulatory requirements in 40 CFR 51.308 do not apply to the NAAQS nor include the consideration of other public health benefits.

Renee Weinberg, NW IA Sierra Club:
The commenter was concerned over the GNN and GNS facilities and their air quality impacts in Sioux City and spoke for better air quality even though there are no Class I areas nearby.

DNR Response
The DNR takes its responsibility to protect public health seriously. The regulatory ambient air quality monitor in Sioux City is currently measuring $PM_{2.5}$ concentrations that are better than required by federal standards. Dispersion modeling of GNN and GNS conducted by the DNR in support of the designation process for the 2010 1-hour SO_2 NAAQS predicted that ambient 1-hour SO_2 concentrations would be better than required. Based on this information and previous designations, the Sioux City area is meeting EPA's federal health standards for all criteria pollutants. However, the regulatory requirements in 40 CFR 51.308 do not apply to the NAAQS nor include the consideration of other air quality benefits beyond visibility protections within the 156 Class I areas covered by the regional haze rule.

12.2. Evidence of Public Notice

The public notice of the DNR's intention to revise the SIP to address the second implementation period of the RHR was published in the *Des Moines Register* on February 13, 2023. Proof of publication is provided below. The notice announced both the public comment period and the public hearing. In accordance with CAA §169A(d) [42 U.S.C. §7491(d)], the notice also included a summary of the conclusions and recommendations of the FLMs. Additionally, electronic delivery of a similar notice was provided to over 27,000 subscribers of the DNR's Air Quality News listserve. The DNR's website and Event Calendar also advertised the public hearing.

An electronic copy of the draft regional haze SIP, the draft construction permits, the other draft appendices, and participation instructions for the public hearing were posted on the DNR's Public Participation web page (imaged below) prior to the start of the public comment period. The public could also arrange to access those materials at the Wallace State Office Building, 502 East 9th St., Des Moines, IA 50319.

The DNR certifies that the public hearing was held virtually using video conference and telephone options on March 16, 2023, at 2:00 p.m., in accordance with the information in the public notice and the state's laws and constitution.

Proof of Publication

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AFFIDAVIT OF PUBLICATION

State of Wisconsin

County of Brown, ss.:

The undersigned, being first duly sworn on oath, states that The Des Moines Register and Tribune Company, a corporation duly organized and existing under the laws of the State of Iowa, with its principal place of business in Des Moines, Iowa, the publisher of

THE DES MOINES REGISTER

newspaper of general circulation printed and published in the City of Des Moines, Polk County, Iowa, and that an advertisement, a printed copy of which is attached as Exhibit "A" and made part of this affidavit, was printed and published in The Des Moines Register in the editions dated:

Ad No.	Start Date:	Editions Dated:	Cost:
0005587457	2/13/23	02/13/2023	$97.61

Copy of Advertisement
Exhibit "A"

Staff member, Register Media

Subscribed and sworn to before me by said affiant this

13 day of February, 2023

Kathleen Allen
Notary Public

1-7-25
Commission expires

KATHLEEN ALLEN
Notary Public
State of Wisconsin

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IDNR AIR QUALITY

Public Notice
Iowa Department of Natural Resources

The Department of Natural Resources (DNR) is requesting public comment on a proposed revision to Iowa's state implementation plan (SIP) to address the second 10-year planning period (2019-2028) of the federal regional haze rule. This comment opportunity also includes two proposed air construction permitting actions that establish plan requirements for new emissions reductions. The draft regional haze plan further provides a 5-year progress report to close out the first 10-year planning period (2009-2018).

The federal regional haze rule requires all states to reduce emissions that impair visibility in any of the 156 larger national parks and wilderness areas in the U.S. designated as Class I areas. Although Iowa does not contain a Class I area, emissions from Iowa can contribute to decreased visibility in Class I areas in nearby states. The leading cause of visibility impairment in these areas is widespread emissions of sulfur dioxide and nitrogen oxides that react in the air to form small particles that scatter light.

DNR's draft regional haze plan contains an evaluation of Iowa facilities that may contribute to visibility impairment in Class I areas and subsequent analyses of possible control measures. The DNR proposes to require operational improvements to existing control equipment at MidAmerican Energy Company's Louisa Generating Station (LGS) and Walter Scott Jr. Energy Center – Unit 3 (WSEC-3). The improvements would permanently reduce the combined sulfur dioxide emissions from these sources by approximately 9,700 tons per year. Implementation would begin later this year, as specified in draft permits 05-A-031-P6 and 75-A-357-P9 for LGS and WSEC-3, respectively. Find copies of the draft permits in Appendix E to the draft plan.

The public comment period for this proposed SIP revision and associated permitting actions starts on February 13, 2023. All written comments must be received no later than 4:30 p.m. on March 16, 2023. Direct written comments to Matthew Johnson, Department of Natural Resources, Wallace State Office Building, 502 East 9th St., Des Moines, IA 50319-0034; or by email to matthew.johnson@dnr.iowa.gov.

DNR will hold a public hearing for oral comments on Thursday, March 16, 2023, at 2:00 p.m. The public hearing will be held virtually and accessible by video conference or by telephone.

Find the draft plan, the draft permits, and learn how to participate in the public hearing through the DNR's Air Quality Public Participation webpage at https://www.iowadnr.gov/airpublicinput. Look in the Public Input section under "Regional Haze Plan Available for Public Comment." To view copies of the materials at the Wallace State Office Building, please contact Matthew Johnson at the email address above or by phone at (515) 725-9554 to setup a viewing time.

DNR will summarize and respond to public comments after the close of the public comment period and will include the responsiveness summary in the final regional haze plan. DNR will submit the final plan and all associated appendices, including the final permits, to the U.S. Environmental Protection Agency (EPA) as a revision to Iowa's SIP.

In accordance with 42 U.S.C. § 7491(d), the Federal Land Managers (FLMs) have already reviewed the draft plan and draft permits and this notice includes a summary of their conclusions and recommendations. In general, the FLMs provided positive comments regarding the plan's content, organization, technical analyses, and the DNR's consultation efforts. The FLMs also provided recommendations where they saw opportunities to expand the number of Iowa sources evaluated and the potential for additional emissions reductions. See the draft plan and Appendix F for the DNR's full responses and copies of the FLM comment letters.

Individuals with disabilities or limited English proficiency are encouraged to participate in all DNR activities, including submitting public comments. If a reasonable accommodation or language services are needed to participate, contact the Air Quality Bureau staff member listed or Relay Iowa TTY Service at 800-735-7942 in advance to advise them of your specific needs. DNR's language access and disability nondiscrimination plans are available at https://www.iowadnr.gov/About-DNR/Environmental-Justice.

Materials and Notifications Posted to the DNR's Public Participation Web Page.

PUBLIC PARTICIPATION

Stakeholder Involvement

The Air Quality Bureau frequently seeks input and recommendations from stakeholders on various planning and rulemaking activities, along with permits that will be issued.

- **Public Input** allows opportunities for comment and general information to review Air Quality rulemakings and draft permits. Please see the fact sheet Making Your Comments Count PDF for tips on making effective comments.
- **Meetings** are ongoing, regularly scheduled meetings to discuss current and upcoming regulatory issues.
- **Workgroups** are established to assist the Air Quality Bureau with specific air quality program implementation activities.

Interested members of the public can view agendas, documents, and general information; meeting and workgroup activities can also be tracked.

Please note that not all categories will have items available for comment at all times. Public meetings being held throughout the state are also available on the State of Iowa public meeting calendar.

Public Input

+ Construction and Operating Permits

+ Rulemaking Available for Public Comment

+ Draft Modeling Guidance Updates

+ Regional Haze Plan Available for Public Comment

Regional Haze Plan Available for Public Comment

The DNR invites the public to provide comment on a proposed revision to Iowa's state implementation plan (SIP) to address the second 10-year planning period (2019-2028) of the federal regional haze rule. This comment opportunity also includes two proposed air construction permitting actions that establish plan requirements for new emissions reductions. The draft regional haze plan further provides a 5-year progress report to close out the first 10-year planning period (2009-2018).

As part of the proposed SIP revision, the DNR is proposing to require operational improvements to existing control equipment at MidAmerican Energy Company's Louisa Generating Station (LGS) and Walter Scott Jr. Energy Center – Unit 3 (WSEC-3). The improvements would permanently reduce the combined SO_2 emissions from these sources by approximately 9,700 tons per year. Implementation would begin later this year, as specified in draft permits 05-A-031-P6 and 75-A-357-P9 for LGS and WSEC-3, respectively.

The draft plan and its appendices are accessible through the links below. All files are PDF, except Appendices C-1 and C-2, which are relatively large Microsoft Excel files. Appendix E contains the draft permits for LGS and WSEC-3.

Draft SIP Documents

- Draft Regional Haze Plan for the Second Planning Period (2019-2028) PDF
- Appendix A-1: LADCO TSD PDF
- Appendix A-2: LADCO TSD Supplemental Materials PDF
- Appendix B: Area of Influence (AOI) Report PDF
- Appendix C-1: AOI Tool [87 Mb Excel file] XLSX
- Appendix C-2: AOI Results [96 Mb Excel file] XLS
- Appendix D-1: Four-Factor Analysis Report PDF
- Appendix D-2: DNR NOx Cost Analyses PDF
- Appendix D-3: Interest Rate Justification Memo PDF
- Appendix E: Air Quality Construction Permits PDF
- Appendix F: FLM Consultation Documents PDF

Public Comments & Public Hearing Information

Anyone may make written comments on this proposed SIP revison and the draft permits. The comment period starts on February 13, 2023. Written comments must be received no later than 4:30 p.m. on March 16, 2023, and may be sent to:

Iowa Department of Natural Resources
Air Quality Bureau
c/o Matthew Johnson
502 East 9th Street
Des Moines, IA 50319-0034

Or email: matthew.johnson@dnr.iowa.gov

A public hearing will be held virtually on Thursday, March 16, 2023, from 2:00-3:00 p.m. Shortly before the 2:00 start time, participants may access the hearing as follows:

Teleconference: 312-626-6799; Meeting ID: 889 1567 1168; Passcode: 545560

Video Conference: https://us02web.zoom.us/j/88915671168?pwd=d3YzN0RTTy9ydU1xWkRRQlk4cEpJdz09

Those who wish to make comments at the public hearing will be asked to state their name or affiliation for the record.

DNR will summarize and respond to public comments after the close of the public comment period and will include the responsiveness summary in the final regional haze plan. DNR will submit the final plan and all associated appendices, including the final permits, to EPA as a revision to Iowa's SIP. The final documents will be posted online at: https://www.iowadnr.gov/Environmental-Protection/Air-Quality/Implementation-Plans.

Individuals with disabilities or limited English proficiency are encouraged to participate in all DNR activities, including submitting public comments. If a reasonable accommodation or language services are needed to participate, contact the Air Quality Bureau staff member listed or Relay Iowa TTY Service at 800-735-7942 in advance to advise them of your specific needs. DNR's language access and disability nondiscrimination plans are available at https://www.iowadnr.gov/About-DNR/Environmental-Justice.

13. Administrative Materials

As discussed below, the submittal of this SIP revision complies with the procedural elements of Subpart F of 40 CFR 51 and addresses the remaining applicable criteria in Appendix V of 40 CFR 51 (the public participation criteria were addressed in Chapter 12).

A formal letter of submittal from the Governor of the State of Iowa, or their designee, requesting EPA approval of the proposed revision to the SIP for the State of Iowa will be included with the SIP submittal. All the included air construction permits are in their final form, and the DNR has followed all applicable procedural requirements of the state's laws and constitution in the adoption of this plan.

13.1. Evidence of State Adoption

The date of adoption will be addressed in the transmittal letter after the plan is approved by the Environmental Protection Commission (EPC). The EPC is the governing commission for the environmental services portion of the DNR (Iowa Code 455A.6).

13.2. Legal Authority

The DNR is the regulatory agency with primary responsibility for outdoor air quality permitting and compliance activities in the State of Iowa. The DNR's authority is set forth in chapter 455B of the Iowa Code and implemented through 567 IAC Chapters 10 and 20-33, and 561 IAC Chapters 2 and 7. The DNR's permitting and compliance programs and associated rules have previously been approved by EPA as part of Iowa's SIP. Pursuant to the regional haze program, the DNR established special requirements for visibility protection in 567 IAC 22.9. EPA approved these regulations into Iowa's SIP on September 13, 2005 (70 FR 53939).

The DNR has the necessary legal authority under state statute to adopt and implement this plan. Iowa Code section 455B.133(3) provides that the Iowa Environmental Protection Commission shall "[a]dopt, amend, or repeal ambient air quality standards for the atmosphere of this state on the basis of providing air quality necessary to protect the public health and welfare." Iowa Code section 455B.133(4) provides that the commission shall "[a]dopt, amend, or repeal emission limitations or standards relating to the maximum quantities of air contaminants that may be emitted from any air contaminant source." Iowa Code section 455B.134(9) states that the duties of the director include issuing "orders consistent with rules to cause the abatement or control of air pollution, or to secure compliance with permit conditions."

In combination with the DNR's existing legal authority and associated administrative regulations, this SIP revision is adequate to satisfy Iowa's obligations for a 10-year comprehensive SIP revision for the second implementation period (2019-2028) of the regional haze rule.

14. List of Appendices

All files are PDF (Portable Document Format), except those noted as Microsoft Excel files "(xlsx)."

Appendix A-1. LADCO, "*Modeling and Analysis for Demonstrating Reasonable Progress for the Regional Haze Rule 2018 - 2028 Planning Period*," Technical Support Document, June 17, 2021

Appendix A-2. LADCO, TSD Supplemental Materials, June 17, 2021

Appendix B. Ramboll, "*Determining Areas of Influence – CenSARA Round Two Regional Haze*," final report, November 2018

Appendix C-1. AOI Analytical Spreadsheet Tool (xlsx)

Appendix C-2. AOI Analytical Spreadsheet Results for 12 Class I Areas (xlsx)

Appendix D-1. AECOM, "R*egional Haze Reasonable Further Progress Four Factor Analysis*," report prepared for MidAmerican Energy Company, Louisa and Walter Scott Jr. Coal-Fired Boilers, AECOM Project Number 60645615, August 9, 2021

Appendix D-2. DNR's Review of MidAmerican's NO_X Control Cost Estimates

Appendix D-3. MidAmerican Energy Company, "*The Appropriate Interest Rate in a Four Factor Analysis*," memo dated April 5, 2021

Appendix E. Air Construction Permits for Louisa Generating Station (LGS, main boiler), Walter Scott Jr. Energy Center – Unit 3 (WSEC-3), and Unit 4 (WSEC-4)

Appendix F. FLM Formal Consultation and Comment Documents

Appendix G. Public Comment Letters Received

Appendix H. Additional Interstate Consultation Documentation