OFFICE OF THE GOVERNOR
STATE OF MONTANA

GREG GIANFORTE
GOVERNOR

KRISTEN JURAS
LT. GOVERNOR

August 1, 2022

Kathleen 'KC' Becker, Regional Administrator
United States Environmental Protection Agency
Region VIII, 8P-AR
1595 Wynkoop Street
Denver, Colorado 80202-1129

RE: Montana State Implementation Plan Action – Protection of Visibility

Dear Ms. Becker:

For your consideration, this submittal contains Montana's Regional Haze State Implementation Plan (SIP), which fulfills the requirements of the Regional Haze Rule (RHR) in 40 CFR Part 51, Subpart P. The Montana Department of Environmental Quality (DEQ) has worked closely with Environmental Protection Agency (EPA) Region 8 staff to develop an approvable plan for your review.

The objectives of the RHR are to improve existing visibility in mandatory Class I areas, prevent future impairment of visibility by manmade sources, and meet the national goal of natural visibility conditions in all mandatory Class I areas by 2064.

The Montana DEQ examined many sources of emissions, both those that are reasonably anticipated to contribute to visibility impairment in Montana and those outside our control, such as international industries and wildfire emissions. Through this source examination and technical analyses, including air quality modeling and trends in ambient air monitoring data, we have determined that additional controls during the second planning period are not reasonable therefore not required.

Through this document, the State of Montana proposes a revision to the Montana SIP to establish long-term strategies and to set the 2028 reasonable progress goals for successful implementation of the RHR in Montana.

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The information contained in this SIP submittal was published for a 30-day public comment period ending on March 21, 2022. Copies of comments received during the public comment period are included in this submittal, as are the DEQ's responses to comments.

Should you have any questions regarding this action, please contact Rhonda Payne, the DEQ's Regional Haze Project Manager, by telephone at (406) 444-5287 or by email at repayne@mt.gov.

Sincerely,

GREG GIANFORTE
Governor

Enc.
cc: Monica Morales, Director, Air Program, USEPA Region 8
Scott Jackson, Chief, Air Quality Planning Unit, USEPA Region 8
Chris Dorrington, Director, Montana Department of Environmental Quality (DEQ)
Bo Wilkins, Air Quality Bureau Chief, Montana DEQ

AUGUST 10, 2022

Montana Department of Environmental Quality

STATE OF MONTANA REGIONAL HAZE IMPLEMENTATION PLAN

SECOND PLANNING PERIOD

MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY BUREAU

Publication and Contact Information

The State of Montana Department of Environmental Quality posts Regional Haze program information at https://deq.mt.gov/air/Programs/planandrule

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State of Montana Department of Environmental Quality – www.deq.mt.gov

MONTANA Regional Haze State Implementation Plan for the Second Planning Period (2018-2028)

by

State of Montana Department of Environmental Quality – Air Quality Bureau

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LIST OF APPENDICES (SEPARATE DOCUMENT)

LIST OF ACRONYMS

The following acronyms and abbreviations are used throughout the report and appendices.

2028OTBa2	**2028 On-the-Books Emissions Inventory**
2028PAC2	**2028 Potential Additional Controls Emissions Inventory**
AERR	**Air Emissions Reporting Rule**
ARM	**Administrative Rules of Montana**
AQB	**Air Quality Bureau**

AQRC	Air Quality Research Center
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
bbls	Barrels
Bext	Light Extinction Coefficient
BER	Board of Environmental Review
BLM	Bureau of Land Management
CAA	Clean Air Act
CAAAC	Clean Air Act Advisory Committee
CAMD	Clean Air Markets Division
CAMR	Clean Air Mercury Rule
CAMx	Comprehensive Air Quality Model with Extensions
CEMS	Continuous Emission Monitoring Systems
CMAQ	Community Multiscale Air Quality Modeling system
CFR	Code of Federal Regulations
CM	Course Mass
DEQ	Montana Department of Environmental Quality
dv	Deciview
EC	Elemental Carbon
EE	Exceptional Events
EGU	Electric Generating Unit
EI&MP	Emissions Inventory & Modeling Protocol
EPA	United States Environmental Protection Agency
EPAwoF	EPA without Fire
EWRT	Extinction Weighted Residence Time
FCCU	Fluid Catalytic Cracking Unit
FIP	Federal Implementation Plan
FS	Fine Soil
FSWG	Fire and Smoke Work Group
H-L SA	High-level Source Apportionment
hr	Hour
HYSPLIT	Hybrid Single-Particle Lagrangian Integrated Trajectory model
IMPROVE	Interagency Monitoring of Protected Visual Environments
in	Inches
km	Kilometers
lb	Pounds
LAC	Light Absorbing Carbon
L-L SA	Low-level Source Apportionment
LMP	Limited Maintenance Plan
LNB	Low-NOx Burners
LTS	Long Term Strategy
MACT	Maximum Achievable Control Technology
MAQP	Montana Air Quality Permit

MATS	**Mercury and Air Toxics Standards**
MCA	**Montana Code Annotated**
MCF	**Million Cubic Feet**
MID	**Most Impaired Days**
mm	**Millimetres**
Mm-1	**Inverse Megameters**
mmBtu	**Million British Thermal Units**
Montana FIP	**Montana's Federal Implementation Plan**
MOVES	**Motor Vehicle Emissions Simulator**
MT	**Montana**
MW	**Megawatts**
NAAQS	**National Ambient Air Quality Standards**
NAT	**Natural**
NC-II	**Natural Conditions II**
NEI	**National Emission Inventory**
NH_3	**Ammonia**
NO_2	**Nitrogen Dioxide**
NO_x	**Nitrogen Oxides**
NOAA	**National Oceanic and Atmospheric Administration**
NP	**National Park**
NPS	**National Park Service**
NSCR	**Nonselective Catalytic Reduction**
NSPS	**New Source Performance Standards**
NSR	**New Source Review**
O&G	**Oil and Gas**
OGWG	**Oil and Gas Work Group**
OMC	**Organic Carbon**
Plan02d	**Typical-Year Baseline Inventory (Final Revision)**
PM	**Particulate Matter**
PM_{10}	**Particulate with a Diameter of 10 or Smaller µm**
$PM_{2.5}$	**Particulate with a Diameter of 2.5 or Smaller µm**
PMC	**Coarse Mass**
POA	**Primary Organic Aerosol**
POM	**Particulate Organic Matter**
ppb	**Parts per Billion**
ppm	**Parts per Million**
PRP18b	**Preliminary Reasonable Progress Inventory for 2018 (2nd Revision)**
PSAT	**Particulate Source Apportionment Technology**
PSD	**Prevention of Significant Deterioration**
Q/D	**Emissions (in tons)/Distance**
RepBase2	**Representative Baseline Emissions Inventory**
RHPWG	**Regional Haze Planning Work Group**
RHPoE	**Regional Haze Principles of Engagement**

RHR	**Regional Haze Rule**
RH SIP	**Regional Haze State Implementation Plan**
RoP	**Rate of Progress**
RPG	**Reasonable Progress Goal**
RPO	**Regional Planning Organization**
RPS	**Renewable Portfolio Standard**
RRF	**Relative Response Factor**
RTO	**Regional Technical Operations**
SCC	**Standard Classification Code**
SCR	**Selective Catalytic Reduction**
SNCR	**Selective Non-Catalytic Reduction**
SIP	**State Implementation Plan**
SMP	**Smoke Management Plan**
SNCR	**Selective Noncatalytic Reduction**
SO_2	**Sulfur Dioxide**
SOFA	**Separated Over-Fire Air**
SO_x	**Sulfur Oxides**
TBtu	**Trillion British Thermal Units**
TDWG	**Tribal Data Work Group**
TSC	**Technical Steering Committee**
TSS	**Technical Support System**
µg/m3	**Micrograms per Cubic Meter**
µm	**Micron (Micrometer)**
URP	**Uniform Rate of Progress**
USFS	**United States Forest Service**
USFWS	**United States Fish and Wildlife Service**
VOCs	**Volatile Organic Compounds**
WA	**Wilderness Area**
WEP/AOI	**Weighted Emissions Potential/Area of Influence**
WESTAR	**Western States Air Resources Council**
WRAP	**Western Regional Air Partnership**
WRF	**Western Regional Framework**
ZROW	**Zero-out International Emissions**
µg/m3	**Micrograms per Cubic Meter**
µm	**Micron (Micrometer)**
ARM	**Administrative Rules of Montana**
BACT	**Best Available Control Technology**
BART	**Best Available Retrofit Technology**
bbls	**Barrels**
Bext	**Light Extinction Coefficient**
CAA	**Clean Air Act**
CAMD	**Clean Air Markets Division**
CAMR	**Clean Air Mercury Rule**

CEMS	**Continuous Emission Monitoring Systems**
CFR	**Code of Federal Regulations**
dv	**Deciview**
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EE	**Exceptional Events**
EGU	**Electric Generating Unit**
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SNCR	Selective Noncatalytic Reduction
SO_2	Sulfur Dioxide
SOFA	Separated Over-Fire Air
SO_x	Sulfur Oxides
TBtu	Trillion British Thermal Units
TSS	Technical Support System
VOCs	Volatile Organic Compounds
WESTAR	Western States Air Resources Council
WRAP	Western Regional Air Partnership

EXECUTIVE SUMMARY

The purpose of this document is to meet the requirements of the Regional Haze Rule (RHR) – codified in Title 40 of the Code of Federal Regulations (CFR), Part 51.308 – for a State Implementation Plan (SIP) for the Second Planning Period. *See* 40 CFR 51.308(f) (requiring periodic comprehensive revisions of state implementation plans for regional haze by July 31, 2021).

The objectives of the RHR are to improve existing visibility in 156 national parks, wilderness areas, and monuments (identified as Mandatory Class I areas), prevent future impairment of visibility by manmade sources, and meet the national goal of natural visibility conditions in all mandatory Class I areas by 2064.

The RHR establishes several planning periods extending from 2005 – 2064. The State of Montana (Montana) is required to develop a Regional Haze (RH) SIP for each period. The RH SIP must provide for improvement of visibility on the most impaired days and protection of existing visibility on the clearest days. The RH SIP must also address mandatory Class I areas outside of the state that are reasonably anticipated to be affected by emissions from Montana.

The first planning period from 2005-2018 was covered by a Federal Implementation Plan (FIP) administered by the US Environmental Protection Agency (EPA). In June 2016, Montana Governor Steve Bullock released his blueprint for Montana's Energy Future, which in part directed the Department of Environmental Quality (DEQ) to become the governmental authority for the Regional Haze program. On March 23, 2020, DEQ submitted to EPA a proposed SIP revision to include the requirements of EPA FIP in Montana's SIP. DEQ anticipates EPA approval of this submission soon. Moving forward into the second planning period from 2018-2028, the state has prepared its plan for how to protect visibility in our Class I areas. This plan builds on the foundational requirements set forth in the first planning period by addressing the following regulatory steps:

- Determine current visibility conditions and comparing to natural conditions;
- Develop a long-term strategy to reduce emissions that contribute to visibility impairment;
- Establish 2028 reasonable progress goals for the end of the implementation period; and
- Submit a monitoring strategy.

The RHR requires that states demonstrate the progress made to date and determine any additional progress needed to achieve the visibility improvement goals during this planning period. As part of its long-term strategy, Montana is required to set reasonable progress goals that 1) must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and 2) ensure no degradation in visibility for the least impaired days over the same period. This SIP revision examines the need to implement additional emission reduction measures on sources that are reasonably anticipated to contribute to visibility impairment. This examination is known as a four-factor analysis and consists of four criteria: 1) cost of compliance, 2) time necessary for compliance,

3) energy and non-air quality environmental impacts, and 4) remaining useful life. The four-factor analysis is a regulatory requirement (CAA §169A(g)(1)) and assists states toward developing their reasonable progress goals for inclusion in the long-term strategy for the planning period.

Montana reviewed industrial sources that, based on emissions and proximity to Class I areas, potentially impact Class I areas in and outside of the state. While Montana primarily engaged in a four factor analysis as required by statute, Montana also considered future emission changes due to facilities' retirements, replacements and ongoing pollution control programs when deciding on reasonable control measures. In Montana, coal-fired electrical generating units (EGUs) are a large contributor to air pollution, yet since the first planning period, a number of EGUs in Montana have closed: J.E. Corette 153-MW Steam Electric station (shutdown April, 2015), Units 1 & 2 (307 MW each) at Colstrip Steam Electric Station (shutdown January, 2020), and the 50 MW Montana-Dakota Utilities Lewis & Clark Station (shutdown March, 2021). In total, oxides of nitrogen (NO_x) (a precursor to ammonium nitrate, a visibility-impairing particulate) have declined almost 40 percent from this planning period's baseline (2014) to the projected 2028 levels at the end of this planning period. Levels of sulfur dioxide (SO_2), a precursor to another type of visibility-impairing species, ammonium sulfate, are expected to decline 21 percent by 2028 from the baseline.

These emissions reductions from source retirements were considered in the decision toward requiring controls on remaining sources this planning period. Another important consideration are the sources of emissions that Montana cannot control, both anthropogenic and natural. International emissions from Canada and beyond disperse into Montana and have a large impact on our eastern Class I areas. Wildfire emissions impact much of the West and have become a natural part of the summer and fall in Montana. Additional prescribed fire activities are becoming more accepted as a control strategy for wildfire. In Montana, smoke from both wildfire and prescribed fire impact our Class I areas.

Technical analyses, such as large-scale photochemical grid modeling, estimate the contribution of these sources as well as industrial sources in Montana and project 2028 visibility to be on track to meet our reasonable progress goals for this planning period. Montana reviewed the extensive air quality modeling and trends in ambient air monitoring data to assemble a weight of evidence demonstration for this SIP revision. Taken as a whole, these demonstrations support Montana's determination that additional controls during the second planning period are not reasonable and therefore not required.

Through this document, <u>the State of Montana proposes a revision to the Montana SIP to establish long-term strategies and to set the 2028 reasonable progress goals for successful implementation of the RHR in Montana.</u>

Chapter 1 contains the background and overview of the RHR, the Class I areas in Montana and the history of the Regional Haze program in Montana, as well as the science of haze and how it's measured.

Chapter 2 speaks in more depth to Montana's SIP development process, including consultation with federal land managers, states, tribes, and public stakeholder engagement. This section also describes how Montana coordinates with the Western States Air Resource Council (WESTAR) and the Western Regional Air Partnership (WRAP), regional planning organizations that help coordinate policy and technical analyses used in this SIP.

Chapter 3 addresses progress to date, in terms of emissions controls, emission trends, and visibility trends. This chapter serves as Montana's embedded progress report.

Chapter 4 contains an analysis of visibility conditions in Montana Class I areas, and Class I areas in neighboring states. Baseline visibility, current visibility, natural visibility and visibility progress made since the baseline period are presented. Additionally, the uniform rate of progress (URP) and the methodology for adjusting the URP to account for international anthropogenic and prescribed fire emissions are described in detail.

Chapter 5 contains emissions inventory information for all the sources of emissions in Montana. These inventories are necessary in SIP development as inputs to regional modeling as well as to assist states in selecting sources for potential additional control analyses.

Chapter 6 contains the information pertaining to emission control analyses in Montana: source screening methodologies and results, and summarized four-factor analyses from "screened-in" sources.

Chapter 7 presents the five additional requirements that must be considered when developing a long-term strategy, as well as coordinated management strategies and agreements between states in terms of each state's long-term strategy.

Chapter 8 ties the long-term strategy, the conclusions of the four-factor reports, and the results of modeling the long-term strategy to the resultant reasonable progress goal for each Class I area in Montana. Montana must check that the selected reasonable progress goals allow for improvement in visibility on the most impaired days, and that the clearest days are not degraded as a result of implementing the long-term strategy.

Chapter 9 addresses Montana's monitoring strategy and other plan requirements. Montana has participated and plans to continue participating in the Interagency Monitoring of Protected Visual Environments (IMPROVE) network.

Chapter 10 contains information on Montana's consultation & public review periods and the states responses to comments, as well as Montana's commitment to further Regional Haze planning.

Appendix A – Documentation of State-to-State & Source Communications

Appendix B – Regional Modeling Delay Information

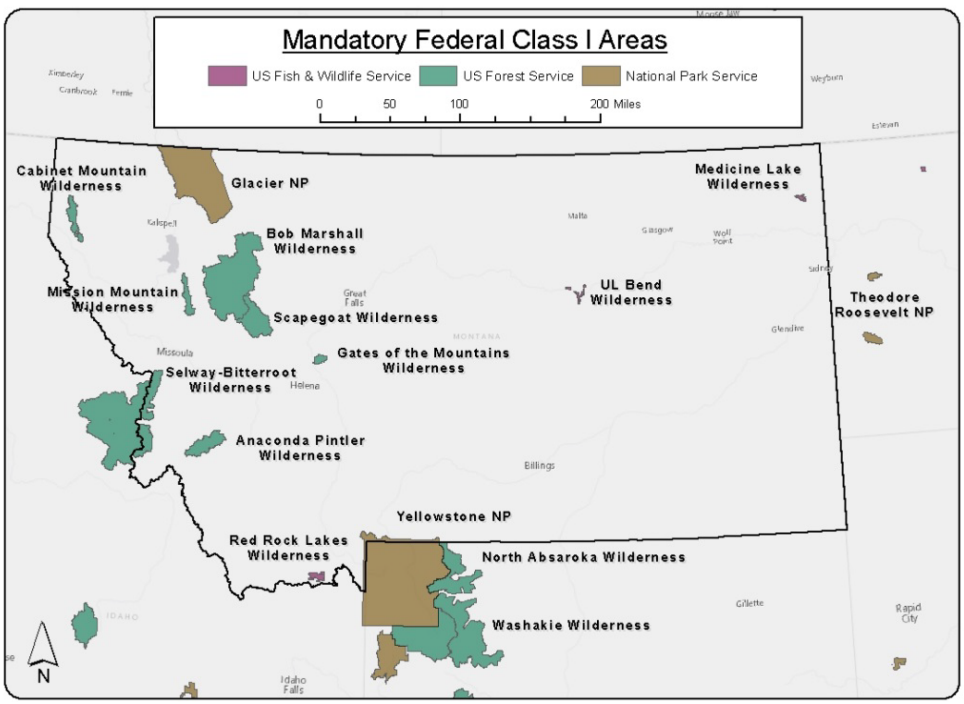
1 Background and Overview of the Regional Haze Rule

In 1977, Congress amended the Clean Air Act (CAA) with provisions to protect scenic vistas in certain Class I areas. In these amendments, Congress declared the following national visibility 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." (CAA § 169A)*

The U.S. Environmental Protection Agency (EPA) adopted the Regional Haze Rule (RHR) on July 1, 1999[1] and revised on January 10, 2017[2] to establish a comprehensive visibility protection program for the nation's 156 mandatory Class I areas. In Montana, there are 12 Mandatory Federal Class I areas as shown in the map in Figure 1-1.[3]

Figure 1-1. Mandatory Federal Class I Areas



The RHR[4] specifies that these Class I areas should attain 'natural conditions' by 2064 and that states should make progress in controlling air pollution to meet this goal. The timeline is broken into 10-year planning

[1] The Regional Haze Rule is codified in Part 51, Section 308, of Title 40 of the Code of Federal Regulations (CFR).

[2] Final Rule: Protection of Visibility: Amendments to Requirements for State Plans, 82 FR 3078, January 10, 2017.

[3] Where this report uses the term Class I Area, it is referring to a mandatory federal Class I Area, as described here and identified at 40 CFR Part 81, Subpart D, https://www.gpo.gov/fdsys/pkg/CFR-2016-title40-vol20/xml/CFR-2016-title40-vol20-part81-subpartD.xml.

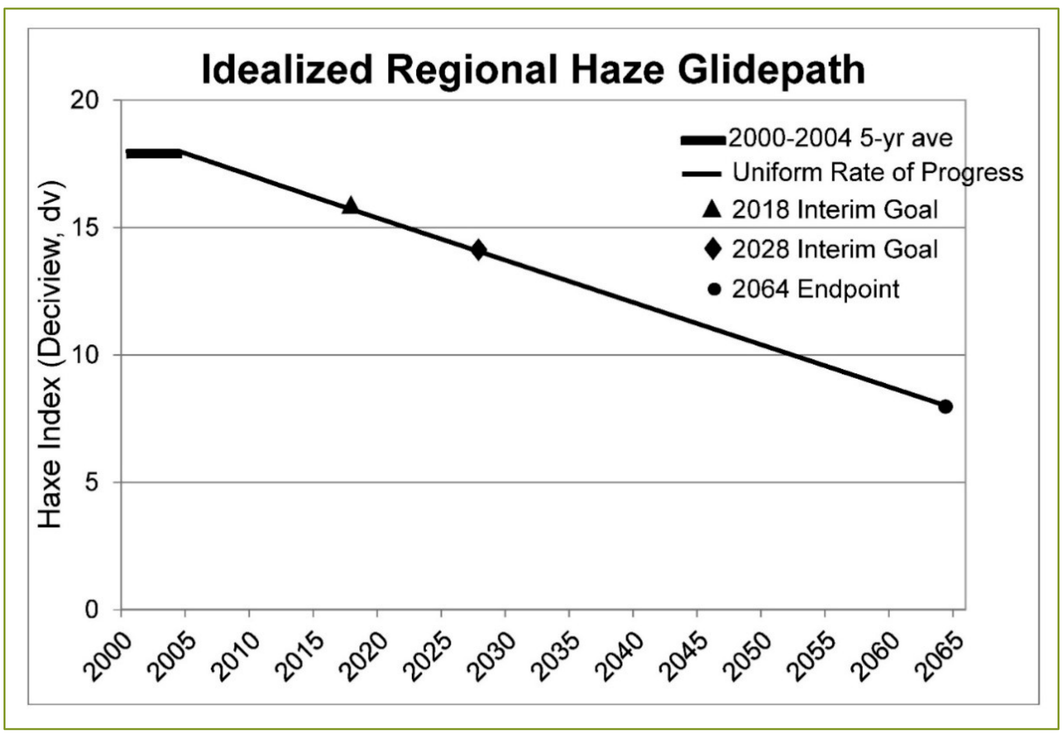
[4] For the purposes of this SIP submittal, the RHR acronym refers to the 2017 Regional Haze Rule revisions.

periods, and in each period, states must show emissions of haze-causing pollutants are being reduced along a linear path, or glidepath, toward the 2064 end goal.

To meet the planning requirements in the rule, states conduct analyses of visibility in each Class I area, identify the available reasonable measures to reduce haze, and implement those measures as part of the Long Term Strategy (LTS) for the planning period. The implemented measures establish the required Reasonable Progress Goals (RPG) for each Class I area. The RPGs are the visibility improvement benchmarks on the glidepath toward the long-term goal of natural conditions in 2064. The content of the LTS and the resultant RPGs are key strategy components for states, and must be included in a State Implementation Plan (SIP). States are also required to assess progress halfway through the 10-year implementation period, a process that is intended to keep states on-target to meet the 10-year goals established for each Class I area.

Figure 1.2 visually describes the key elements of tracking progress toward natural conditions in 2064.

Figure 1-2. RH Glidepath



The following section describes Montana's Class I areas, many of which are some of the most visited parks and treasured places in our nation.

1.1 CLASS I AREAS IN MONTANA

Table 1-1. List of Class I areas in Montana

AREA NAME	ACREAGE	FEDERAL LAND	PUBLIC LAW
Anaconda -Pintler Wilderness Area	157,803	USDA-FS	88-577
Bob Marshall Wilderness Area	950,000	USDA-FS	88-577
Cabinet Mountains Wilderness Area	94,272	USDA-FS	88-577
Gates of the Mtn Wilderness Area	28,562	USDA-FS	88-577
Glacier NP	1,012,599	USDI-NPS	61-171
Medicine Lake Wilderness Area	11,366	USDI-FWS	94-557
Mission Mountain Wilderness Area	73,877	USDA-FS	93-632
Red Rock Lakes Wilderness Area	32,350	USDI-FWS	94-557
Scapegoat Wilderness Area	239,295	USDA-FS	92-395
Selway - Bitterroot Wilderness Area{1}	251,930	USDA-FS	88-577
UL Bend Wilderness Area	20,890	USDI-FWS	94-557
Yellowstone NP{2}	167,624	USDI-NPS	({3})

1.1.1 Anaconda -Pintler Wilderness Area[5]

Figure 1-3. Anaconda -Pintler Wilderness Area

Photo credit: Great Falls Tribune

Located in Southwest Montana, the Anaconda -Pintler Wilderness Area is administered by the United States Forest Service (USFS). The Anaconda -Pintler Wilderness Area straddles the Continental Divide in southwest Montana, approximately 22 miles west of Anaconda, MT. The area is known for its high, rugged peaks where mountain goats make their home. Elevations range from 5,100 feet in the lower extents to the summit of West Goat Peak at 10,793 feet. The area is home to not only mountain goats, but also to elk, moose, dear, bears and mountain lions. The area contains glacial cirques and hanging valleys, alpine lakes and long, forested areas where award-winning trout streams flow. The wilderness area is not highly -used, in part due to its rugged nature and lack of main access points. This leaves the area to be a secluded stretch of unbroken wildland.

[5] Class I area information in Sections 1.1.1 – 1.1.12 was collected from the Montana Office of Tourism - Visit MT website: www.visitmt.com

1.1.2 Bob Marshall Wilderness Area

Figure 1-4. White River Pass in the Bob Marshall Wilderness Area

Photo credit: Montana Public Radio

The United States Congress designated the Bob Marshall Wilderness Area as part of the original Wilderness Act of 1964 and it now encompasses over 1.5 million acres. The 'Bob' is named for the Wilderness Society co-founder Bob Marshall, an early wilderness management advocate. The Continental Divide separates the Bob Marshall into the Flathead and Sun River drainages, with elevations ranging from 4,000 feet to over 9,000 feet. The wilderness area is host to the popular Wild and Scenic South Fork of the Flathead River as well as the many lakes, concentrated in the South Fork drainage, including the largest in the Bob Marshall Wilderness Complex, Big Salmon Lake (972 acres). The Bob Marshall is the last holdout habitat south of Canada for the grizzly bear and provides critical habitat to the endangered gray wolves as well. Summer is the major season of use in the Bob Marshall Country, with July being the peak month. From the September 15 early rifle season on, big-game hunting becomes the most popular recreational activity west of the Continental Divide.

1.1.3 Cabinet Mountains Wilderness Area

Figure 1-5. Cabinet Mountains near Libby, MT

Photo credit: University of Montana

The Cabinet Mountains Wilderness Area occupies the higher reaches of the northern Cabinet Range, southwest of Libby, MT. The wilderness area runs north to south for 40 miles and is entirely encompassed in wildland area around the designated wilderness. Snow-capped peaks, glacial lakes and cascading waterfalls make up the area, where wolverine, deer, elk, moose and black bear roam. A small, threatened grizzly population does live in the area as well. Approximately 90 percent of the Cabinet Wilderness visitors travel on foot, with the remainder riding in on horses or hiking in with pack stock. As a result, this area is nearly pristine in that there are very few roads and other access points.

1.1.4 Gates of the Mountains Wilderness Area

Figure 1-6. Gates of the Mountains

Photo credit: National Park Service

The Gates of the Mountains Wilderness Area covers 28,465 acres and is managed by the Helena National Forest. The nearest population center is Helena, MT, about 21 miles south of the wilderness area. It was Meriwether Lewis who was responsible for naming the landmark and was the first to leave a record of his passage: "from the singular appearance of this place I called it the gates of the mountains." The area is known for its prominent cliffs that flank the Missouri River, appearing to act as a gateway to the Rocky Mountains. Bighorn sheep and mountain goats climb the cliffs high above the river, while ospreys and eagles can be seen circling in the skies. Because the area is near a population center and major interstate, its 53 miles of trails are often frequented by hikers.

1.1.5 Glacier National Park

Figure 1-7. Going to the Sun Road in Glacier National Park

Photo credit: National Geographic

One of Montana's most popular destinations is Glacier National Park (Glacier) – the "Crown of the Continent." Glacier, and Watertown Lakes National Park in Alberta, CA, were joined in 1932 to create the world's first international peace park. Glacier is one of the top-ten most visited parks in the National Park system, with over 3 million visitors in 2018; visitors in that year alone, spent $344 million in communities near the park. That spending supported 5,230 jobs in the local area and had a cumulative benefit to the local economy of $484 million.[6] In addition to being a national park and international peace park, Glacier is a biosphere reserve and world heritage site. Glacier encompasses over 1 million acres of wilderness area in the Rocky Mountains of northwestern Montana. Over 130 named lakes, glacier-carved peaks and numerous U-shaped valleys make up the park. Hiking throughout the park's nearly 700 miles of trails is by far the most popular recreational activity to be had. Part of the trail system includes 110 miles of the Continental Divide National Scenic Trail, spanning most of the distance of the park north to south. The Pacific Northwest National Scenic Trail crosses the park on 52 miles from east to west.

[6] Tourism to Glacier National Park Adds $484 Million in Local Economic Benefits. National Park Service News https://www.nps.gov/glac/learn/news/19-28.htm

1.1.6 Medicine Lake Wilderness Area

Figure 1-8. Medicine Lake Wilderness Area

Photo credit: Great Falls Tribune

The Medicine Lake Wilderness Area lies within the boundaries of Medicine Lake National Wildlife Refuge, in northeast Montana. The Medicine Lake Wilderness is the smallest wilderness area in Montana, covering 11,366 acres and is divided into two units: the main waterbody of the lake and the Sandhills Unit. The Sandhills area is unique, with rolling hills, native grass, and brush patches. The south tract is located near Homestead, MT and consists 1,280 acres of wetlands. Thousands of migrating waterfowl make their summer home within the refuge. Great blue herons, white pelicans, sandhill cranes, grebes and 12 different species of ducks share the prairie lake ecosystem.

1.1.7 Mission Mountain Wilderness Area

Figure 1-9. Mission Mountains Wilderness Area

Photo credit: The Missoulian

The Mission Mountain Wilderness Area encompasses 73,877 acres within the Mission Mountain range in northwestern Montana. The wilderness area is a paradise for hiking, camping and fishing activities. Often referred to as the American Alps, the scenery boasts rugged, snowcapped peaks, several small glaciers, alpine lakes, meadows and clear, cold streams. In 1979, the Confederated Salish and Kootenai tribes designated 89,500 acres of privately owned tribal lands along the western slopes as Wilderness. This is the only Tribal Wilderness in the nation to be established by a tribe. The west side of the Tribal Wilderness is managed with a priority for wildlife. Each summer grizzlies gather on the snow fields of McDonald Peak, the highest peak in the range at 9,280 ft. Along with the distinguished grizzly bear population, mountain goats, black bears, elk, mule deer, and white-tailed deer are also found in the Wilderness.

1.1.8 Red Rock Lakes Wilderness Area

Figure 1-10. Red Rock Lakes Wilderness Area

Photo credit: The Billings Gazette

Red Rock Lakes National Wildlife Refuge is located in the extreme southwest portion of Montana near the Idaho border. In addition to the expansive tracts of grassland, sagebrush, steppe habitats and forested areas, the refuge boasts the largest wetland complex within the Greater Yellowstone Ecosystem. The refuge was established in 1935 to protect waterfowl and migratory birds and at one point served as a very important breeding area for trumpeter swans. Abundant hiking opportunities, bird watching, fishing and camping in the primitive campgrounds within the refuge are but some of the many ways visitors can enjoy this special place.

1.1.9 Scapegoat Wilderness Area

Figure 1-11. Scapegoat Wilderness Area

Photo credit: Visit Montana

The Scapegoat Wilderness is composed of 239,936 acres of pristine mountain and forest that straddles the Continental Divide south of the Bob Marshall Wilderness. The Wilderness is located 75 miles northeast of Missoula and 10 miles north of Lincoln. Together with the Bob Marshall and the Great Bear Wilderness, these 3 wildernesses comprise the more that 1.5-million-acre Bob Marshall Wilderness Complex. Massive limestone cliffs that dominate the Scapegoat Wilderness are an extension of the Bob Marshall's Chinese Wall. Wildlife includes wolverine, deer, elk, moose, grizzly bear, black bear, mountain goat, mountain sheep and mountain lion. The Bob Marshall/Scapegoat wilderness complex is the only place outside national parks in the lower 48 states that supports a population of grizzly bears. Most of the 14 lakes and about 89 miles of streams in the Scapegoat provide fishing opportunities.

1.1.10 Selway-Bitterroot Wilderness Area

Figure 1-12. Selway-Bitterroot Wilderness Area

Photo credit: Selway-Bitterroot Frank Church Foundation

The Selway-Bitterroot Wilderness Area comprises 1.3 million acres of land straddling Idaho and Montana. It is the 3rd largest wilderness areas in the lower 48 states. The Bitterroot Mountains form the rugged border between Idaho and Montana, dominating the landscape with their high crest, granite peaks. Below the peaks are deep canyons covered in thick coniferous forest, rich with old-growth cedar, fir and spruce. The wilderness area has large, trail-less expansions and is home to the Selway elk herd, deer, moose, black bears, mountain lions and wolves. Approximately 1,800 miles of trails wind through the area, providing access to both the Montana and Idaho sides of the mountains. Most of these trails are unmaintained and rugged, making it a wilderness area where few humans visit. The Wild and Scenic Selway River rushes out of the mountains of Idaho and meets with the Lochsa River. The Selway is a premier whitewater river offering a wild and remote wilderness experience.

1.1.11 UL Bend Wilderness Area

Figure 1-13. UL Bend Wilderness Area

Photo credit: U.S. Fish and Wildlife Service

The UL Bend Wilderness Area is a rare and treasured wildlife watching area that is one of the remote areas in Montana where elk still occupy their native prairie year-round. Wildlife viewers may also see deer, pronghorn antelope, birds, prairie dogs, and bighorn sheep in this area. The Charles M. Russell National Wildlife Refuge (NWR) surrounds the UL Bend area. UL Bend NWR, a 'refuge-within-a-refuge', lies in the Charles M. Russell NWR and is 20,000 acres. The Fort Peck Reservoir surrounds the southern half of the area. These impounded waters of the Missouri River provide an ecological barrier for wildlife associated with land. Recreational opportunities include boating, hunting, fishing, wildlife viewing, and archaeological/historic sites, as well as access to the Missouri Breaks wilderness region.

1.1.12 Yellowstone National Park

Figure 1-14. Yellowstone National Park

Photo credit: Yellowstone National Park

The first national park in the U.S., Yellowstone National Park is also widely held to be the first national park in the world. The park is mostly in Wyoming, with portions extending into Montana and Idaho. Established primarily to protect hydrothermal areas that contain about half the world's active geysers, the park also forms the core of the Greater Yellowstone Ecosystem. At 28,000 square miles, it is one of the largest, nearly intact temperate-zone ecosystems on Earth. It preserves a great variety of terrestrial, aquatic, and microbial life. The park contains the headwaters of the Yellowstone River, sections of which are officially classed as a blue-ribbon stream. Yellowstone NP is one the most visited parks in the national parks system with over 4 million visitors a year.

Protecting the visibility in all these special areas is at the heart of the RHR. The RHR does this by defining improvement of visibility on the most impaired days, and what the protection of existing visibility on the clearest days means. The RHR specifies that the haziest days are the "20 percent most impaired days (MID)" each year at each Class I area, based on anthropogenic impairment.[7] To ensure visibility isn't being impacted on the clearest days, the rule requires states to measure the "20 percent clearest days" and show

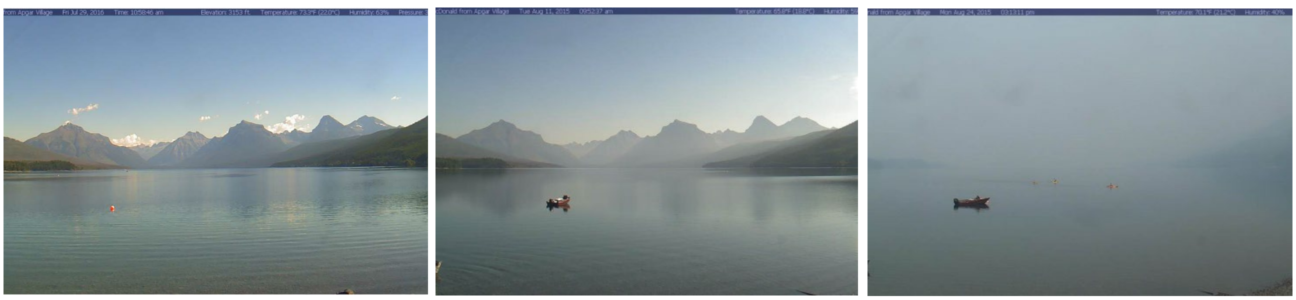
[7] In the 1999 rule, states were required to track visibility progress on the 20 percent *worst* visibility days.

that there is not degradation on these days. The following section describes how states measure and analyze haze in Class I areas.

1.2 HAZE CHARACTERISTICS AND EFFECTS

Haze is caused by the presence of tiny particles in the air that block, absorb, and scatter sunlight. More particles that are present means more light is scattered and thus we see views less clearly. We call this diminished clarity haze. Haze obscures the color, texture, and form of objects that we can see at a distance. As good example of how haze impacts what we see is depicted in the pictures below. All three photographs were taken at Lake McDonald in Glacier National Park.

Figure 1-15. Visibility in Glacier National Park



The picture on the left shows a day with relatively good visibility. Not much haze obscures the color and texture of the mountains in the distance. The picture in the middle is a bit hazier, with less texture visible on the mountains. On the right, the mountains are completely obscured by smoke from wildfires. Smoke is made up of several different types of fine particles that contribute to haze. Wildfire smoke is considered a natural source of pollution and is just one source of haze in Montana. Haze is also human-caused, or anthropogenic, emissions from activities such as electric power generation, industrial and manufacturing processes, motor vehicle emissions, burning related to forestry and agriculture, and construction activities.

Table 1-2 provides an overview of the type of source and what types of particles, or emissions, are generated from that source or activity. The pollutants that contribute to visibility impairment are: Sulfur Dioxide (SO_2), Nitrogen Oxides (NO_x), Ammonia (NH_3), Volatile Organic Compounds (VOCs), Primary Organic Aerosol (POA), Elemental Carbon (EC), Fine Soil, and Coarse Mass (CM).

Table 1-2. Visibility Impairing Pollutants[8]

Emitted Pollutant	Major Sources	Notes
Sulfur Dioxide (SO_2)	Point Sources; Mobile Sources	SO_2 emissions are generally associated with anthropogenic sources such as coal-burning power plants, other industrial sources such as refineries and cement plants, and diesel engines.
Oxides of Nitrogen (NO_x)	Mobile Sources; Point Sources; Area Sources	NO_x emissions are generally associated with anthropogenic sources. Common sources include virtually all combustion activities, especially those involving cars, trucks, power plants, and other industrial processes.
Ammonia (NH_3)	Area Sources; Mobile Sources	Gaseous NH_3 has significant effects on particle formation because it can form particulate ammonium. Ammonium affects formation potential of ammonium sulfate and ammonium nitrate. All measured nitrate and sulfate is assumed to be associated with ammonium for reporting purposes.
Volatile Organic Compounds (VOCs)	Biogenic Sources; Mobile Sources; Area Sources	VOCs are gaseous emissions of carbon compounds, which are often converted to particulate matter through chemical reactions in the atmosphere.
Primary Organic Aerosol (POA)	Wildfires; Area Sources	POA represents organic aerosols that are emitted directly as particles, as opposed to gases. Wildfires in the west generally dominate POA emissions. Large wildfire events are generally sporadic and highly variable from year-to-year.
Elemental Carbon (EC)	Wildfires; Mobile Sources	Large EC events are often associated with wildfires Other sources include mobile diesel engines.
Fine soil	Windblown Dust; Fugitive Dust; Road Dust; Area Sources	Fine soil is reported here as the crustal or soil components of $PM_{2.5}$ (particulate with a diameter of 2.5 or smaller μm).
Coarse Mass (CM)	Windblown Dust; Fugitive Dust	Coarse mass is reported by the IMPROVE Network as the difference between PM_{10} (particulate with a diameter of 10 or smaller μm) and $PM_{2.5}$ mass measurements. Coarse mass is not separated by species in the same way that $PM_{2.5}$ is speciated, but these measurements are generally associated with crustal components. Similar to crustal $PM_{2.5}$, natural windblown dust is often the largest contributor to PMC.

[8] Air Resource Specialists, Inc, "Western Regional Air Partnership Regional Haze Rule Reasonable Progress Summary Report" (28 June 2013), Available at: https://www.wrapair2.org/documents/SECTIONS%201.0%20-%203.0/WRAP_RHRPR_Sec_1-3_Background_Info.pdf.

Through reactions in the atmosphere, gases and particles emitted from various sources form different species: SO_2 is ultimately converted to sulfates, such as ammonium sulfate ($(NH_4)2SO_4$) and nitrogen oxides (NOx) convert to nitrates such as nitric acid or ammonium nitrate (NH_4NO_3). Therefore, SO_2 and NO_x are considered 'precursors' to ammonium sulfate and ammonium nitrate.

Regional haze is the cumulative impact of emissions from these varied activities, often located over a broad geographic area. These haze-causing particles can be transported great distances in the air, sometimes hundreds or thousands of miles. One single source of emissions may not have a visible impact on haze by itself, but emissions from many sources across a region can add up to cause haziness.

There are different metrics to measure impact on visibility. The most intuitive measure of visibility is Visual Range (V.R.), or the greatest distance a large black object can be seen on the horizon, expressed in kilometers (km) or miles (mi).[9] In the West, natural visual range is approximately 140 mi. Another way to quantify visibility is through a measurement called light extinction. Light extinction is the attenuation of light due to scattering and absorption as it passes through a medium, measured in inverse megameters (Mm-1). The benefit of using a light extinction value to describe visibility is that it can be related to pollution particle concentration. The disadvantage is that the measurement is non-linear compared to a person's perception. To overcome this, visibility can be measured in deciviews (dv), a unitless metric that is the logarithmic transformation of the light extinction value. The RHR uses the deciview as the main metric for tracking visibility.

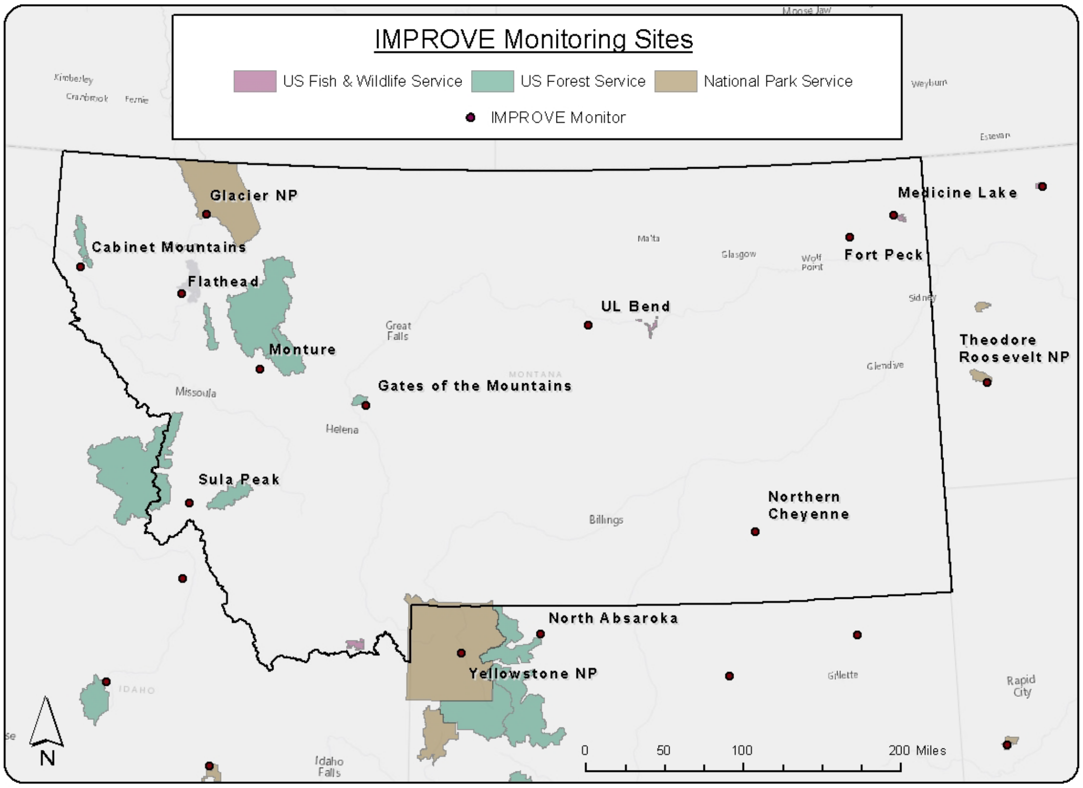
The pollution particles in the air must be measured and divided into various chemical components, or species, to help further visibility analysis in the state. The following section describes how particles are measured and speciated.

1.3 IMPROVE Program

Visibility is measured by an air-monitoring network called IMPROVE (Interagency Monitoring of Protected Visual Environments). IMPROVE was developed in 1985 to establish current visibility conditions, track changes in visibility, and help determine the causes and sources of visibility impairment in Class I areas. The network is comprised of 110 monitoring sites across the nation, ten of which are in Montana. Montana relies on the IMPROVE monitoring network to assess visibility at Class I Areas across the state. The IMPROVE locations in Montana are shown relative to Class I Areas in Figure 1-16.

[9] Definitions of visibility metrics are taken from http://vista.cira.colostate.edu/Improve/visibility-basics/

Figure 1-16. IMPROVE Monitoring Sites



The IMPROVE monitoring sites contain equipment that is programmed to automatically collect samples of haze-forming particles from the air on an ongoing basis. Local operators at each field site—in many cases a park ranger, firefighter, or rancher—inspect the samplers and exchange filters weekly, shipping all exposed filters back to the Air Quality Research Center (AQRC) at the University of California (UC) Davis every three weeks. Each month, the program's 160 field sites generate about 7,000 filters, which are processed in AQRC's laboratories by staff members and UC Davis students working part-time.[10] The analyses conducted at the AQRC tests samples for various pollutants and trace metals and estimates the light scattering effect of each species. This estimation results in a light extinction value. For purposes of the RHR, light extinction is estimated for sulfate, nitrate, organic mass by carbon (OMC), light absorbing carbon (LAC), fine soil (FS), sea salt, and coarse material (CM), all components of particulate emissions.

Figures 1-17 and 1-18 show the outside and inside of the IMPROVE site located at Gates of the Mountains and Figure 1-19 shows the four separate modules used for sampling the different species.

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[10] Air Quality Research Center – University of California Davis. https://aqrc.ucdavis.edu/improve (accessed 5/5/2020)

Figure 1-17. Gates of the Mountains (Outside Station)

Figure 1-18. Gates of the Mountains (Inside Station)

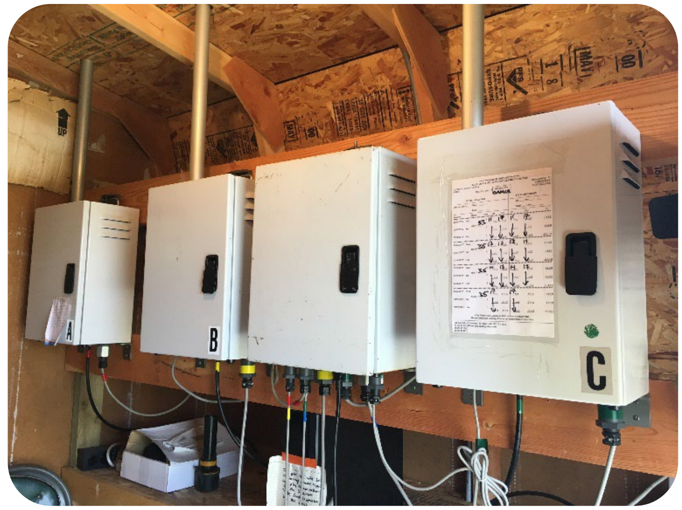
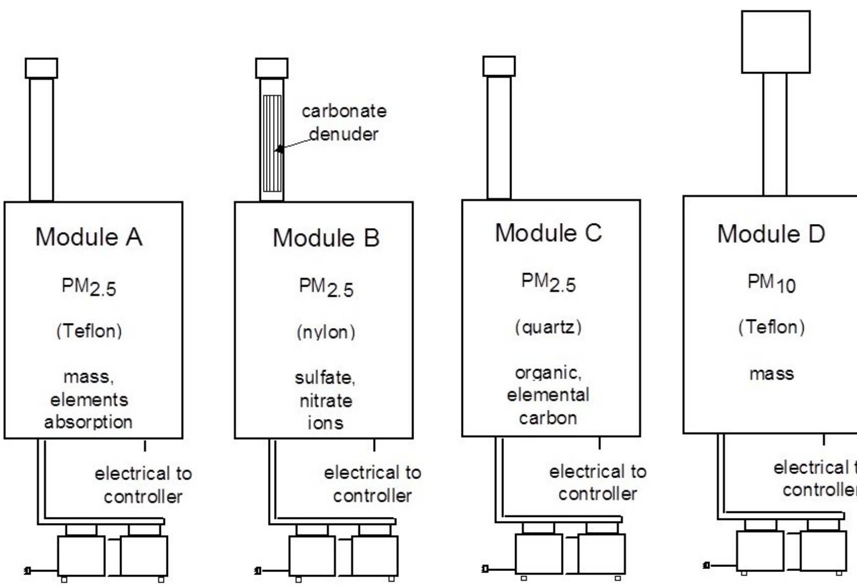


Figure 1-19. Four Modules Used for Regional Haze Sampling



http://vista.cira.colostate.edu/Improve/improve-program/

IMPROVE samplers collect 24-hour samples, every three days. The IMPROVE particle monitor consists of four independent sampling modules. Three modules (A, B, and C) collect only fine particles ($PM_{2.5}$), while the fourth (module D) collects both fine and coarse particles (PM_{10}). Species' concentration data from all the modules are used to calculate the light extinction, using a formula to account for each species' different efficiencies at scattering light. As mentioned previously, the RHR established the deciview (dv) as the main metric describing visibility impairment. The deciview index was designed to be linear with respect to human perception of visibility. A '1' deciview change is approximately equivalent to a 10% change in extinction, whether visibility is good or poor. A deciview of 1 is considered to be the minimum change the average person can detect with the naked eye. Therefore, the light extinction value estimated at the measuring site is logarithmically transformed to a deciview. A lower deciview value indicates better visibility over a greater distance.

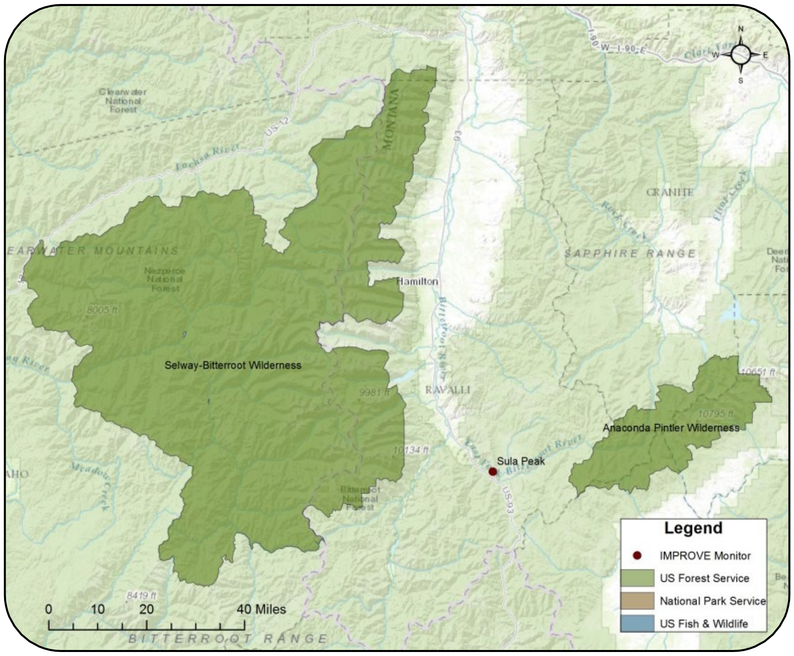
IMPROVE monitors are not available for all of Montana's 12 Class I areas. For Class I areas without IMPROVE monitors, the closest representative monitor is selected as a surrogate as per EPA guidance.[11] A crosswalk of Class I area to representative IMPROVE monitor is shown in Table 1-3. Because visibility conditions will be the same for all Class I areas sharing a monitor, in this submittal visibility will be discussed by IMPROVE site, not Class I area. This table also indicates the two closest monitor sites in Wyoming and in North Dakota.

Table 1-3. Representative IMPROVE Monitoring Sites

Class I Area Name	Representative IMPROVE	Location
Anaconda-Pintler Wilderness Area	Sula Peak (SULA1)	45.8598, -114.0001
Bob Marshall Wilderness Area	Monture, MT (MONT1)	47.1222, -113.1544
Cabinet Mountains Wilderness Area	Cabinet Mountains (CABI1)	47.9549, -115.6709
Gates of the Mtn Wilderness Area	Gates of the Mtn (GAM01)	46.8262, -111.7107
Glacier National Park	Glacier (GLAC1)	48.5105, -113.9966
Medicine Lake Wilderness Area	Medicine Lake (MELA1)	48.4871, -104.4757
Mission Mountain Wilderness Area	Monture, MT (MONT1)	47.1222, -113.1544
Red Rock Lakes Wilderness Area	Yellowstone (YELL2)	44.5653, -110.4002
Scapegoat Wilderness Area	Monture, MT (MONT1)	47.1222, -113.1544
Selway-Bitterroot Wilderness Area	Sula Peak (SULA1)	45.8598, -114.0001
UL Bend Wilderness Area	U. L. Bend (ULBE1)	47.5823, -108.7196
Yellowstone National Park	Yellowstone (YELL2)	44.5653, -110.4002
North Absaroka Wilderness Area (WY)	North Absaroka (NOAB1)	44.7448, -109.3816
Theodore Roosevelt National Park (ND)	Theodore Roosevelt (THRO1)	46.8948, -103.3777

[11] EPA, Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program, (20 Dec. 2018), Available at: https://www.epa.gov/sites/production/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf (accessed 12/10/20).

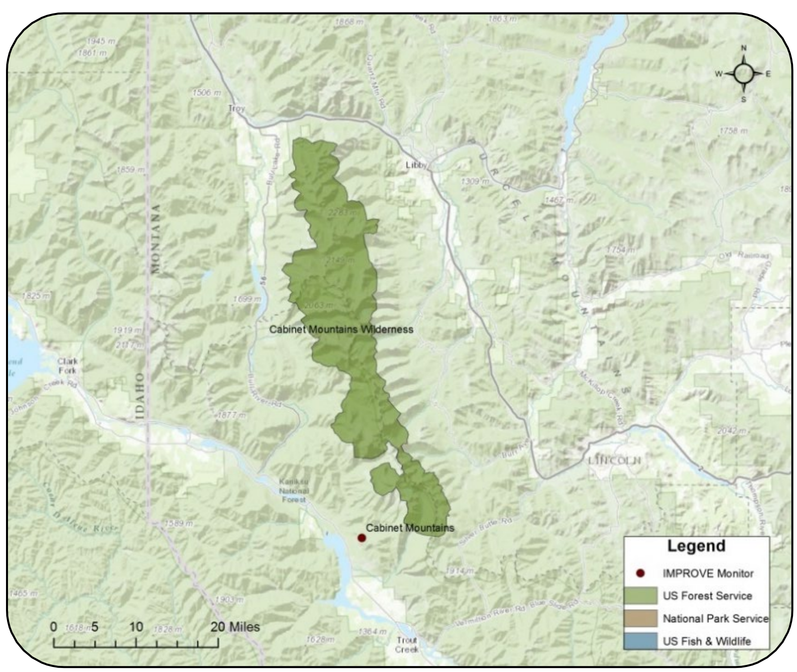
Figure 1-20. Sula Peak IMPROVE Monitor



The Sula Peak IMPROVE monitoring site is located at the southern end of the Bitterroot Valley and is the representative station for the Anaconda-Pintler Wilderness and the Selway-Bitterroot Wilderness Class I areas. The Selway- Bitterroot Wilderness Area spans both Idaho and Montana, bordering the western edge of the Bitterroot Valley in Ravalli County, MT. The Anaconda-Pintler Wilderness Area is located to the east of the Selway-Bitterroot Wilderness Area, at the southern end of the Sapphire Mountain Range.

Figure 1-21. Cabinet Mountains IMPROVE Monitor

The Cabinet Mountains IMPROVE monitoring site is located just south of the Cabinet Mountains Wilderness Area and is the representative station for the Cabinet Mountains Wilderness Class I Area. The wilderness area is located in the northwest corner of the state, and runs from north of Trout Creek, MT to west of Libby, MT. Figure 1-21 shows a zoomed in view of the Class I area.



The Gates of the Mountains IMPROVE monitoring site is located just southeast of the Gates of the Mountains Wilderness Area and is the representative station for the Gates of the Mountain Wilderness Class I Area. The wilderness area is located north of Helena, MT. Figure 1-22 shows a zoomed in view of the Class I area.

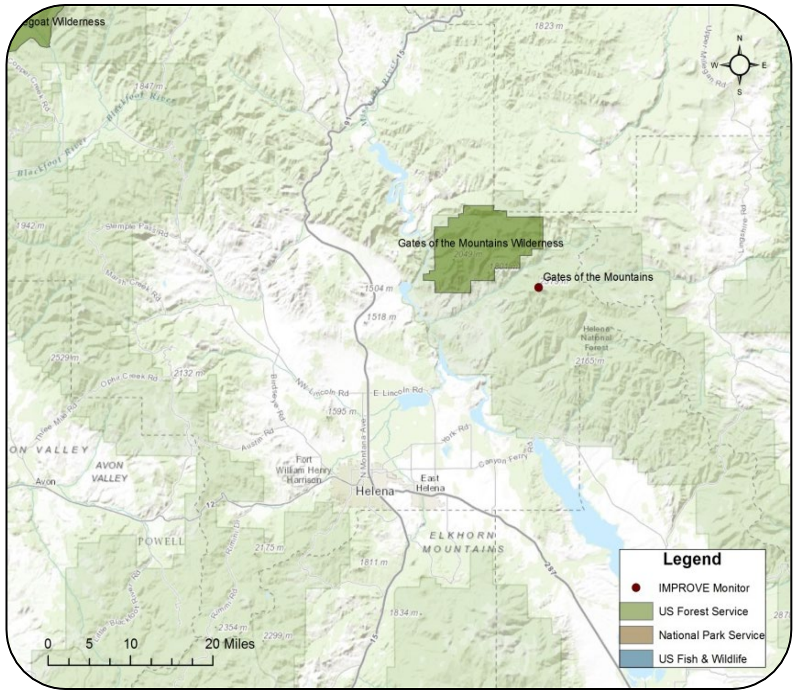


Figure 1-22. Gates of the Mountains IMPROVE Monitor

The Glacier IMPROVE monitoring site is located in Glacier National Park and is the representative station for the Glacier National Park Class I Area. The national park is located in the northcentral part of the state, along the Continental Divide. Figure 1-23 shows a zoomed in view of the Class I area.

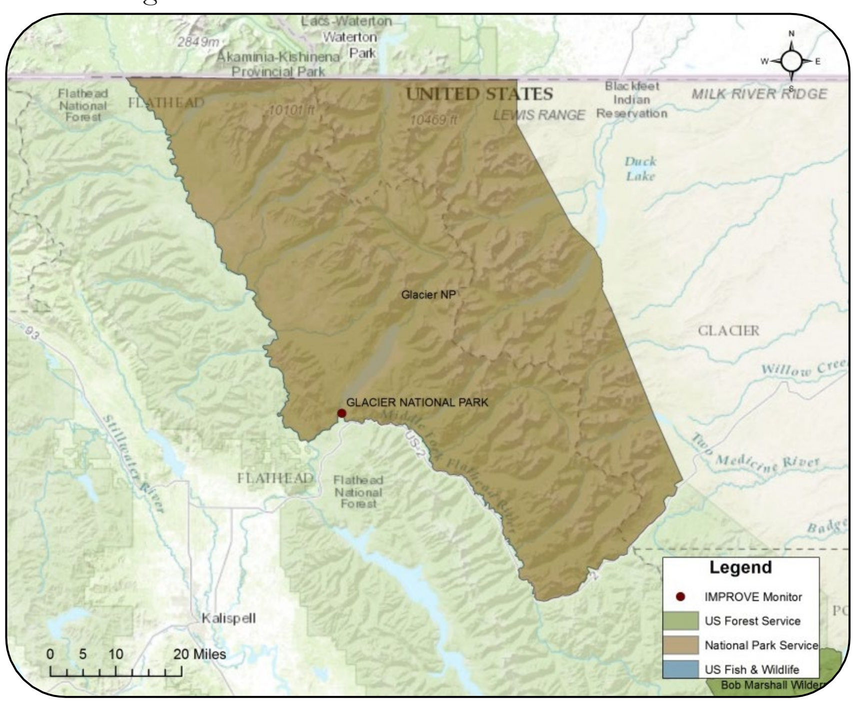
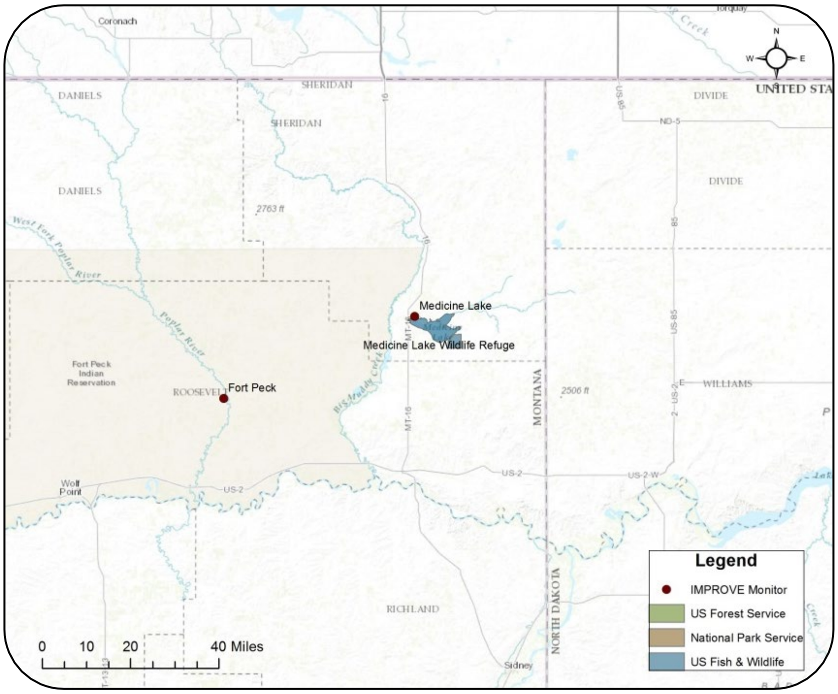


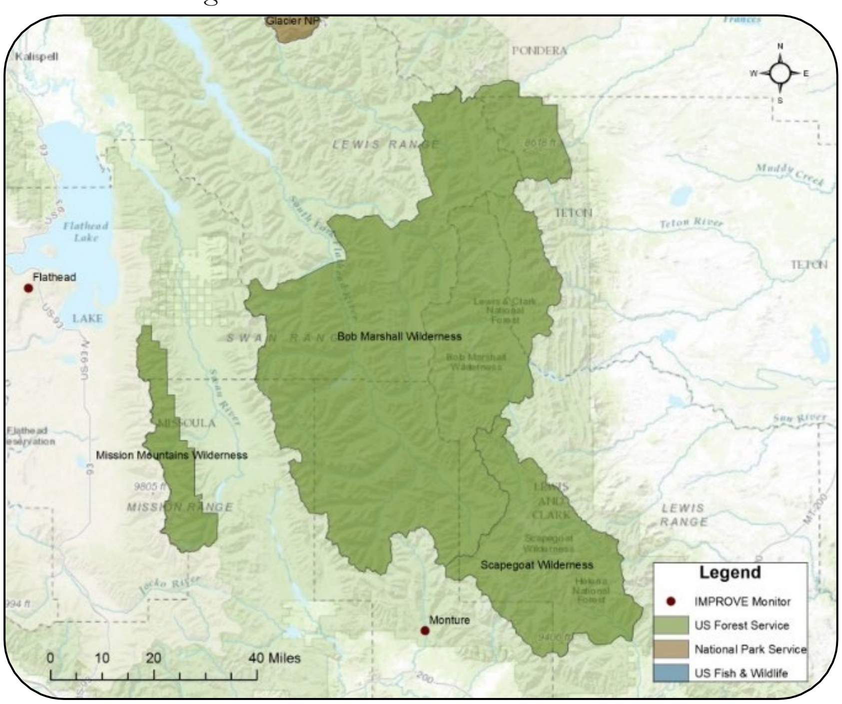
Figure 1-23. Glacier IMPROVE Monitor

Figure 1-24. Medicine Lake IMPROVE Monitor



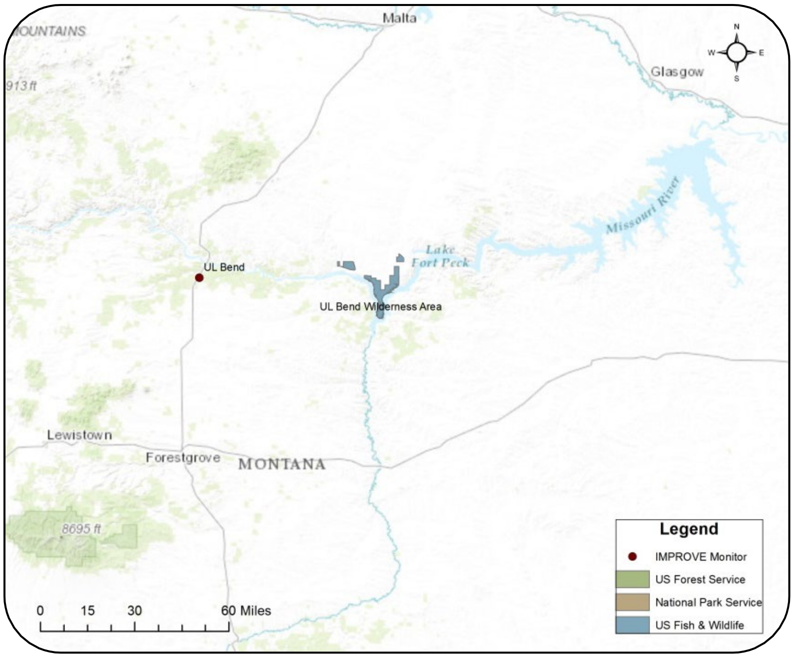
The Medicine Lake IMPROVE monitoring site is located in the Medicine Lake National Wildlife Refuge and is the representative station for the Medicine Lake National Wildlife Refuge Class I Area. The wildlife refuge is located in the northeast corner of the state, close to the North Dakota border. Figure 1-24 shows a zoomed in view of the Class I area.

Figure 1-25. Monture IMPROVE Monitor



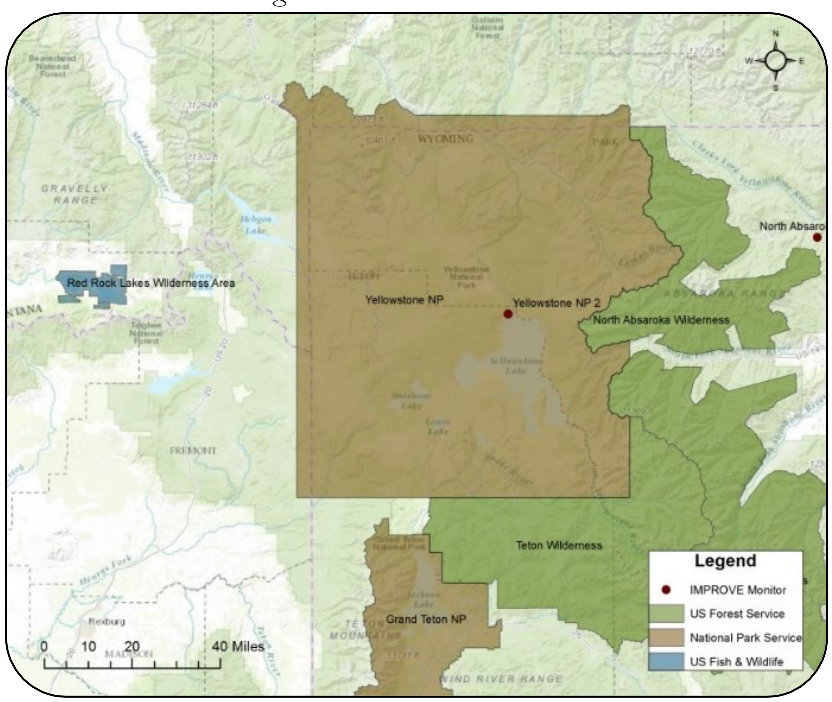
The Monture IMPROVE monitoring site is located in Powell County Montana and is the representative station for the Bob Marshall Wilderness Class I Area, the Mission Mountains Wilderness Class I Area, and the Scapegoat Wilderness Class I Area. The wilderness areas are located south of Glacier National Park and stretch from the eastern side of the Flathead Valley in the west to the Rocky Mountain Front in the east. Figure 1-25 shows a zoomed in view of the Class I areas.

Figure 1-26. UL Bend IMPROVE Monitor



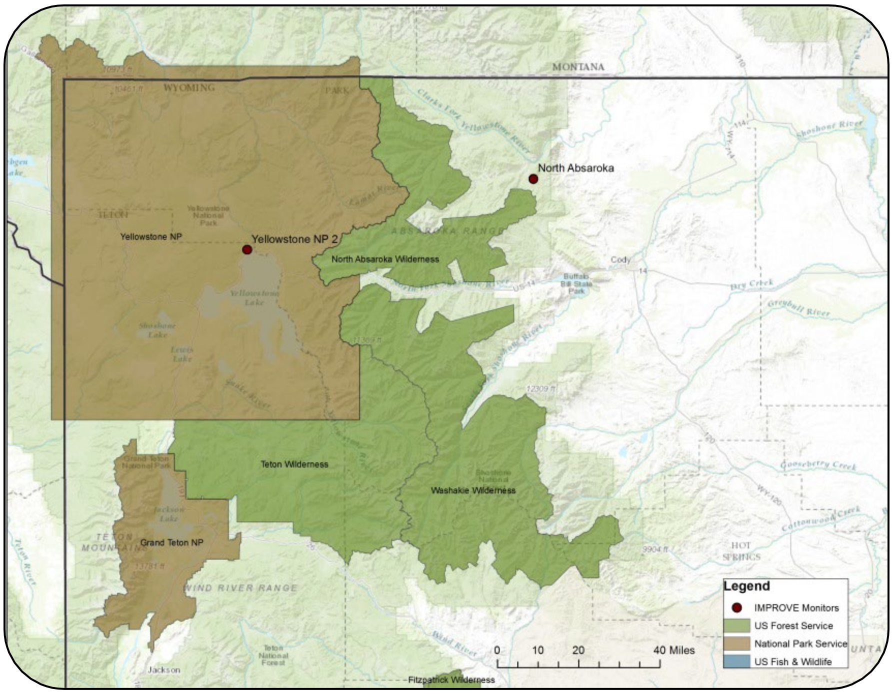
The UL Bend IMPROVE monitoring site is located west of the UL Bend Wilderness Area and is the representative station for the UL Bend Wilderness Class I Area. The wilderness area is located in central Montana at the start of Fort Peck Lake. Figure 1-26 shows a zoomed in view of the Class I area.

Figure 1-27. Yellowstone IMPROVE Monitor



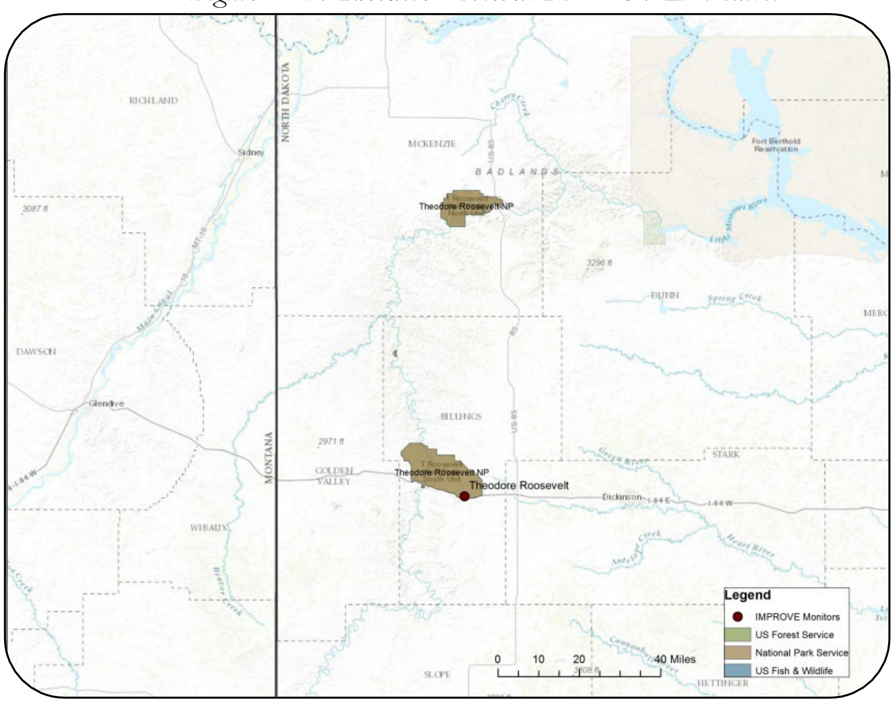
The Yellowstone NP 2 IMPROVE monitoring site is located in Yellowstone National Park and is the representative station for the Yellowstone National Park Class I Area and the Red Rock Lakes Wilderness Area. The national park is located in the northwest corner of Wyoming with the northwest and north borders crossing into Montana. The Red Rock Lakes Wilderness Area is located to the west of the national park, near the Montana/Idaho border. Figure 1-27 shows a zoomed in view of the Class I area.

Figure 1-28. North Absaroka IMPROVE Monitor



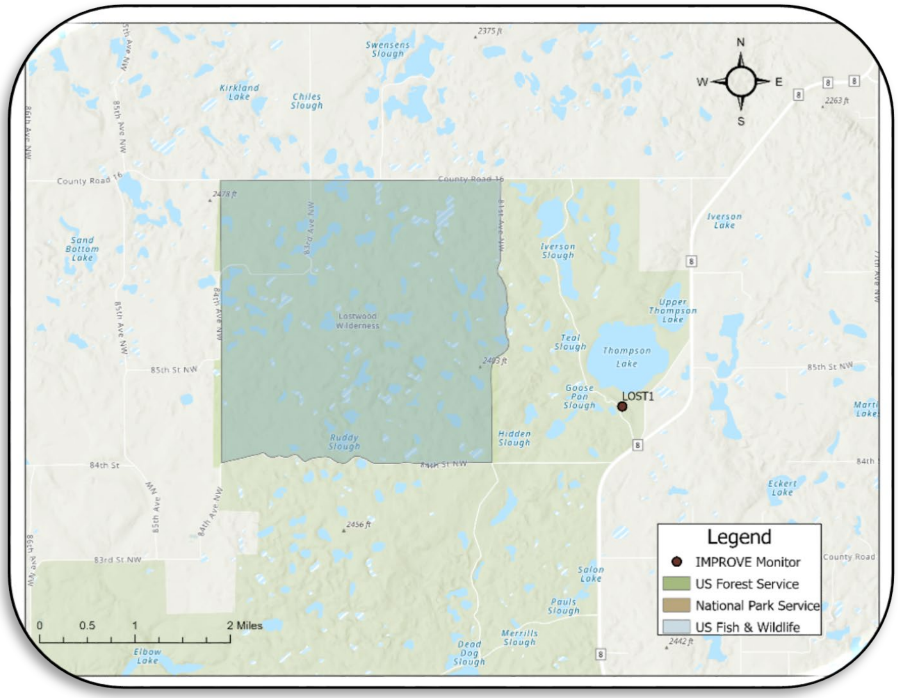
The North Absaroka IMPROVE monitoring site is located to the east of the North Absaroka Wilderness Area and is the representative station for the North Absaroka Wilderness Area and the Washakie Wilderness Area. Both wilderness areas are located along the eastern edge of Yellowstone National Park. Figure 1-28 shows a zoomed in view of the Class I areas.

Figure 1-29. Theodore Roosevelt IMPROVE Monitor



The Theodore Roosevelt IMPROVE monitoring site is located in western North Dakota and is the representative IMPROVE monitor for the Theodore Roosevelt National Park. Figure 1-29 shows a zoomed in view of the Class I area.

Figure 1-30. Lostwood IMPROVE Monitor



The Lostwood IMPROVE monitoring site is located in western North Dakota and is the representative IMPROVE monitor for the Lostwood National Wildlife Refuge. Figure 1-30 shows a zoomed in view of the Class I area.

1.4 History of Regional Haze in Montana

As mentioned previously, to show progress toward the goal of reaching natural visibility conditions by 2064, the RHR requires that states develop SIPs containing strategies to control emissions of air pollutants that contribute to haze. In 2006, for a variety of reasons including available funding and staff resources, Montana declined to submit a SIP by the prescribed due date.[12] In response, on September 18, 2012, EPA finalized a Federal Implementation Plan (Montana FIP), thereby taking the lead on controlling haze in Montana.[13]

The Montana FIP described visibility conditions at each Class I area in Montana for the baseline years of 2000-2004 and established a long-term strategy, to be implemented over the ten-year period ending in 2018, toward the goal of achieving natural visibility conditions. The Montana FIP included the RPGs that each Class I area was expected to achieve by 2018. The RPGs are the interim visibility improvement benchmarks on the glidepath toward the long-term goal of natural conditions. Achievement of the RPGs relies on control measures to improve visibility, including existing federal and state air pollution control programs, as well as the installation of new retrofit controls on some older sources of air pollution. Because Montana did

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[12] Montana did submit limited SIP revisions regarding visibility, including a Smoke Management Plan (SMP), to satisfy that portion of the RHR and retain control of the SMP in our state.
[13] EPA, Approval and Promulgation of Implementation Plans; State of Montana; State Implementation Plan and Regional Haze Federal Implementation Plan, 77 Fed. Reg. 57863 (18 Sep. 2012), https://www.federalregister.gov/d/2012-20918.

not submit a SIP, EPA performed the necessary analysis to determine what types of controls to include in the Montana FIP.

In June 2016, Montana Governor Steve Bullock released his Blueprint for Montana's Energy Future. The blueprint "charts a course for the future that not only seeks to protect existing jobs in the coal industry, but also embraces the promise of new jobs in renewable energy, energy efficiency, and developing technologies to more cleanly and efficiently produce energy from fossil fuels."[14] This means ensuring that Montana controls the fate of the energy industry within the state, both for existing and potential new energy producers. As the state seeks to protect its scenic vistas for recreation, personal enjoyment, and tourism, it must also consider the potential impacts that decisions and regulations may have on the industries that support Montana's economy and residents. For this reason, the Governor's blueprint directed the state to take over authority for the Regional Haze program.

To start, Montana worked with EPA and Federal Land Managers (FLMs) to submit the required 5-year progress report for the first implementation period for the Montana FIP. The work required to develop the progress report provided Montana with the opportunity to re-engage in the program and to better understand visibility issues in our state. The progress report was due to EPA on September 18, 2017 and was approved and finalized by EPA on October 4, 2019.[15] This finalization determined that the existing FIP was adequate and did not require revisions.

Shortly after the progress report was submitted, Montana began work on transferring the requirements of the Montana FIP to a SIP, administered by Montana. Montana worked with regional EPA staff, industry, and the Board of Environmental Review (BER), the body that issues air quality orders and adopts rules in Montana, to adopt the requirements in 40 CFR 52 § 1396 Approval and Promulgation of Implementation Plans; State of Montana; Regional Haze Federal Implementation Plan.[16] The BER issued two Board Orders:

- One Board Order that included the coal-fired electric generating units at Colstrip Steam Electric Station, (Units 1 and 2) and the JE Corette Steam Electric Station in Billings, MT, both then operated by PPL Montana, LLC.

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[14] State of Montana, "Montana Energy Future" (21 Jun. 2016), Available at: https://governor.mt.gov/Newsroom/governor-bullock-releases-blueprint-for-montanas-energy-future.

[15] Approval and Promulgation of Implementation Plans; Montana; Regional Haze 5-Year Progress Report State Implementation Plan (October 4, 2019), Available at: https://www.federalregister.gov/documents/2019/10/04/2019-21266/approval-and-promulgation-of-implementation-plans-montana-regional-haze-5-year-progress-report-state

[16] Approval and Promulgation of Air Quality Implementation Plans; Montana; Regional Haze Federal Implementation Plan (12 Sept. 2017), Available at: https://www.federalregister.gov/documents/2017/09/12/2017-19210/approval-and-promulgation-of-air-quality-implementation-plans-montana-regional-haze-federal

- One Board Order that included the cement kiln in Montana City, then owned by Ash Grove Cement Company, and the Trident cement kiln in Three Forks, then owned by Holcim (US) Inc.

These Board Orders (comprised of a Findings of Fact and associated Exhibit A for each Board Order), effective October 18, 2019, incorporated the emission control strategies for those facilities outlined in the Montana FIP. On March 23, 2020, Montana sent a request to EPA Region 8 to include the Regional Haze provisions into the Montana SIP.

As evidenced by this submission, Montana continues to engage in regional haze. By rule,[17] the SIP revision is due to EPA by July 31, 2021. Montana did not submit by the deadline, due to a number of setbacks in regional modeling, discussed further in Chapter 2.

1.5 General Planning Provisions

1.5.1 Regional Haze Program Requirements

The requirements for the regional haze rule are identified in 40 CFR 51.308. Specifically, 51.308(f) lists the requirements for haze SIP updates, including a reference to the requirements in 51.308(d). In addition to re-evaluating all elements required in paragraph (d), the states must also:

- Assess current visibility conditions for the most impaired and least impaired days.
- Address actual progress made towards natural conditions during the previous implementation period.
- Determine the effectiveness of the long-term strategy for achieving reasonable progress goals over the prior implementation period.
- Affirm or revise reasonable progress goals according to procedures in paragraph (d).

As noted above, the section addressing the requirements for the SIP revisions references the requirements of paragraph (d). This paragraph's requirements address:

- Establishing reasonable progress goals for the implementation period, including the four-factor analysis.
- Determining current visibility conditions and comparing to natural conditions.
- Developing long-term strategies to reduce emissions that contribute to visibility impairment.
- Submitting a monitoring strategy.

40 CFR 51.308(f)(5) requires states to address the requirements of paragraphs 51.308(g)(1)-(5) in the 2021 plan revision. According to the requirements of 40 CFR 51.308(g), states shall submit periodic reports that describe progress toward the reasonable progress goals. This RH SIP submittal also serves as a progress report addressing the period since Montana's September 18, 2017 progress report. The RHR requires that subsequent progress reports are due by January 31, 2025, July 31, 2033, and every 10 years thereafter.

[17] 40 CFR 51.308(f)

1.5.2 SIP Submission and Planning Commitments

This SIP revision meets the requirements of the EPA's RHR and the CAA. Sections of this SIP address the core elements required by 40 CFR Section 51.308(f)(3), the establishment of RPGs, and measures that Montana will take to meet the RPGs. This SIP revision also addresses 40 CFR 51.308(f)(2) (Long-Term Strategy) and 40 CFR 51.308(i)(2) (State and Federal Land Manager Coordination); and commits to develop future plan revisions and adequacy determinations as necessary.

Montana participates in a regional planning process, as a member state through the Western States Air Resource Council (WESTAR) and as a partner in the Western Regional Air Partnership (WRAP). WESTAR is a partnership of 15 western states formed to promote the exchange of information, serve as a forum to discuss western regional air quality issues and share resources for the common benefit of the member states. WRAP is a voluntary partnership of state, tribes, federal land managers (FLMs), local air agencies, and the EPA whose purpose is to understand current and evolving regional air quality issues in the West.

The regional planning process describes the process, goals, objectives, management and decision-making structure, and deadlines for completing significant technical analyses of the regional group. To assist in making sound planning decisions, Montana assisted the regional planning organization to complete regional analyses that include certain methods, inputs, and resources. Montana commits to continue regional participation through future SIPs.

Pursuant to the Tribal Authority Rule[18], any Tribe whose lands are within the boundaries of the State of Montana have the option to develop a regional haze Tribal Implementation Plan (TIP) for their lands to assure reasonable progress in the twelve Class I areas in Montana. As such, no provisions of this Implementation Plan shall be construed as being applicable to tribal lands.

1.5.3 Montana Statutory Authority

The Montana Code Annotated (MCA) 75-2-112(2)(c) states the powers and responsibilities of the Department to prepare and develop a comprehensive plan for the prevention, abatement, and control of air pollution in this state. This SIP is a compilation of analyses that demonstrate Montana's statutory authority and is consistent with what is required in under §110 and §169 of the CAA for states to submit RH SIPs.

2 MONTANA REGIONAL HAZE SIP DEVELOPMENT PROCESS

The development of this SIP is two-fold: 1) The documentation seeks to explicitly address the regulatory requirements for specific analyses (such as determining current visibility conditions) in the RHR, and 2) to describe Montana's strategy for making planning decisions (such as determining what control measures are

[18] 40 CFR Parts 9, 35,49, 50 and 81

reasonable to include in our LTS). There is not always a direct relationship between individual sections of the rule and the specific planning tasks.

Successful development of a RH SIP requires that the responsible agencies effectively communicate and consult with a variety of stakeholders on a defined timeline with varying degrees of formality.[19] As mentioned in Section 1.5.1, the RHR contains requirements for formal consultation with state, federal, and tribal agencies. Montana's informal communication strategy with other states, tribes, the EPA, state and federal natural resource agencies, other stakeholders, and the public helped to develop a robust demonstration[20] of Montana's long-term strategy for the second implementation period. This chapter outlines both the formal and informal consultation and communication process for the second implementation period. For additional details regarding individual source consultation, see Chapter 6 Emissions Control Analysis and Chapter 7 – Long Term Strategy for Second Planning Period.

This chapter also includes important information regarding the development of the technical framework used to support states' strategic decisions. As allowed under 40 CFR 51.308(d)(3)(iii) and 40 CFR 51.308(f)(2)(iii), Montana relied on the technical analysis developed by a regional planning process (e.g. WESTAR/WRAP) to determine Montana's apportionment of emission reduction obligations necessary for achieving reasonable progress in each Class I area affected by Montana emissions sources.

Extensive issues in the modeling were experienced during the planning process, leading to a significant delay in receipt of modeling data and results. Modeling information is vital to the regional haze regulations as it is the only tool available to determine what future visibility impairment in the Class I areas is projected to be, what impact additional controls may have on Class I area visibility projections, and to determine the impact individual states and sectors (e.g., coal-fired EGUs) have on visibility in the Class I areas. Since the regional haze regulation is focused on improving visibility in Class I areas, Montana was obligated to wait for this information to become available to perform a thorough analysis. Once available, Montana performed a detailed review and incorporated the applicable results into this SIP package.

The modeling contractor, Ramboll U.S. Contracting – Environment and Health unit (Ramboll), provided a memo and letter to WRAP on February 8, 2021 detailing and explaining the issues that led to the delays in completing the regional haze modeling, including: COVID-19, delays in data processing decisions at EPA, various bugs in the model platform, wildfires causing power outages in both 2019 and 2020, errors and double counting in emissions inventories, and many other issues. Copies of this information can be found in

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[19] This chapter references excerpts taken from WRAP Communication Framework for Regional Haze Planning, (28 Aug. 2019), Available at: https://www.wrapair2.org/pdf/WESTAR-WRAP_Communication_Framework_Aug28_2019approved%20by%20RHPWG%20consensusSept3rd.pdf

[20] 40 CFR 51.308(f)(3)(ii)(A)

Appendix B. For context, the 2018–2019 WRAP board approved workplan[21] projected the regional haze modeling to be completed in Quarter 2 of 2020, with results available for state use in Quarter 3 of 2020. The modeling was completed and made available for state use in March 2021. On April 1, 2021, a results meeting was held to present the final data needed for incorporation into states' plans.[22] Refer to Appendix B for further information explaining why Montana missed the July 31, 2021 deadline.

2.1 WESTAR/WRAP ENGAGEMENT

Due to the regional nature and complexity of the plans, which address long-range transport and cumulative impacts of air pollution, close collaboration among agencies is essential. To support this interagency effort, EPA established Regional Planning Organizations (RPOs) across the U.S. to assist states and tribes in conducting the technical and policy analyses to provide a common basis for the individual SIPs and TIPs. In the West, this organization is WESTAR/WRAP[19].

The WRAP group specifically focuses on regional technical analyses that assist states, tribes and local air agencies develop plans required by the CAA. Additionally, the WRAP facilitates a stakeholder process to ensure a consensus building approach in environmental decision making. Because FLMs participate in WRAP discussions, many technical analyses were developed with direct input from FLMs. The Technical Steering Committee (TSC) of the WRAP provides oversite of the WRAP projects and Work Groups[23] and coordinates with WESTAR work groups and committees to provide needed support. The WRAP includes five work groups tasked with addressing more specific topics. The WRAP Work Groups are listed below:

- Fire and Smoke Work Group (FSWG),
- Oil and Gas Work Group (OGWG),
- Tribal Data Work Group (TDWG),
- Regional Technical Operations Work Group (RTO), and
- Regional Haze Planning Work Group (RHPWG)
  The RHPWG is further divided into the following subcommittees[24]
  - Coordination and Glide Path,
  - Emissions Inventory and Modeling Protocol (EI&MP), and
  - Control Measures.

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[21] WRAP, 2018-2019 WRAP Workplan, (4 April 2018), Available at: https://www.wrapair2.org/pdf/2018-2019%20WRAP%20Workplan%20update%20Board%20Approved%20April.3.2019.pdf [wrapair2.org]

[22] WRAP, Regional Haze Planning Work Group, See April 1, 2021 – Meeting 8. Available at: https://www.wrapair2.org/RHPWG.aspx [wrapair2.org].

[23] More information on Work Groups can be found here: https://www.wrapair2.org/About.aspx#b1

[24] More information of RHPWG subcommittees can be found here: https://www.wrapair2.org/RHPWG.aspx

These subcommittees work on supporting the important regional technical analyses to be used in RH SIP development. These include evaluating methods for identifying most impaired days from IMPROVE data, assembling and coordinating emissions inventories, providing input to source apportionment modeling and interpreting control measure analyses. The work products of these groups provide the important 'weight of evidence' tools used in SIP preparation.

On April 4, 2018, the WRAP Board adopted the "Regional Haze Principles of Engagement" (RHPoE)[25] that lays out many guiding principles for the western Regional Haze planning effort and WESTAR/WRAP's role in the process. While WESTAR/WRAP will provide close coordination between agencies, the state is ultimately responsible for the development and content of the RH SIP. However, much of the intent of the RHR is such that the requirements to engage in close collaboration and coordination among agencies leads to better SIP development; therefore, Montana has participated significantly in the entire regional planning process as a means to develop an adequate and approvable RH SIP.

2.1.1 Technical Information and Data

2.1.1.1 WRAP TSS 2.0

The WRAP Technical Support System (TSS) 2.0 is the data warehouse and online portal used by air quality planners to evaluate the technical data and analytical results used to support regional haze implementation plans. The TSS 2.0 is a "system of systems" that integrates capabilities from many systems, including systems focused on: monitoring data analysis efforts, emissions data management systems, fire emissions tracking system, photochemical aerosol regional modeling analyses, and visualization and summary data analyses.[26] These diverse data sets can be analyzed through the TSS and the resultant outputs can be downloaded for use in SIP reports.

This SIP submittal relies on the data stored in and retrieved from the TSS 2.0 system.

2.2 Regional Modeling Overview

Air quality models provide a framework to organize and assess information about what is contributing to visibility impairment. This information includes actual and planned future air pollutant emissions, meteorological conditions, ambient air monitoring information and emission changes based on potential control strategies. The objective of using regional modeling in RH SIP development is to capture the scientific relationships between sources of emissions and visibility impairment and to what extent emission controls have on improving visibility.

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[25] WESTAR/WRAP, Regional Haze Principles of Engagement (4 Apr. 18), Available at: https://www.wrapair2.org/pdf/RH%20principles%20ofengagement_WRAP_Board_final_adopted_April4_2018.pdf

[26] WRAP Technical Support System, About the WRAP Technical Support System (TSS), Available at: https://views.cira.colostate.edu/tssv2/About/Default.aspx

For this planning period, a regional photochemical grid modeling platform was developed/coordinated by WRAP with the assistance of Ramboll, who performed the Comprehensive Air Quality Model with Extensions CAMx[27] simulations. The modeling framework provides important information to 1) estimate reasonable progress goals, and 2) understand source apportionment and sector contribution.

Source apportionment and sector contribution modeling helps identify air pollution sources and quantifies their contribution to visibility impairment. In developing an LTS, states must understand what the sources of visibility impairment are, both natural and anthropogenic, when making decisions on what reasonable measures should be included in the LTS.

The RHR requires that states project the average of the daily visibility conditions on the 20 percent most impaired days and on the 20 percent clearest days at each Class I area within the state at the end of the implementation period.[28] This projection takes into account the content of the LTS (including emission reduction measures) with the goal of estimating the RPG, which is the deciview measurement that is a result of a state's strategy.

The following simulations and their targeted outcome were performed:

[27] CAMx, Comprehensive Air Quality Model with Extensions. Available at: https://www.camx.com/

[28] 40 CFR 51.308(f)(3)(i)

Modeling Scenarios for Estimating Reasonable Progress Goals

- Representative Baseline Scenario (WRAP-RepBase2): Represent large facility / source type "current representative baseline" emissions (circa 2014 - 2018 timeframe) for comparison to future scenarios
- Future 2028 'On the Books' Scenario (WRAP-2028OTBa2): Model visibility impact / calculate Reasonable Progress Goal for each Class I area "if no additional controls" were adopted
- 2028 Potential Additional Controls (WRAP-2028PAC2): Model visibility impact / calculate RPG for each Class I area "if additional controls" were to be adopted
- Modeled US Anthropogenic Rate of Progress

Source Apportionment and Sector Contribution Modeling

- High-Level and Low-Level Source Approtionment using the RepBase2 and the 2028OTBa2 Emissions Scenarios: Source apportionment modeling is used to identify states and sectors that are contributing haze.

More information regarding the model simulations is presented in the following sections. This information is also well documented in the WRAP's Modeling Methods, Results, and References document, finalized September 30, 2021.[29]

2.2.1 2014v2 Base Case Simulation (2014v2)

To start, a model performance evaluation was developed using 2014 actual emissions, 2014 WRF meteorology and the results from the Western-State Air Quality Study[30]. The 2014 year was chosen because conditions were more typical compared to the episodic impacts that occurred in 2015 and 2016. The 2014

[29] WRAP Technical Support System for Regional Haze Planning: Modeling Methods, Results and References, (30 Sept. 21), Available at: https://views.cira.colostate.edu/tssv2/Docs/WRAP_TSS_modeling_reference_final_20210930.pdf

[30] Western-State Air Quality Modeling Study (WSAQS) – Weather Research Forecast 2014 Meteorological Model Application/Evaluation, (1 Jan. 16), Available at: http://views.cira.colostate.edu/wiki/Attachments/Modeling/WAQS_2014_WRF_MPE_January2016.pdf

base year emissions used the 2014 NEI as a starting point and included updates from western states.[31] Updates were made to point and non-point-source sectors, including incorporation of refined actual 2014 fire emissions modifications based on recommendations of the WRAP FSWG. The initial "shakeout" runs were used to evaluate model performance and various sensitivity analyses that ultimately led to the final 2014v2 CAMx configurations.[32]

2.2.2 Representative Baseline and 2028 On the Books (RepBase2 & 2028OTBa2)

Building off of the 2014v2 simulation, Ramboll conducted two additional modeling scenarios, The Representative Baseline (RepBase) and 2028 On the Books (OTB) simulations.[33] These simulations used a mix of emission inputs based on the 2014v2 emissions scenario with 2014 meteorology. Point source emissions were refined with more typical 2014-2018 emissions estimates ("RepBase"). Emissions for the 2028OTBa2 scenario were updated to reflect expected operations in 2028. Most notably, the largest emissions changes between the RepBase2 and 2028OTBa2 scenario originated from source retirements, enforceable shutdowns of EGUs, and emissions reductions due to ongoing pollution control programs. These two modeling runs are important used to determine the relative response factors (RRFs); the relative emissions changes between these runs will directly affect the projections of the monitored extinction to the 2028 levels. This is discussed in more detail in section 2.2.4.

The CAMx runs were performed on the 36-km (36US1) and 12-km (12WUS2) domains, depicted in Figure 5-1. The meteorological inputs were held constant for both runs, with the 2014 meteorology used for the 2014v2 run. EPA modeling (EPA-2016fh and EPA-2028fh[34]) were used for the emissions outside the 12WUS2 domain and within the 36US1 domain. Within the western U.S. region, emissions were developed from a combination of the NEI, WRAP Workgroups, and individual states submissions. A brief summary of those emissions follows.

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[31] WRAP Regional Haze Planning Workgroup, Emissions Inventory & Modeling Protocol Subcommittee, Recommendations for Base Year Modeling, (1 Feb 19), Available at: https://www.wrapair2.org/pdf/WRAP%20Regional%20Haze%20SIP%20Emissions%20Inventory%20Review%20Documentation_for_Docket%20Feb2019.pdf

[32] Intermountain West Data Warehouse, WRAP/WAQS 2014v2 Modeling Platform Description and Western Region Performance Evaluation (MPE), Available at: https://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx

[33] Ramboll, Run Specification Sheet, Representative Baseline (RepBase2) and 2028-On-The-Books (2028OTBa2) CAMx Simulations, (30 Sept. 2020), Available at: https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/EmissionsSpecifications_WRAP_RepBase2_and_2028OTBa2_RegionalHazeModelingScenarios_Sept30_2020.pdf

[34] Technical Support Document (TSD) preparation of Emissions Inventories for the Version 7.2 2016 North American Emissions Modeling Platform, (Sept. 2019), Available at: https://www.epa.gov/sites/production/files/2019-09/documents/2016v7.2_regionalhaze_emismod_tsd_508.pdf

Electrical generating units (EGUs) were broken into three categories: fossil-fueled EGUs with Continuous Emissions Monitors (CEMS) from the CAMD database; fossil-fueled EGUs without CEMS; and non-fossil fueled EGUs. The fossil-fueled emissions for the RepBase2 and 2028OTBa2 scenarios were based on the WRAP EGU Emissions Analysis Study conducted by the Center for the New Energy Economy.[35] All other emissions, including all EGUs in non-WRAP states and all non-fossil fueled EGUs are based on EPA's 2016fh and 2028fh scenarios.

Emissions from oil and gas sources (O&G) were broken in to three sources: California Air Resources Board for O&G sources in California; WRAP OGWG projections for seven WRAP states; and EPA's 2016fh and 2028fh for other WRAP states and non-WRAP states.

Non-EGU point source emissions came from the WRAP-2014v2, with any updates provided for RepBase2 scenarios, along with EPA's 2028fh for other non-EGU point source emissions. Mobile emissions projections were produced from a WRAP study, while 2014v2 were used as the RepBase2, with EPA's runs for mobile outside the western domain. For other non-point and Canada/Mexico, EPA's scenarios were used.

Representative baseline fire emissions were developed by WRAP's FSWG and were used for the RepBase2 and 2028OTBa2 runs. Natural and Boundary Conditions were held constant at the 2014v2 levels for both RepBase2 and 2028OTBa2.

Table 2-1. Data sources for WRAP emissions sectors for the 12-km 12WUS2 and 36-km US domains for the 2014v2, Representative Baseline (RepBase2) and 2028OTBa2 model scenarios.

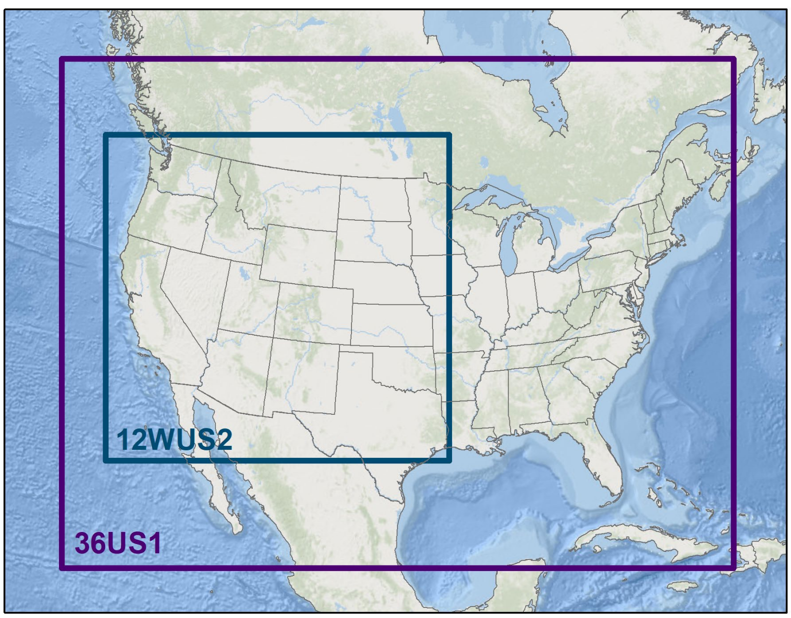
Source Sector	2014v2	RepBase2	2028OTBa2
California All Sectors 12WUS2	CARB-2014v2	CARB-2014v2	CARB-2028
WRAP Fossil EGU w/ CEM	WRAP-2014v2	WRAP-RB-EGU[1]	WRAP-2028-EGU[1]
WRAP Fossil EGU w/o CEM	EPA-2014v2	WRAP-RB-EGU[1]	WRAP-2028-EGU[1]
WRAP Non-Fossil EGU	EPA-2014v2	EPA-2016v1	EPA-2028v1
Non-WRAP EGU	EPA-2014v2	EPA-2016v1	EPA-2028v1
O&G WRAP O&G States	WRAP-2014v2	WRAP-RB-O&G [2]	WRAP-2028-O&G [2]
O&G WRAP Other States	EPA-2014v2	EPA-2016v1	EPA-2016v1 [3]
O&G non-WRAP States	EPA-2014v2	EPA-2016v1	EPA-2016v1 [3]
WRAP Non-EGU Point	WRAP-2014v2	WRAP-2014v2 [4]	WRAP-2014v2 [4]
Non-WRAP non-EGU Point	EPA-2014v2	EPA-2016v1	EPA-2016v1
On-Road Mobile 12WUS2	WRAP-2014v2	WRAP-2014v2	WRAP-2028-Mobile [5]
On-Road Mobile 36US	EPA-2014v2	EPA-2016v1	EPA-2028v1
Non-Road 12WUS2	EPA-2014v2	EPA-2016v1	WRAP-2028-Mobile [5]

[35]WRAP, EGU Emissions Analysis Project, Available at: https://www.wrapair2.org/EGU.aspx

Source Sector	2014v2	RepBase2	2028OTBa2
Non-Road non-WRAP 36US	EPA-2014v2	EPA-2016v1 [6]	EPA-2028v1 [6]
Other (Non-Point) 12WUS2	EPA-2014v2	EPA-2014v2 [7]	EPA-2014v2 [7]
Other (Non-Point) 36US	EPA-2014v2	EPA-2016v1	EPA-2016v1
Can/Mex/Offshore 12WUS2	EPA-2014v2	EPA-2016v1	EPA-2016v1
Fires (WF, Rx, Ag)	WRAP-2014-Fires	WRAP-RB-Fires [8]	WRAP-RB-Fires [8]
Natural (Bio, etc.)	WRAP-2014v2	WRAP-2014v2	WRAP-2014v2
Boundary Conditions (BCs)	WRAP-2014-GEOS	WRAP-2014-GEOS	WRAP-2014-GEOS

1. WRAP-RepBase2-EGU and WRAP-2028OTBa2-EGU include changes/corrections/updates from WESTAR-WRAP states
2. WRAP-RepBase2-O&G and WRAP-2028OTBa2-O&G both include corrections for WESTAR-WRAP states.
3. O&G for other WRAP states and Non-WRAP states use EPA-2016v1 assumptions for 2028OTBa2 and unit-level changes provided by WESTAR-WRAP states.
4. WRAP-2014v2 Non-EGU Point is used for RepBase2 and 2028OTBa2, with source specific updates provided by WESTAR-WRAP states.
5. WRAP-2028-MOBILE is used for On-Road and Non-Road sources for the 12WUS2 domain.
6. EPA-2016v1 and EPA-2028v1 are used for On-Road and Non-Road Mobile for the 36km US domain.
7. Non-Point emissions use 2014v2 emissions for RepBase2 and 2028OTBa2 scenarios, including state-provided corrections.
8. RepBase fires are used for both RepBase2 and 2028OTBa2

Figure 2-1. Modeling Domains



Additionally, a potential additional controls run (PAC2) was also performed, where states had the opportunity to model emissions reductions from additional controls in order to capture the visibility effects due to those controls. Montana elected not to submit a revised emission inventory for this run.

2.2.3 Source Apportionment Simulations using RepBase2 and 2028OTBa2 Emissions

High-level and low-level source apportionment simulations[36] were performed using the CAMx Particulate Source Apportionment Technology (PSAT) tool for the RepBase2 and 2028OTBa2 emissions scenarios. The Source Apportionment runs are used to tie modeled concentrations at each Class I area back to the contributing emission sources and regions. The model is set up to track families of tracer compounds and precursors (25 total) to visibility-impairing species, which are simulated at the IMPROVE monitors. For the high-level simulations, the sources are broken into five origin categories: U.S. Anthropogenic (US_Anthro), U.S. Wildfire (US_Wildfire), U.S. Prescribed Fire (US_RxWildlandFire), Natural, Canada and Mexico Fire (CanMexFire), and International Anthropogenic (International_Anthro). The one difference between the RepBase2 and the 2028OTBa2 high-level runs is that the RepBase2 has one source group for all U.S. anthropogenic emissions, while the 2028OTBa2 splits the U.S. anthropogenic emissions into two groups: WRAP-states and non-WRAP-states.

For low-level simulations, contributions are further divided into five anthropogenic emission source sectors from each of the 13 WRAP states, for only ammonium nitrate and ammonium sulfate precursors. The anthropogenic source contributions are EGU Point, Non-EGU Point, Oil and Gas (Point and Non-Point), Mobile (On-Road and Non-Road), and Remainder Anthropogenic (e.g. rail, fugitive dust, agricultural, etc.). These analyses help illuminate the high-level and low-level sources of visibility-impairing particulates at each Class I area and therefore can inform the LTS.

The source apportionment simulations are a significant aspect of the analysis, as they provide the basis for glidepath endpoint adjustments for international and prescribed fire impacts (described further in sections 2.2.6 and 4.3.1).

2.2.4 Projection Methodology and RRFs

To project 2028 future visibility and set RPGs, the RepBase2 and 2028OTBa2 simulations are used to calculate Relative Response Factors (RRFs) in order to scale the IMPROVE monitoring data to the modeled 2028 scenario. EPA's guidance on Regional Haze modeling[37] suggests a methodology for doing so, by calculating the ratio of the future year (2028OTBa2) to the current year (RepBase2), then apply ratios to the observed MID from 2014-2018, to get the 2028 visibility projections. The model is used in a relative sense to scale the MID from 2014-2018 to 2028. The result of this calculation is the RPG, in deciviews. In addition to the EPA default method, two modified projections methods were implemented by Ramboll and

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[36] Ramboll, Run Specification Sheet, High-Level and Low-Level Source Apportionment Modeling Using the RepBase2 and 2028OTBa2 Emission Scenario, (29 Sept. 2020), Available at: https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/SourceApportionmentSpecifications_WRAP_RepBase2_and_2028OTBa2_High-LevelPMandO3_and_Low-Level_PM_andOptionalO3_Sept29_2020.pdf

[37] EPA.gov, Modeling Guidance for Demonstrating Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze, (29 Nov. 2018), Available at: https://www.epa.gov/sites/production/files/2020-10/documents/o3-pm-rh-modeling_guidance-2018.pdf

displayed, along with the EPA default method, on the TSS2.0. These projection methodologies[38] and the use of RRFs are summarized below.

EPA's default method involves calculating RRFs for each impairment-producing PM species, based on the modeled baseline period (RepBase2 in this case) and modeled future period (2028OTBa2) on the MIDs. Based on the 2014 calendar MIDs, the species-specific RRF is the ratio of the modeled concentrations (example for ammonium sulfate):

$$RRF_{SO4} = \frac{average(2028OTB_{SO4})}{average(RepBase_{SO4})} \{on\ 2014\ MIDs\}$$

These RRFs are then used to project future concentrations (again, for ammonium sulfate):

$$Projected\_SO4_{2028} = IMPROVE\_SO4_{2014-2018} \times RRF_{SO4}$$

The two additional methods are based on EPA's guidance but offer some differences. In order to address the influence of wildfire on the 2014 MIDs, the WRAP developed a slightly modified approach, termed "EPAwoF" (EPA without fire) was developed. This method uses the default methodology above except that it attempts to remove the obvious wildfire impacts in the base year from the selected MIDs, in order for the RRFs to better respond to changes in non-wildfire emission changes. Otherwise, significant modeled wildfire impacts will dominate the RRF calculation, making the RRF 'stiff', or nonresponsive to anthropogenic emissions improvements between the two periods. High-level source apportionment runs are used to determine EPAwoF RPGs, where the days with obvious fire impacts (wildfire, prescribed fire, and agriculture fire) are removed from the CAMx RepBase2 and 2028OTBa2 concentrations before the RRFs are calculated.

The second alternative, termed "ModMID" (modeled most impaired days) involves the same methodology as EPAwoF except for its selection of MIDs. Instead of using 2014 MIDs, source apportionment is used to select MIDs based on the *modeled* most anthropogenically impaired days. The ModMID method identifies the 20% U.S. anthropogenic emission contributions from the 2014 days in which the CAMx RepBase source apportionment has the highest absolute visibility impairment due to U.S. anthropogenic emissions in the concentrations (without fire).

Montana chose to use the "EPAwoF" approach for calculating the 2028OTBa2 projection, as recommended by WRAP. For reasons described above, Montana agrees that wildfire impacts within the MIDs would affect the projections. As described in more detail from the source apportionment results (section 4.3) and from the wildfire impacts exploration (section 4.5), it is clear that many of Montana's

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[38]Ramboll, Procedures for Making Visibility Projections and Adjusting Glidepaths using the WRAP-WAQS 2014 Modeling Platform, (1 Mar. 2021), Available at: https://www.wrapair2.org/pdf/2028_Vis_Proj_Glidepath_Adj_2021-03-01draft_final.pdf

western sites still contain a significant influence from wildfire smoke, so this method seemed appropriate for Montana.

2.2.5 Modeled U.S. Anthropogenic Emissions Rate of Progress

The Modeled U.S. Anthropogenic Emissions Rate of Progress (RoP)[39] is an alternative approach that can be used as a weight of evidence to supplement the default projection method described in Section 2.2.4. This approach uses the absolute CAMx PSAT modeling results from RepBase2 and 2028OTBa2 in addition to a 2002 Hindcast emissions scenario to construct a RoP slope from the modeled total deciview in 2002 using absolute concentrations, to the 2064 target that would have no U.S. anthropogenic concentrations. There are a number of benefits to using this approach to evaluate visibility at a Class I area, including that the analysis is based on U.S. anthropogenic emissions, which are the best-known component in the RH modeling and are the emissions that states have the authority to control.

Montana evaluated the results of this modeling effort and have included portions of the analyses in this submittal as weight of evidence. However, Montana relied on the CAMx RepBase2 and 2028OTBa2 modeling results to project the observed 2014-2018 IMPROVE MID to 2028 projected IMPROVE MID using the EPAwoF technique.

2.2.6 International and Prescribed Fire Adjustments

Glidepath adjustments[38] are specified in the revised RHR[40], allowing for what amounts to additions to the 2064 Uniform Rate of Progress (URP) endpoint to account for contributions to impairment from international and prescribed fire sources. The glidepath graphically describes the URP, which is the uniform path from the baseline (2000-2004) period to the 2064 natural conditions endpoint in 2064. Details about the glidepath, the URP and natural conditions for Montana are described in Chapter 4 of this document.

Essentially, the slope of the glidepath is reduced to account for emissions from international sources and prescribed fire activities, thus allowing for an elevated 2064 target. EPA released technical guidance[11] that offers several methods to estimate international and prescribed fire contributions and to adjust the endpoint. WRAP chose to estimate the adjustments from the international and prescribed fire impacts in a relative sense, by looking at the source apportionment modeling of the 2028OTBa2 results. Similar to the projection methodology (section 2.2.4), the 2014-2018 IMPROVE data is projected based on scaling factors from the RepBase2 to 2028OTBa2 in two separate runs: 2028OTBa2, and 2028OTBa2 with the high-level 2028 source apportionment results (section 2.2.3) used to remove international and prescribed fire impacts. The difference in these two projected results gives the international and prescribed fire contributions to the glidepath. These source contributions are added to the 2064 natural conditions, which are calculated from

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[39] WRAP Technical Support System. United States Anthropogenic Emissions Rate of Progress, Available at: https://views.cira.colostate.edu/tssv2/Docs/USAnthroRoP.aspx (accessed 12/13/2021).

[40] See 40 CFR 51.308(f)(1)(vi)(B)

the IMPROVE data and described briefly in section 4.1 of this document. EPA technical guidance recommends using the modeling results in relative sense, added to the default natural conditions.

Montana chose to adjust the glidepath for both international and prescribed fire emissions, using the methodology outlined in EPA's guidance[41] and WRAP's specification sheet[42]. Source apportionment modeling results suggest the elevated impacts of both international (at Montana's eastern Class I areas) and prescribed fire (at Montana's western Class I areas), which warrants the adjustment. Although the contributions vary spatially, it was decided to apply the same adjustment to all Class I areas, the specifics of which are described in more detail in section 4.3.1.

2.2.7 Weighted Emissions Potential (WEP)/Area of Influence (AOI)

WEP/AOI analyses can identify what significant emission sources are upwind from a Class I area. The WEP/AOI analyses[43] were conducted in several steps, each one leveraging more information to determine the influence on the MIDs at the Class I area monitors. The residence time was determined from the HYSPLIT (Hybrid Single Particle Lagrangian Integrated Trajectory) model, which is used for computing simple air parcel trajectories. The back trajectories were determined as passing over the Class I area on the MIDs, which gives estimates of the origins of those air parcels, based on the meteorology. These resident times are weighted by the monitored extinction level (for ammonium nitrate and ammonium sulfate), which gives the Extinction Weighted Residence Time (EWRT). The Weighted Emissions Potential (WEP) is then obtained for each Class I area and visibility precursor by overlaying the 2028 gridded emissions (for NO_x and SO_2) by source sector on the EWRT to obtain the relative probability that sources of the visibility precursor in a grid cell contributed to extinction at the specified Class I area on the MID. Further, the WEP values associated with NO_x and SO_2 are assigned to all the point sources, which can be used to "rank" the influence of those sources on each Class I area monitor. These analyses are referred to as Rank Point, and results for Montana Class I areas and facilities are shown in section 6.1 to support facility screening and in section 7.2.1 for interstate impacts.

2.2.8 Natural (NAT) and Zero-Out International Emissions (ZROW) scenarios

Two anthropogenic zero-out simulations[44] were performed to better characterize natural and international impacts at Class I areas. The natural (NAT) scenario eliminates all anthropogenic emissions worldwide,

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[41] EPA. Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling, (19 Sept. 2019), Available at: https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling

[42] WRAP. Adjusting the URP Glidepath Accounting for International Anthropogenic Emissions and Wildland Prescribed Fires using the WRAP-WAQS 2014/2028 Modeling Platform Results Draft (24 July 24 2020), Available at: http://www.wrapair2.org/pdf/URP_Glidepath_Adjust_WRAP_2020-07-24draft.pdf

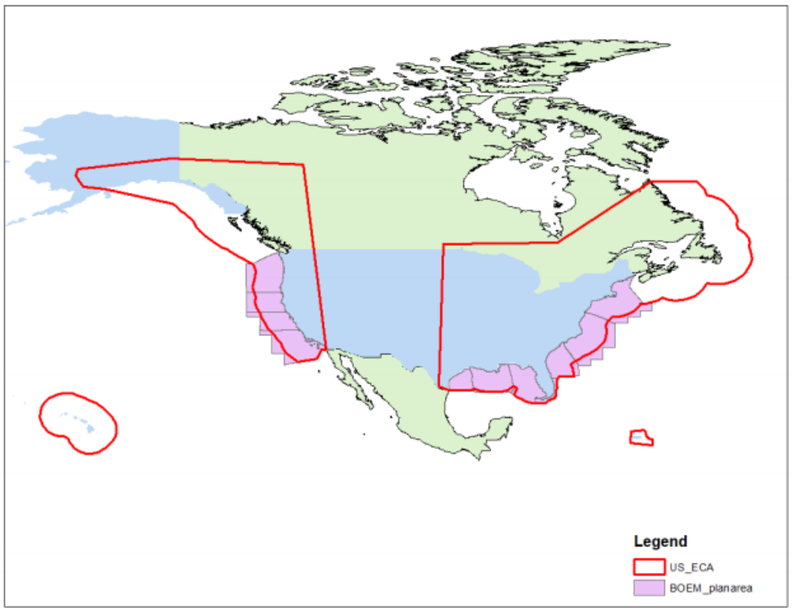
[43] WRAP Technical Support System, WEP/AOI Analysis for western U.S. Class I Areas, (25 Sept. 2020) Available at: https://views.cira.colostate.edu/tssv2/WEP-AOI/

[44] Ramboll, Run Specification Sheet, Natural (NAT) and No International Anthropogenic Emissions (ZROW) GEOS-CHEM and CAMx Simulations, (5 Feb. 2020), Available at: https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/Run_Spec_WRAP_2014_Task1-7_NAT-ZROW_v4.pdf

while the zero-out (ZROW) scenario eliminates all non-U.S. anthropogenic emissions. The ZROW scenario includes all emissions sources within the continental U.S., Alaska, and Hawaii, and includes commercial marine vessel emissions within the economic control area off the coasts of the U.S., as shown by the red shapes in Figure 2-2.

The ZROW run was used in addition to Hemispheric Community Multiscale Air Quality Modeling (CMAQ) and base-case simulations to determine the international boundary conditions. It was necessary to separate contributions of international emissions to determine glidepath adjustments, described in more detail in section 2.2.6.

Figure 2-2. Map showing the economic control area included in U.S. Anthropogenic emissions



2.3 Consultation with Federal Land Managers (FLM)

The primary federal agencies responsible for overseeing Regional Haze plans are the EPA and FLMs. The federal land management agencies with jurisdiction over mandatory Class I federal areas in the West include the National Park Service (NPS), Department of Agriculture Forest Service (USFS), and the Fish and Wildlife Service (FWS). Although not responsible for overseeing a mandatory Class I area, the Bureau of Land Management (BLM) does manage federal lands in western states and is an active participant in air resource management on public lands. FLMs have a critical role in protecting air quality in national parks, wilderness and other federally protected areas, and have an affirmative responsibility to protect air quality related values, including visibility, in all Class I areas (40 CFR Section 51.166(p)(2)).

40 CFR 51.308(i)(2) requires coordination between states and the FLMs at a point early enough in the state's policy analyses of its long-term strategy so that any recommendations provided by the FLM can meaningfully inform the state's decision on the long-term strategy. This consultation is considered early enough if it takes place at least 120 days prior to holding any public hearing or other public comment opportunity on the RH SIP. The opportunity for consultation on the plan revision must be provided no less than 60 days prior to said public hearing or public comment opportunity.

The purpose of this consultation is to provide FLMs an opportunity to discuss their:

(i) Assessment of impairment of visibility in any mandatory Class I Federal area; and

(ii) Recommendations on the development and implementation of strategies to address visibility impairment.

Numerous opportunities were provided through the WRAP for states and FLMs to participate fully in the development of technical analyses, of which the results are included in this SIP. This included the ability to review and comment on these analyses, reports and policies. A summary of the WRAP-sponsored meetings and conference calls is provided on the WRAP website https://www.wrapair2.org/RHPWG.aspx.

Montana started early coordination in January 2020, when Montana presented to FLMs the Class I area visibility analyses, emissions trends, source screening methodologies and the list of facilities being considered for four-factor analyses. On May 4, 2020, Montana shared the first 3 chapters of this plan revision to FLMs for draft review. NPS provided comments on these chapters to Montana on June 3, 2020.

Originally, Montana planned that Governor Bullock would sign the submittal before leaving office December 31, 2020. To accommodate this timing, Montana began the 120-day early engagement with FLMs on July 10, 2020.

However, due to modeling delays, Montana was only able to share the draft Chapter 6 - Emission Control Analysis to review on July 10, 2020. This chapter contains emissions inventory information, source screening steps, four-factor analyses for reasonable progress sources and Montana's conclusion on controls required. On August 18th, 2020, the NPS provided general feedback along with 11 four-factor reviews and the remaining 5 four-factor reviews were shared on September 4th, 2020.

The modeling delays resulted in Montana not meeting the original planning deadline of gubernatorial signature by December 31, 2020. Additional chapters were shared as part of the formal consultation period. Per discussions with the NPS and USFS, both agencies were satisfied with the early engagement and expected full/formal consultation 60 days prior to public comment. Montana began the formal consultation period on September 27, 2021. Montana received comments from the USFS on November 22, 2021. The NPS provided comments to Montana on December 2, 2021. Appendix F of this document contains a summary of the FLM comments received during early coordination and formal consultation and Montana's response to comments.

2.4 Consultation with Tribes

Tribal governments are responsible for coordinating with federal and state governments to protect air quality on their sovereign lands and to ensure emission sources on tribal lands meet federal requirements. The tribes in Montana are: Blackfeet Tribe of the Blackfeet Reservation, Chippewa Cree Tribe of Rocky Boy's Reservation, Confederated Salish & Kootenai Tribes of the Flathead Reservation, Crow Tribe of the Crow Reservation, Fort Belknap Tribes of the Fort Belknap Reservation, Fort Peck Assiniboine & Sioux Tribes of the Fort Peck Reservation, Little Shell Chippewa Tribe and Northern Cheyenne Tribe of the

Northern Cheyenne Reservation. This SIP did not identify any emission sources on tribal lands that impact a nearby Class I area.

Montana provided the draft RH SIP to the tribes on September 27, 2021, the beginning of the 60-day formal FLM consultation period. Montana did not receive any comments on the draft RH SIP.

2.5 CONSULTATION WITH OTHER STATES

The RHR requires that each state develops an LTS that includes any control measures necessary to make reasonable progress at each Class I area outside of the state "that may be affected by emissions from the state"[45]. Montana used the TSS 2.0 analyses tools, including emissions tools and source apportionment modeling results, to determine if an in-state source could be impacting an out-of-state Class I area, as well as out-of-state point sources that could impact Montana's Class I areas. Montana consulted with neighboring states, both through webinars and calls organized through the WRAP, and via state-to-state communication, to address the requirements of the RHR for coordinated emissions control strategies between states. Specifically, 40 CFR 51.308(f)(2)(ii) requires that Montana consult with other states that have emissions that are reasonably anticipated to contribute to visibility impairment in Montana Class I areas to develop coordinated emission management strategies containing the emission reduction necessary to make reasonable progress.

Montana relied on the technical analyses conducted by the WRAP to evaluate interstate emissions impacts. These analyses include source apportionment modeling (2.2.3) and WEP/AOI analyses (2.2.7). Montana discussed the results of these analyses with surrounding states as well as Montana's long-term strategy for reducing haze. To determine what out-of-state point sources may impact Montana's Class I areas, Montana reviewed the WEP/AOI analyses and selected the top ten point sources at each Class I area. Discussions were held with Regional Haze planners within those states to determine if any controls were being planned to address impacts as well as whether controls may be necessary to reduce impacts on Montana's Class I areas.

Additional information on Montana's consideration of interstate visibility impacts can be found in Section 7.2 - Coordinated Emission Management Strategies.

Montana demonstrates through this SIP submittal that we have considered/included in our implementation plan, all measures agreed to during state-to-state consultations.

2.6 PUBLIC AND STAKEHOLDER OUTREACH

As previously stated, many different agencies and interests come together to develop a RH SIP. Prior to formal public review and EPA action, states should communicate regularly with industry and the public. Therefore, in addition to the parties discussed above, Montana communicated regularly with regulated industry, including the sources that may be impacted by the long-term strategy control plan, as well as

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[45] 40 CFR 51.308(f)(2)

members of the public. Montana has the benefit of being part of a long-standing advisory group, the Clean Air Act Advisory Committee (CAAAC), made up of stakeholders with a diverse range of air quality interests. CAAAC was formed to enhance communication between Montana Department of Environmental Quality – Air Quality Bureau (AQB) and a diverse range of air quality stakeholder groups. Through quarterly meetings, CAAAC advises AQB on a wide range of air quality issues, including implementation of laws and rules; program funding; compliance assistance; and regional air quality issues, impacts, and challenges. AQB staff presented Regional Haze information to and solicited feedback from members of CAAAC in these regular meetings and via email correspondence.[46] Additionally, Montana invited industry representatives from the refinery sector to a stakeholder meeting where important RHR requirements and Montana's plan for SIP submittal were shared. This meeting occurred in Billings, MT on May 20, 2019. This process included collaboration during development of key plan elements, such as visibility analyses and source screening, to the required four-factor analyses and modeling emissions data inputs. For more detailed information on individual source communications, refer to Appendix A.

Montana provided a 30-day public comment period from February 3 – March 4, 2022. An in-person public hearing for this SIP revision will be held on February 23, 2022 at the Montana DEQ – Lee Metcalf Building, 1520 E. 6th Avenue, Helena, MT. This hearing was made accessible via Microsoft TEAMS and included a dial-in phone option. Hearing registration and meeting details were provided on the Montana DEQ webpage: https://deq.mt.gov/public/publiccomment. On February 10, 2022, Montana received a request from eleven conservation organizations (Citizens for Clean Energy, Coalition to Protect America's National Parks, Great Burn Conservation Alliance, Montana Environmental Information Center, Montana Health Professionals for a Healthy Climate, National Parks Conservation Association, Natural Resources Defense Council, Northern Plains Resource Council, Park County Environmental Council, Sierra Club, and 350 Montana) to extend the public comment period deadline and the delay the public hearing. Specifically, the conservation organizations asked that the public hearing be extended to at least March 16, 2022 and the deadline for comments be extended to April 18, 2022. Montana agreed to extend the public comment period to March 21, 2022, and moved the public hearing to March 18, 2022. More information on public comment and Montana's response to comment can be found in Section 10.3 and Appendices G, H and I.

3 PROGRESS TO DATE

3.1 EMBEDDED PROGRESS REPORT REQUIREMENTS

Section 51.308(f)(5) of the RHR requires states to address in the plan revision the requirements of paragraphs 51.308(g)(1) through (5), so that the plan revision due to EPA in 2021 will serve also as a progress report addressing the period since submission of the progress report for the first implementation period[47]. Section 1.4 of this document details Montana's role in submitting the first planning period's

[46] For more information on CAAAC, go to https://deq.mt.gov/air/resources

[47] EPA.gov, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period (accessed 7/20/2021).

progress report, on behalf of EPA, on September 18, 2017 and that was approved and finalized by EPA on October 4, 2019[15].

The intent of this chapter is to inform the public and EPA about implementation activities since 2017.

3.1.1 Implementation Status of all measures in first planning period (*40 CFR 51.308(g)(1)*)

As a one-time requirement during the first implementation period, the RHR (40 CFR 51.308(e)) required states to evaluate potential best available retrofit technology (BART) controls for qualifying older, existing sources of visibility impairing pollutants. The status of BART implementation at the affected facilities is described in this section.

All planning period analyses must also consider additional controls deemed necessary to make reasonable progress toward visibility improvement. This is done through a statutory process, (40 CFR 51.308(f)(2)(i)) that requires states to consider four statutory factors (costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life) of any potentially affected sources to decide what emission control measures are necessary to make reasonable progress toward natural visibility conditions at Class I areas.

The 2012 FIP for Montana evaluated five sources subject to BART and requested nine additional facilities submit a four-factor analysis. Information on implementation of these measures for achieving reasonable progress goals were included in Montana's 2017 Progress Report and much remains the same. However, since 2017 there have been a few significant changes at the Ash Grove cement plant, the GCC Trident, LLC cement plant and at Units #1 and #2 at the Colstrip Steam Electric Station. Those changes are summarized here.

3.1.1.1 Montana BART Implementation Status

Ash Grove Cement

As indicated in the 2017 Progress Report, under a Consent Decree initiated by EPA pursuant to violations of Sections 113(b) and 167 of the Clean Air Act, Ash Grove Cement (Ash Grove) agreed to achieve a lower SO_2 limit at the Montana City Plant. Ash Grove also agreed to achieve the NO_x limit on a faster timeline and to determine a potentially more stringent NO_x limit based on process and control equipment optimization. The settlement required the facility to achieve an SO_2 limit of no more than 2.0 lb/ton (30-day rolling average), required by April 8, 2015 (described as the 210th day after September 10, 2014), and an initial NO_x limit of no more than 8.0 lb/ton (30-day rolling average), required 30 days after September 10.[48]

[48] Consent Decree, United States v. Ash Grove Cement Company, No. 2:13-cv-02299-JTM-DJW, D. Kan. (2013), doc. 27 as amended by doc. 28, https://www.courtlistener.com/docket/4267857/united-states-of-america-v-ash-grove-cement-company/.

Following the process optimization requirements contained in Appendix A of the Consent Decree, Ash Grove demonstrated the ability to meet an even lower NO_x emission limit of 7.5 lb/ton.[49] This permit limit was finalized by EPA on December 29, 2016, when EPA issued an acceptance letter for an Ash Grove Demonstration Report, which had been submitted by Ash Grove to EPA on August 25, 2016.[50] This new limit is now in effect and incorporated into Title V Operating Permit OP#2005-09, which became final on June 20, 2017 (Title V Operating Permit #OP2005-11 is the latest Title V, finalized August 15, 2019). Ash Grove continues to successfully operate their SNCR system and maintain compliance with the lower NO_x limit.

GCC Trident, LLC

The facility entered dialogue with EPA in mid-2016 to revisit the BART determination from the first planning period, based on a request submitted to the Acting Air Director of EPA Region 8. GCC Trident, LLC (GCC) expressed concerns to EPA that the original NO_x limit of 6.5 lb/ton of clinker may not be able to be achieved consistently, particularly without a visible detached plume at the site.[51] Based on past experience, the facility expressed that any visible plume from the site is likely to cause significant concern from area residents. As part of the request to EPA, GCC prepared a revised BART analysis in which the facility requested a revised NO_x limit of 8.3 lb/ton of clinker. EPA reviewed the submitted information and, on April 14, 2017, published a proposed revision to the Montana FIP raising the NO_x limit from 6.5 to 7.6 lb/ton of clinker.[52] The new limit was finalized on September 12, 2017, and became effective October 12, 2017.[53] The revised permit limit of 7.6 lb/ton is now included in Title V Operating Permit (OP #0982-06), which became effective on August 15, 2019. Of note, GCC also installed a direct fired coal-feeding system

[49] Department of Justice, Montana City NOx Demonstration Report and Data, No. 90-5-2-1-08221 Ash Grove Cement Co (25 Aug 2016 approved 29 Dec. 2016).

[50] Ibid.

[51] In the manufacture of Portland cement, clinker occurs as lumps or nodules, usually 3 millimetres (0.12 in) to 25 millimetres (0.98 in) in diameter, are produced by sintering (fusing together without melting to the point of liquefaction) limestone and alumino-silicate materials such as clay during the cement kiln stage.

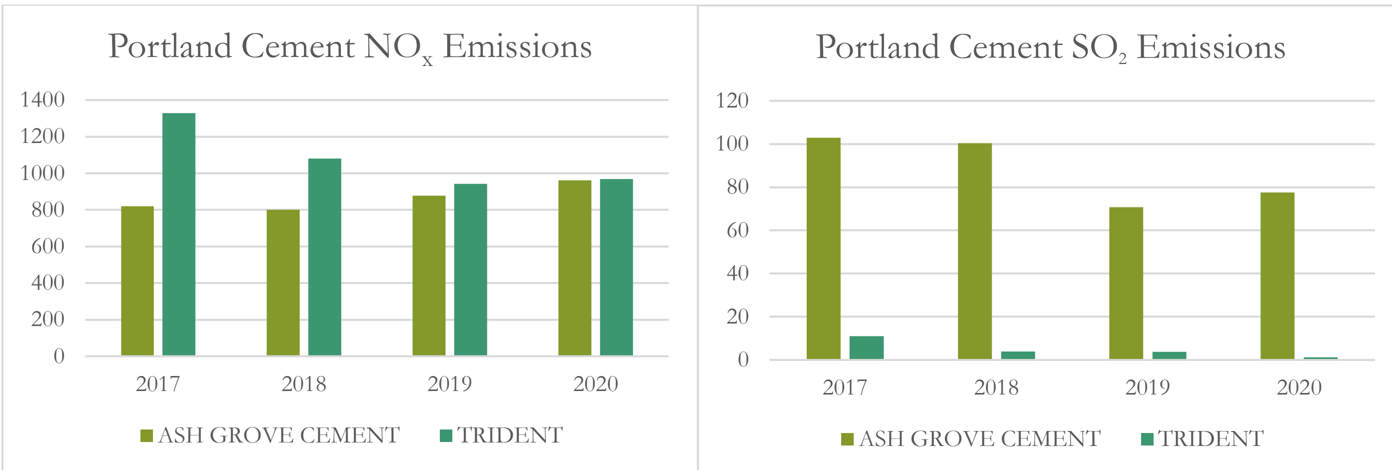
[52] EPA, Approval and Promulgation of Air Quality Implementation Plans; Montana; Regional Haze Federal Implementation Plan, Proposed Rule, 82 Fed. Reg. 17948 (14 Apr. 2017), Available at: https://www.federalregister.gov/d/2017-07597.

[53] EPA, Approval and Promulgation of Air Quality Implementation Plans; Montana; Regional Haze Federal Implementation Plan, Final Rule, 82 Fed. Reg. 42738 (12 Sep. 2017), Available at: https://www.federalregister.gov/d/2017-19210.

in 2017. This continued optimization may result in a reduction in the amount of ammonia that may be required to maintain the same level of NO_x control.

Figure 3-1 shows emission levels at Montana Portland Cement plants since 2017.

Figure 3-1. NO_x and SO_2 Emissions at Portland Cement plants in Montana, 2017 - 2020



<u>Colstrip Units 1 and 2</u>

In the summer of 2016, an agreement was reached between Sierra Club and the owners of the Colstrip facility. As part of the agreement, Colstrip Units 1 and 2 must shut down no later than July 1, 2022. In addition, the owners agreed that Units 1 and 2 would comply with the following NO_x and SO_2 emission limits until such time as the units cease operation:

- Unit 1 NO_x limit – 0.45 lb/mmBtu (30-day rolling average)
- Unit 2 NO_x limit – 0.20 lb/mmBtu (30-day rolling average)
- Units 1 and 2 SO_2 limit – 0.40 lb/mmBtu (30-day rolling average)

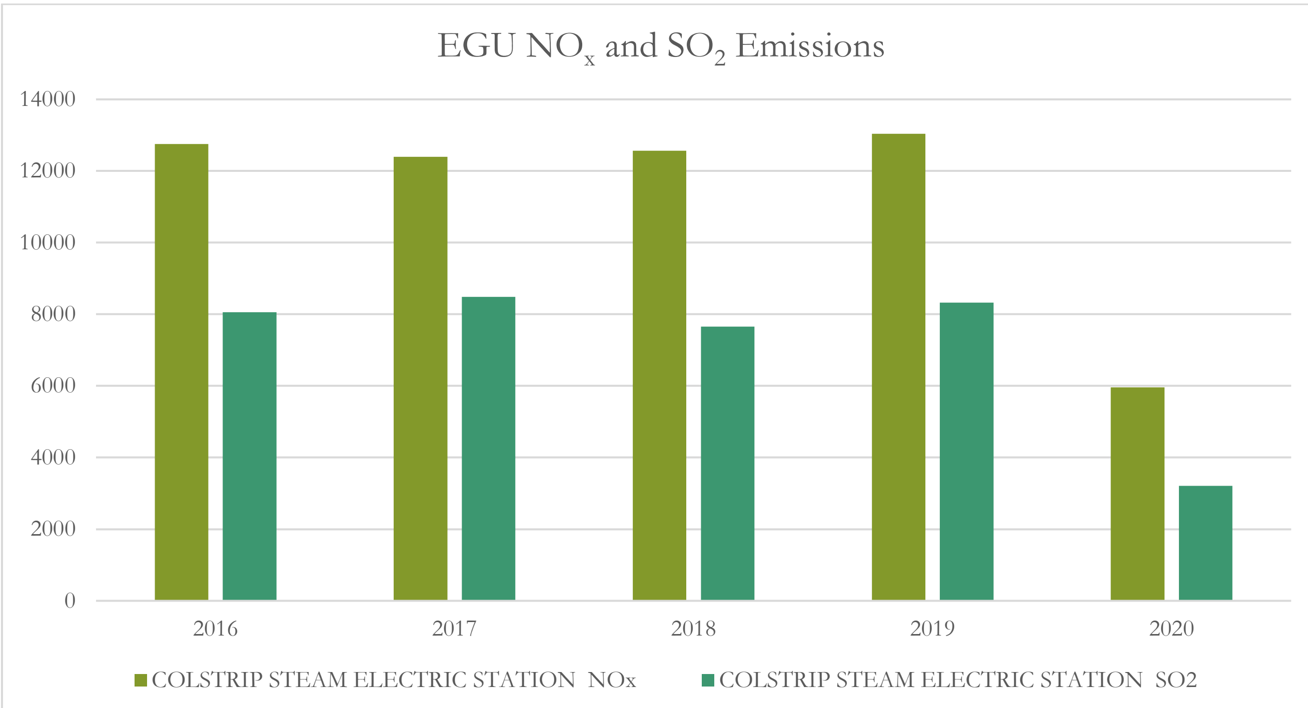
This Consent Decree is binding and, as such, these emission limits were beneficial for emission reductions until Colstrip Units 1 and 2 closed, at which time all emissions associated with these units will be gone.[54]

The owners came to a decision that Units 1 and 2 would cease operation sooner, and in January 2020 the units were shutdown (see Appendix E for retirement letter and Title V Operating Permit modification that removed these units). Had these units stayed in operation longer, it's likely that a revised BART analysis or a reasonable progress analysis would have been required. Over the 2014 – 2017 baseline period, Units 1 -4 averaged 22,863 tpy of NO_x and SO_2 combined. The significant reductions from the shutdown of Units 1 and 2 resulted in a combined SO_2 and NO_x reduction of 10,147.4 tons per year (tpy) from the 2014-2017 baseline. This reduction represents 44.4 percent of total facility SO_2 and NO_x emissions at the Colstrip facility.

[54] Sierra Club v. Talen Montana, LLC et al., No. 1:13-cv-00032-DLC-JCL, D. Mon. (2016), doc. 316-1.

If Selective Catalytic Reduction (SCR) were to be installed on both Units 3 and 4, it would provide an overall NO_x reduction of 4,318 tpy from the 2014-2016 baseline. The total reduction from the closure of Units 1 and 2 provides annual reductions of over twice that amount.

Figure 3-2. NO_x Emissions Changes at BART Sources - EGUs



3.1.1.2 Improvements at Reasonable Progress Sources

<u>MDU Lewis and Clark</u>

Although the Montana FIP did not set reasonable progress emission limits for MDU Lewis and Clark (MDU), the facility did propose in the 2011 four-factor analysis to upgrade the existing scrubber system. This modification was expected to improve particulate control and enhance SO_2 control with the addition of a continuous lime injection system. MDU was also subject to the Mercury and Air Toxics MACT standard (MATS) and an upgraded scrubber system began operation in 2015 to comply with MATS. Upgrades included a mist eliminator retrofit and installation of sieve trays to reduce filterable particulate matter (PM), which resulted in the significant reduction in SO_2. These upgrades were completed in 2015, to satisfy the non-mercury metals emission standard of 0.03 lbs/MMBtu for filterable PM. The system was fully operational in early 2016. Both the proposed and final FIP did not incorporate SO_2 reductions, largely because EPA believed any reductions would be relatively minor. However, had the fact that the MATS-required scrubber modifications been known to achieve such a large reduction in SO_2, it's possible this would have been demonstrated in the 2011 analysis, and thus required in the Montana FIP. The scrubber upgrades resulted in SO_2 reductions from 1045.6 tpy in 2014 to 22.6 tpy in the 2017-2018 baseline. NOx reductions of approximately 100 tpy have also occurred from 2014 to the 2017-2018 baseline.

CHS Inc. Refinery Laurel

CHS has incorporated several changes since 2017:

- Platformer Recycle Compressor: The natural gas-fired driver for this compressor was replaced with an electric motor during 2018. This resulted in a reduction in NO_x emissions from the 2017-2018 baseline.
- #2 Crude Unit Vacuum Heater: This refinery fuel gas (RFG) fired process heater is nearing the end of its serviceable life. CHS has identified that it will be replaced prior to 2028 with a heater that includes ultra-low NOx burners. This will result in a reduction in actual NO_x emissions from the 2017-2018 baseline. (*The unit was replaced in October 2021, during Montana's formal FLM consultation period and noted here for accuracy).*
- Stationary Emergency Engines: Several stationary emergency engines were first added to the refinery emissions inventory in 2018, and because of this, a small increase in actual NO_x emissions from the 2017-2018 baseline occurred.
- Main Refinery Flare: CHS continues to optimize and increase the utilization of the Flue Gas Recovery System (FGRS), and with ongoing work practices required by applicable regulations, it is conservatively estimated that SO_2 emissions from the main refinery flare will decrease by 20% from the 2017-2018 baseline by 2028.

ExxonMobil Billings Refinery

The Billings Refinery averaged 539.4 tpy of SO_2 emissions in 2015-2016, with 75 percent of those emissions attributed to the Fluid Catalytic Cracking Unit (FCCU). As required under the Federal Consent Decree[55], the Billings Refinery worked through an extended demonstration period for controlling SO_2 emissions from the FCCU.by operating the FCCU in Full Burn Operation while using a desulfurization (DeSOx) additive. It is likely that this SO_2 control strategy (and pending final emission limits) between EPA and the Billings Refinery will considerably reduce SO_2 emissions from the FCCU. The FCCU SO_2 limit was finalized on June 28, 2021 and incorporated in Exxon Refinery's Operating Permit #OP1564-18[56] and MAQP #1564-35[57]. The limits are 177.3 ppm at 0% O2 on a 365-day rolling average and 300.0 ppm at 0% O2 on a 7-day rolling average.

Since 2012, SO_2 emissions from the FCCU have been reduced by almost 4,000 tpy due to the DeSOx additive. The remainder of the SO_2 emissions are attributed to either the KCOB (during YELP downtime, particularly in 2016) or small boilers and heaters subject to NSPS Subpart J or other requirements.

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[55] Third Amendment Making Material Modifications to Consent Decree, Case No. 05 C 5809. Available at: https://www.epa.gov/sites/default/files/documents/3rdmod-exxonmobil1208-cd.pdf

[56] Operating Permit #OP1564-18, (2 November 2021), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/ARMpermits/OP1564-18.pdf,

[57] Montana Air Quality Permit MAQP #1564-35, (21 September 2021), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/ARMpermits/1564-35.pdf

Phillips66

Since 2010, SO_2 and NOx emissions at Phillips 66 (P66) have been relatively stable, with around 100 tpy SO_2 and 500 – 600 tpy of NOx.

In this second implementation period, Boilers #1 and #2 were evaluated through the four-factor analysis for NOx reductions (summary can be found in Section 6.2.20). In that analysis, SCR and SNCR were evaluated and found to not be cost effective. However, these options may have to be considered more seriously in future planning periods. It is very likely that future emission reductions at P66 will occur when older equipment is no longer serviceable and must be replaced with new equipment that provides much lower levels of emissions. All new equipment will be subject to 40 CFR 60 Subpart Ja – Standards of Performance for Petroleum Refineries and will also go through Montana's air quality permitting program which requires Best Available Control Technology (BACT) review on all projects. Current plant operations are not likely to result in large emission changes in the short term.

3.1.1.3 Adjacent States' Bart Implementation Status

In the 2017 Progress Report, Montana reported on the status of BART sources for the following states. The most recent information has been added for completeness.

Idaho

Idaho has five Class I Areas, including Hells Canyon Wilderness, Craters of the Moon Wilderness, Sawtooth Wilderness, and two that are shared with Montana: Selway-Bitterroot Wilderness and Yellowstone National Park. According to Idaho's Regional Haze documentation, Idaho had one BART source, Amalgamated Sugar Company, LLC (TASCO Riley Boiler located in Nampa, Idaho), which was required to install new emission controls by July 22, 2016.[58] This facility was required to install and operate low NO_x burners after it was determined that SCR was not technically feasible for the specific process at this facility. There are also two other boilers (B&W Boilers 1 and 2) at this facility that became part of a BART Alternative Controls option, resulting in a combined NOx limit for the three boilers. The initial performance test for the new BART limits was required by December 20, 2016. The B&W boilers are currently permitted to burn natural gas only and the Riley Boiler fires natural gas until coal-fired LNBs are installed.

As part of the BART determination, three non-BART pulp dryers were also shut down at the facility in an effort to provide the necessary SO_2 reductions. The rationale for this shutdown was to provide more improvement in visibility than otherwise would have occurred from the original BART determination. A second facility in Soda Springs (P4 Production, LLC), Idaho, went through a BART analysis but EPA determined that no additional control was required (no feasible NOx controls and recent BACT determination were enough for PM and SO_2 controls).

[58] Idaho Department of Environmental Quality, "Regional Haze Plan" (8 Oct. 2010), Available at: http://www.deq.idaho.gov/air-quality/air-pollutants/haze/.

North Dakota

North Dakota has two Class I Areas, including the Lostwood Wilderness and Theodore Roosevelt National Park, each located in the western third of the state. To make visibility progress during the first implementation period, North Dakota primarily relied on NO_x and SO_2 emission reductions resulting from controls at existing EGUs. These controls include BART at Coal Creek Station (2 units), Leland Olds Station (2 units), Milton R. Young Station (2 units), and Stanton Station, as well as reasonable progress controls at Antelope Valley Station (2 units), Coyote Station, and R.M. Heskett Station.[59] The BART emission limits were required to be met by no later than May 7, 2017. On April 6, 2012, EPA took action to partially approve and partially disapprove the state's RH SIP and finalize a FIP addressing disapproved portions.[60] On September 23, 2013, the U.S. Court of Appeals for the 8th Circuit ruled that EPA's refusal to consider the existing pollution control technology at the Coal Creek Station was arbitrary and capricious.[61] The court vacated the FIP requiring SNCR at the facility. On April 26, 2018 EPA proposed to approve North Dakota's NOx BART determination for Coal Creek Station. After the public comment period ended, EPA never took final action to finalize approval or reject the BART determination. North Dakota, Great River Energy (owner of Coal Creek Station), and EPA have been engaged to resolve the issue since May 2018. Great River Energy completed installation of North Dakota's recommended NOx BART controls in 2020 on Unit 1. Unit 2 has North Dakota-determined BART controls installed since 2010. North Dakota is continuing to evaluate Coal Creek Station during the second-round planning period in addition to finalizing the plan for the first round of Regional Haze planning. Great River Energy indicated plans for a shutdown in 2022 unless a buyer could be found.

South Dakota

South Dakota is home to two of the nation's 156 mandatory federal Class I Areas: Badlands National Park and the Wind Cave National Park. Each is located in the southwest corner of South Dakota. South Dakota has only one BART source, the Big Stone I coal-fired power plant, located in the northeastern corner of South Dakota. Air pollution controls and limits for this source, established under the BART determination, must be installed and implemented by April 26, 2017 (within five years of EPA's approval of South Dakota's RH SIP on April 26, 2012).

The BART determination made in 2010 required SCR and separated over-fire air for NO_X control, a dry flue gas desulfurization system for SO_2 control, and a fabric filter for PM control. The control system was

[59] State of North Dakota, "Regional Haze State Implementation Plan Periodic Progress Report" (Jan. 2015).

[60] EPA, Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze, 77 Fed. Reg. 20894 (06 Apr. 2012), Available at: https://www.federalregister.gov/d/2012-6586.

[61] State of North Dakota v. U.S. Environmental Protection Agency (EPA), Nos. 12-1844, 12-1961, 12-2331, United States Court of Appeals for the Eighth Circuit (2013).

completed in December 2015, ahead of the 2017compliance deadline. The BART controls resulted in emissions reductions of 90.7 percent NO_x and 93.9 percent SO_2, from 2015 to 2017.

Oregon

Oregon has twelve mandatory Class I areas. According to the RH Update Plan for Oregon, a total of five facilities were impacted by BART determinations. Four facilities chose the option of a federally enforceable permit condition exempting them from BART determinations by reducing visibility impacts below 0.5 deciviews. The PGE Boardman (Boardman) facility BART determination required controls and to cease burning coal by December 31, 2020. Boardman completed installation of BART SO_2 controls consisting of a semi-dry flue gas desulfurization system in early 2014 and is required to further reduce SO_2 emissions in 2018.[62] Boardman shutdown on October 15, 2020.

Wyoming

Wyoming has seven Class I Areas including Yellowstone National Park, a portion of which is located in Montana. On January 30, 2014, EPA published a Regional Haze FIP for Wyoming, approving the state-proposed BART limits for PM and/or NOx for 17 units. The majority of these limits do not take effect until future years, extending as late as December 31, 2022. EPA also disapproved the state's proposed NO_x limits for five units and developed new BART limits as part of the FIP for these sources. The compliance date for these five sources was March 4, 2019. Portions of EPA's final action were appealed and are still pending a final determination. Most of the BART determinations require SCR and CEMS for NOx control.[63] EPA completed final action on BART limits related to units at the Laramie River Station for Units 1, 2 and 3 on May 20, 2019.

3.1.2 **Summary of emission reductions achieved by control measure implementation (*40 CFR 51.308(g)(2)*)**

More information regarding Montana's emissions by source category can be found in Chapter 5. Table 3-1 below provides a crosswalk of examples of progress toward emission reductions achieved by control measure implementation and where they can be found in Chapter 5:

[62] Oregon Department of Environmental Quality, "Oregon Regional Haze Plan 5-Year Progress Report and Update" (Feb. 2016), Available at: http://www.deq.state.or.us/aq/haze/docs/2016ORRegHazeUpdate.pdf.

[63] EPA, Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze, 79 Fed. Reg. 5031 (30 Jan. 2014), Available at: https://www.federalregister.gov/d/2014-00930.

Table 3-1. Emission Reduction Progress and Chapter 5 Examples

Emission Reduction Progress Examples	Chapter 5 Figure
Montana Point Source Inventory (2014 – 2017, including 2028 projections)	*Figure 5-1. Montana Point Emissions by Emissions Scenario*
Montana EGU Emissions (2014 – 2017 including 2028 projections)	*Figure 5-2. Montana NO_x and SO_2 EGU Emissions by Emissions Scenario*
Montana non-EGU Emissions (2014 – 2017 including 2028 projections)	*Figure 5-3. NO_x and SO_2 Emissions from Non-EGU Sources by Emissions Scenario*

3.1.3 Assessment of visibility conditions (*40 CFR 51.308(g)(3))*

More information regarding Montana's visibility analyses can be found in Chapter 4. The table below provides a crosswalk of the embedded progress report rule requirements and where they can be found in Chapter 4:

Table 3-2. Embedded Progress Report Requirement to Chapter 4 Crosswalk

Embedded Progress Report Requirement	Chapter 4 Section and Matching Requirement	Chapter 4 Table
40 CFR 51.308(g)(3)(i) The current visibility conditions for the most impaired and least impaired days	4.2.3 Current (2014-2018) visibility for the most impaired and clearest days (40 CFR 51.308(f)(1)(iii))	*Table 4-5. Current visibility (2014-2018) conditions at Montana Class I areas.*
40 CFR 51.308(g)(3)(ii) The difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions	4.2.4 Progress to date for the most impaired and clearest days (40 CFR 51.308(f)(1)(iv))	*Table 4-6. Progress to date for the most impaired and clearest days*
40 CFR 51.308(g)(3)(iii) The change in visibility impairment for the most impaired and least impaired days over the period since the period addressed in the most recent plan required under paragraph (f) of this section.	4.2.4 Progress to date for the most impaired and clearest days (40 CFR 51.308(f)(1)(iv))	*Table 4-6. Progress to date for the most impaired and clearest days.* (Table 4-6 includes previous implementation period data)

Another way to assess Montana's visibility progress is to look at the modeled change in visibility due to U.S. anthropogenic emissions from the 2002 past year to the current representative baseline conditions in this planning period and to the 2028 future year. The U.S. Anthropogenic Modeled Rate of Progress

Glidepath.[64] analysis offers a novel way to see how decreasing U.S. anthropogenic emissions provides for visibility improvement. The simulation 'backcasts' the U.S. anthropogenic emissions in the 2014v2 modeling run to the 2002 period, using backcast scaling factors for each pollutant (i.e., VOC, NO_x, SO_2, CO, NH_3, $PM_{2.5}$ and PM_{10}). Emission sources other than U.S. anthropogenic of emissions (natural, fire, and international) are held constant, so just the change in U.S. anthropogenic emissions can be assessed. Ultimately, the U.S. Anthropogenic Modeled Rate of Progress Glidepath helps to assess progress in reducing U.S. anthropogenic contributions to visibility impairment at Class I areas.

Table 3-3 shows the results of this modeling endeavor: the light extinction from just U.S. anthropogenic sources at each IMPROVE monitor in the beginning of the first planning period (2002) compared to light extinction values in the representative baseline (RepBase2) period for this second implementation period.

Table 3-3. U.S. Anthropogenic Source Contributions to Light Extinction in 2002 vs RepBase

Class I Area	2002 Hindcast – US Anthro Source Contribution (Mm-1)	RepBase2 – US Anthro Source Contribution (Mm-1)
MELA1	10.35	7.56
ULBE1	4.56	3.18
SULA1	4.56	2.65
GLAC1	9.07	5.61
MONT1	5.27	3.16
GAMO1	4.14	2.65
CABI1	7.55	4.76
LOST1	14.76	11.15
THRO1	8.68	6.55
YELL2	5.28	3.22
NOAB1	2.97	1.75

[64] Ramboll, Run Specification Sheet Dynamic Evaluation – 2002 CAMX Simulation and Analysis, (24 Feb. 2020), Available at: https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/Run_Spec_WRAP_2014_Task3_Dynamic-Evaluation_v1.pdf

3.1.4 Analysis of any changes in emissions from all sources and activities within the state (*40 CFR 51.308(g)(4))*

Figure 3-3 – Figure 3-6 show the emissions trends in Montana, from large point sources, oil and gas sources, nonpoint or area sources, and mobile sources. The emissions from these sources during the baseline years (2000-2004) are represented by a 2002 inventory, which was developed with support from the WRAP for use in the first implementation period (termed "plan02d"). The 2008 and 2011 are extracted from the 2008 Progress (WestJump08c) and 2011 Progress (IWDW-2011) emissions scenarios[65]. In this section, trends between inventories are represented as the difference between the inventories used in the first planning period (Plan02d, WestJump08c and IDWD-2011) and the inventories used in this implementation period (2014v2, RepBase2 and 2017NEI). The first planning period emissions scenarios source categories were mapped to the source categories in 2014v2 emissions scenario.

Comparing the 2002 and the 2017 NEI inventories, NOx from area, mobile, point and oil and gas sources has decreased by 47 percent, SO_2 has decreased 62 percent, VOC by 28 percent and a 12 percent decrease in particulate matter ($PM_{2.5}$+PM_{10}).

Emissions estimation procedures are updated over time, which can create inconsistencies and make it difficult to conduct trend analyses. For example, the methodology for calculating VOC emissions from area sources has been updated over the years to better reflect actual emissions; therefore, the 2017 NEI data is likely more reflective of actual annual emissions. Moreover, it is very difficult to conduct trend analysis on fire (both prescribed and natural) because of the changes in methodology and the inherent variability of the activity. Year to year prescribed fire activity can change due to weather and available resources, which in turn greatly affects emissions. Fire emissions are not included in the following trend graphs. Section 5.4 describes fire emissions in greater detail. Emissions changes in the generalized source categories are displayed in the tables on the following pages.

[65] WRAP TSS Archived Site, http://vista.cira.colostate.edu/tss/

Figure 3-3. NOx Emissions by Sector

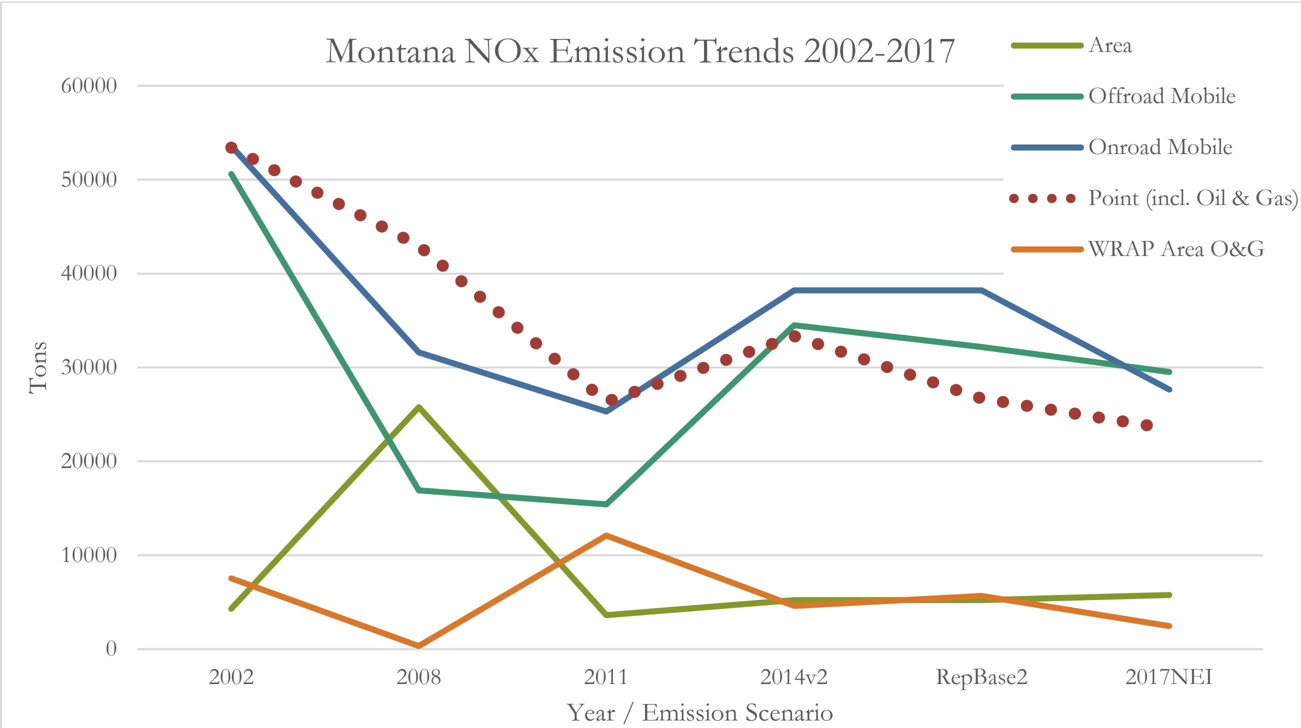


Figure 3-4. SO_2 Emissions by Sector

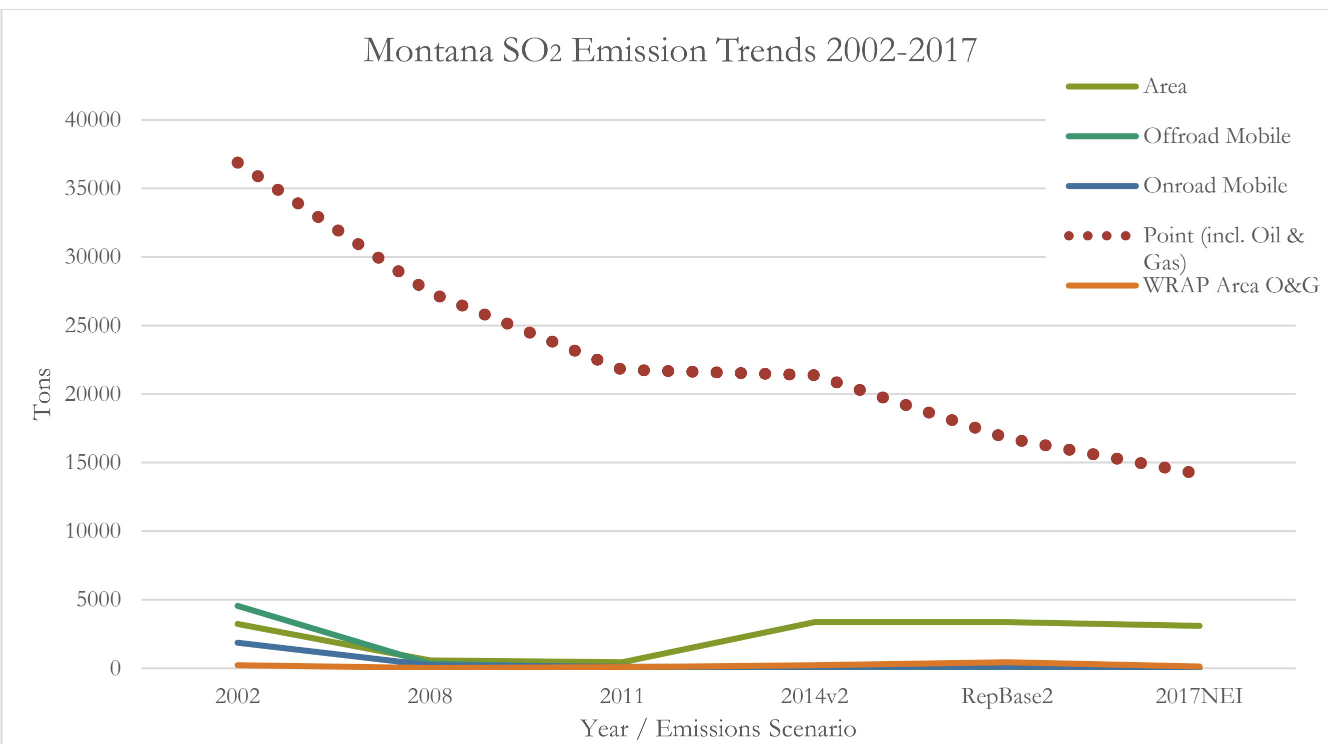


Figure 3-5. VOC Emissions by Sector

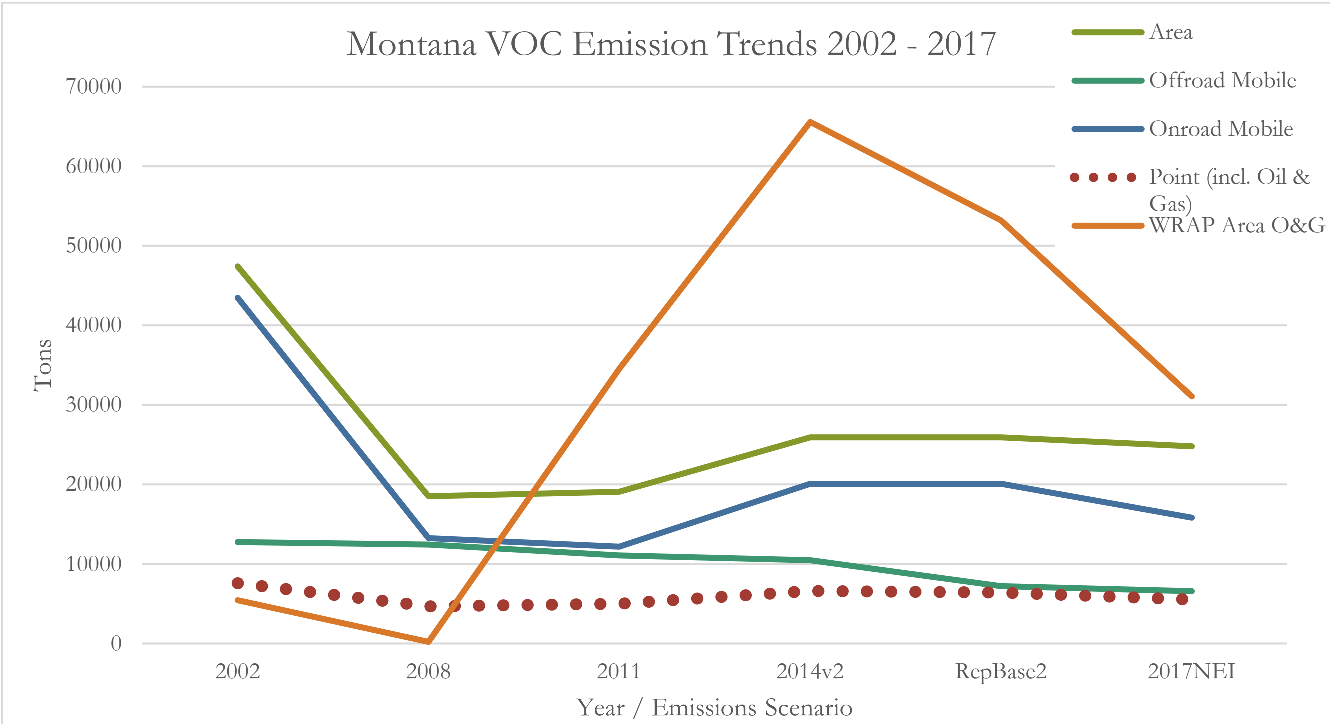
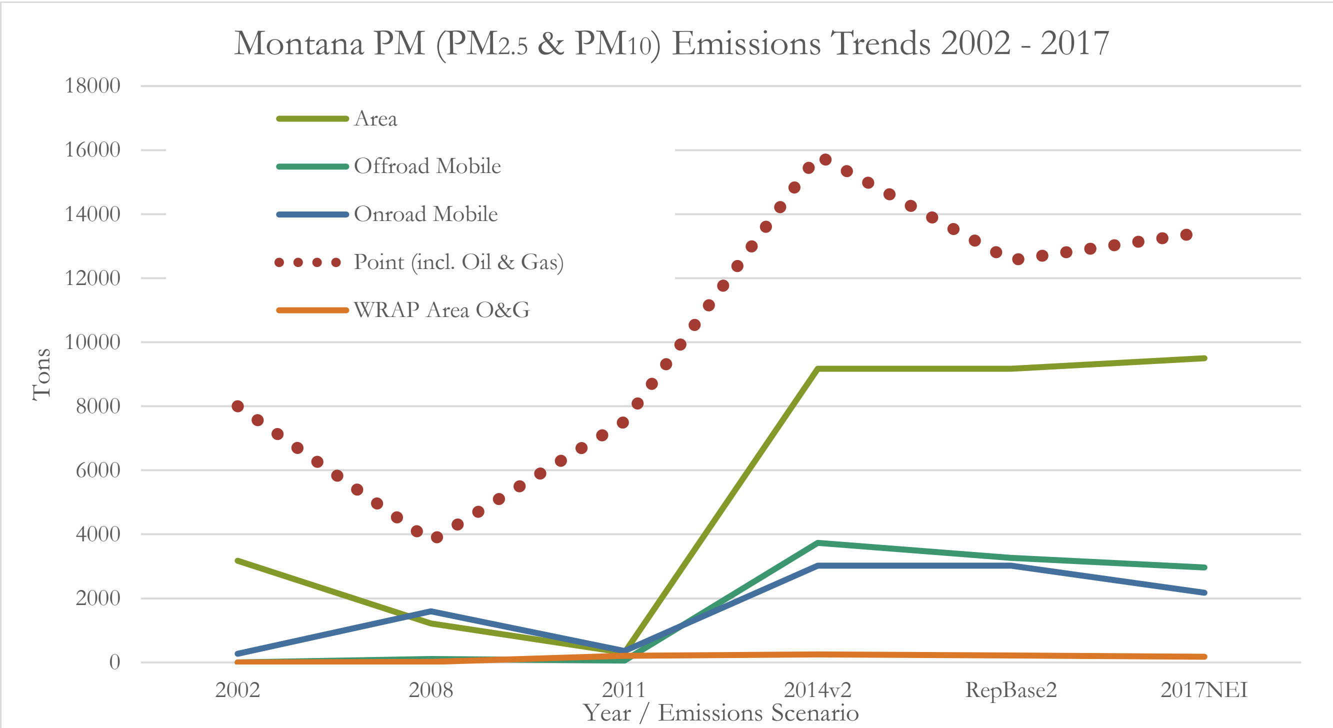


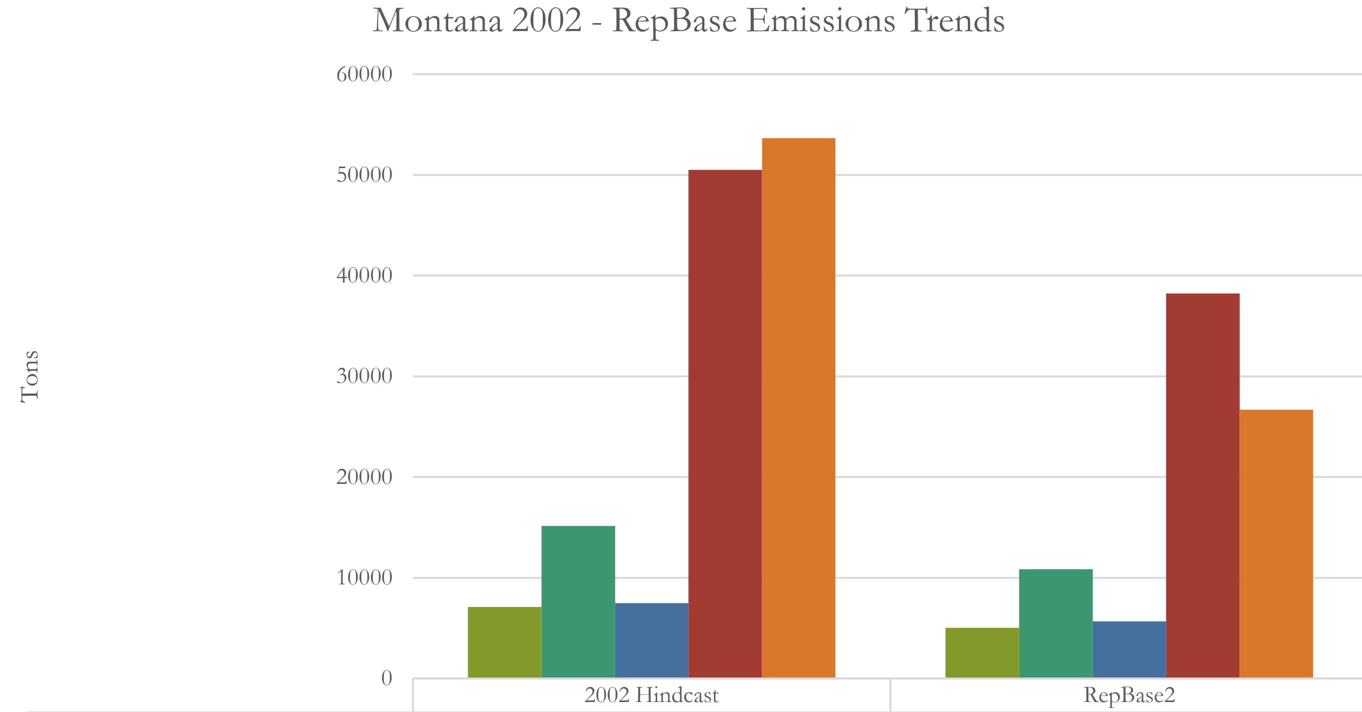
Figure 3-6. PM Emissions by Sector



Another approach to examining emissions trends is to compare the 2002 Hindcast emissions scenario with the RepBase2 emissions scenario from the Modeled U.S. Anthropogenic Rate of Progress model run. Because emissions inventory development methodologies have changes greatly since 2002, it can be difficult to tease out meaningful trends. The 2002 Hindcast emissions scenario is more consistent with current emissions inventory methodologies because the scenario was created by backcasting the 2014v2 U.S. anthropogenic emissions. State-specific and species-specific 2002/2014 scaling factors were created for most source sectors, so that the lateral comparison can be made.

Comparing the two emissions scenarios, the 2002 Hindcast and RepBase2, indicates that anthropogenic emissions from NO_x, SO_2 and PM_{10} have decreased significantly. Both VOC and $PM_{2.5}$ have increased in Montana.

Figure 3-7. 2002 Hindcast vs RepBase2 emissions comparisons



	2002 Hindcast	RepBase2
nonpt	7109.956	5040.786
nonroad	15137.055	10868.09
np_oilgas_wrap	7496.556	5659.707
onroad	50500.66	38219.939
Point (pt_oilgas + ptegu + ptnonipm)	53659.143	26687.466

Taking the next step in the analysis, we can look at the source contributions to light extinction in both the 2002 Hindcast and RepBase2 periods, shown in Table 3-4.

Table 3-4. U.S. Anthro Source Contributions to Light Extinction

Site ID	2002 Hindcast (Mm-1)	RepBase2 (Mm-1)
CABI1	10.05	6.04
GAMO1	4.13	2.66
GLAC1	13.96	8.39
LOST1	19.46	15.35
MELA1	12.74	9.94
MONT1	5.4	3.19
NOAB1	3.93	2.41
SULA1	4.62	2.69
THRO1	15.04	10.01

Site ID	2002 Hindcast (Mm-1)	RepBase2 (Mm-1)
ULBE1	4.53	3.01
YELL2	6.07	4.08

Figure 3-8 and Figure 3-9. show the light extinction by aerosol species from U.S. anthropogenic sources only, at each Class I area, as modeled in the 2002 Hindcast and RepBase2 periods.

Figure 3-8. Modeled U.S. Anthro Contributions on MIDs for western sites

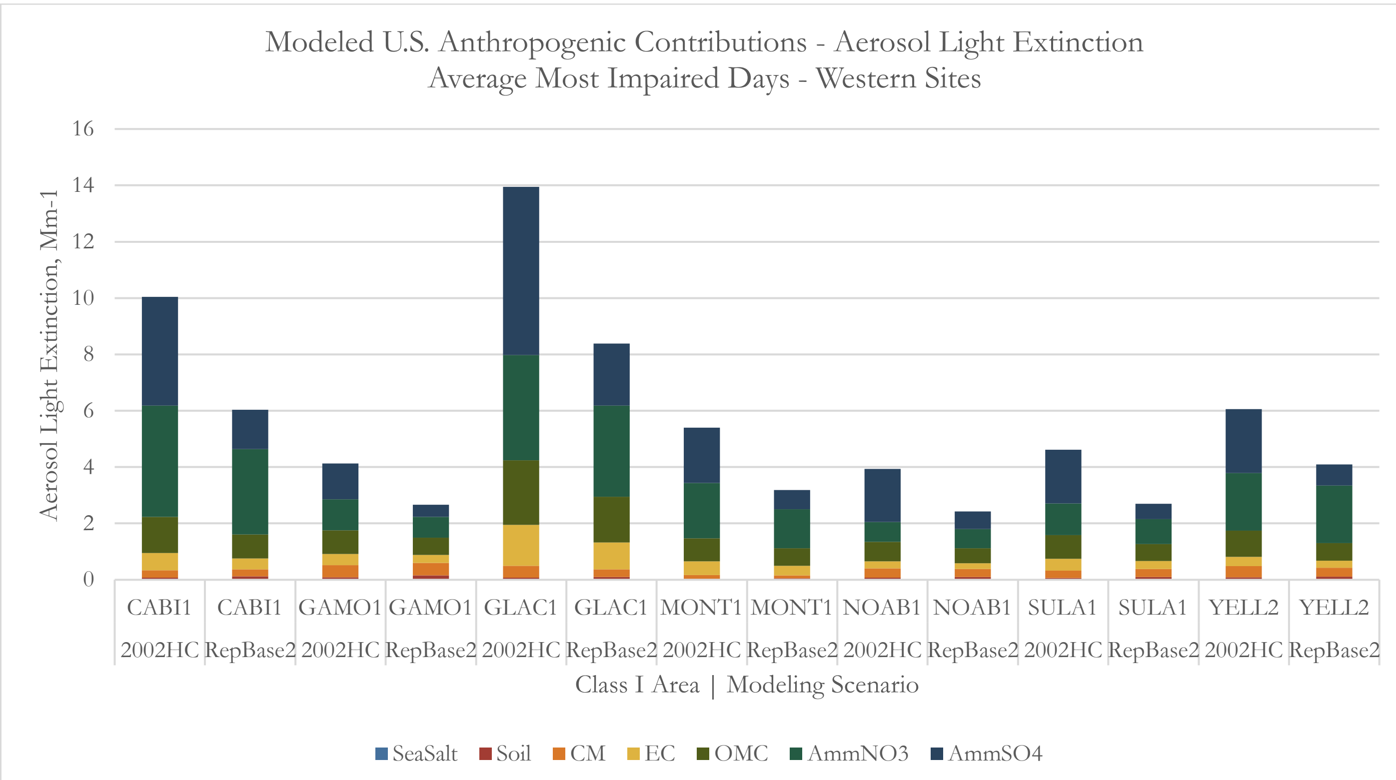
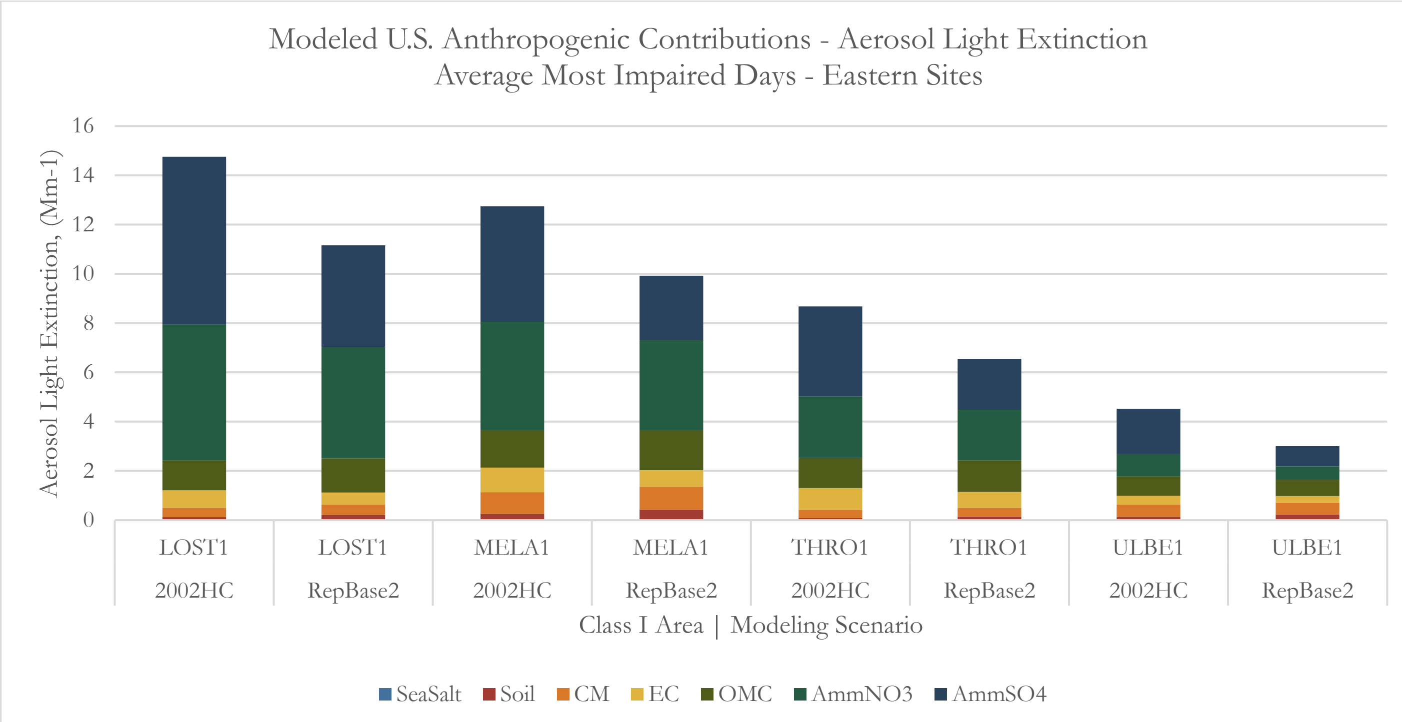


Figure 3-9. Modeled U.S. Anthro Contributions on MIDs for eastern sites



3.1.5 Assessment of any changes in emissions from within or outside the state, including whether these changes were anticipated in previous planning period and whether those changes limited/impeded reduction of emissions of improvements in visibility (*40 CFR 51.308(g)(5)*)

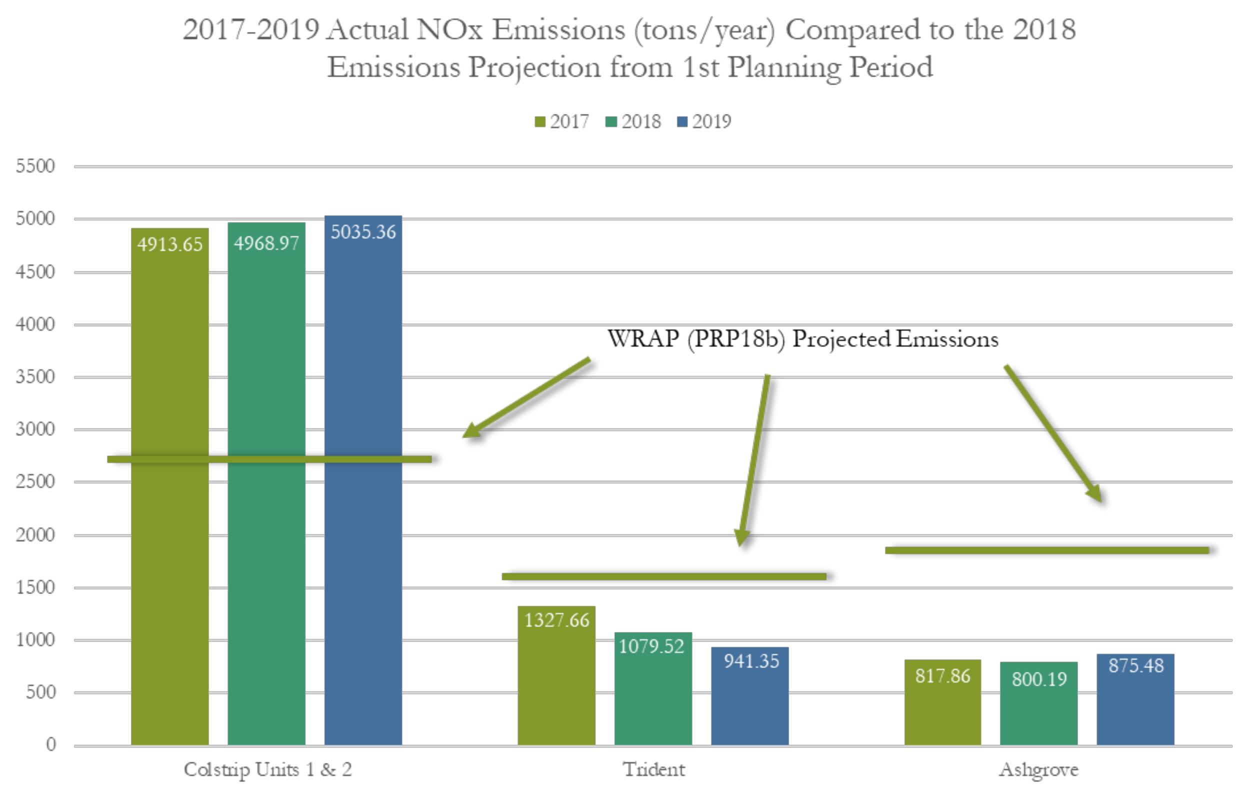
Although emissions are generally decreasing across the state, measuring progress under the Regional Haze program relies on a comparison of actual progress to expected/anticipated progress. As such, 40 CFR 51.308(g)(5) requires "[an] assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred over the period since the period addressed in the most recent plan required under paragraph (f) of this section including whether or not these changes in anthropogenic emissions were anticipated in that most recent plan and whether they that have limited or impeded progress in reducing pollutant emissions and improving visibility."[66]

The compliance dates for the large industrial facilities described in Section 3.1.1 have all occurred and sources continue to meet the required limit(s). The early closure of Colstrip's Units 1 and 2 provided additional emission reductions that had not been expected until later in the second implementation period. The following graphs show the 2018 projections that were modeled for the first planning period. Of note,

[66] EPA, 40 CFR 51.308(g)(5) (2016).

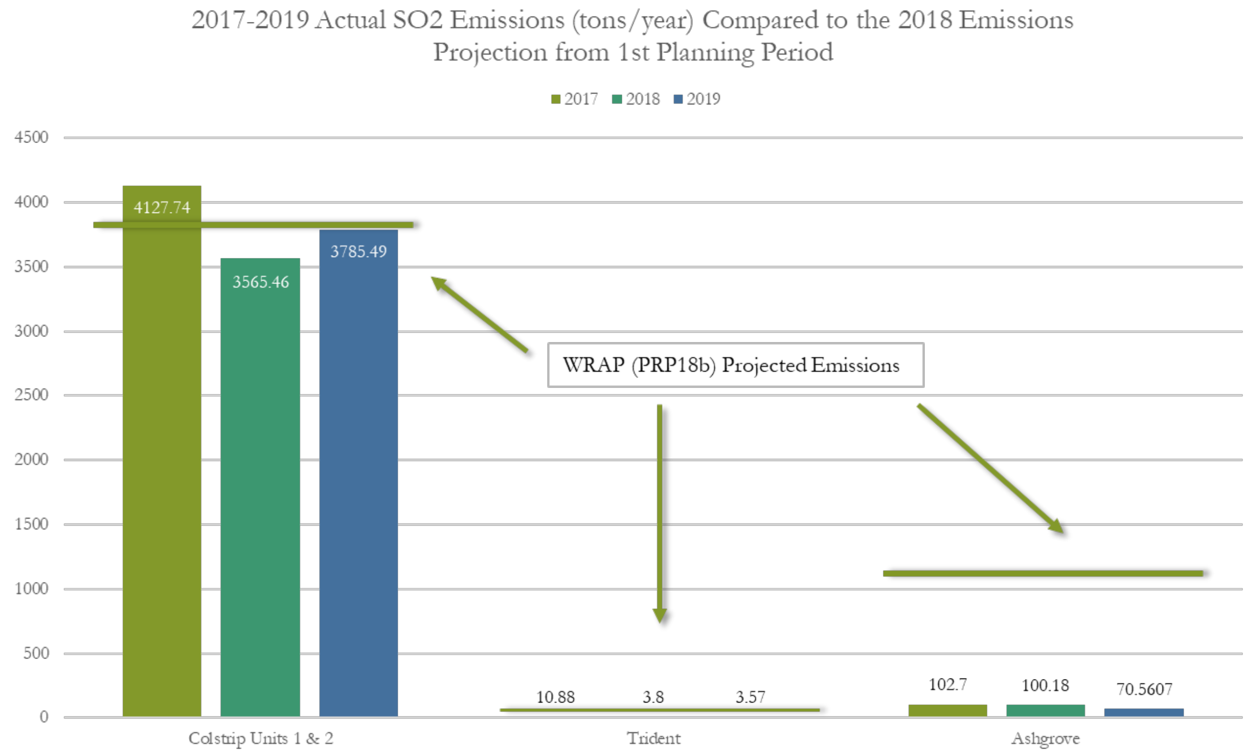
the 2018 projected emissions for Colstrip Units 1 & 2 were based on the EPA's BART decision, which was vacated on June 9, 2015, by the United States Court of Appeals for the Ninth Circuit. The court found the NO_x and SO_2 emission limits for Units 1 & 2 to be arbitrary and capricious, and remanded the determination back to EPA.[67] However, the plant operator did install separated overfire air controls on Units 1 and 2 and SmartBurn[R] technology on Unit 2 before the original BART limits were vacated.

Figure 3-10. BART Sources NO_x Emissions - Actual vs Projected



[67] National Parks Conservation Association (NPCA) v. U.S. Environmental Protection Agency (EPA), No. 12-73710, United States Court of Appeals for the Ninth Circuit (2015), Available at: http://caselaw.findlaw.com/us-9th-circuit/1703871.html.

Figure 3-11. BART Sources SO_2 Emissions - Actual vs Projected



As the 2017 Montana Regional Haze Progress Report pointed out, international sources play a part in visibility impairment, more so in Montana's eastern Class I areas. Section 4.3.1 explains in more detail the role of international sources in visibility impairment in Montana's Class I areas.

An example of a large source of international emissions is the Poplar River Power Station, a two-unit 582 MW coal-fired electric generating station in southern Saskatchewan Province, about 5 miles from the Montana/Canada border.

Figure 3-12 and Figure 3-13 show annual NO_x and SO_2 emissions from the source in metric tons. [68] This facility is upwind, emits significant levels of visibility-impairing pollutants compared to Montana's large emitting sources, and potentially affects northeastern Montana and Medicine Lake.

[68] Government of Canada, Environment and Climate Change Canada, National Pollutant Release Inventory, Available at: http://ec.gc.ca/inrp-npri/default.asp?lang=En&n=4A577BB9-1, (accessed 5 Apr. 2021).

Figure 3-12. Nitrogen Oxide Emissions (tonnes), 2005-2014 – Poplar River[69]

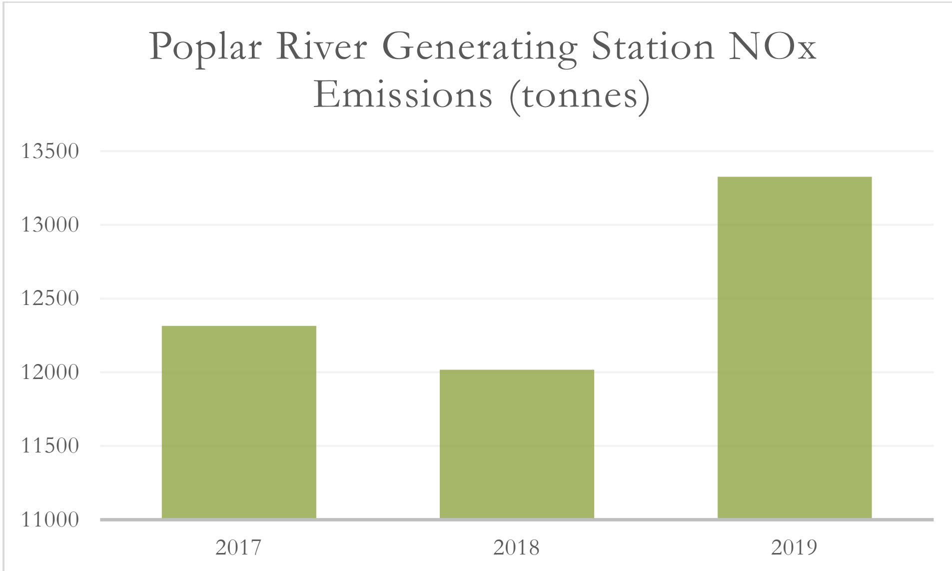
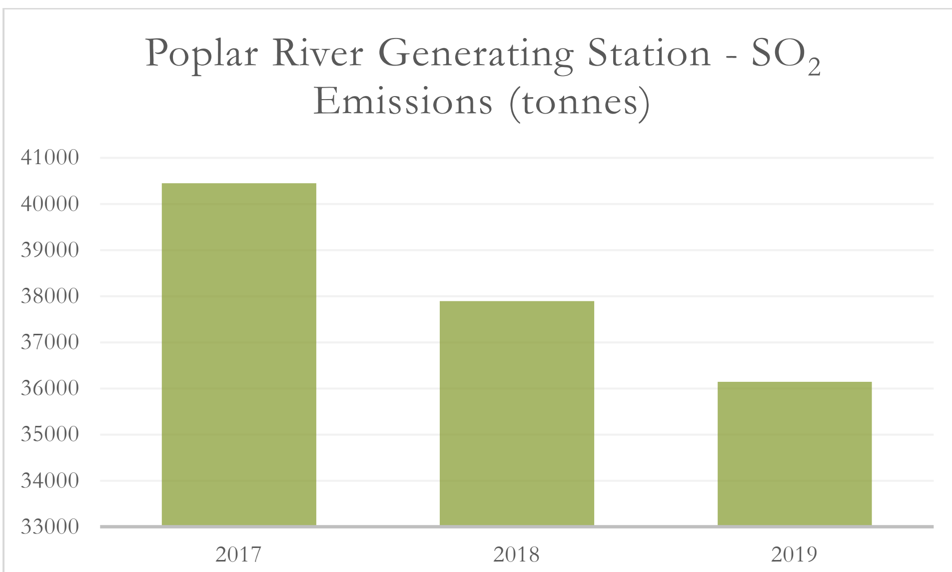


Figure 3-13. Sulfur Oxide Emissions (tonnes), 2017-2021 – Poplar River



[69] Government of Canada, Environment and Climate Change Canada, Available at: http://maps-cartes.ec.gc.ca/indicators-indicateurs/detailPage.aspx?lang=en&type=air_emissions_tpm&objectid=0000002079 (accessed 5 Apr. 2021). Graphs are intended to provide overview of emission trends.

Table 3-5 provides a summary of other large point sources within about 100 miles of the Montana border that emitted more than 100 tons per year of SO_2 and/or NO_x in 2019. Particulate matter emissions are also included for information purposes.

Table 3-5. Canadian Facilities Emitting >100 tpy of SOx and/or NOx near the MT Border (~100mi)[70]

		2019 Emissions (tonnes)			
Facility Name	**NAICS**	**SO_x**	**NO_x**	**$PM_{2.5}$**	**PM_{10}**
Poplar River Power Station	Fossil-Fuel Electric Power Generation	36,144.76	13,326.85	435.97	1,519.21
Boundary Dam Power Station	Fossil-Fuel Electric Power Generation	28,957.57	12,293.95	64.13	223.48
Shand Power Station	Fossil-Fuel Electric Power Generation	11,861.24	3,290.04	17.13	59.61
Waterton Complex	Conventional Oil & Gas Extraction	5,825.74	445.94	9.96	14.03
Trail Operations	Non-Ferrous (ex. Al) Smelting/Refining	3,810.87	525.62	45.92	66.10
Leitchville Sour Gas Plant	Conventional Oil & Gas Extraction	1,081.88	261.06	5.60	5.60
Glen Ewen Sour Gas Plant 05-14	Conventional Oil & Gas Extraction	994.87	50.70	1.00	1.00
Beinfait Mine - Char Plant	Lignite Coal Mining	433.10	159.40	18.30	52.33
Border Chemical Company Ltd	All Other Basic Inorganic Chemical Mfg	367.63	--	--	--
Burnaby Refinery	Petroleum Refineries	227.10	206.40	20.40	26.20
Kisbey	Conventional Oil & Gas Extraction	194.24	21.21	4.65	4.65
Neptune Oil Battery 05-31	Conventional Oil & Gas Extraction	175.78	4.91	8.09	8.09
Steelman Gas Plant	Conventional Oil & Gas Extraction	165.70	50.73	29.22	29.22
Viewfield Sour Gas Plant 13-05	Conventional Oil & Gas Extraction	151.36	109.85	5.05	5.05
Midale Complex	Conventional Oil & Gas Extraction	144.27	13.30	16.13	16.13
Nottingham Gas Plant 07-17-005-32-W1	Conventional Oil & Gas Extraction	107.21	14.51	12.06	12.06
Travers Gas Plant	Conventional Oil & Gas Extraction	37.54	112.03	0.13	0.13
	Totals	90,680.84	30,886.50	693.74	2,042.89

4 MONTANA VISIBILITY ANALYSIS

4.1 BACKGROUND

In the first planning period, the RHR instructed states to use the 20% haziest days in each year to track visibility progress. The WRAP used regional photochemical grid models to project visibility improvement between the 2002 base year and the 2018 future year and to set RPGs for the RHR state implementation plans. Despite the western states projecting large emission reductions from fossil fuel-fired EGUs, mobile sources and smoke management programs, the results of the 2018 visibility RPGs indicated many western Class I areas were projected to achieve less progress than uniform rate of progress, set by the glidepath to natural conditions.

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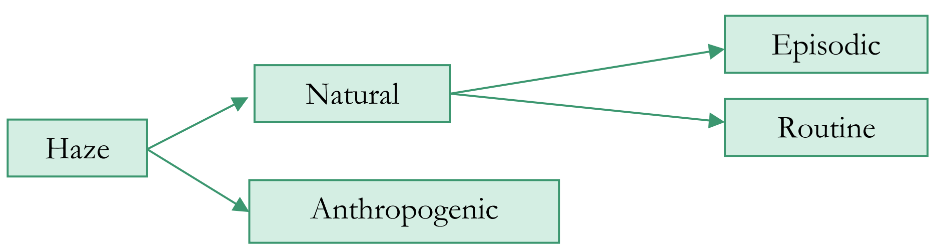
[70] Government of Canada. Environment and Climate Change Canada, Available at: http://maps-cartes.ec.gc.ca/indicators-indicateurs/detailPage.aspx?lang=en&type=air_emissions_tpm&objectid=0000002079 (accessed 5 Apr. 2019).

After more analysis, several western states cited the influences of wildfires and dust storms on the haziest days as important reasons that visibility RPGs projected less progress than the URP. The elevated organic carbon and coarse material that can be attributed to wildfires or dust storms often are the dominate components on the haziest days for many western states. Therefore, it was more difficult to demonstrate the visibility improvement attributable to reductions in anthropogenic emissions.

The 2017 RHR revised the approach to tracking visibility progress over time. Rather than focus on the days with the poorest visibility, which in many Class I areas in Montana were significantly affected by uncontrollable emissions from wildfires, the new approach sought to remove these extreme events to better assess poor visibility due to anthropogenic sources. The method requires the light extinction data on the most impaired days to be split into natural and anthropogenic contributions. The natural contribution is grouped into two types: episodic and routine. The episodic contribution is intended to capture extreme, uncontrollable events such as large wildfires. Natural routine contribution is defined as natural haze that occurs on all or most days in a year or season and that is more consistent from year to year. Natural routine contribution includes biogenic sources, sea salt, and incorporates the site-specific value for Rayleigh scattering. Figure 4-1 describes this breakdown:

Figure 4-1. Elements of the updated metric to track regional haze

$$dv_{total} = dv_{natural} + dv_{anthro}$$



The EPA method defined a threshold for the episodic portion of natural haze for the carbonaceous species (organic mass carbon (OMC), elemental carbon (EC)) and crustal material (fine soil plus coarse mass (CM)), components that are indicators of wildfires and dust storms, respectively. EPA recommended nominal cutoffs for each episodic species' combinations as the minimums of the yearly 95th percentile for the 15-year period from 2000-2014. That portion of the daily species extinction values greater than the 95th percentile threshold are assigned to the natural episodic bin. Smaller, routine natural contributions from biogenic or geogenic emissions are assumed to be a constant fraction of the measured IMPROVE species concentrations on each day, with the fraction calculated as the ratio of a previously estimated annual average natural concentration[71] (Natural Conditions II, NC-II) divided by the non-episodic annual average measured IMPROVE concentration for each species. The metric calculates the natural routine portion, such that its

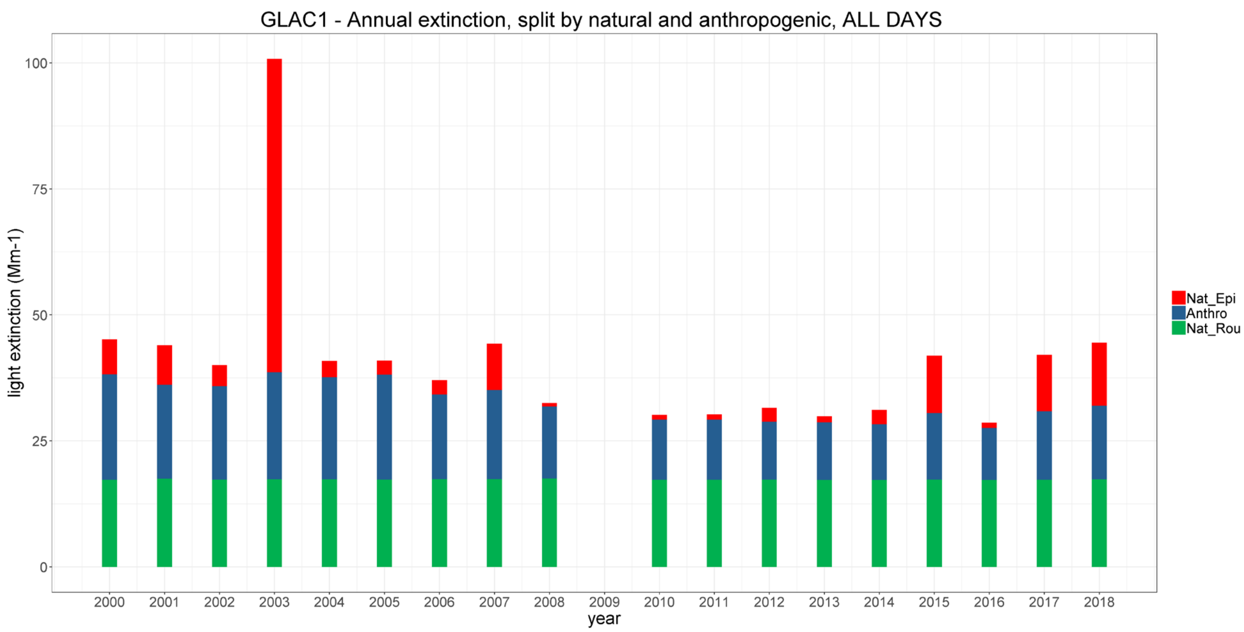
[71] IMPROVE. 2007. Natural Haze Levels II: Application of the New IMPROVE Algorithm to Natural Species Concentrations Estimates. Interagency Monitoring of Protected Visual Environments, Available at: http://vista.cira.colostate.edu/Improve/gray-literature/ (accessed August 2017)

annual average (excluding episodic events) equals the site and species-specific NC-II concentrations. The natural routine is calculated by:

$$nat_{rou} = \frac{daily.ext(woE3)}{ann.av(woE3)} \times NC_{II}$$

For example, the Natural Conditions II annual average estimate of nitrate for Glacier is $0.95 Mm^{-1}$, and the annual average measured nitrate at Glacier NP is $1.47 Mm^{-1}$, thus, the daily routine natural nitrate at Glacier NP is assumed to be 65% of the daily measured IMPROVE nitrate. The remainder of total haze not assigned to natural contributions is assumed to be anthropogenic in origin.[72] An example plot displaying how the annual extinction is split for the Glacier National Park monitor is shown below:

Figure 4-2. Glacier National Park



Daily anthropogenic impairment (in deciviews) can be calculated from light extinction:

$$dv_{anthropogenic} = 10 \times \ln\left(\frac{bext_{total}}{bext_{natural}}\right)$$

Daily anthropogenic impairment values are ranked from highest to lowest impairment to select the 20 percent most impaired days (MIDs) in each year. This approach differs from the previous round in which the 20 percent most impaired days were selected as simply the days with the highest total impairment (no anthropogenic-natural separation). In the revised approach, states are required to determine the baseline (2000-2004) visibility condition for the 20 percent most anthropogenically impaired days. Then, states must

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[72] WRAP, Monitoring Data & Glide Path Summary Document, 2018 Work Summary Document, (27 Feb. 2019),Available at: http://www.wrapair2.org/pdf/final%20MDGPS%20summary%20document%20Feb27-2019.pdf

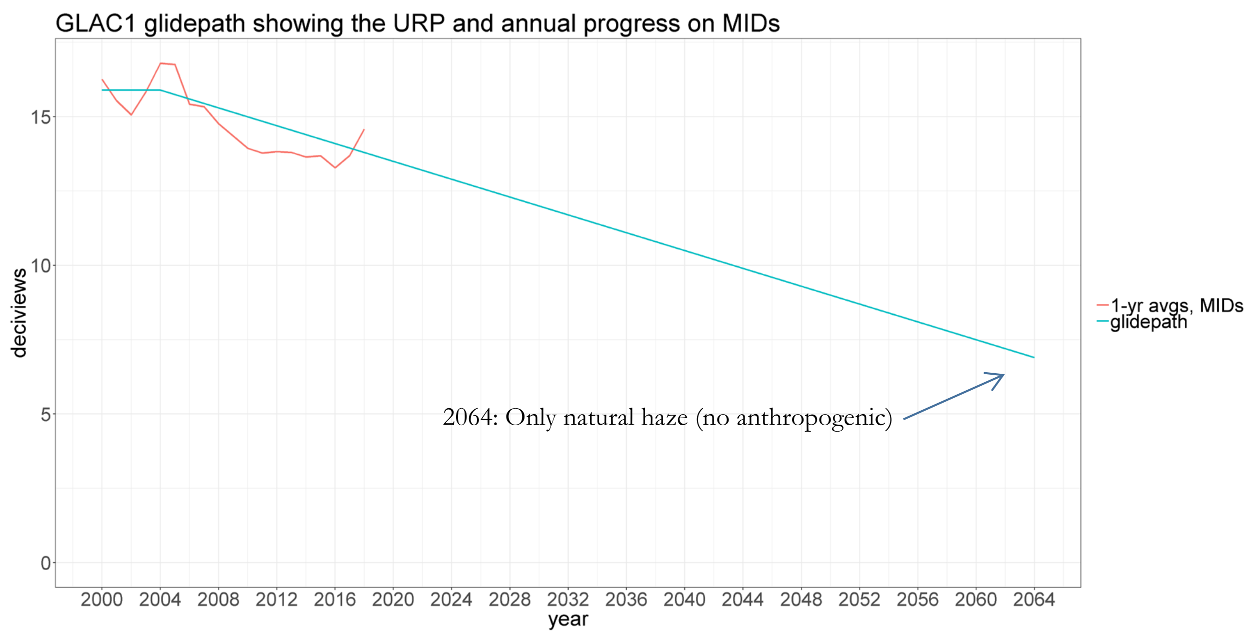
calculate the rate of improvement in visibility over time necessary to reach natural conditions by 2064 for the 20 percent most impaired days. Using the metric described above for separating natural (episodic and routine) and anthropogenic, natural conditions are calculated as the average of the daily natural contributions on the 20 percent most impaired days, in the period 2000-2014. The line drawn from the baseline to the endpoint is termed the glidepath, or the uniform rate of progress (URP), is calculated for each Class I Area, and serves as a tracking metric for the path to natural conditions. The URP is calculated according to the following formula:

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

The most impaired days are the 20 percent of days with the highest anthropogenic fraction of total haze. Tracking visibility progress on those days with highest impairment is intended to limit the influence of episodic wildfires and dust storms on the visibility trends.

An example of the URP for Glacier is below:

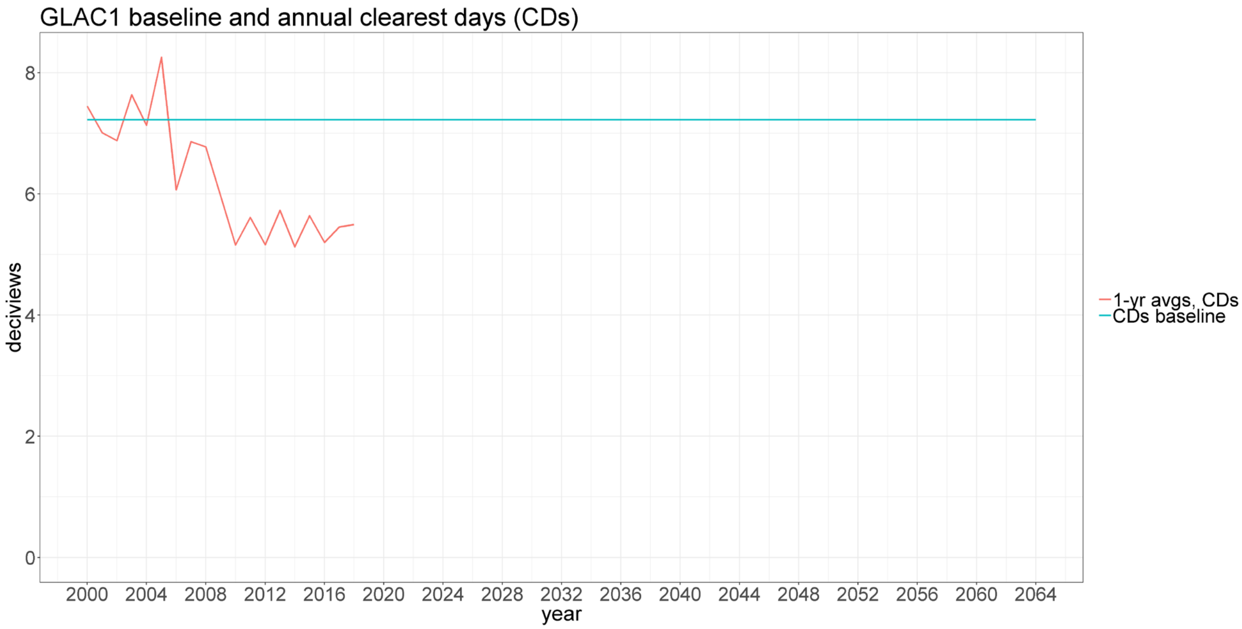
Figure 4-3. URP for Glacier National Park



No changes were made from the previous implementation period in how the 20% clearest days are calculated. The 20 percent clearest days are calculated from the days with the lowest total impairment. As stated previously, the RHR requires states to demonstrate that there is no degradation in the 20 percent clearest days from the baseline period.

An example plot tracking the clearest days' progress relative to the baseline is shown below:

Figure 4-4. Clearest days for Glacier National Park



4.2 Baseline, Current Conditions And Natural Visibility Conditions

As required in 40 CFR 51.308(f)(1)(i)-(iv), states must determine the baseline, current and natural visibility conditions for the 20 percent clearest and most impaired days. The baseline visibility period is the average of the annual deciview index values for the calendar years from 2000-2004, for both the 20 percent most impaired days and the 20 percent clearest days. Because the revised 2017 RH rule updated the meaning of the haziest days to be the most (anthropogenically) impaired days, the baseline average values were calculated differently for Montana Class I areas in this SIP submission.[73] Therefore, the baseline values may be different than in the Montana FIP due to the different metric used to calculate the most impaired days versus the haziest days. Current conditions are calculated for both the 20 percent most impaired days and the 20 percent clearest days as the average annual deciview index values for the most recent 5-year period with available data, which, for this submission, is 2014-2018. Natural visibility is calculated from considering only the natural contributions to the annual means on the 20 percent *most impaired days*, over the period 2000-2014. To ensure no degradation in visibility for the 20 percent clearest days, the clearest days' baseline averages serve as the visibility tracking metric (to stay below). To calculate natural visibility on clearest days, the NC-II values are extracted from the clearest days (Group=10), from data located on the CIRA website.[74] Those values are displayed in the following tables for the clearest days, however they do not serve as the tracking metric and are not displayed in any plots.

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[73] See values in Appendix A of EPA's Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program (20 Dec. 2018), Available at: https://www.epa.gov/sites/production/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf

[74] http://vista.cira.colostate.edu/IMPROVE/Data/NaturalConditions/nc2_12_2019_2p.csv

Table 4-1 and Table 4-2 provide reference information for the IMPROVE sites that track visibility conditions at Montana's Class I areas, the site location, Site ID and the Air Quality System (AQS) code of the site.

Table 4-1. Representative IMPROVE Monitoring Sites

Class I Area Name	Representative IMPROVE Site	Site ID
Anaconda-Pintler Wilderness Area	Sula Peak	SULA1
Bob Marshall Wilderness Area	Monture, MT	MONT1
Cabinet Mountains Wilderness Area	Cabinet Mountains	CABI1
Gates of the Mountains Wilderness Area	Gates of the Mountains	GAMO1
Glacier National Park	Glacier	GLAC1
Lostwood National Wildlife Refuge (ND)	Lostwood	LOST1
Medicine Lake Wilderness Area	Medicine Lake	MELA1
Mission Mountain Wilderness Area	Monture, MT	MONT1
North Absaroka Wilderness Area (WY)	North Absaroka	NOAB1
Red Rock Lakes National Wildlife Refuge	Yellowstone	YELL2
Scapegoat Wilderness Area	Monture, MT	MONT1
Selway-Bitterroot Wilderness Area	Sula Peak	SULA1
Theodore Roosevelt National Park (ND)	Theodore Roosevelt	THRO1
UL Bend Wilderness Area	U. L. Bend	ULBE1
Yellowstone National Park	Yellowstone	YELL2

Table 4-2. IMPROVE site information for Class I Areas

Site ID	Class I Area Name(s)	Latitude	Longitude	State	AQS Code
CABI1	Cabinet Mountains Wilderness Area	47.9549	-115.6709	MT	30-089-9000
GAMO1	Gates of the Mountains Wilderness Area	46.8262	-111.7107	MT	30-049-9000
GLAC1	Glacier National Park	48.5105	-113.9966	MT	30-029-9001
LOST1	Lostwood National Wildlife Refuge (ND)	48.6419	-102.4022	ND	38-013-0004
MELA1	Medicine Lake Wilderness Area	48.4871	-104.4757	MT	30-091-9000
MONT1	Bob Marshall Wilderness Area, Mission Mountain Wilderness Area, Scapegoat Wilderness Area	47.1222	-113.1544	MT	30-077-9000
NOAB1	North Absaroka Wilderness Area (WY)	44.7448	-109.3816	WY	56-029-9002

Site ID	Class I Area Name(s)	Latitude	Longitude	State	AQS Code
SULA1	Anaconda-Pintler Wilderness Area, Selway-Bitterroot Wilderness Area	45.8598	-114.0001	MT	30-081-9000
THRO1	Theodore Roosevelt National Park (ND)	46.8948	-103.3777	ND	38-007-0002
ULBE1	UL Bend Wilderness Area	47.5823	-108.7196	MT	30-027-9000
YELL2	Red Rock Lakes National Wildlife Refuge, Yellowstone National Park	44.5653	-110.4002	WY	56-039-9000

4.2.1 Baseline (2000-2004) visibility for the most impaired and clearest days (40 CFR 51.308(f)(1)(i))

The 5-year average baseline visibility for the clearest and most impaired visibility days for each Class I area was calculated using data from the IMPROVE monitoring sites. The calculations were made in accordance with 40 CFR 51.308(f)(1)(i) and EPA's Technical Support Document (TSD) Revised Recommendations for Visibility Progress Tracking Metrics for the Regional Haze Program.[75]

Table 4-3. Baseline Visibility for the 20% Most Impaired Days and 20% Clearest Days

Site ID	Class I Area Name(s)	Clearest Days (dv)	Most Impaired Days (dv)
CABI1	Cabinet Mountains Wilderness Area	3.62	10.73
GAMO1	Gates of the Mountains Wilderness Area	1.71	8.95
GLAC1	Glacier National Park	7.22	15.89
LOST1	Lostwood National Wildlife Refuge (ND)	8.19	18.27
MELA1	Medicine Lake Wilderness Area	7.27	16.62
MONT1	Bob Marshall Wilderness Area, Mission Mountain Wilderness Area, Scapegoat Wilderness Area	3.86	11.00
NOAB1	North Absaroka Wilderness Area (WY)	2.02	8.78
SULA1	Anaconda-Pintler Wilderness Area, Selway-Bitterroot Wilderness Area	2.57	10.06
THRO1	Theodore Roosevelt National Park (ND)	7.76	16.35
ULBE1	UL Bend Wilderness Area	4.75	12.76
YELL2	Red Rock Lakes National Wildlife Refuge, Yellowstone National Park	2.58	8.30

[75] EPA.gov, Technical Support Document (TSD) Revised Recommendations for Visibility Progress Tracking metrics for the Regional Haze Program, (July 2016), Available at: https://www.epa.gov/sites/production/files/2016-07/documents/technical_support_document_for_draft_guidance_on_regional_haze.pdf

4.2.2 Natural visibility for the most impaired and clearest days (40 CFR 51.308(f)(1)(ii))

The revised metric applied in this second round of planning was used to recalculate the 2064 endpoint for the most impaired days to match the updated tracking metric and revised base year values, which results in new estimates of natural visibility conditions and glidepaths for the most impaired days.

The natural visibility condition for each Class I area represents the visibility goal expressed in deciviews for the 20 percent most impaired days and the 20 percent clearest days that would exist if there were no anthropogenic impairments, calculated using the years 2000-2014 for each site. The 20 percent most impaired days' natural conditions (2000-2014) correspond to the visibility goals for each Class I area.

Natural visibility conditions for each Montana Class I area were calculated by estimating the average deciview index considering only natural contributions for the most impaired days and clearest days, based on IMPROVE monitoring data from 2000-2014 for each site and using EPA's recommended data analysis techniques; namely the same approach outlined in Figure 4-1, with results listed below in Table 4-4.

Table 4-4. Natural visibility values for Montana Class I areas

Site ID	Class I Area Name(s)	Clearest Days (dv)	Most Impaired Days (dv)
CABI1	Cabinet Mountains Wilderness Area	1.48	5.64
GAMO1	Gates of the Mountains Wilderness Area	0.32	4.53
GLAC1	Glacier National Park	2.43	6.90
LOST1	Lostwood National Wildlife Refuge (ND)	2.92	5.87
MELA1	Medicine Lake Wilderness Area	2.96	5.95
MONT1	Bob Marshall Wilderness Area, Mission Mountain Wilderness Area, Scapegoat Wilderness Area	1.48	5.53
NOAB1	North Absaroka Wilderness Area (WY)	0.59	4.55
SULA1	Anaconda-Pintler Wilderness Area, Selway-Bitterroot Wilderness Area	1.12	5.45
THRO1	Theodore Roosevelt National Park (ND)	3.04	5.94
ULBE1	UL Bend Wilderness Area	2.46	5.87
YELL2	Red Rock Lakes National Wildlife Refuge, Yellowstone National Park	0.43	3.97

4.2.3 Current (2014-2018) visibility for the most impaired and clearest days (40 CFR 51.308(f)(1)(iii))

The 2017 RHR specifies that current visibility be calculated using the average of the annual deciview values for the years in the most recent 5-year period, ending with the most recently available data. Montana calculated the current visibility on the 20 percent clearest days and the 20 percent most impaired days for each Class I area for the period from 2014-2018:

Table 4-5. Current visibility (2014-2018) conditions at Montana Class I areas

Site ID	Class I Area Name(s)	Clearest Days (dv)	Most Impaired Days (dv)
CABI1	Cabinet Mountains Wilderness Area	2.46	9.87
GAMO1	Gates of the Mountains Wilderness Area	0.66	7.47
GLAC1	Glacier National Park	5.38	13.77
LOST1	Lostwood National Wildlife Refuge (ND)	7.45	16.18
MELA1	Medicine Lake Wilderness Area	6.19	15.30
MONT1	Bob Marshall Wilderness Area, Mission Mountain Wilderness Area, Scapegoat Wilderness Area	2.56	10.06
NOAB1	North Absaroka Wilderness Area (WY)	0.75	7.17
SULA1	Anaconda-Pintler Wilderness Area, Selway-Bitterroot Wilderness Area	1.60	8.37
THRO1	Theodore Roosevelt National Park (ND)	5.85	14.06
ULBE1	UL Bend Wilderness Area	3.71	10.93
YELL2	Red Rock Lakes National Wildlife Refuge, Yellowstone National Park	1.43	7.52

4.2.4 Progress to date for the most impaired and clearest days (40 CFR 51.308(f)(1)(iv))

Montana calculated actual progress toward the goal of natural visibility conditions since the baseline period for each Class I area. This progress can be seen by the difference between the average visibility condition in the 5-year baseline, previous implementation period and each subsequent 5-year period up to and including the current period:

Table 4-6. Progress to date for the most impaired and clearest days

Site ID	2000-2004 Baseline (dv)		2008-2012 Previous implementation period (dv)		2014-2018 Current (dv)	
	20% Clearest	20% Most Impaired	20% Clearest	20% Most Impaired	20% Clearest	20% Most Impaired
CABI1	3.62	10.73	2.58	10.23	2.46	9.87
GAMO1	1.71	8.95	0.75	7.74	0.66	7.47
GLAC1	7.22	15.89	5.68	14.07	5.38	13.77
LOST1	8.19	18.27	8.03	18.59	7.45	16.18
MELA1	7.27	16.62	6.42	16.60	6.19	15.30
MONT1	3.86	11.00	2.79	10.24	2.56	10.06
NOAB1	2.02	8.78	1.37	7.75	0.75	7.17
SULA1	2.57	10.06	1.95	8.86	1.60	8.37
THRO1	7.76	16.35	6.39	15.99	5.85	14.06
ULBE1	4.75	12.76	4.14	12.16	3.71	10.93
YELL2	2.58	8.30	1.51	7.49	1.43	7.52

4.2.5 Differences between current and natural for the most impaired and clearest days (40 CFR 51.308(f)(1)(v))

Table 4-7 below compares the current deciview values to the estimated natural visibility for the most impaired days and the clearest days.

Table 4-7. Current visibility compared to natural visibility

Site ID	2014-2018 Current (dv)		Natural Visibility (dv)		Difference (dv)	
	20% Clearest	20% Most Impaired	20% Clearest	20% Most Impaired	20% Clearest	20% Most Impaired
CABI1	2.46	9.87	1.48	5.64	0.98	4.23
GAMO1	0.66	7.47	0.32	4.53	0.34	2.94
GLAC1	5.38	13.77	2.43	6.90	2.95	6.87
LOST1	7.45	16.18	2.92	5.87	4.53	10.31
MELA1	6.19	15.30	2.96	5.95	3.23	9.35
MONT1	2.56	10.06	1.48	5.53	1.08	4.53
NOAB1	0.75	7.17	0.59	4.55	0.16	2.62
SULA1	1.60	8.37	1.12	5.45	0.48	2.92
THRO1	5.85	14.06	3.04	5.94	2.81	8.12
ULBE1	3.71	10.93	2.46	5.87	1.25	5.06
YELL2	1.43	7.52	0.43	3.97	1.00	3.55

Figure 4-11 graphs this data to show at what sites the current visibility conditions exceed the natural visibility condition, for the clearest and most impaired days.

4.3 Uniform Rate of Progress (40 CFR 51.308(f)(1)(vi))

Montana calculated the URP needed to reach natural visibility conditions by the year 2064 for the Class I areas. The analysis compared the baseline visibility conditions in each Class I area to the natural visibility conditions in each Class I area and determined the URP needed to reach natural conditions by 2064. The analysis constructed the URP consistent with the requirements of the RHR and consistent with the EPA's guidance on tracking visibility. Of note, however, is the provision added in the 2017 RHR that allows EPA to approve adjustments to the URP to reflect the impacts of international sources and wildland prescribed fire.[76] Section 4.3.1 describes this further, and explains Montana's proposed adjustments.

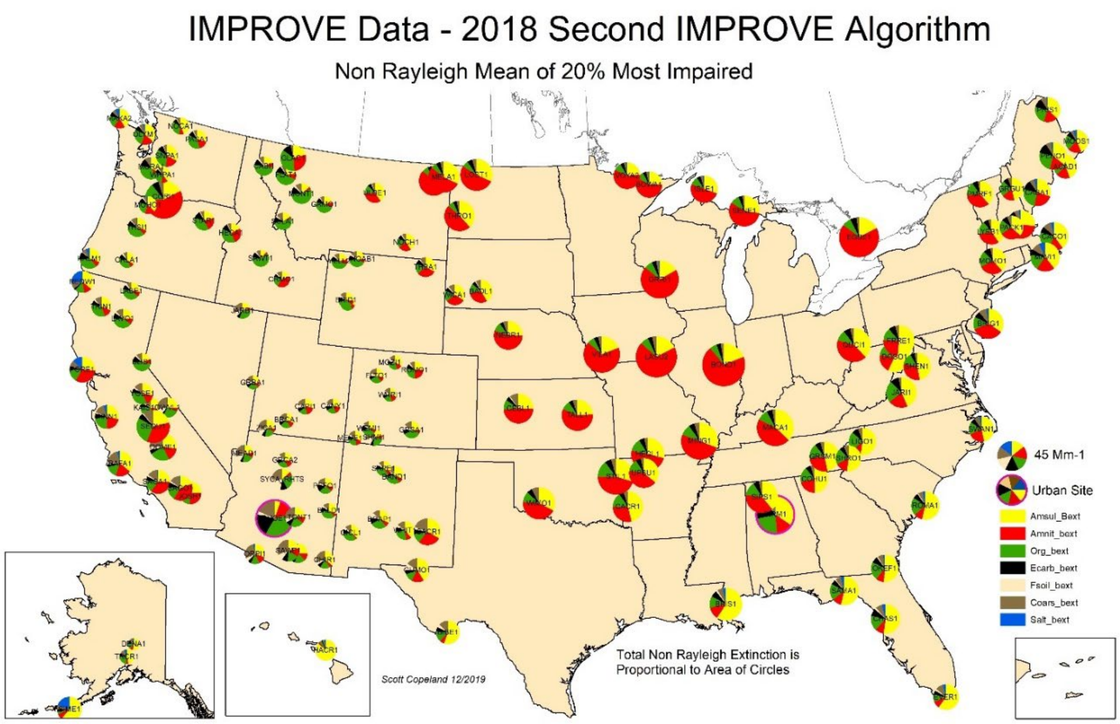
4.3.1 Adjustments to the uniform rate of progress to account for international impacts and/or prescribed fire (40 CFR 51.308(f)(1)(vi)(B)(1) and (2))

As noted in the Montana Progress Report for the first planning period and in Chapter 3 of this document, emissions from Canada have the potential to impact Class I areas in the state, as do low-level fire and smoke impacts.

[76] 40 CFR 51.308(f)(1)(vi)(B)

In fact, many sites, as shown in Figure 4-5, show considerable contributions from elemental and organic carbon on the most impaired days, especially at the western Montana sites. This is likely indicative of wildfire and prescribed fire impacts present at these sites, as described further in this section. The eastern Montana and western North Dakota sites show a different species contribution profile, both in magnitude of light extinction and the dominance of sulfates and nitrates. Some of these contributions can be attributable to Canadian sources.

Figure 4-5. Data Summary Plot for the 20% MID



On September 19, 2019, EPA released a Technical Support Document (TSD) that detailed updated 2028 regional haze modeling data and results, including domestic and international source contributions to Class I areas.[77] EPA used source apportionment modeling results to quantify the international and prescribed fire contributions on the 20% most anthropogenically impaired days. The contributions from the international and prescribed fire sectors were calculated using projected (2028) ambient IMPROVE data and relative model results (percent contribution of each sector to the total modeled impairment in 2028, by species). The results of the analyses are below:

[77] EPA. Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling, (19 Sept. 2019), Available at: https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling

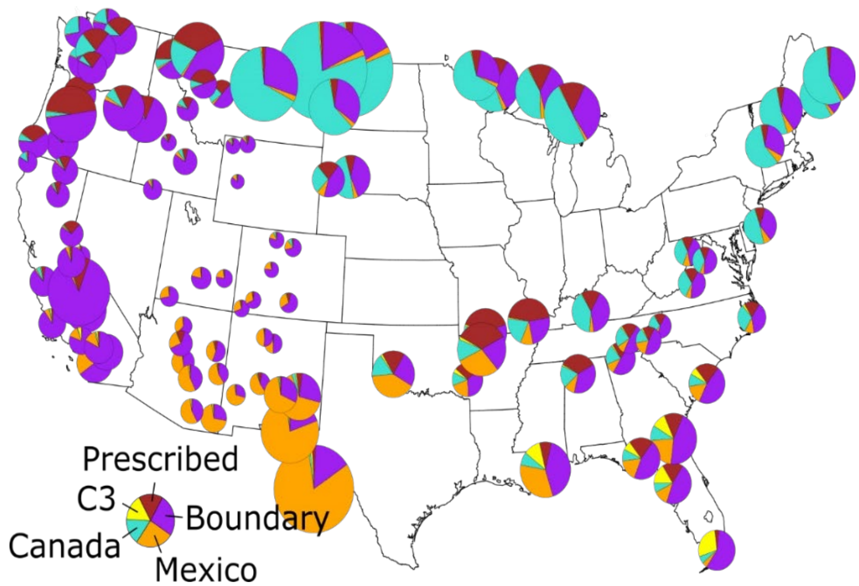
Table 4-8. Relative modeled 2028 contributions to visibility impairment on the 20% MID for international anthropogenic and prescribed fire components[78]

Class I Area Name	IMPROVE Site ID	Canada Anthro. (Mm-1)	Mexico Anthro. (Mm-1)	Boundary Inter. Anthro. (Mm-1)	Total Inter. Anthro. (Mm-1)	Prescribed Fire (Mm-1)
Cabinet Mountains Wilderness	CABI1	0.57	0.13	3.32	4.02	3.96
Gates of the Mountains Wilderness	GAMO1	1.27	0.16	2.78	4.22	1.41
Glacier NP	GLAC1	2.50	0.14	4.89	7.56	4.23
Lostwood National Wildlife Refuge	LOST1	14.97	0.42	3.02	18.43	0.61
Medicine Lake	MELA1	15.49	0.40	3.43	19.33	0.35
Bob Marshall Wilderness, Mission Mountain Wilderness Area, Scapegoat Wilderness	MONT1	0.51	0.07	2.89	3.47	2.32
North Absaroka Wilderness	NOAB1	0.11	0.18	2.92	3.21	0.25
Anaconda-Pintler Wilderness Area, Selway-Bitterroot Wilderness Area	SULA1	0.46	0.11	3.44	4.02	0.80
Theodore Roosevelt NP	THRO1	6.63	0.29	3.69	10.61	0.59
UL Bend	ULBE1	9.77	0.37	4.38	14.52	0.34
Yellowstone NP, Red Rock Lakes	YELL2	0.15	0.16	2.71	3.02	0.17

[78] Ibid..

Figure 4-6 shows the makeup and relative magnitude of the international anthropogenic and prescribed fire components from Table 4-8. The pies are scaled based on the magnitude of the total contribution of the components.

Figure 4-6. International anthropogenic and prescribed fire components – contribution to impairment on the 20% MID[78]



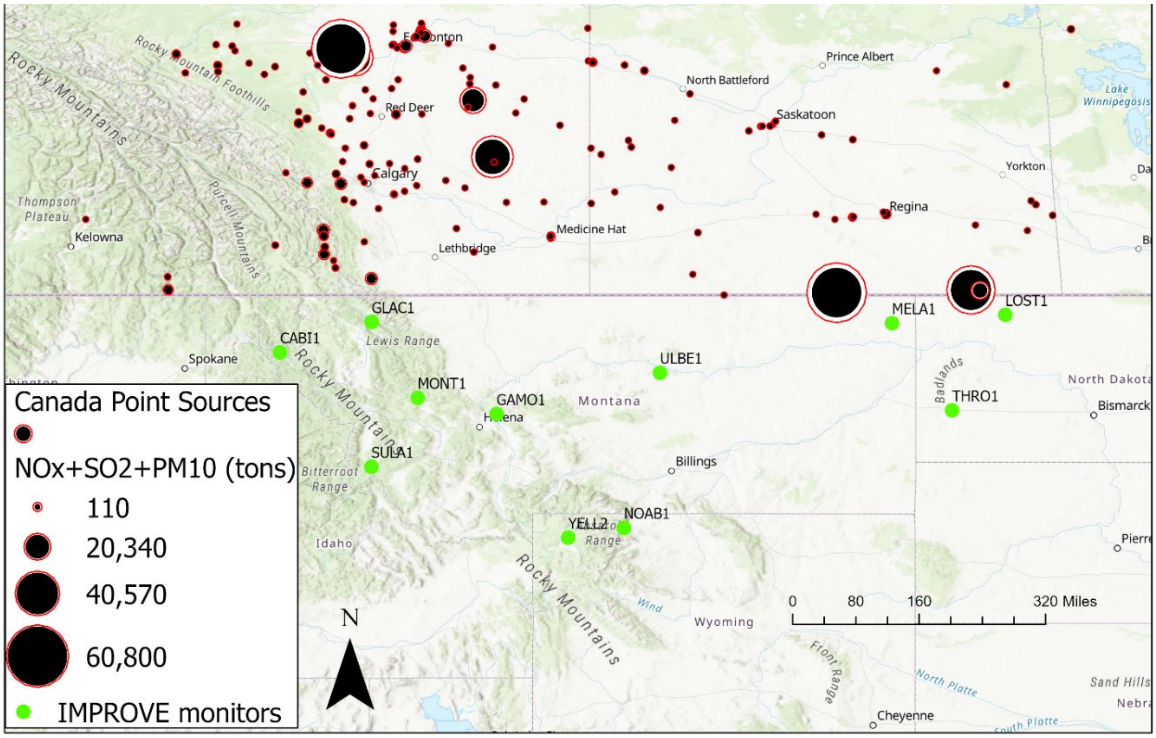
Based on the EPA modeling, the impact of international and prescribed fire emissions is significant in Montana Class I areas. WRAP modeling and regional analyses also contain estimates of international and prescribed fire impacts, as discussed in Section 2.2.6. Because Montana is a WRAP member state, Montana used the WRAP modeling results to form the technical basis of this RH SIP update, including using the WRAP estimates of international impacts and prescribed fire to evaluate the URP adjustment at Montana Class I areas.

There are some key points that make the URP adjustment to account for international and prescribed fire emissions important in Montana. As pointed out in Montana's 2017 progress report, the Medicine Lake Class I area (Medicine Lake) was the only site where sulfates and nitrates, those pollutants typically associated with anthropogenic emissions, contributed more than 50% to light extinction on the worst days. Medicine Lake is just 40 miles south of the Canadian border and 20 miles west of North Dakota. The area surrounding Medicine Lake is rural, with much of the oil and gas activity occurring to the east, in the Williston Basin of North Dakota. Based on the analyses of weather patterns, wind roses and emissions data, Montana's 2017 progress report concluded that the emissions from Canadian sources are likely the primary contributors to light extinction at Medicine Lake.[15] Section 3.1.5 of this document describes the large emission sources in Canada and their 2019 emission levels.

As evidenced by EPA's modeling presented above, Canadian emissions show a considerable impact at several Class I areas. To model these international emissions, WRAP's RepBase2 modeling run relied on

EPA's 2016v1 Canada and Mexico emissions in the other point category.[79] These emissions were downloaded from EPA's FTP site[80] and mapped in Figure 4-7 below. Only points with greater than 100 tons of any pollutants including NO_x, SO_2, PM_{10}, or $PM_{2.5}$ were included in the mapped vicinity. Notably, the Poplar River Power Station and the Boundary Dam Power Station, just north of the border, contribute to haze.

Figure 4-7. Modeled Canada Point Sources and IMPROVE monitors.



As many of the eastern sites show a notable international contribution, prescribed fire impacts start to take a noticeable slice of the overall extinction profile towards the west, closer to the vicinity of forested terrain where this activity is more likely to occur.

WRAP's 2028 high-level source apportionment model results are presented in Table 4-9 and illustrate how the major source categories contribute to each Class I area. Table 4-9 shows, in Mm-1, the modeled contributions from international anthropogenic, US prescribed fire, US wildfire, natural and non-US fire, and US anthropogenic sources at monitoring locations. Figure 4-8 shows the relative contributions of

[79]National Emissions Collaborative, Emissions Modeling Platform Collaborative: 2016v1 Canada and Mexico Point Sources, (15 Oct. 2019), Available at: http://views.cira.colostate.edu/wiki/Attachments/Inventory%20Collaborative/Documentation/2016v1/National-Emissions-Collaborative_2016v1_canada-mexico-point_15Oct2019.pdf

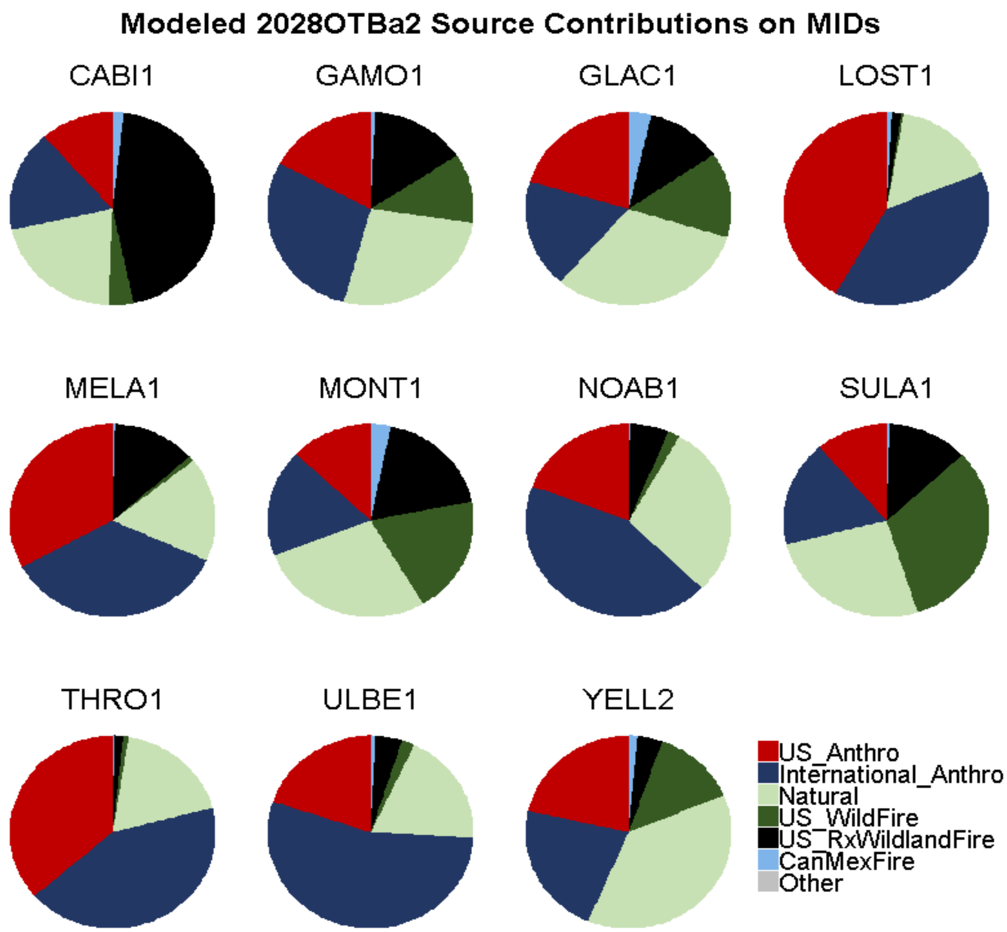
[80] EPA Air Emissions Inventories FTP site, Available at: ftp://newftp.epa.gov/Air/emismod/2016/v1/2016emissions/ (accessed 4/12/2020).

international emissions (in blue) at the monitoring sites, compared to the total US anthropogenic emissions (in red).

Table 4-9. High level source categories from WRAP's 2028OTBa2 modeling results on MIDs (contributions in Mm-1).

SiteCode	US Anthro	International Anthro	Natural	US WildFire	US RxWildlandFire	CanMexFire
CABI1	3.24	4.78	5.88	1.1	12.66	0.49
GAMO1	2.09	3.5	3.28	1.42	1.83	0.09
GLAC1	4.03	3.58	6.25	2.82	2.36	0.7
LOST1	10.22	9.64	3.94	0.09	0.36	0.2
MELA1	6.59	7.06	3.47	0.17	2.61	0.08
MONT1	2.16	3.01	4.6	3.28	3.12	0.53
NOAB1	1.35	3.05	2.05	0.13	0.43	0.02
SULA1	1.95	3.08	4.49	5.54	2.19	0.09
THRO1	5.58	6.53	2.82	0.13	0.2	0.05
ULBE1	2.52	6.9	2.42	0.26	0.53	0.1
YELL2	2.25	2.31	3.95	1.41	0.4	0.15

Figure 4-8. 2028OTBa2 Relative Contributions for 11 Class I areas



Furthermore, Figure 4-9 and Figure 4-10 show the relative source contributions on the MID for Sulfate and Nitrate and carbonaceous PM species (Figure 4-9). These pie charts indicate that international anthropogenic emissions of SO_2 and NO_x and fine particulate emissions from prescribed fire and wildfire, contribute to haze on the MID.

Figure 4-9. Modeled SO_2 & NOx Relative Contributions

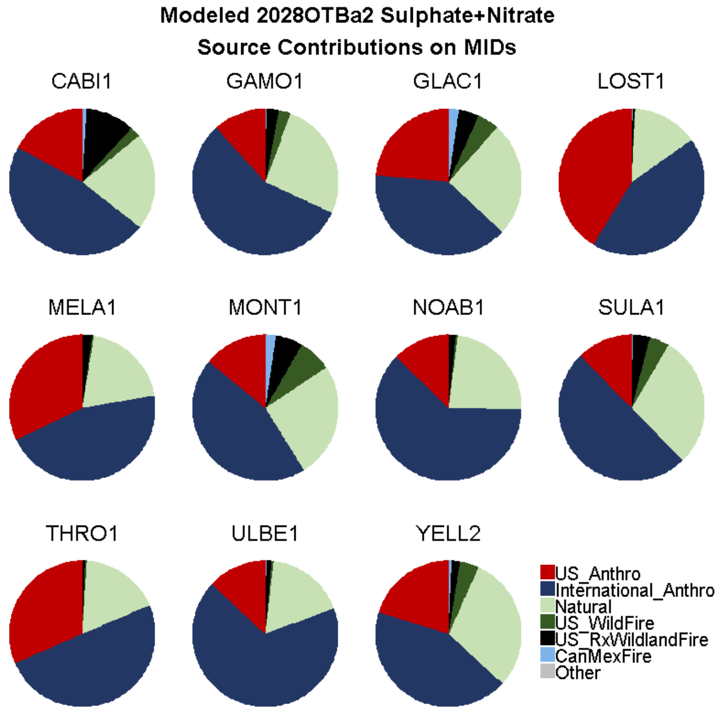


Figure 4-10. Modeled Carbon Relative Contributions

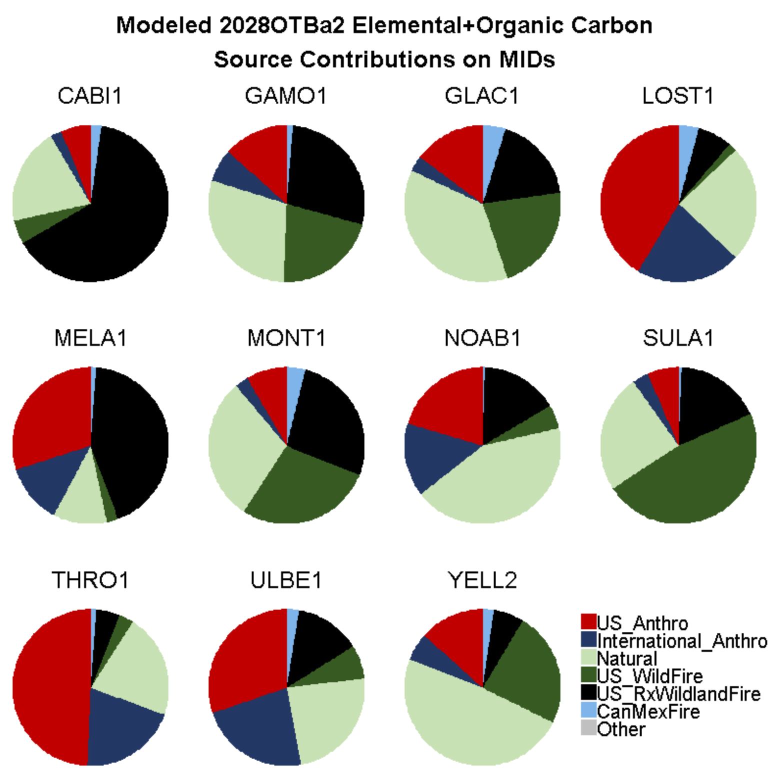


Table 4-10 shows the rate of progress for each IMPROVE Site ID, and includes the unadjusted URP as well as the adjusted URP.

Table 4-10. Uniform Rates of Progress

Site ID	URP (dv/year)	Adjusted URP (dv/year)
CABI1	0.08	0.02
GAMO1	0.07	0.03
GLAC1	0.15	0.09
LOST1	0.21	0.09
MELA1	0.18	0.07
MONT1	0.09	0.04
NOAB1	0.07	0.03
SULA1	0.08	0.04
THRO1	0.17	0.08
ULBE1	0.11	0.03
YELL2	0.07	0.04

Using the calculated URPs for each site, Figure 4-11 graphs the differences between the monitored current visibility on most impaired days and three points along the glidepath, at years 2018, 2028, and 2064. The plot is intended to show the deciview visibility improvements needed to follow the glidepath to natural visibility on most impaired days. As annotated in the figure, a negative "visibility improvement needed" indicates that the current visibility is already below the glidepath for that year. More details for each site can be found in subsequent figures in this section.

Figure 4-11. Comparison between current and natural visibility

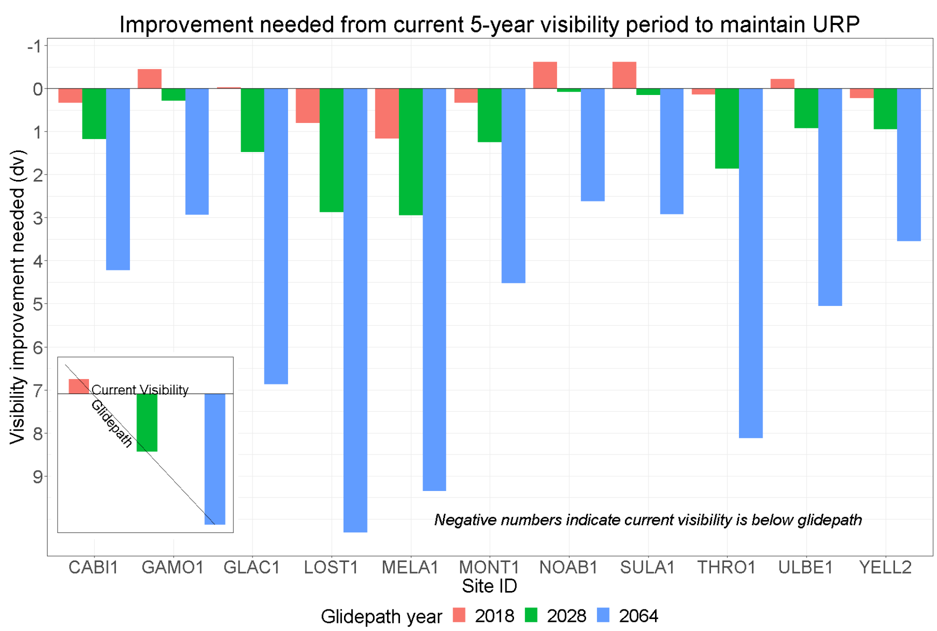


Figure 4-12. Visibility Improvement Needed to Maintain URP (Adjusted)

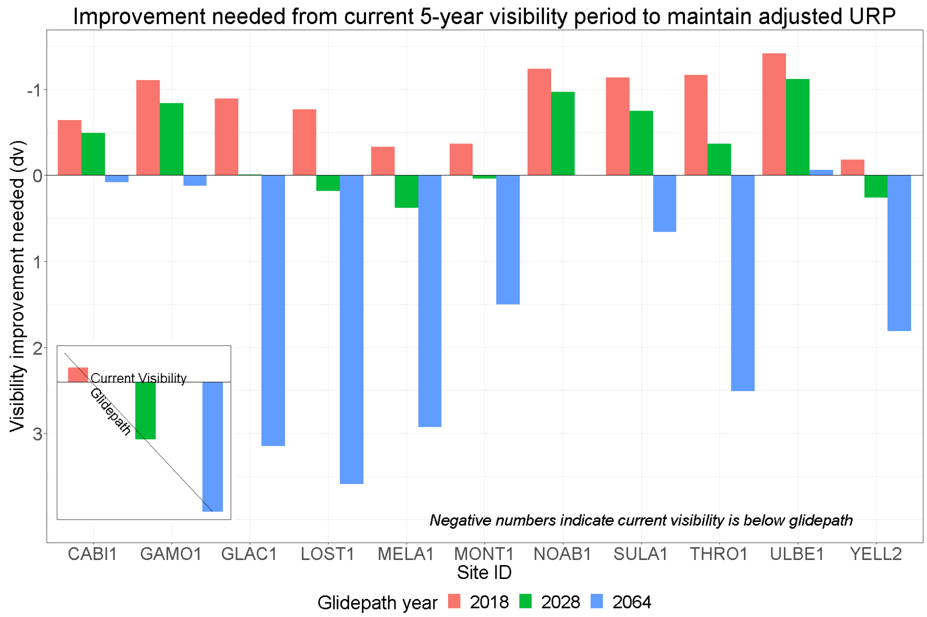


Figure 4-13 through Figure 4-23 graph the monitored 5-year visibility periods on the most impaired and clearest days, relative to the tracking metric (namely the most impaired days glidepath to natural conditions and the clearest days baseline visibility). The adjusted (solid line) and unadjusted (dotted line) glidepaths are also shown.

Figure 4-13. CABI1 IMPROVE site URP – Cabinet Mountains W.A.

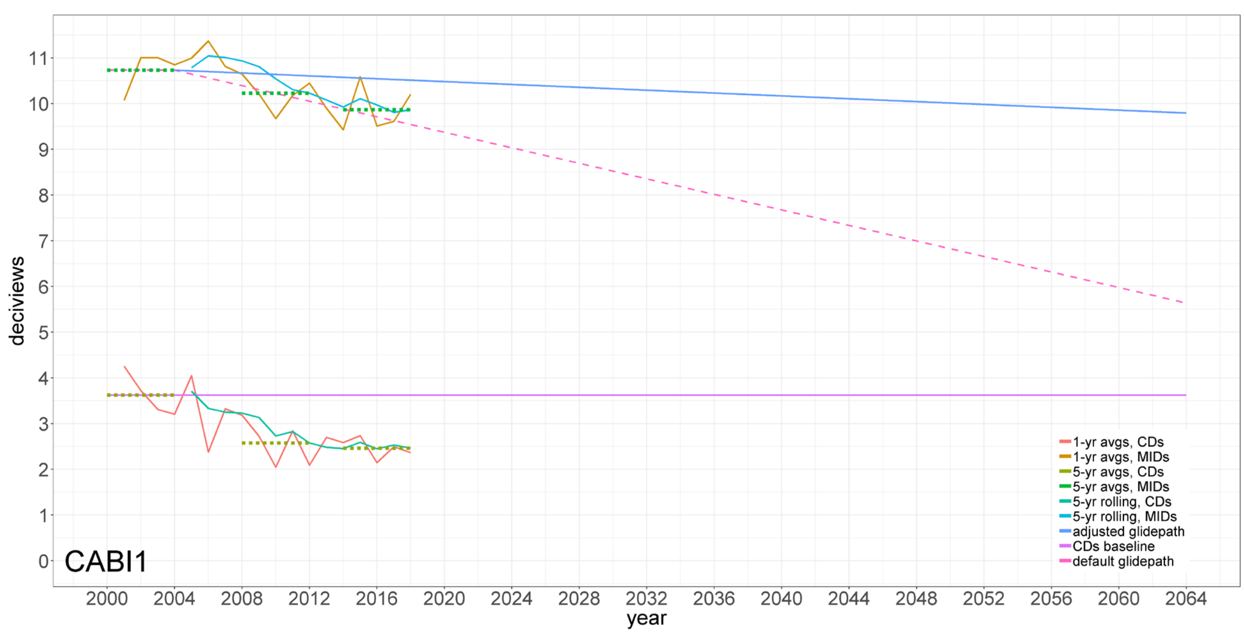


Figure 4-14. GAMO1 IMPROVE site URP - Gates of the Mountains W.A.

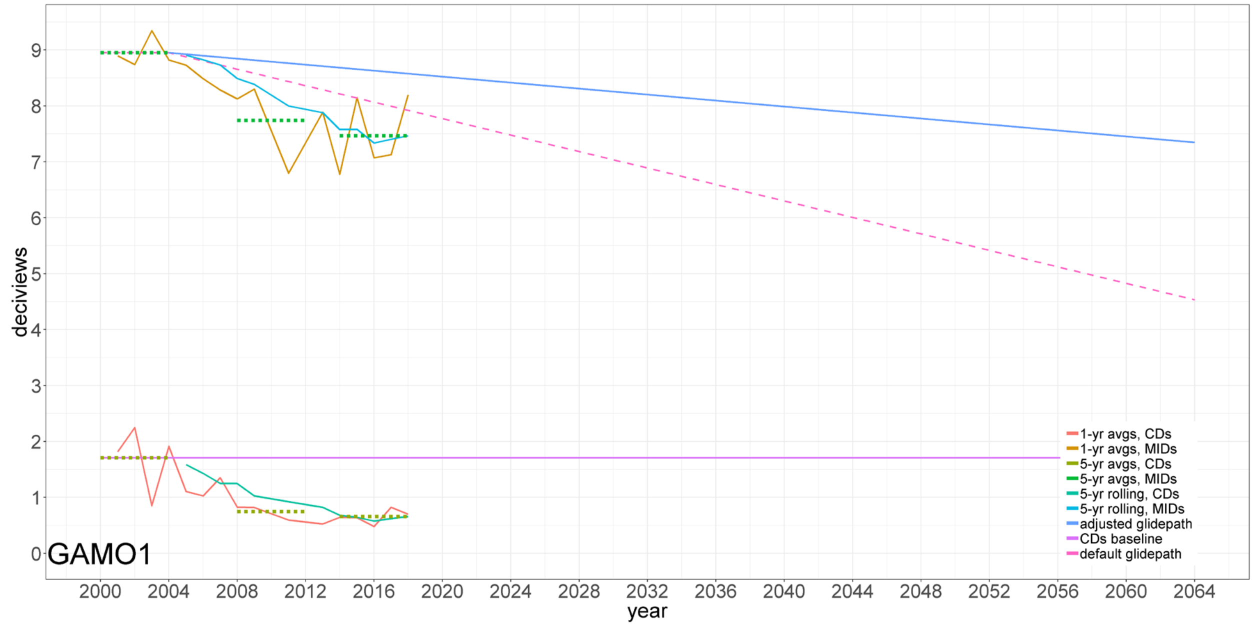


Figure 4-15. GLAC1 IMPROVE Site URP - Glacier NP

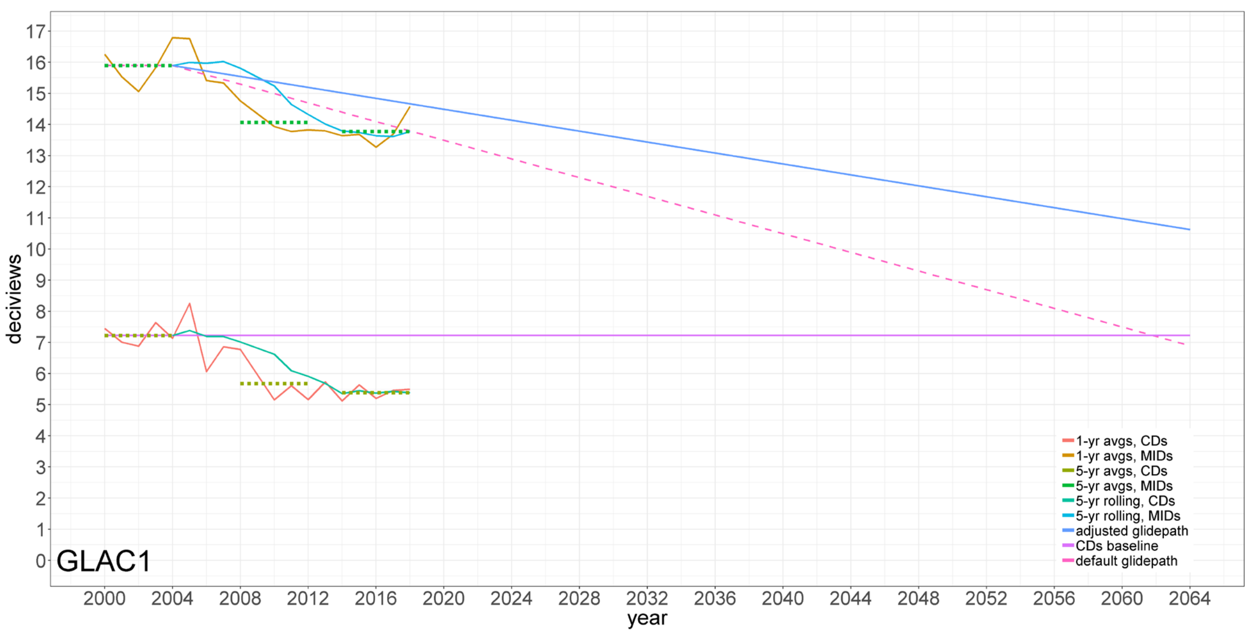


Figure 4-16. LOST1 IMPROVE Site URP - Lostwood NWR

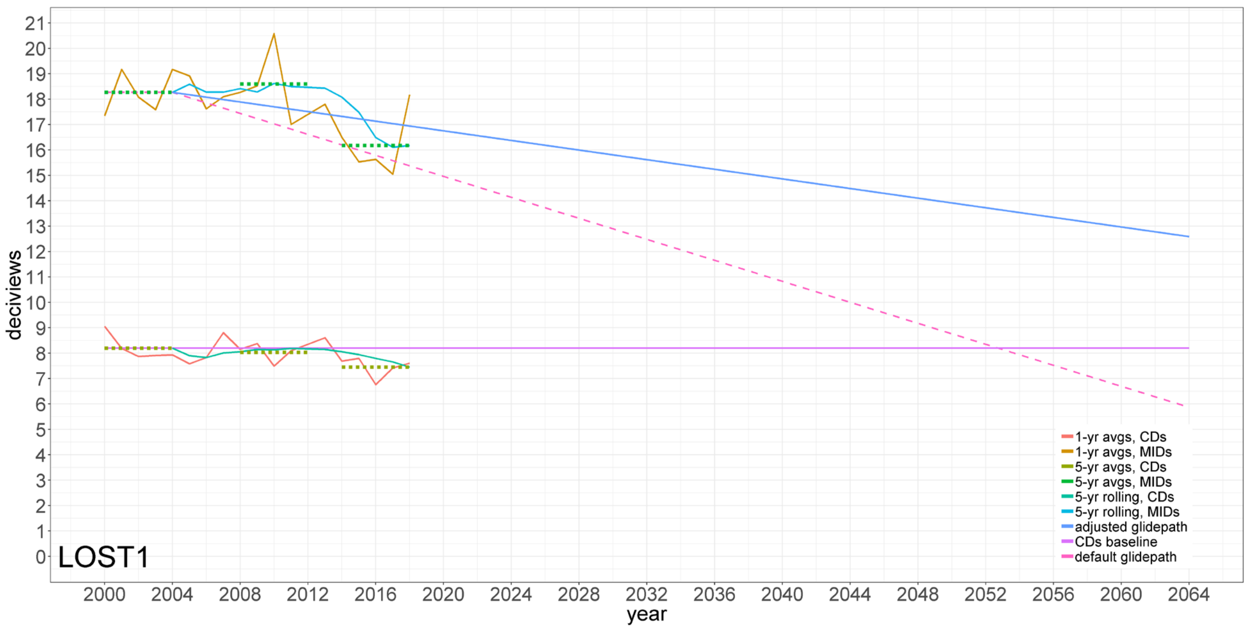


Figure 4-17. MELA1 IMPROVE Site URP - Medicine Lake W.A.

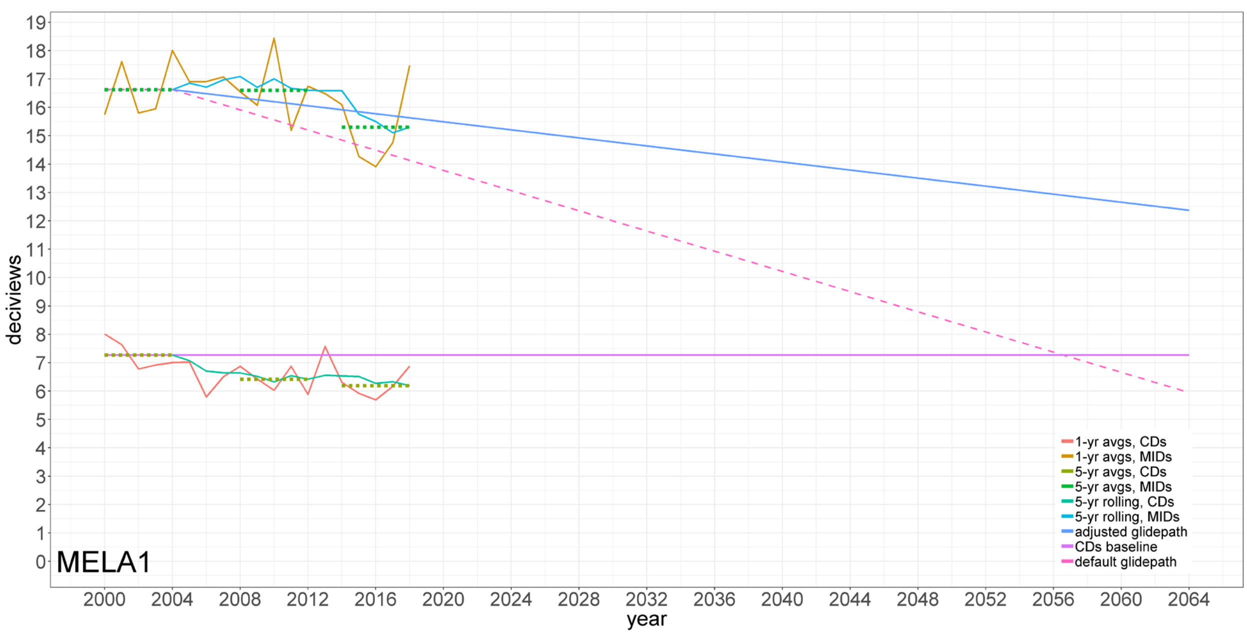


Figure 4-18. MONT1 IMPROVE Site URP - Bob Marshall W.A., Mission Mtn W.A. & Scapegoat W.A.

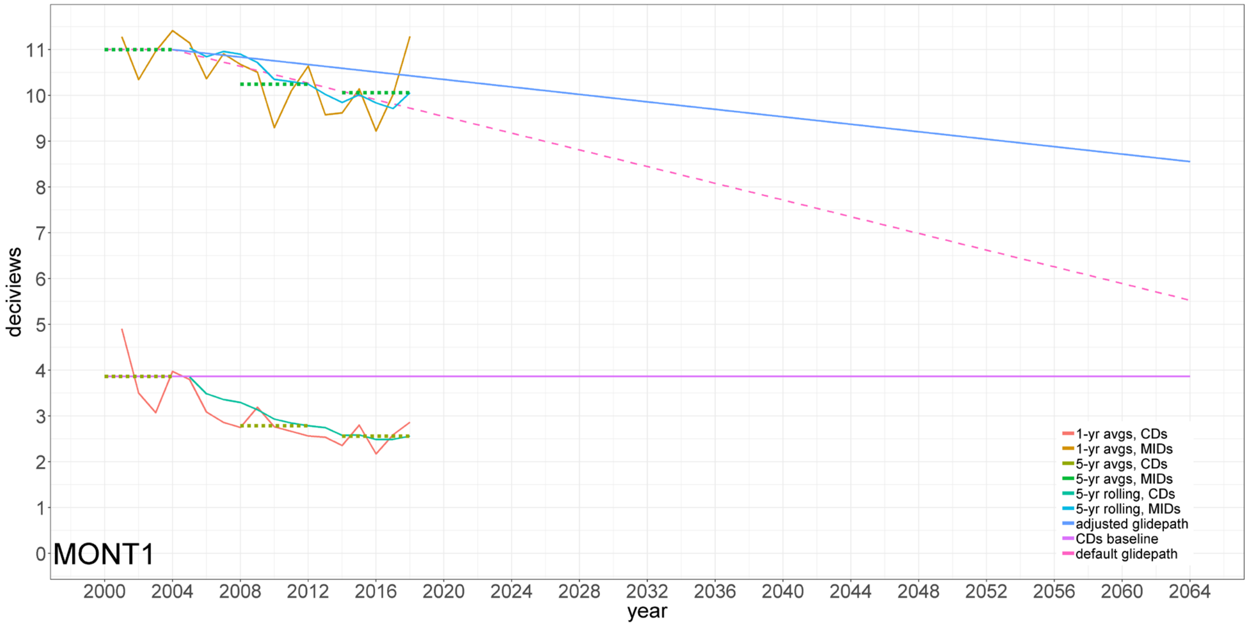


Figure 4-19. NOAB1 IMPROVE Site URP - North Absaroka W.A.

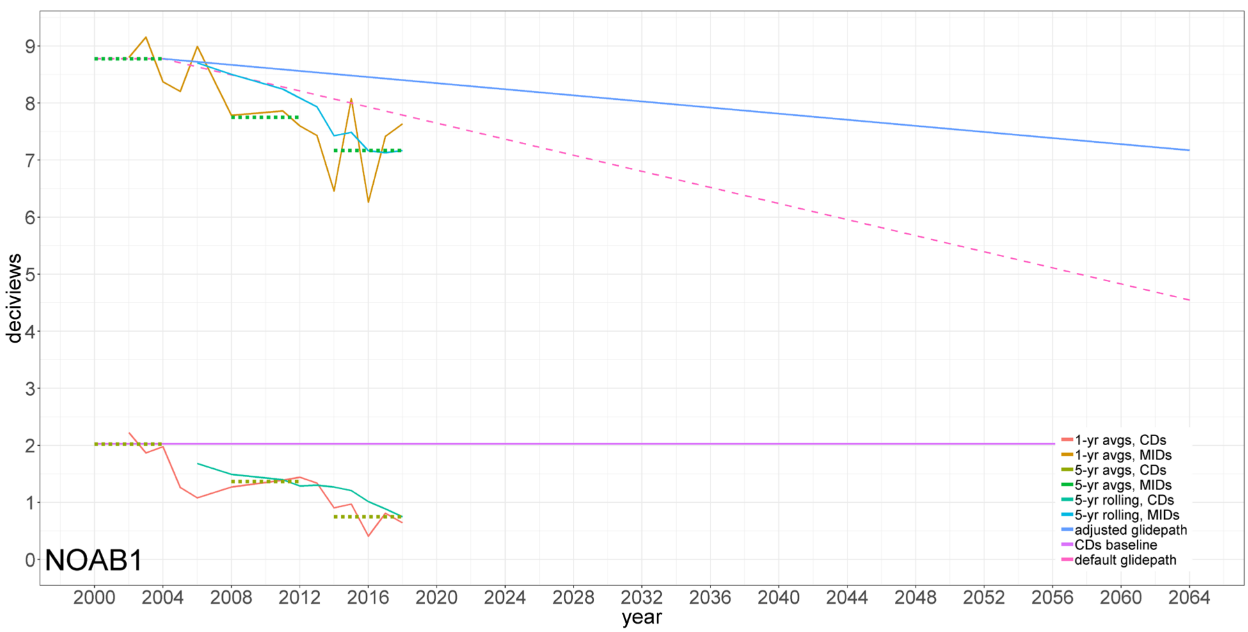


Figure 4-20. SULA1 IMPROVE site URP – Anaconda-Pintler W.A. & Selway Bitterroot W.A.

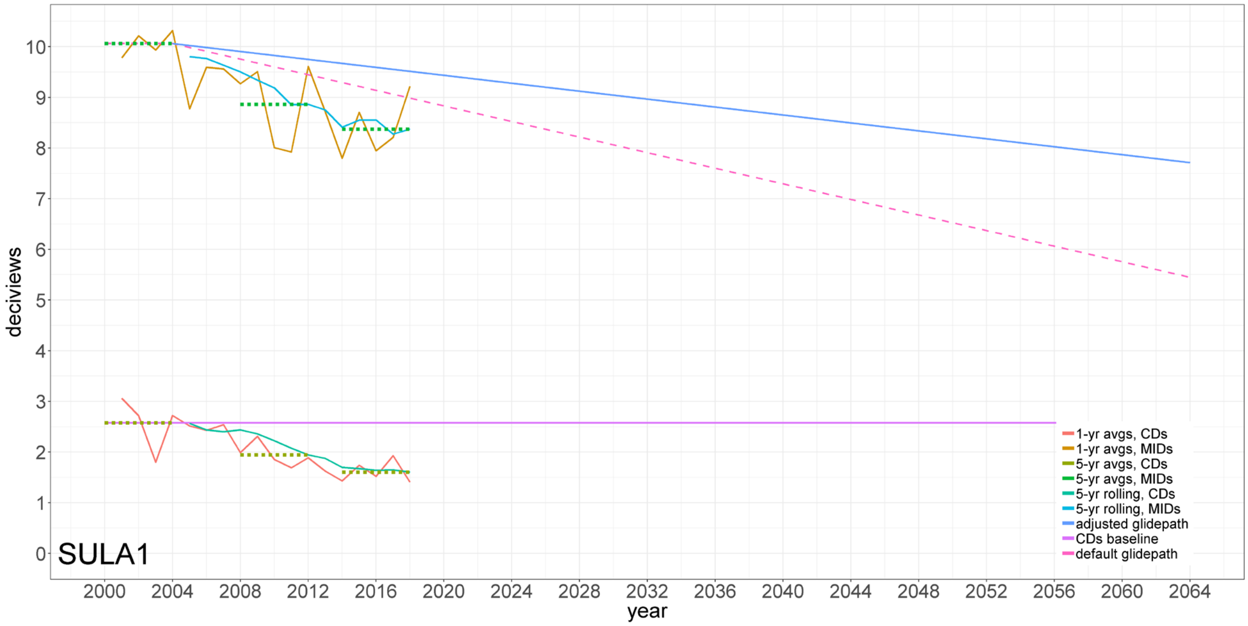


Figure 4-21. THRO1 IMPROVE site URP - Theodore Roosevelt NP

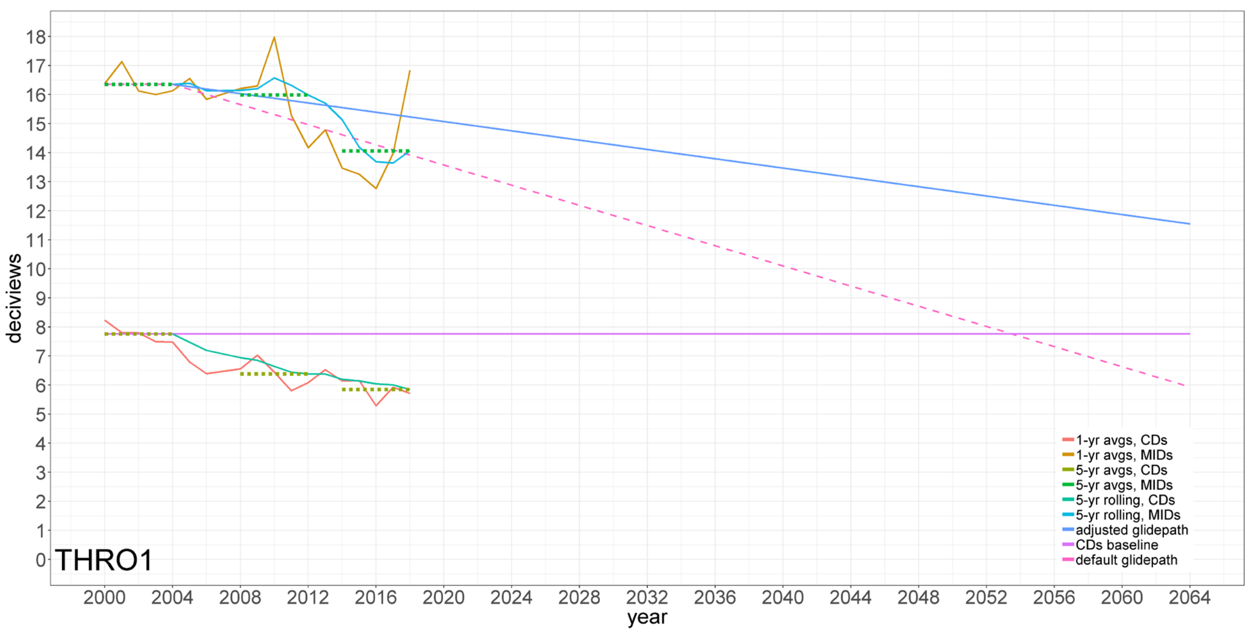


Figure 4-22. ULBE1 IMPROVE site URP - UL Bend W.A.

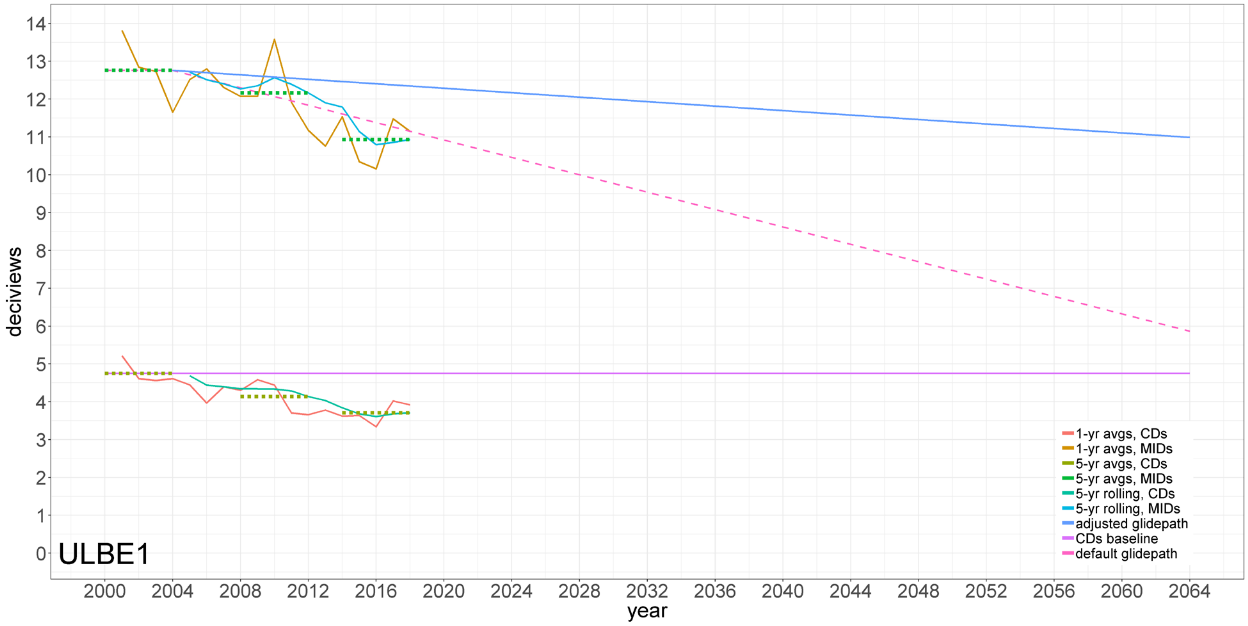
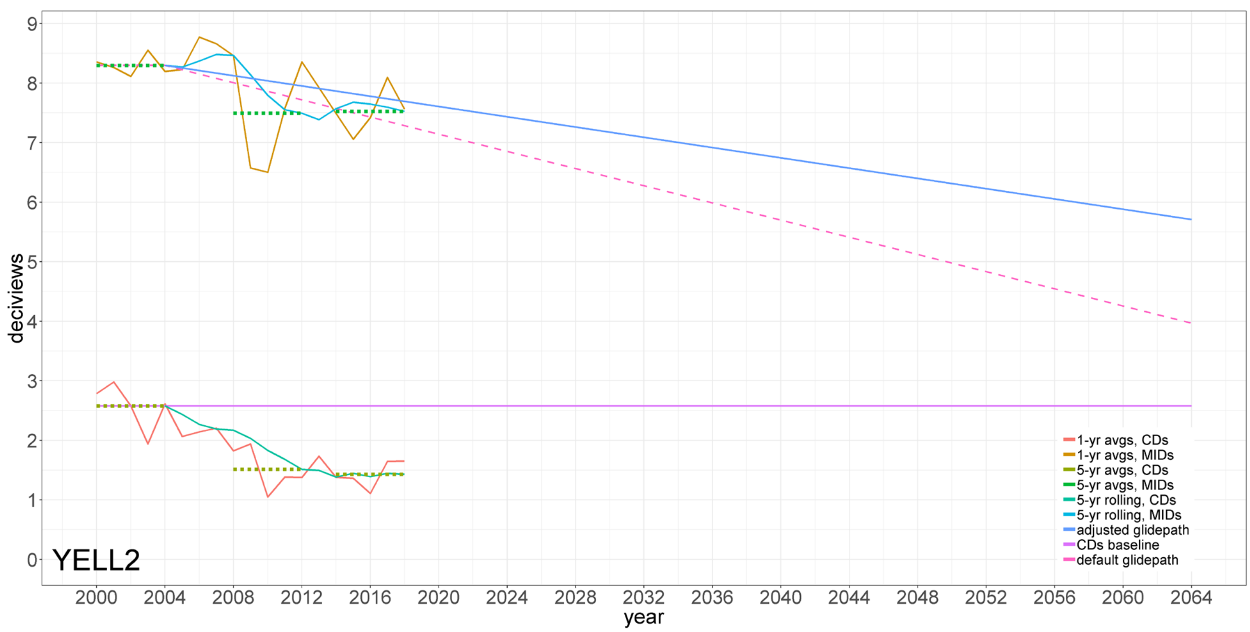


Figure 4-23. YELL2 IMPROVE site URP - Yellowstone NP



4.4 Source Contribution to Visibility Impairment

To address haze most effectively in Class I areas, the causes of haze must first be determined. Source apportionment modeling can inform what sources impact visibility, and in Montana, we see contributions primarily from U.S. anthropogenic sources, international sources, wildfire, and prescribed fire.

4.4.1 Source Apportionment Results

As described in section 2.2.3, the high-level source apportionment model partitions visibility impairment into five source categories and then further divided into each source category's particulate species contribution. Additionally, for the US anthropogenic sources for ammonium nitrate and ammonium sulfate, the impairment is broken into five source sectors and thirteen WRAP states, which results in the low-level data. Figures 4-24 – 4-34 combine the high-level with the low-level results, so that the relative contributions can be seen. Some of the source values are very small and therefore do not show up significantly.

Montana used source apportionment results to inform state-to-state consultation, to determine out-of-state impacts to Montana Class I areas (discussed further in Section 7.2).

The Cabinet Mountains' source apportionment results show the dominant contribution from organic carbon from prescribed fire, followed by ammonium sulfate from international anthropogenic impacts. The US anthropogenic, by comparison, contributes less to the total impairment predicted by the model. The low-level results show dominant ammonium sulfate and ammonium nitrate contributions from Washington, Montana, and Idaho sources. Results in the bottom panel of Figure 4-24 identify non-EGU point sources for SO_2 from Washington, mobile sources for NO_x from Washington, Idaho and Montana, and a sizable remaining anthropogenic portion from Montana for SO_2, likely indicative of local area sources like residential wood heating.

Figure 4-24. CABI1 - Contributors to visibility impairment

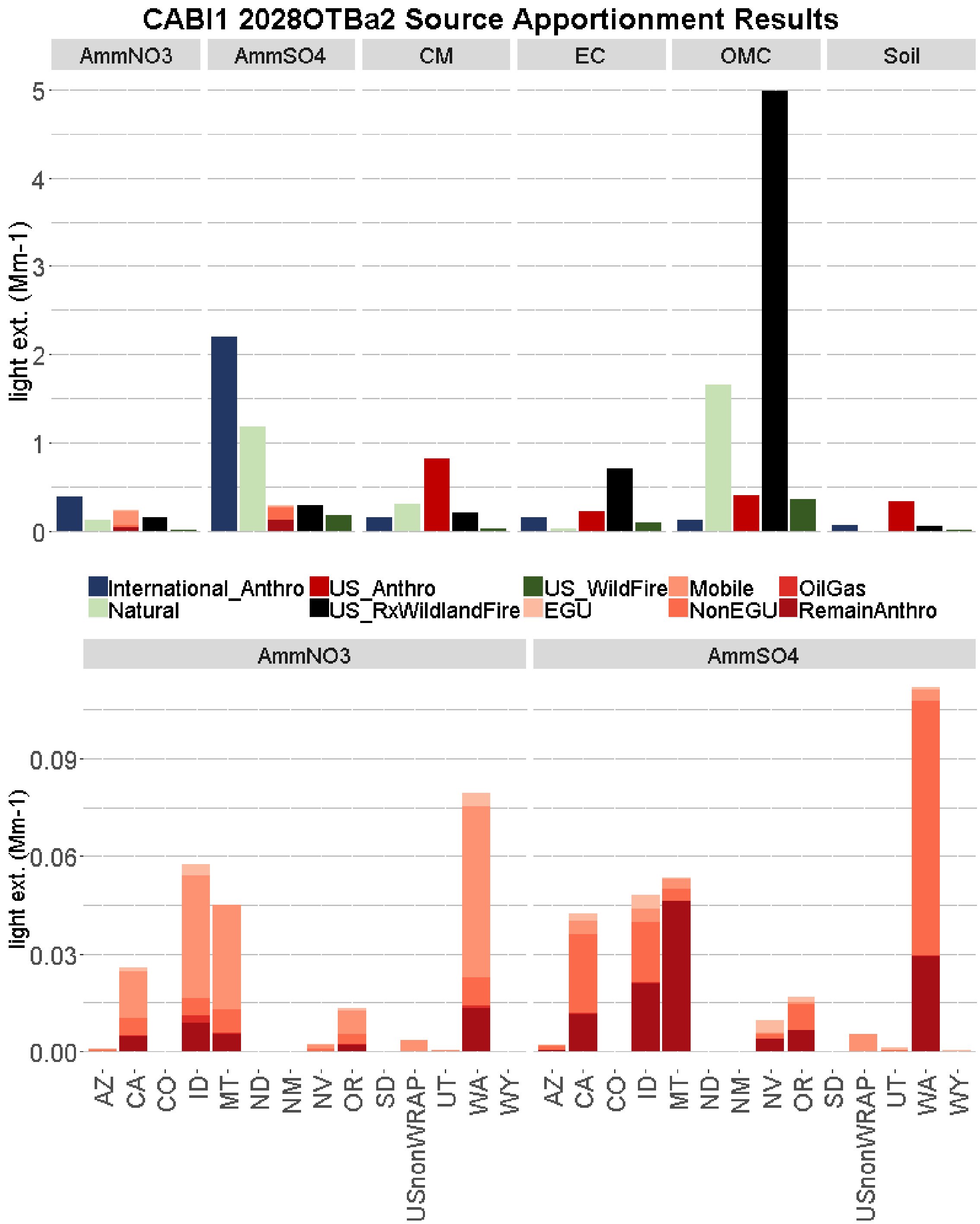
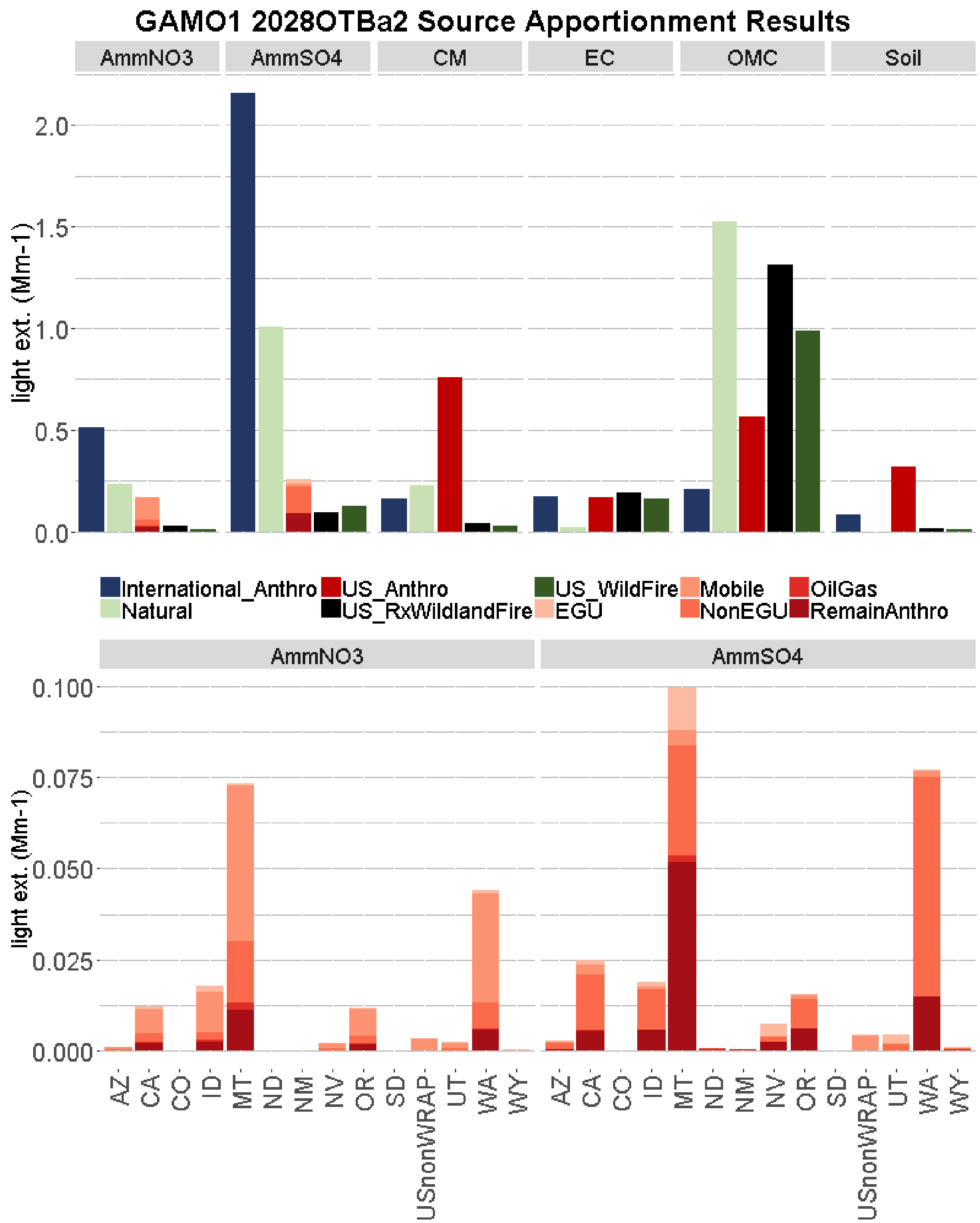


Figure 4-25 shows the source apportionment results for Gates of the Mountains. The results show a sizable ammonium sulfate contribution from international anthropogenic sources, along with a considerable organic carbon contribution, due to prescribe fire, wildfire, and natural sources. Drilling down to the low-level sulfate and nitrate US anthropogenic contributions, reveal sources primarily from Montana and Washington.

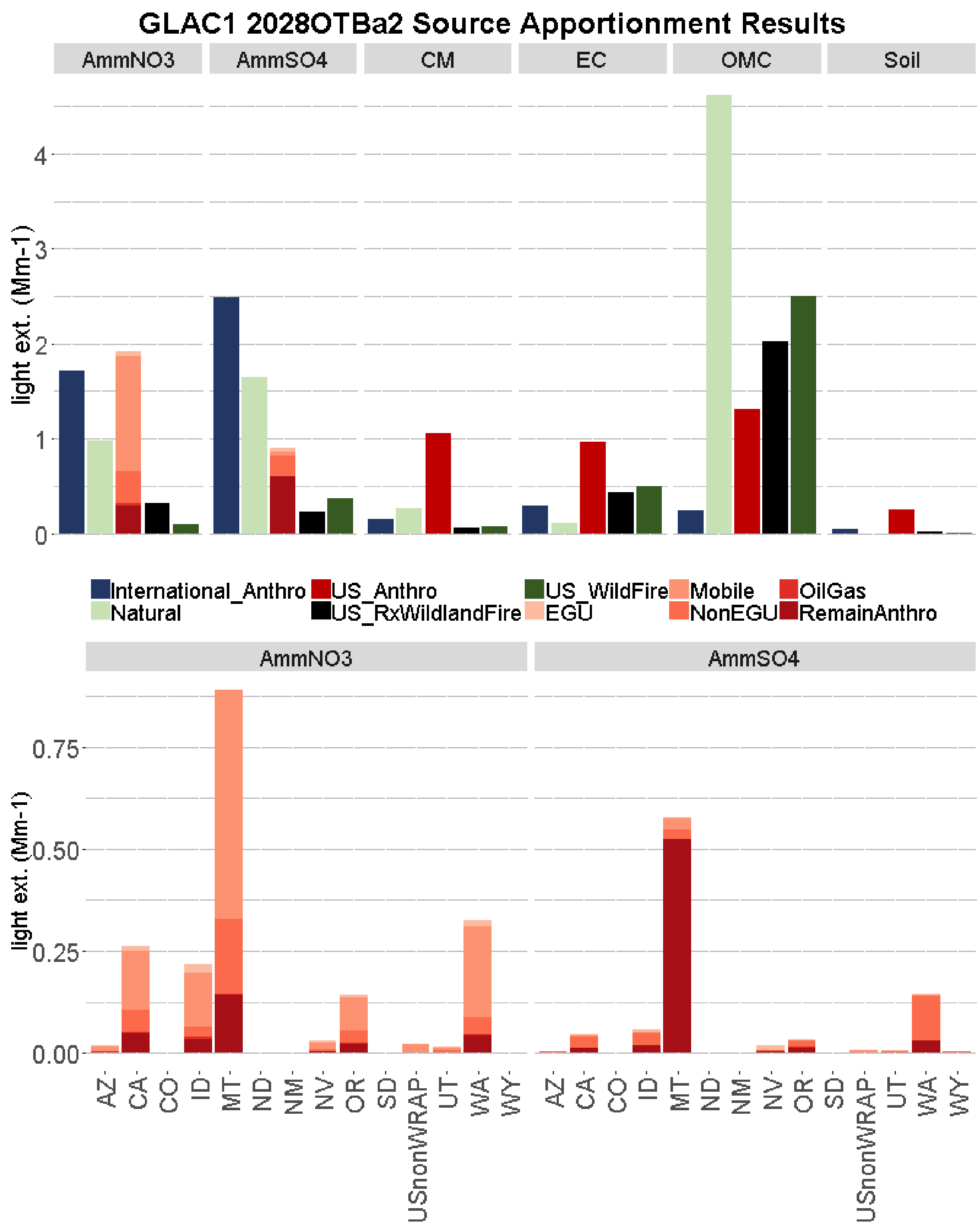
The magnitude of these contributions are quite low, compared to the levels of organic carbon and international sulfate.

Figure 4-25. GAMO1 - Contributors to visibility impairment



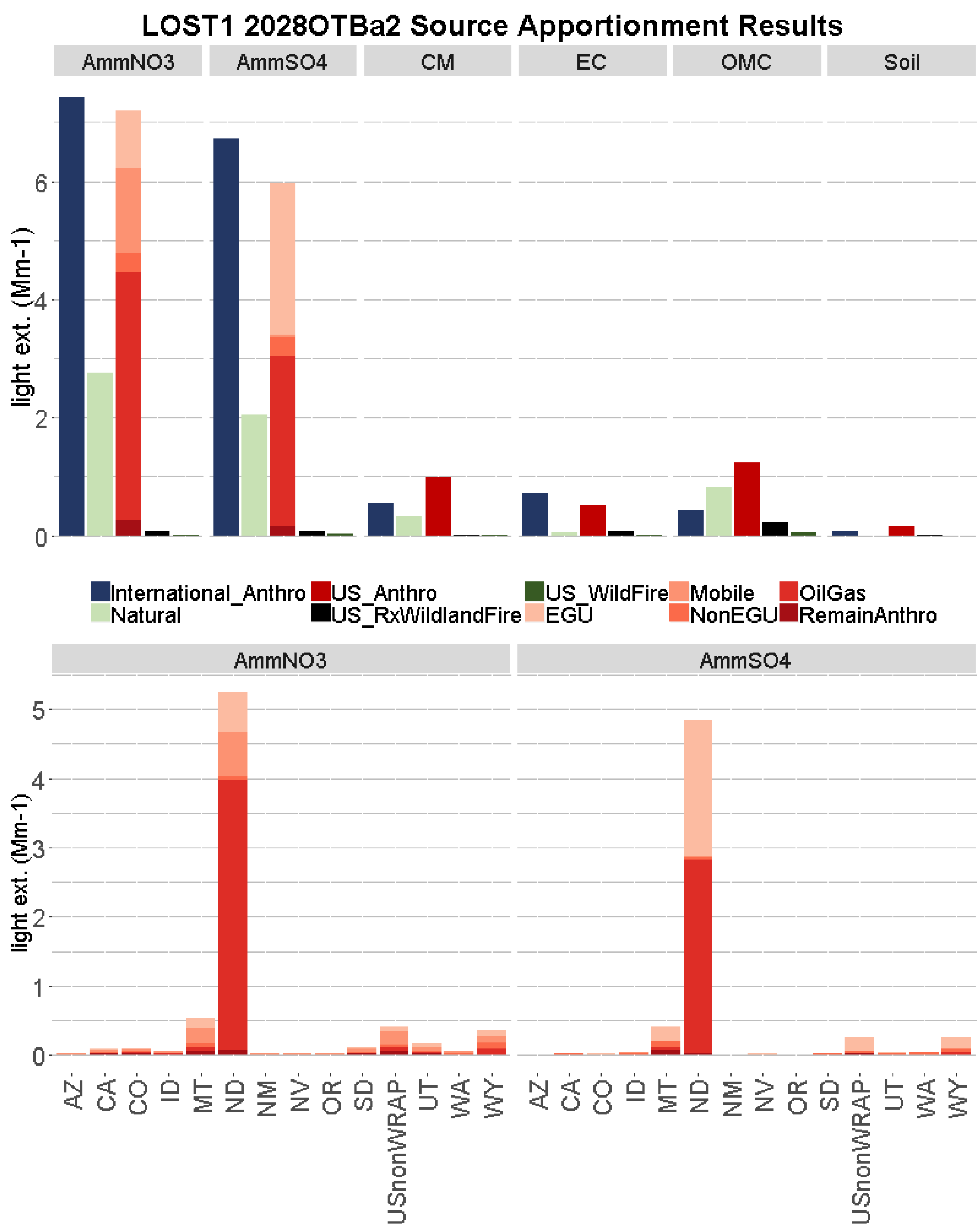
Like many of the western Montana Class One Areas, organic carbon contributes a significant portion to the most impaired days at Glacier (Figure 4-26), primarily from natural (biogenic), prescribed fire, and wildfire sources. International anthropogenic sources contribute to ammonium nitrate and ammonium sulfate signatures. The US anthropogenic nitrate and sulfate primarily comes from Montana sources, from mobile (nitrate) and remaining anthropogenic (sulfate) contributing the largest fractions. Washington mobile also contributes to modeled nitrate levels.

Figure 4-26. GLAC1 - Contributors to visibility impairment



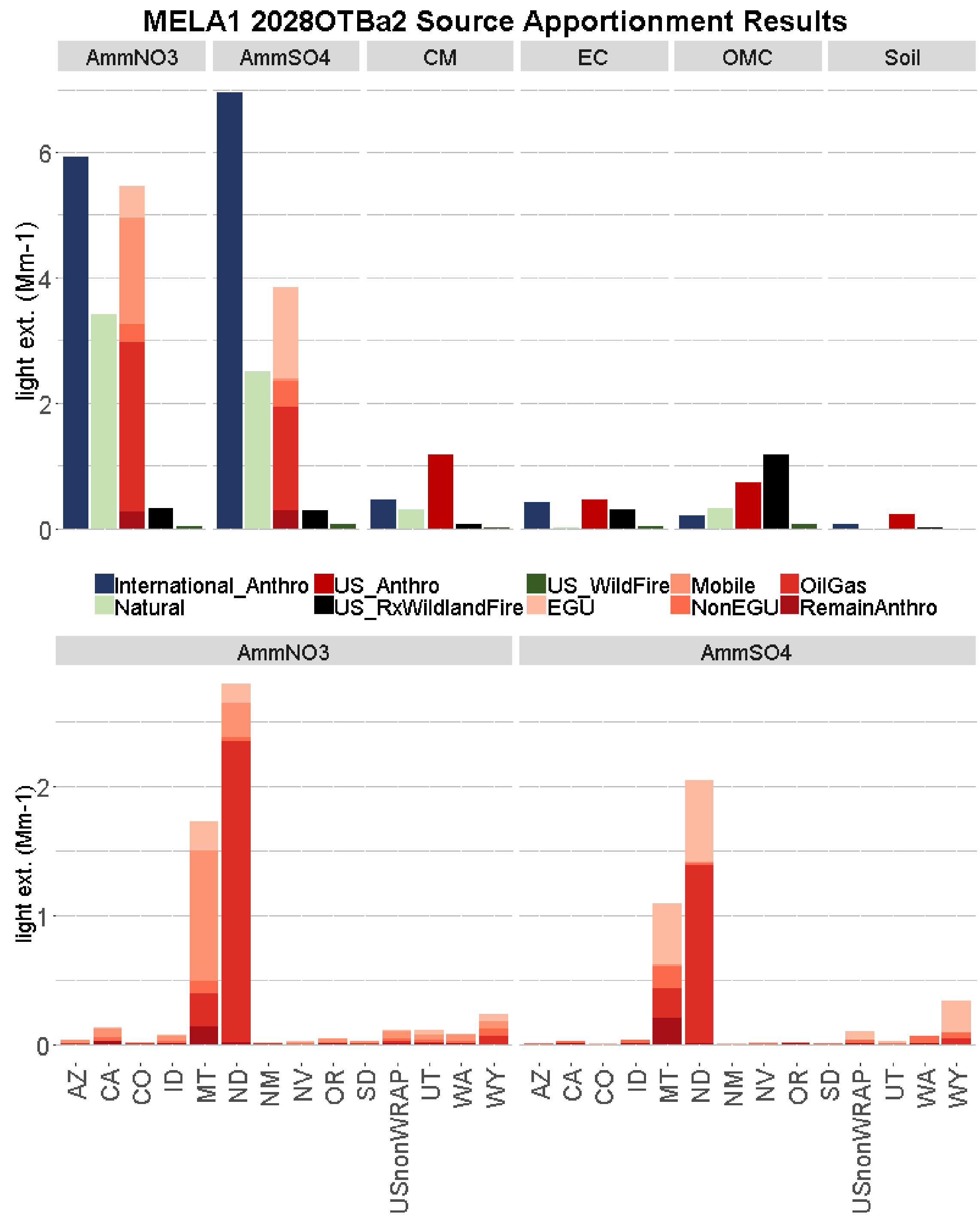
Unlike the previously discussed source apportionment results, much of the modeled contribution to Lostwood Class I area (Figure 4-27) is from ammonium nitrate and ammonium sulfate, with US and international anthropogenic taking up a significant portion. Additionally, the overall magnitude of the modeled impacts is larger than some of the western Montana Class I areas. Of the US anthropogenic ammonium sulfate and ammonium nitrate, the model predicts much of its contribution from the North Dakota oil and gas sector.

Figure 4-27. LOST1 - Contributors to visibility impairment



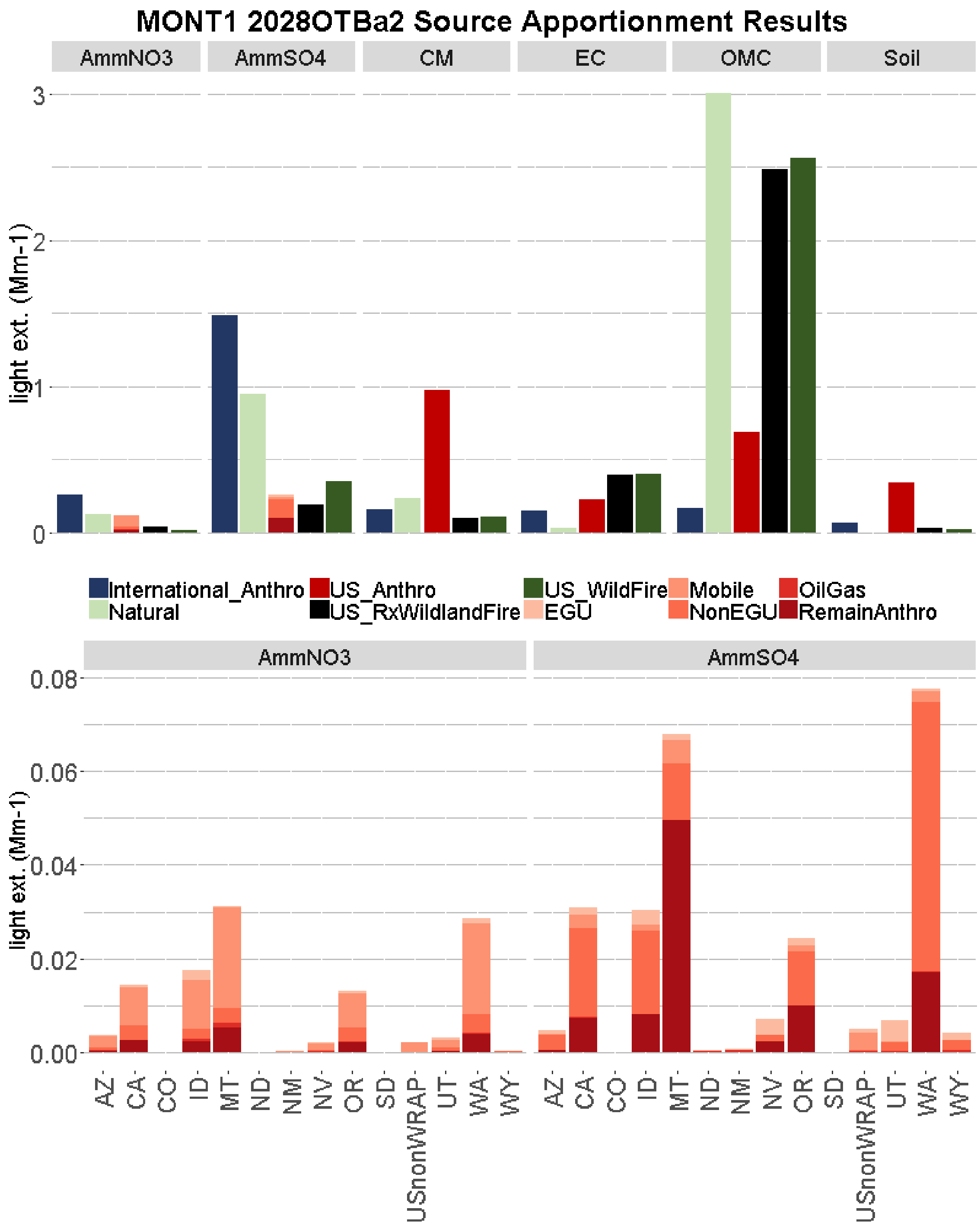
Like other Eastern Montana sites, the modeled contribution at Medicine Lake Class I area (Figure 4-28) is less driven by carbon and more driven by ammonium nitrate and ammonium sulfate, which is consistent with the monitored concentrations. North Dakota oil and gas is a large contributor, along with a mix of Montana mobile (nitrates), oil and gas, and EGU.

Figure 4-28. MELA1 - Contributors to visibility impairment



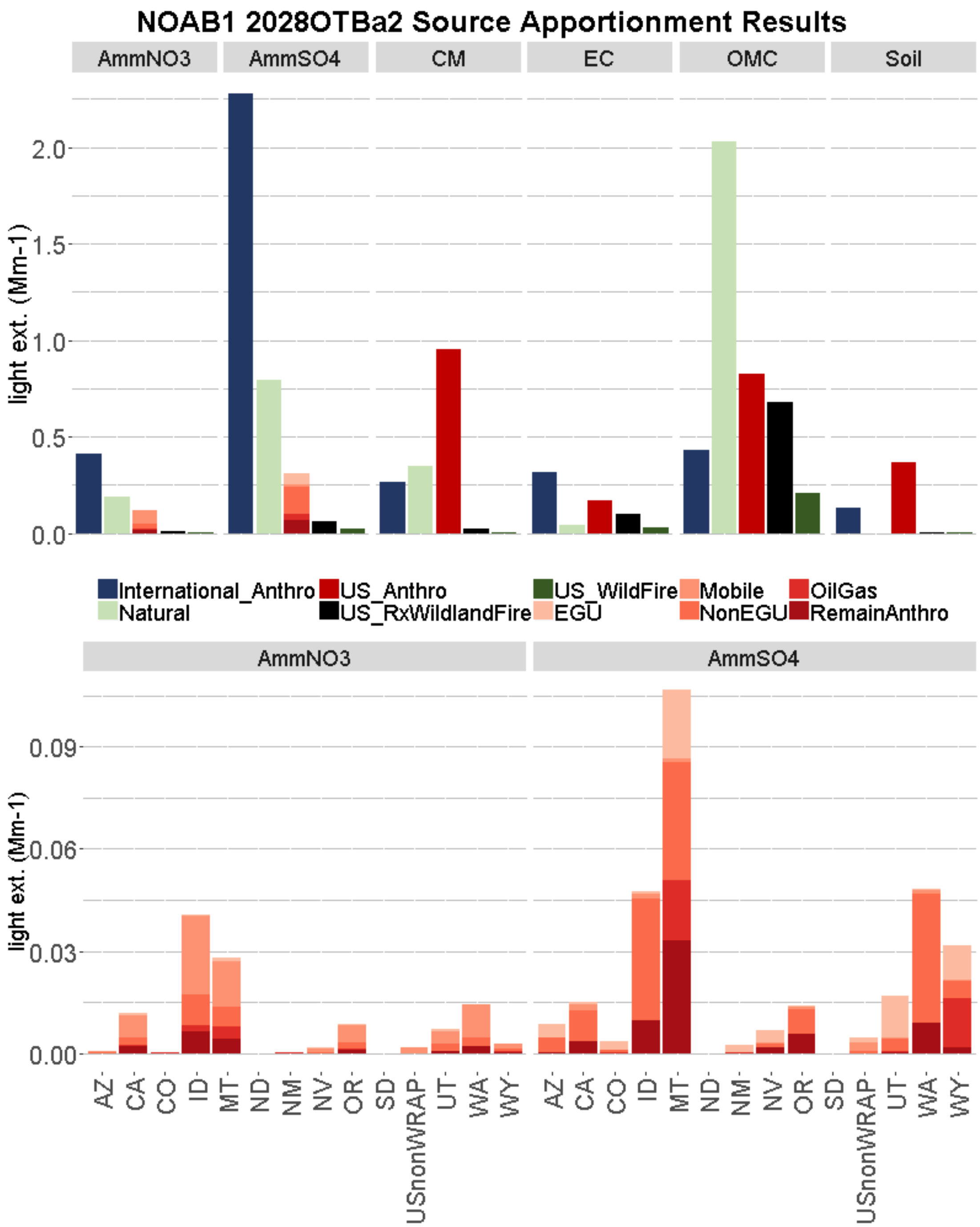
Like other Western Montana sites, the overall light extinction at Monture Class I area is dominated by organic carbon, with ammonium nitrate and sulfate contributing a lesser fraction of the visibility impairment on most impaired days. Wildfire, prescribed fire, and natural sources dominate, followed by US anthropogenic coarse mass and organic carbon, and international ammonium sulfate (Figure 4-29).

Figure 4-29. MONT1 - Contributors to visibility impairment



North Absaroka Class I area source apportionment modeling results shows a little more of a mixed story than the sites that can more readily be classified as "eastern" or "western" Montana sites. The overall light extinction is relatively low by comparison to other eastern Class I areas, and there is a mixed dominant signal between ammonium sulfate from international sources and a natural organic carbon piece. The US anthropogenic contribution to ammonium nitrate and ammonium sulfate is comparatively small and dominated by Montana and Idaho sources, compared to natural and international contributions.

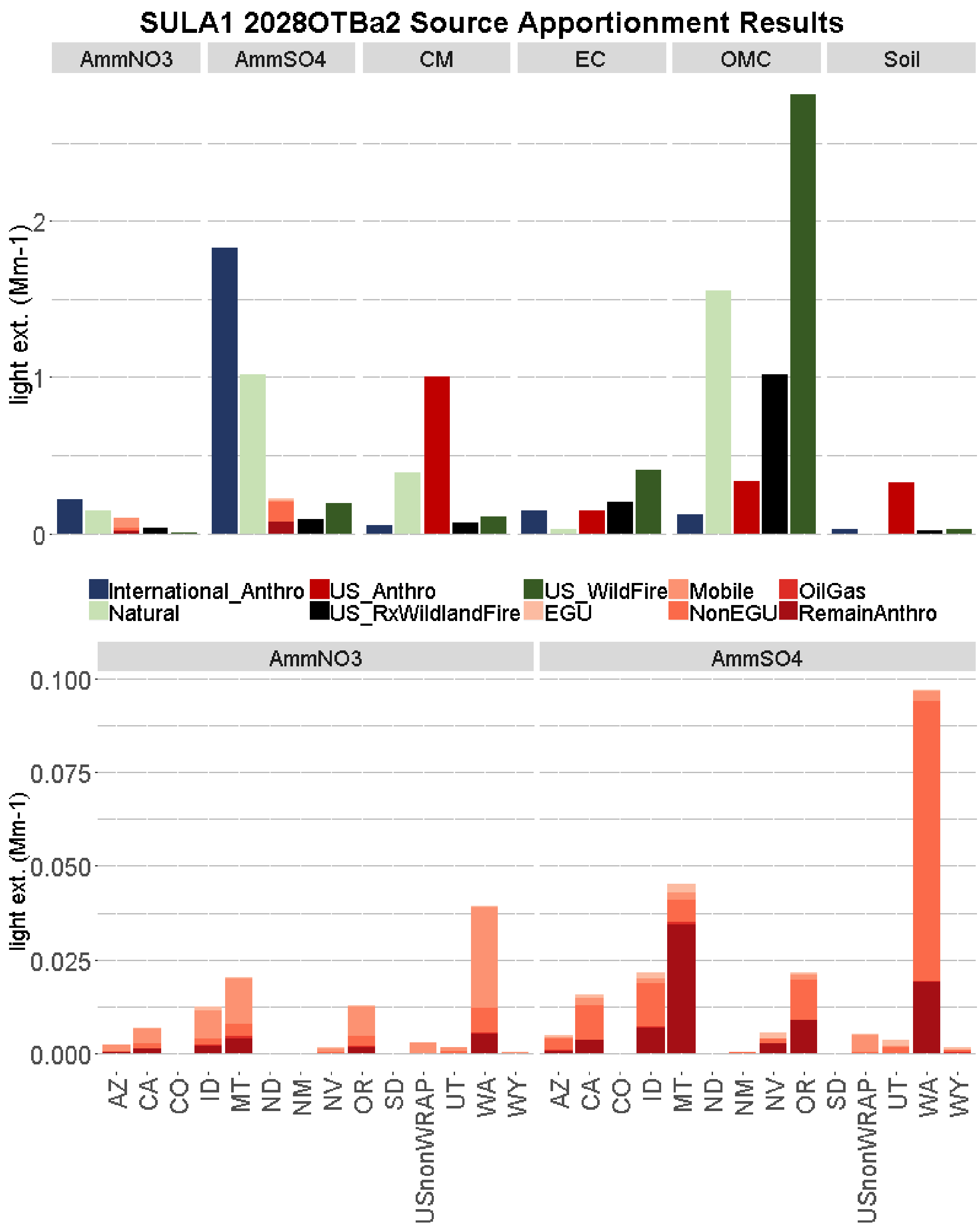
Figure 4-30. NOAB1 - Contributors to visibility impairment



The modeling results for Sula show many characteristics of other western Montana, remote Class I areas. Organic carbon, specifically from wildfire, natural, and prescribed fire, dominate the visibility impacts, with an ammonium sulfate signal from international sources following. The modeled and monitored data shows relatively good visibility by comparison to other Class I areas on most impaired days, with Montana and

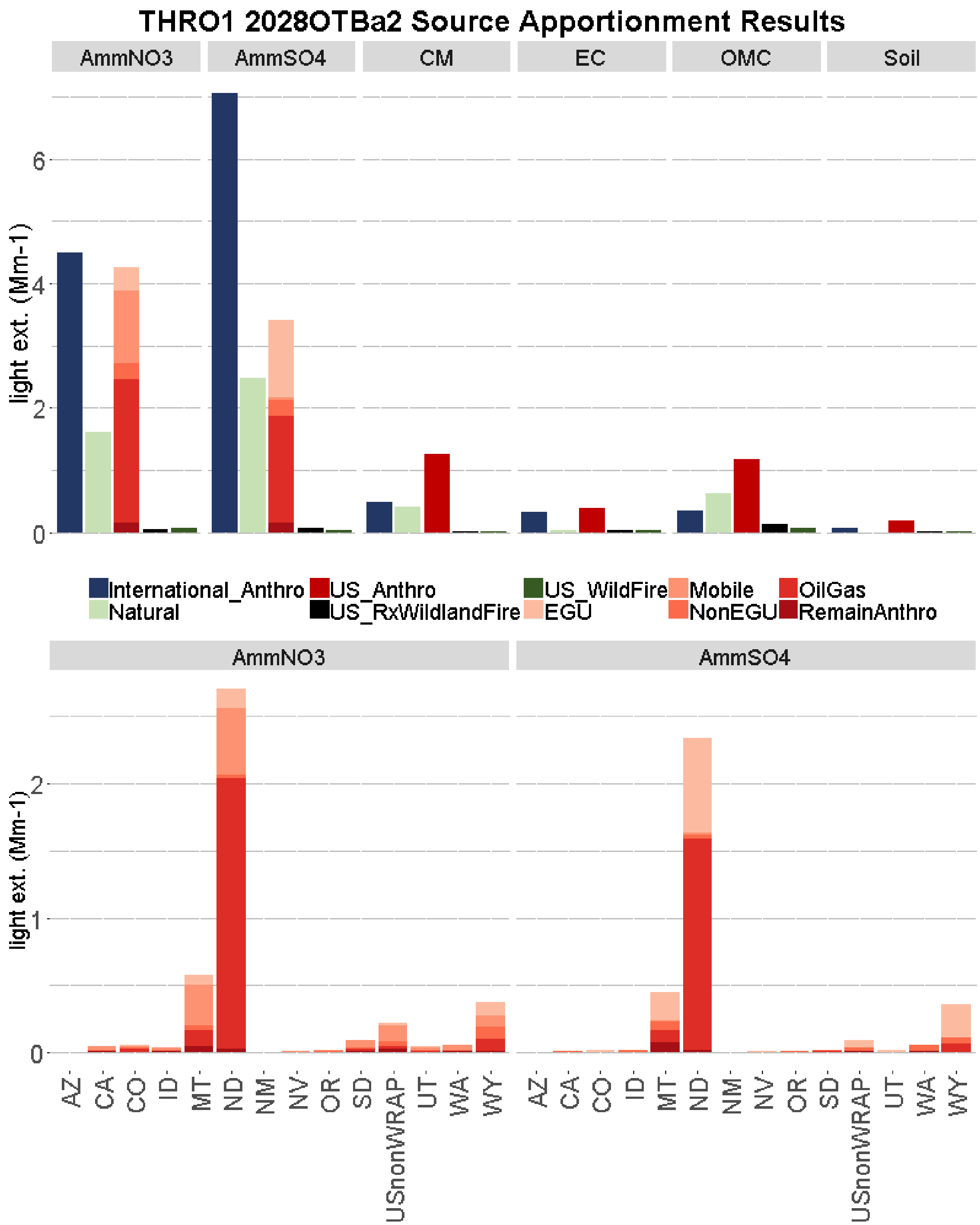
Washington sources contributing most to ammonium sulfate (Figure 4-31).

Figure 4-31. SULA1 - Contributors to visibility impairment



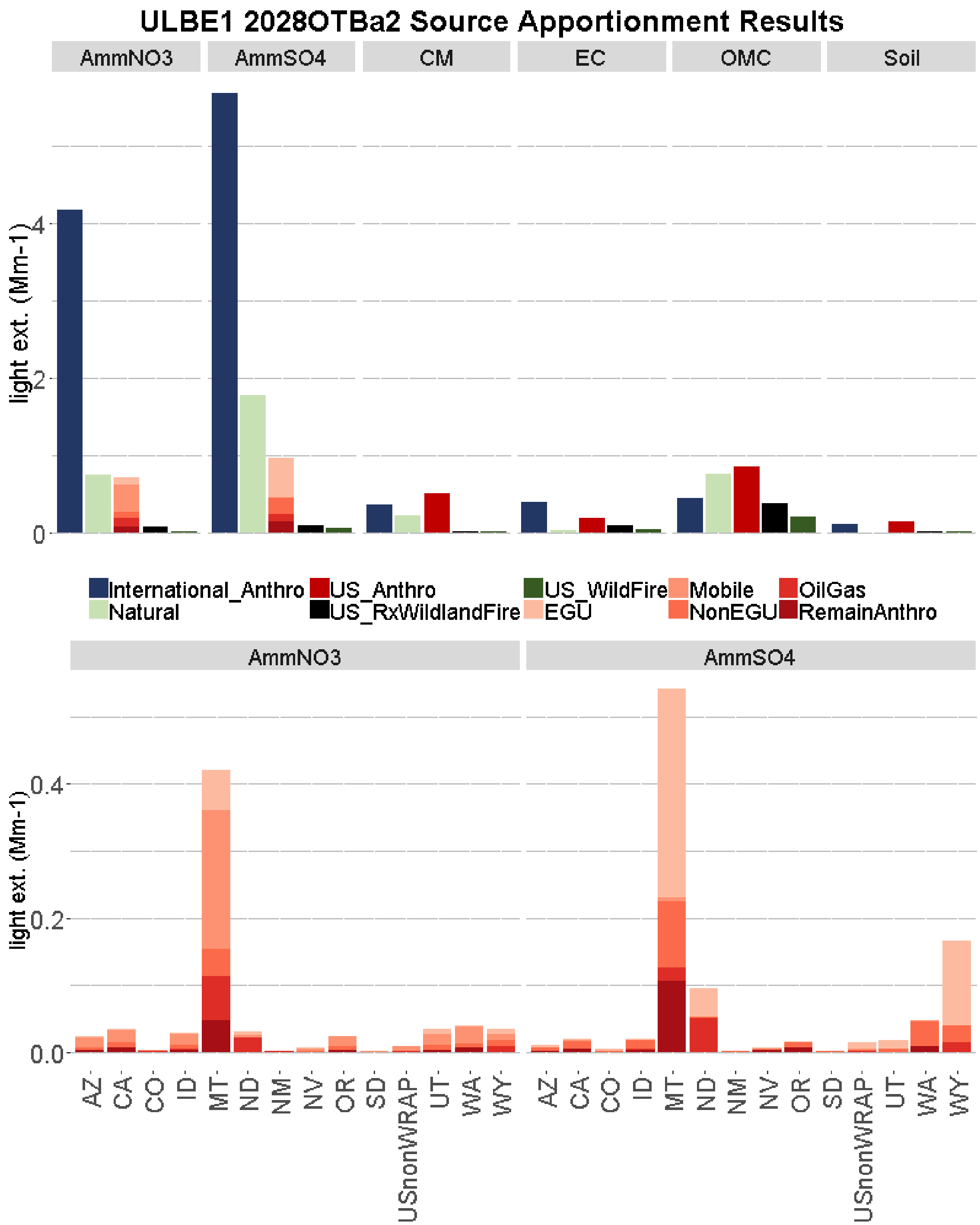
The modeled Theodore Roosevelt Class I area results (Figure 4-32) show a greater visibility impairment overall, dominated by the ammonium nitrate and ammonium sulfate signals. Those can be broken down into a significant international piece and a US anthropogenic piece. Much of the US anthropogenic contributions come from oil and gas sectors of North Dakota and Montana, followed by some mobile and EGU sources.

Figure 4-32. THRO1 - Contributors to visibility impairment



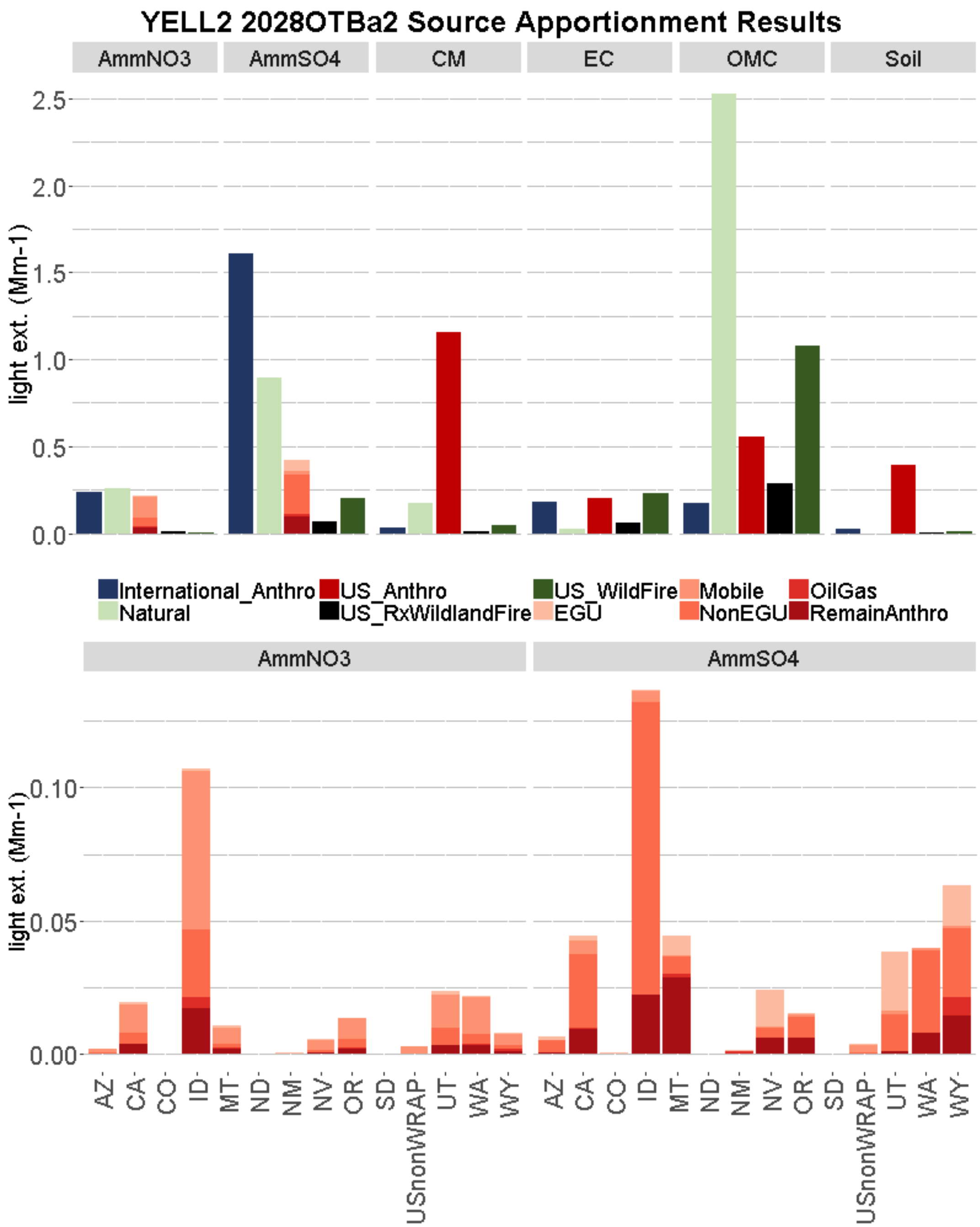
UL Bend source apportionment modeling results (Figure 4-33) also show dominant ammonium nitrate and ammonium sulfate signatures; however the international portion show a much larger contribution compared to the US anthropogenic piece. The US anthropogenic contribution to ammonium nitrate and ammonium sulfate come primarily from Montana, within the mobile, EGU and Non-EGU point sectors.

Figure 4-33. ULBE1 - Contributors to visibility impairment



The source apportionment results for the Yellowstone Class I area (Figure 4-34) shows a large organic carbon contribution, from natural and wildfire sources, from biogenic sources and wildfire smoke, respectively. International ammonium sulfate and US anthropogenic coarse mass also contribute sizable pieces. Notable is how little ammonium nitrate contributes to the most impaired days. Drilling into what little nitrate and sulfate is predicted reveals that US non-EGU point sources and mobile sources from Idaho contribute the most to the ammonium sulfate and ammonium nitrate, respectively.

Figure 4-34. YELL2 - Contributors to visibility impairment



4.4.2 Progress with 2028 Source Apportionment Results

To plot the source apportionment results alongside the glidepath progress, the state-level and regional-level results were combined so that the contributions can be seen within the same bar on the plot. To do so, the source apportionment results must be scaled to match the projected RPGs. This is similar to how the 2014-2018 IMPROVE data is scaled to calculate the 2028 RPGs (see section 2.2.4 for projection methodology and Chapter 8 for RPG results). Montana chose to scale the raw modeling results so that the effects of the long-term strategy can be looked at more granularly, where the relative source contribution is comparable to the glidepath constructs. Appendix E describes the methodology for normalizing the data.

The Montana sources are first separated out, with the remaining state-level anthropogenic sources lumped into the same category. Figures 4-35 – 4-45 display the results of the 2028 source apportionment modeling, with the URP overlaid for context. The glidepath data is shown in extinction units, Mm-1, along with the various sources in 2028, which contribute to the 2028 RPG. The URPs are slightly curved due to the logarithmic relationship between deciviews and light extinction.

The sources contributing to visibility impairment include Montana EGU (MT_EGU), Montana oil and gas (MT_OilGas[81]), Montana mobile (MT_Mobile), Montana non-EGU (MT_NonEGU), remaining Montana anthropogenic (MT_RemainAnthro), all other US anthropogenic (US_Anthro_nonMT), international anthropogenic (International_Anthro), Canadian-Mexican fire (CanMexFire), natural, US prescribed wildland fires (US_RxWildland Fire), US wildfires (US_Wildfire), and Rayleigh. Also shown in Figures 4-35 – 4-45 are the typical glidepath constructs, including the baseline visibility conditions from 2000-2004 (5-yr avgs, MIDs, baseline), IMPROVE 5-yr rolling average trend line (5-yr rolling, MIDs), the current visibility conditions (5-yr avgs, MID, current) unadjusted uniform rate of progress (glidepath_default), and adjusted uniform rate of progress (glidepath_adj), all in light extinction units.

Tables 4-11 - 4-21 break down each source category's particulate species (ammonium nitrate, ammonium sulfate, coarse mass, elemental carbon, organic mass, sea salt, and soil) percent contribution to visibility impairment. For the state-level sources, the visibility impairment species only includes ammonium nitrate and ammonium sulfate, the anthropogenically-created species of most interest. All MT impairment from coarse mass, elemental carbon, organic mass, sea salt, and soil are combined with the Remaining US category.[82] This helps show the most controllable portion of visibility impairment from Montana anthropogenic sources.

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[81] Note: this includes point, area, and tribal oil and gas sources.

[82] Ammonium nitrate and ammonium sulfate were the only species tracked when determining the US State and sector contributions to light extinction. See section 2.2.3 for details.

Figure 4-35. CABI1 - Contributors to visibility impairment, overall progress since baseline period, and 2028 projection

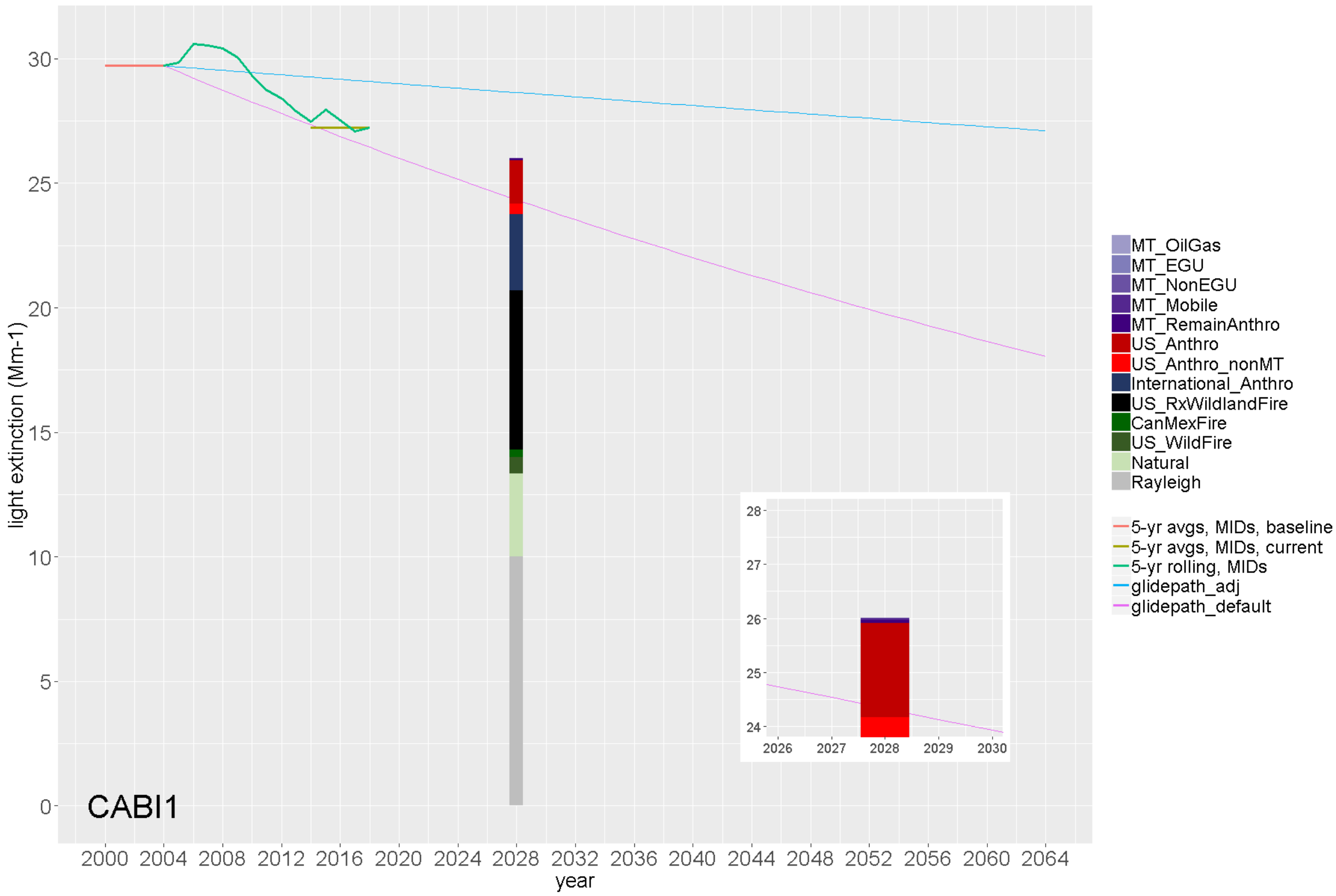


Table 4-11. CABI1 - percent breakdown of 2028 projected visibility impairment

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
CanMexFire	0.03%	0.37%	0.08%	0.56%	0.84%	0.00%	0.02%	**1.89%**
International_Anthro	2.43%	13.69%	0.94%	0.88%	0.73%	0.00%	0.43%	**19.10%**
MT_EGU	0.00%	0.00%	-	-	-	-	-	**0.00%**
MT_Mobile	0.20%	0.02%	-	-	-	-	-	**0.22%**
MT_NonEGU	0.04%	0.02%	-	-	-	-	-	**0.07%**
MT_OilGas	0.00%	0.00%	-	-	-	-	-	**0.00%**
MT_RemainAnthro	0.03%	0.29%	-	-	-	-	-	**0.32%**
Natural	0.78%	7.39%	1.85%	0.17%	10.33%	0.39%	0.00%	**20.90%**
US_Anthro	-	-	5.08%	1.33%	2.48%	0.00%	2.06%	**10.95%**
US_Anthro_nonMT	1.14%	1.49%	-	-	-	-	-	**2.63%**
US_RxWildlandFire	0.91%	1.81%	1.26%	4.41%	31.12%	0.00%	0.35%	**39.85%**
US_WildFire	0.02%	1.07%	0.17%	0.55%	2.21%	0.00%	0.04%	**4.06%**

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
Total:	**5.59%**	**26.15%**	**9.38%**	**7.89%**	**47.71%**	**0.39%**	**2.89%**	**100.00 %**

Figure 4-36. GAMO1 - Contributors to visibility impairment, overall progress since baseline period, and 2028 projection

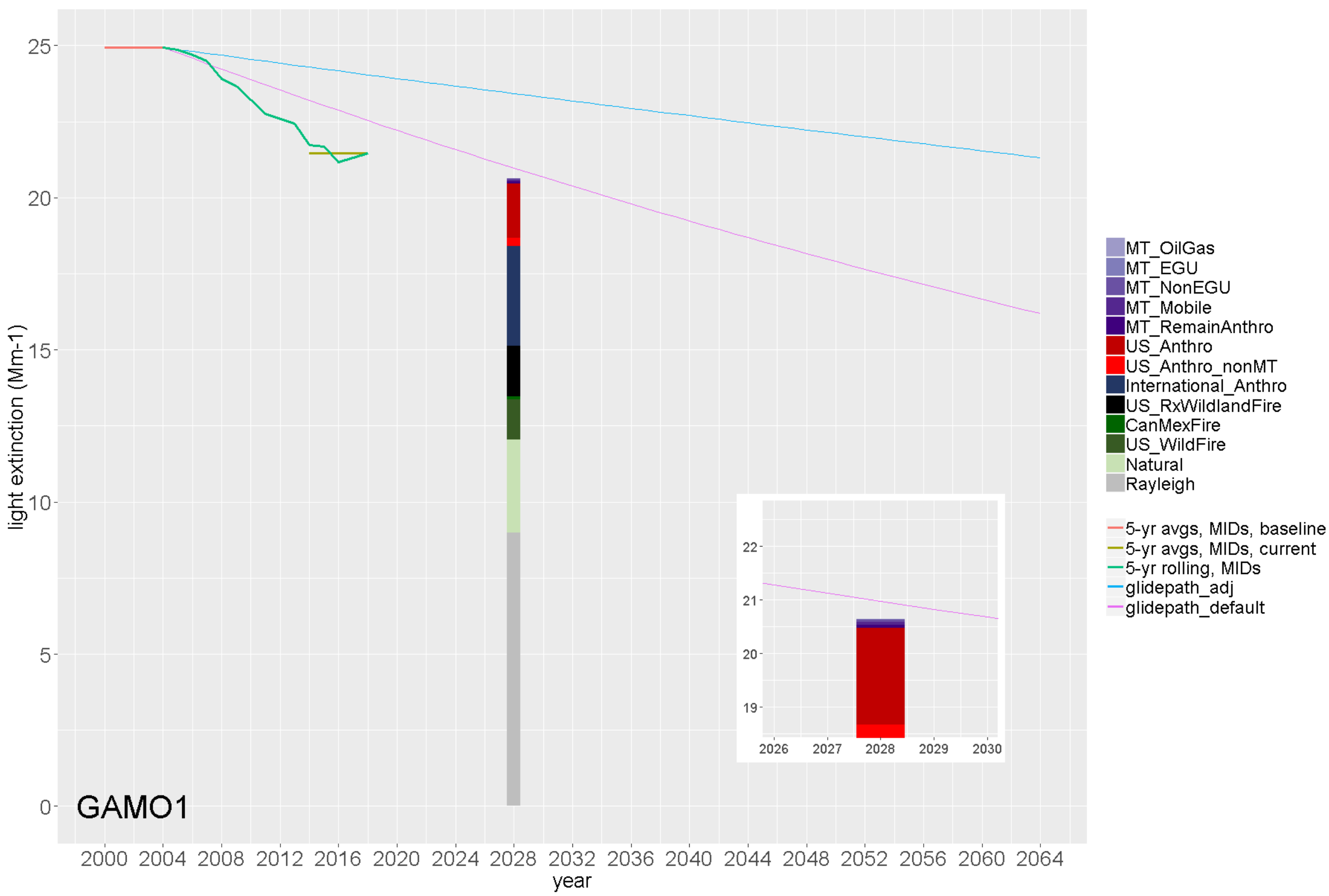


Table 4-12. GAMO1 - percent breakdown of 2028 projected visibility impairment

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
CanMexFire	0.01%	0.10%	0.02%	0.18%	0.43%	0.00%	0.00%	**0.74%**
International_Anthro	4.38%	18.52%	1.38%	1.46%	1.78%	0.00%	0.69%	**28.21%**
MT_EGU	0.01%	0.10%	-	-	-	-	-	**0.11%**
MT_Mobile	0.36%	0.03%	-	-	-	-	-	**0.40%**
MT_NonEGU	0.14%	0.26%	-	-	-	-	-	**0.41%**
MT_OilGas	0.02%	0.01%	-	-	-	-	-	**0.03%**
MT_RemainAnthro	0.10%	0.45%	-	-	-	-	-	**0.54%**
Natural	2.02%	8.66%	1.97%	0.21%	13.12%	0.27%	0.00%	**26.24%**

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
US_Anthro	-	-	6.49%	1.41%	4.85%	0.00%	2.71%	**15.46%**
US_Anthro_nonMT	0.81%	1.35%	-	-	-	-	-	**2.17%**
US_RxWildlandFire	0.26%	0.82%	0.32%	1.62%	11.29%	0.00%	0.11%	**14.41%**
US_WildFire	0.08%	1.04%	0.25%	1.36%	8.48%	0.00%	0.07%	**11.28%**
Total:	**8.20%**	**31.34%**	**10.43%**	**6.24%**	**39.95%**	**0.27%**	**3.58%**	**100.00%**

Figure 4-37. GLAC1 - Contributors to visibility impairment, overall progress since baseline period, and 2028 projection

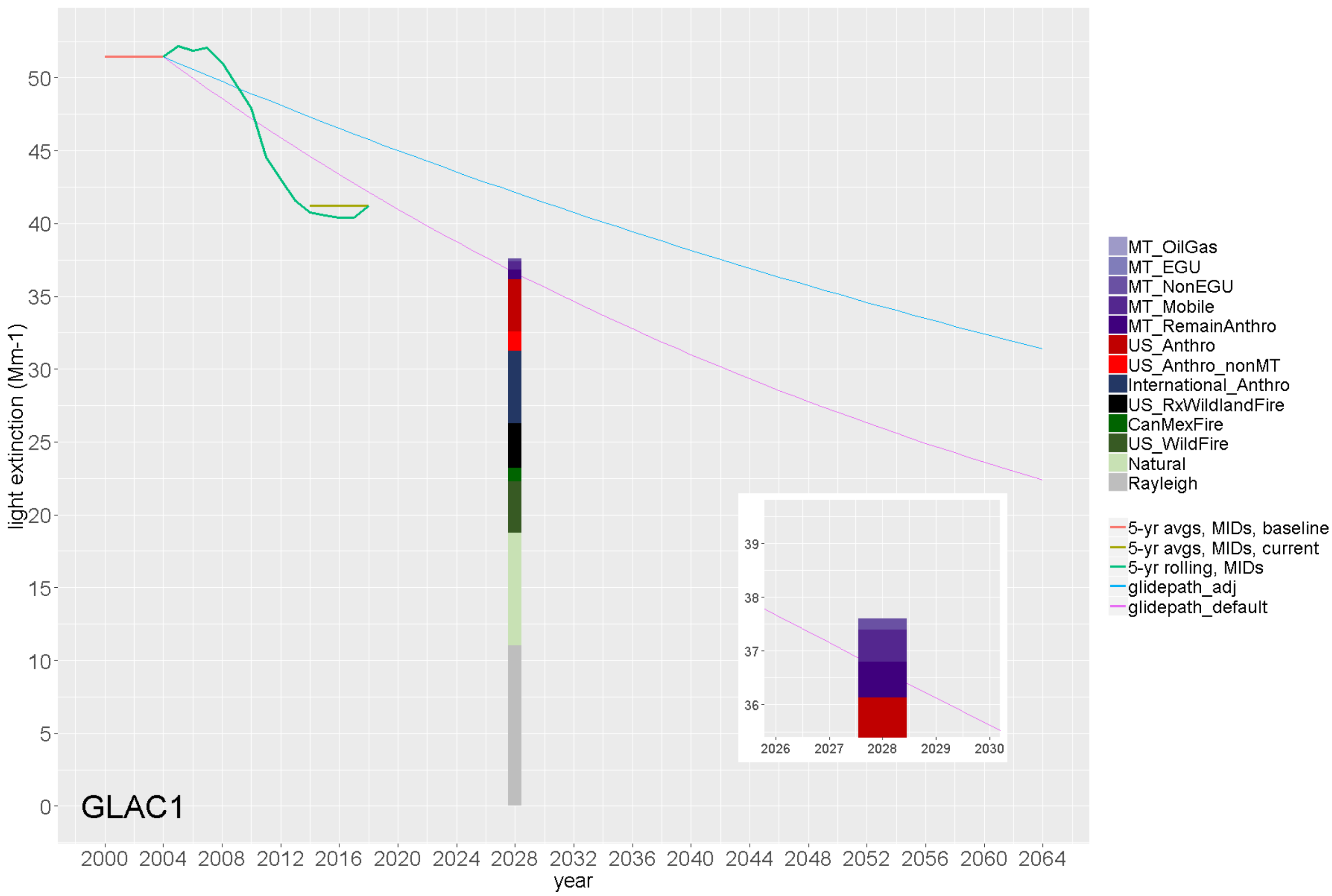


Table 4-13. GLAC1 - percent breakdown of 2028 projected visibility impairment

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
CanMexFire	0.15%	0.66%	0.08%	1.01%	1.63%	0.00%	0.01 %	**3.54%**
International_Anthro	6.45%	9.37%	0.54%	1.08%	0.91%	0.00%	0.18 %	**18.53%**
MT_EGU	0.00%	0.01%	-	-	-	-	-	**0.01%**
MT_Mobile	2.12%	0.10%	-	-	-	-	-	**2.21%**
MT_NonEGU	0.69%	0.10%	-	-	-	-	-	**0.79%**
MT_OilGas	0.01%	0.00%	-	-	-	-	-	**0.01%**
MT_RemainAnthro	0.53%	1.96%	-	-	-	-	-	**2.50%**
Natural	3.66%	6.21%	0.99%	0.40%	17.34%	0.51%	0.00 %	**29.10%**
US_Anthro	-	-	3.94%	3.60%	4.94%	0.00%	0.94 %	**13.41%**
US_Anthro_nonMT	3.87%	1.20%	-	-	-	-	-	**5.07%**
US_RxWildlandFire	1.17%	0.84%	0.24%	1.65%	7.61%	0.00%	0.05 %	**11.55%**
US_WildFire	0.34%	1.37%	0.26%	1.87%	9.39%	0.00%	0.05 %	**13.28%**
Total:	**18.98%**	**21.81%**	**6.05%**	**9.61%**	**41.81%**	**0.51%**	**1.23%**	**100.00%**

Figure 4-38. LOST1 - Contributors to visibility impairment, overall progress since baseline period, and 2028 projection

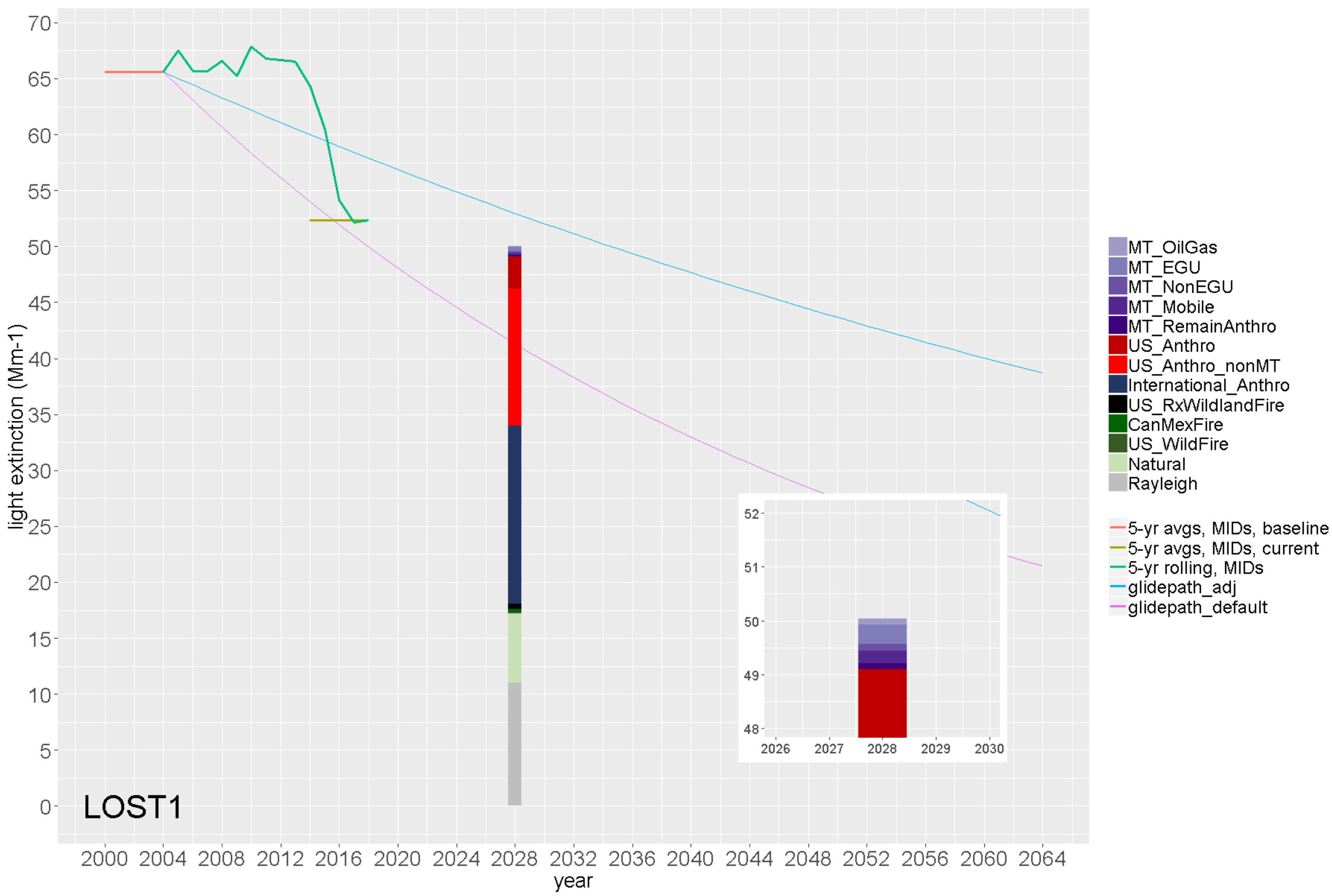


Table 4-14. LOST1 - percent breakdown of 2028 projected visibility impairment

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
CanMexFire	0.09%	0.10%	0.02%	0.23%	0.27%	0.00%	0.00%	**0.71%**
International_Anthro	19.00%	17.22%	1.42%	1.86%	1.11%	0.00%	0.19%	**40.80%**
MT_EGU	0.37%	0.55%	-	-	-	-	-	**0.92%**
MT_Mobile	0.59%	0.01%	-	-	-	-	-	**0.60%**
MT_NonEGU	0.13%	0.20%	-	-	-	-	-	**0.33%**
MT_OilGas	0.17%	0.13%	-	-	-	-	-	**0.29%**
MT_RemainAnthro	0.12%	0.17%	-	-	-	-	-	**0.29%**
Natural	7.03%	5.24%	0.81%	0.14%	2.11%	0.61%	0.00%	**15.95%**
US_Anthro	-	-	2.51%	1.31%	3.14%	0.00%	0.41%	**7.37%**
US_Anthro_nonMT	17.08%	14.27%	-	-	-	-	-	**31.34%**
US_RxWildlandFire	0.17%	0.19%	0.02%	0.18%	0.56%	0.00%	0.00%	**1.12%**
US_WildFire	0.02%	0.08%	0.00%	0.05%	0.13%	0.00%	0.00%	**0.28%**

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
Total:	**44.75%**	**38.15%**	**4.78%**	**3.77%**	**7.33%**	**0.61%**	**0.61%**	**100.00%**

Figure 4-39. MELA1 - Contributors to visibility impairment, overall progress since baseline period, and 2028 projection

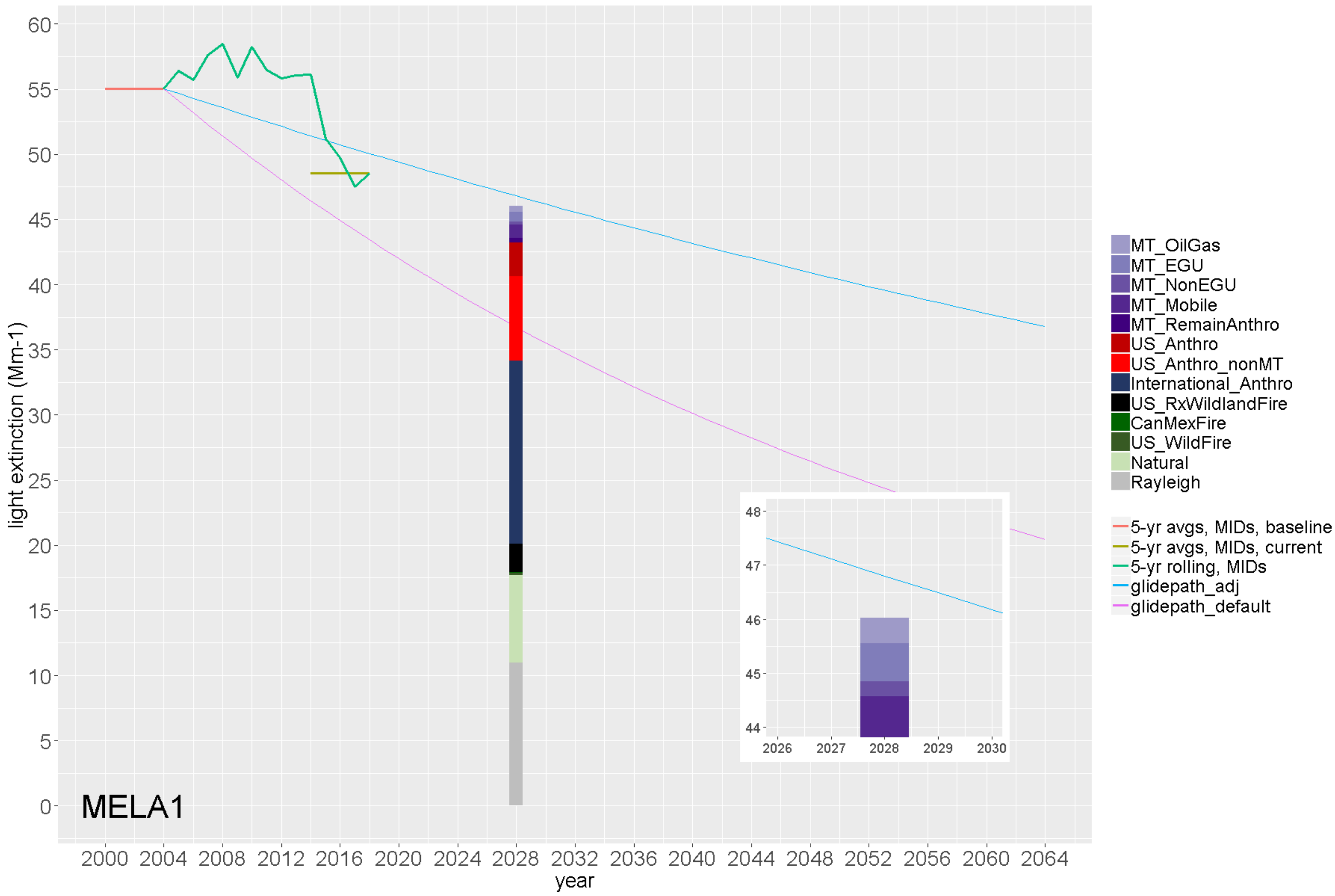


Table 4-15. MELA1 - percent breakdown of 2028 projected visibility impairment

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
CanMexFire	0.02%	0.08%	0.01%	0.07%	0.07%	0.00%	0.00%	**0.26%**
International_Anthro	16.91%	19.83%	1.33%	1.18%	0.60%	0.00%	0.22%	**40.07%**
MT_EGU	0.66%	1.36%	-	-	-	-	-	**2.02%**
MT_Mobile	2.86%	0.04%	-	-	-	-	-	**2.90%**
MT_NonEGU	0.29%	0.48%	-	-	-	-	-	**0.77%**
MT_OilGas	0.72%	0.64%	-	-	-	-	-	**1.37%**
MT_RemainAnthro	0.40%	0.61%	-	-	-	-	-	**1.01%**
Natural	9.74%	7.14%	0.87%	0.04%	0.94%	0.32%	0.00%	**19.06%**
US_Anthro	-	-	3.35%	1.32%	2.06%	0.00%	0.63%	**7.36%**

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
US_Anthro_nonMT	10.66%	7.85%	-	-	-	-	-	**18.50%**
US_RxWildlandFire	0.93%	0.79%	0.21%	0.85%	3.37%	0.00%	0.03%	**6.17%**
US_WildFire	0.06%	0.19%	0.01%	0.07%	0.17%	0.00%	0.00%	**0.51%**
Total:	**43.26%**	**39.01%**	**5.78%**	**3.53%**	**7.21%**	**0.32%**	**0.88%**	**100.00%**

Figure 4-40. MONT1 - Contributors to visibility impairment, overall progress since baseline period, and 2028 projection

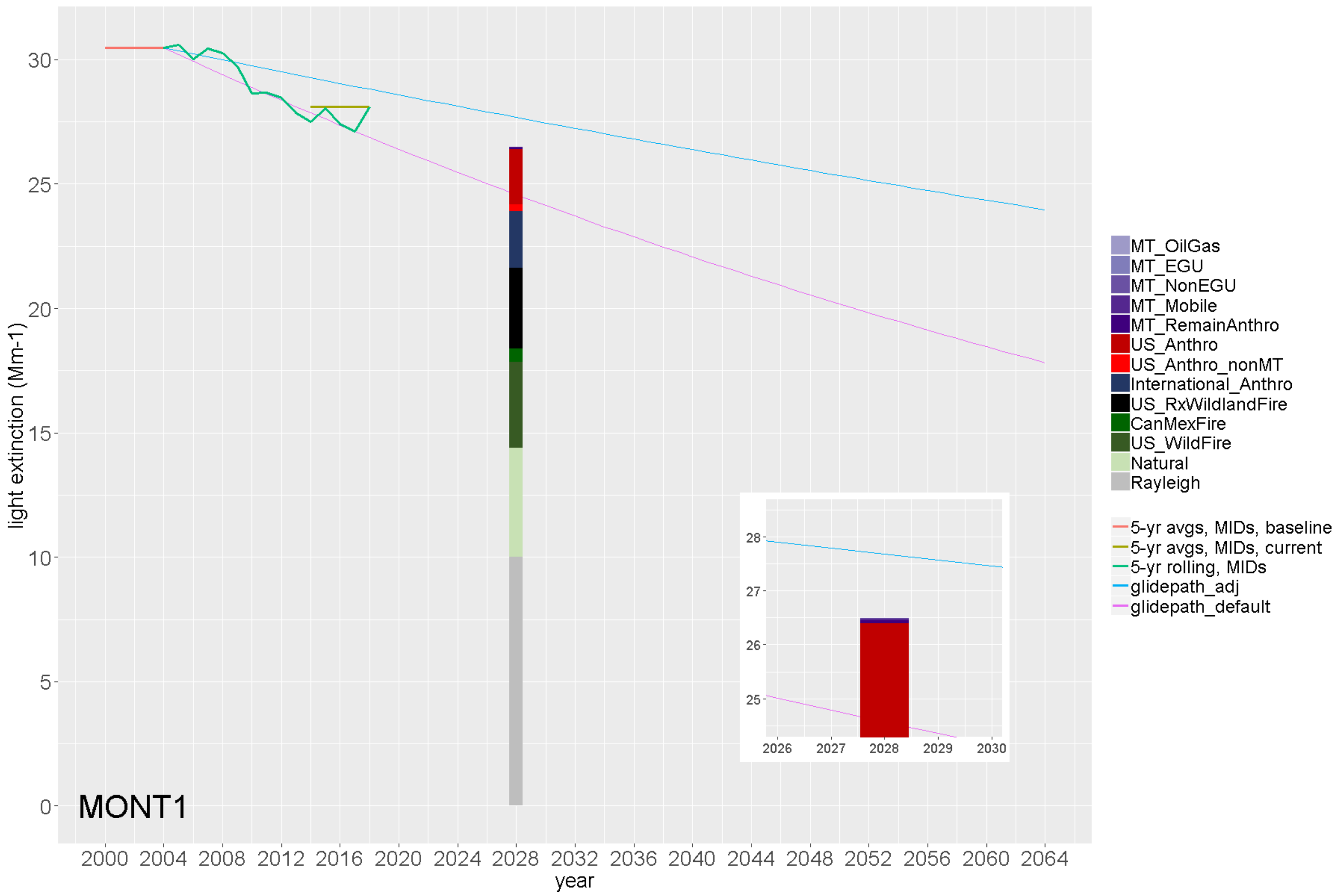


Table 4-16. MONT1 - percent breakdown of 2028 projected visibility impairment

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
CanMexFire	0.03%	0.64%	0.11%	0.82%	1.73%	0.00%	0.02%	**3.35%**
International_Anthro	1.58%	9.03%	0.97%	0.91%	0.98%	0.00%	0.40%	**13.86%**
MT_EGU	0.00%	0.01%	-	-	-	-	-	**0.01%**
MT_Mobile	0.13%	0.03%	-	-	-	-	-	**0.16%**
MT_NonEGU	0.02%	0.07%	-	-	-	-	-	**0.09%**
MT_OilGas	0.01%	0.00%	-	-	-	-	-	**0.01%**
MT_RemainAnthro	0.03%	0.30%	-	-	-	-	-	**0.33%**
Natural	0.72%	5.74%	1.40%	0.19%	18.22%	0.25%	0.00%	**26.52%**
US_Anthro	-	-	5.88%	1.36%	4.15%	0.00%	2.07%	**13.46%**
US_Anthro_nonMT	0.52%	1.17%	-	-	-	-	-	**1.69%**
US_RxWildlandFire	0.22%	1.17%	0.58%	2.39%	15.06%	0.00%	0.16%	**19.58%**
US_WildFire	0.05%	2.14%	0.64%	2.41%	15.55%	0.00%	0.14%	**20.94%**
Total:	**3.30%**	**20.31%**	**9.58%**	**8.08%**	**55.70%**	**0.25%**	**2.79%**	**100.00%**

Figure 4-41. NOAB1 - Contributors to visibility impairment, overall progress since baseline period, and 2028 projection

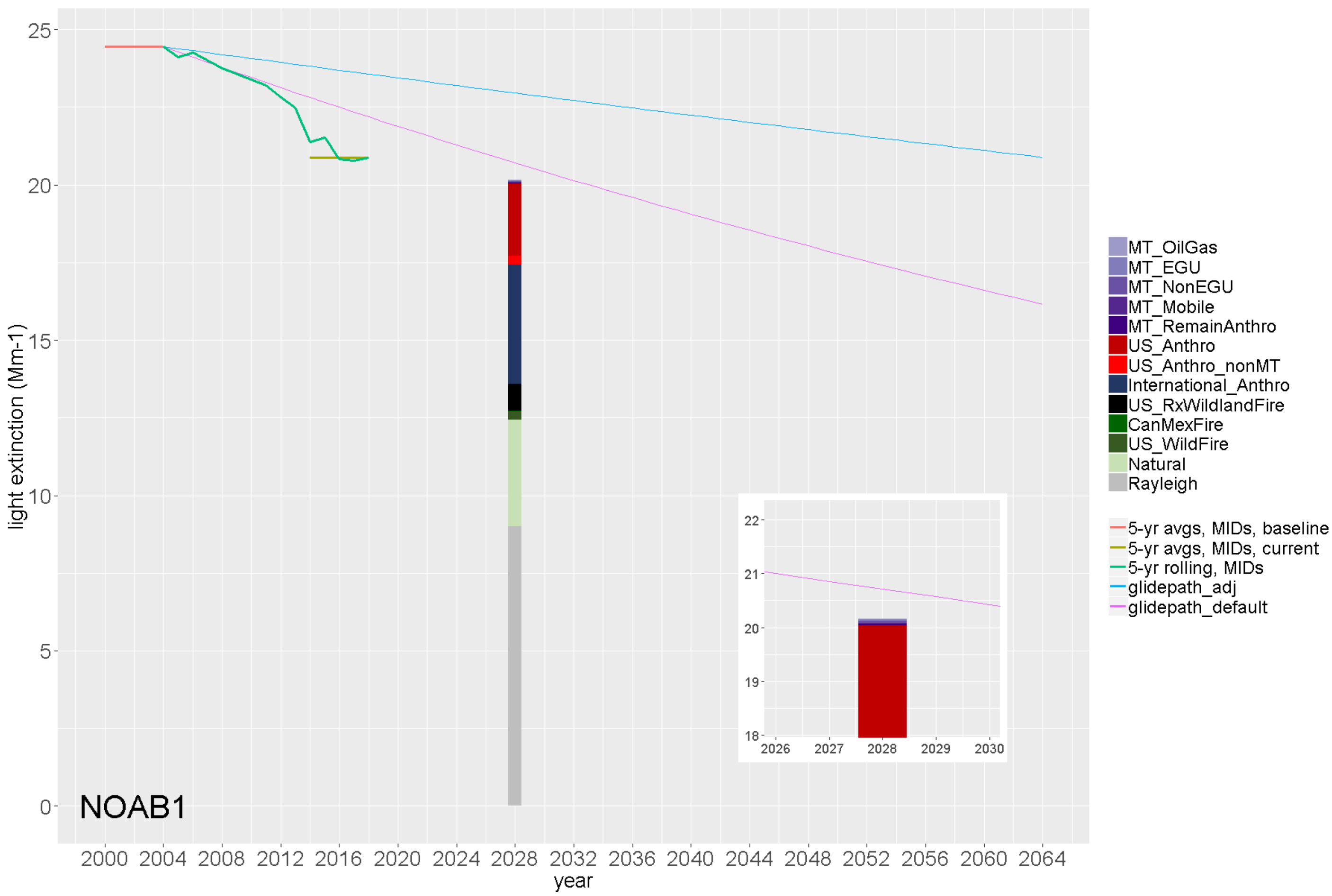


Table 4-17. NOAB1 - percent breakdown of 2028 projected visibility impairment

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
CanMexFire	0.02%	0.02%	0.01%	0.06%	0.15%	0.00%	0.00%	**0.26%**
International_Anthro	3.69%	20.39%	2.37%	2.82%	3.84%	0.00%	1.18%	**34.29%**
MT_EGU	0.01%	0.18%	-	-	-	-	-	**0.19%**
MT_Mobile	0.12%	0.01%	-	-	-	-	-	**0.13%**
MT_NonEGU	0.05%	0.31%	-	-	-	-	-	**0.36%**
MT_OilGas	0.03%	0.16%	-	-	-	-	-	**0.19%**
MT_RemainAnthro	0.04%	0.30%	-	-	-	-	-	**0.34%**
Natural	1.67%	7.13%	3.13%	0.38%	18.21%	0.18%	0.00%	**30.71%**
US_Anthro	-	-	8.57%	1.50%	7.38%	0.00%	3.30%	**20.74%**
US_Anthro_nonMT	0.82%	1.80%	-	-	-	-	-	**2.61%**
US_RxWildlandFire	0.06%	0.53%	0.18%	0.87%	6.07%	0.00%	0.06%	**7.78%**
US_WildFire	0.01%	0.19%	0.05%	0.28%	1.86%	0.00%	0.01%	**2.40%**

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
Total:	**6.52%**	**31.02%**	**14.29%**	**5.92%**	**37.52%**	**0.18%**	**4.55%**	**100.00%**

Figure 4-42. SULA1 - Contributors to visibility impairment, overall progress since baseline period, and 2028 projection

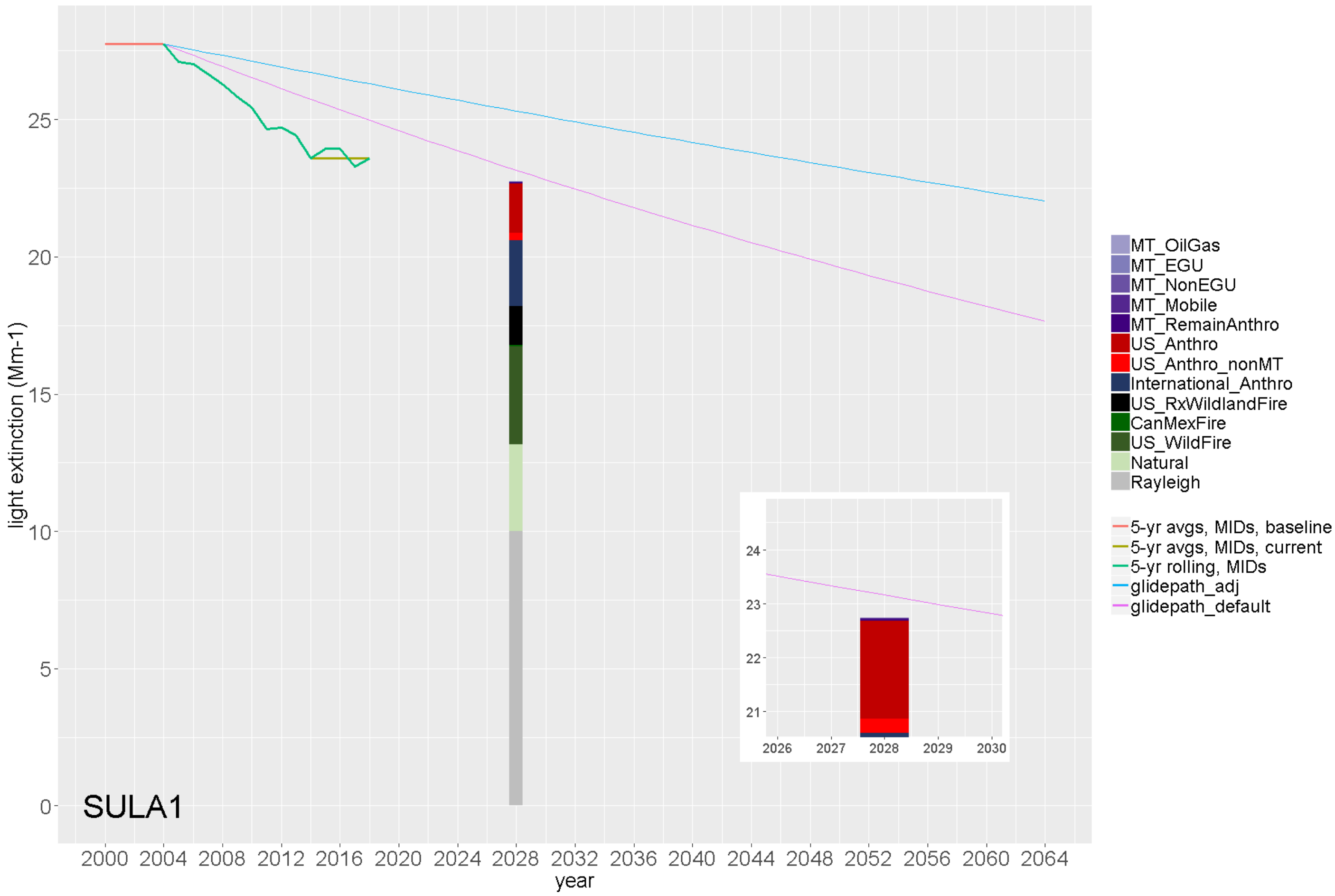


Table 4-18. SULA1 - percent breakdown of 2028 projected visibility impairment

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
CanMexFire	0.01%	0.09%	0.02%	0.15%	0.23%	0.00%	0.00%	**0.50%**
International_Anthro	1.73%	14.37%	0.38%	1.17%	0.94%	0.00%	0.24%	**18.82%**
MT_EGU	0.00%	0.02%	-	-	-	-	-	**0.02%**
MT_Mobile	0.10%	0.02%	-	-	-	-	-	**0.11%**
MT_NonEGU	0.03%	0.05%	-	-	-	-	-	**0.07%**
MT_OilGas	0.00%	0.01%	-	-	-	-	-	**0.01%**
MT_RemainAnthro	0.03%	0.27%	-	-	-	-	-	**0.30%**
Natural	1.17%	8.02%	3.07%	0.20%	12.19%	0.25%	0.00%	**24.91%**
US_Anthro	-	-	7.90%	1.12%	2.61%	0.00%	2.55%	**14.18%**

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
US_Anthro_nonMT	0.63%	1.40%	-	-	-	-	-	**2.03%**
US_RxWildlandFire	0.28%	0.72%	0.50%	1.58%	7.98%	0.00%	0.14%	**11.20%**
US_WildFire	0.05%	1.49%	0.85%	3.17%	22.05%	0.00%	0.23%	**27.84%**
Total:	**4.03%**	**26.45%**	**12.72%**	**7.39%**	**46.00%**	**0.25%**	**3.17%**	**100.00%**

Figure 4-43. THRO1 - Contributors to visibility impairment, overall progress since baseline period, and 2028 projection

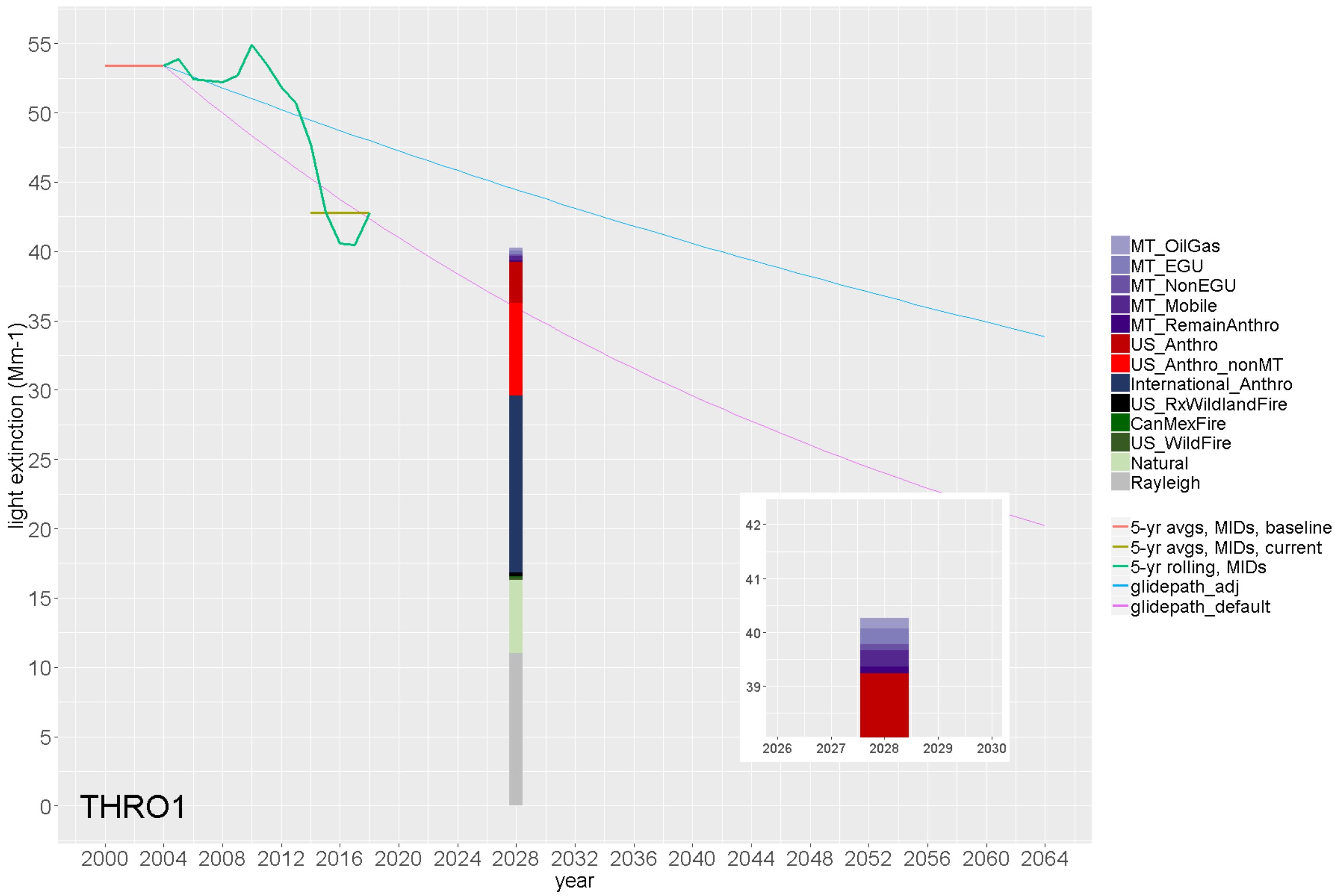


Table 4-19. THRO1 - percent breakdown of 2028 projected visibility impairment

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
CanMexFire	0.01%	0.07%	0.01%	0.05%	0.08%	0.00%	0.00%	**0.23%**
International_Anthro	15.37%	24.09%	1.69%	1.10%	1.19%	0.00%	0.25%	**43.69%**
MT_EGU	0.25%	0.73%	-	-	-	-	-	**0.98%**
MT_Mobile	1.00%	0.01%	-	-	-	-	-	**1.02%**
MT_NonEGU	0.15%	0.24%	-	-	-	-	-	**0.39%**
MT_OilGas	0.40%	0.30%	-	-	-	-	-	**0.70%**
MT_RemainAnthro	0.16%	0.25%	-	-	-	-	-	**0.41%**
Natural	5.49%	8.45%	1.37%	0.10%	2.10%	0.56%	0.00%	**18.06%**
US_Anthro	-	-	4.31%	1.30%	3.99%	0.00%	0.65%	**10.26%**
US_Anthro_nonMT	12.55%	10.09%	-	-	-	-	-	**22.65%**
US_RxWildlandFire	0.19%	0.25%	0.02%	0.08%	0.42%	0.00%	0.00%	**0.96%**
US_WildFire	0.22%	0.11%	0.00%	0.07%	0.25%	0.00%	0.00%	**0.67%**
Total:	**35.79%**	**44.60%**	**7.40%**	**2.70%**	**8.04%**	**0.56%**	**0.91%**	**100.00%**

Figure 4-44. ULBE1 - Contributors to visibility impairment, overall progress since baseline period, and 2028 projection

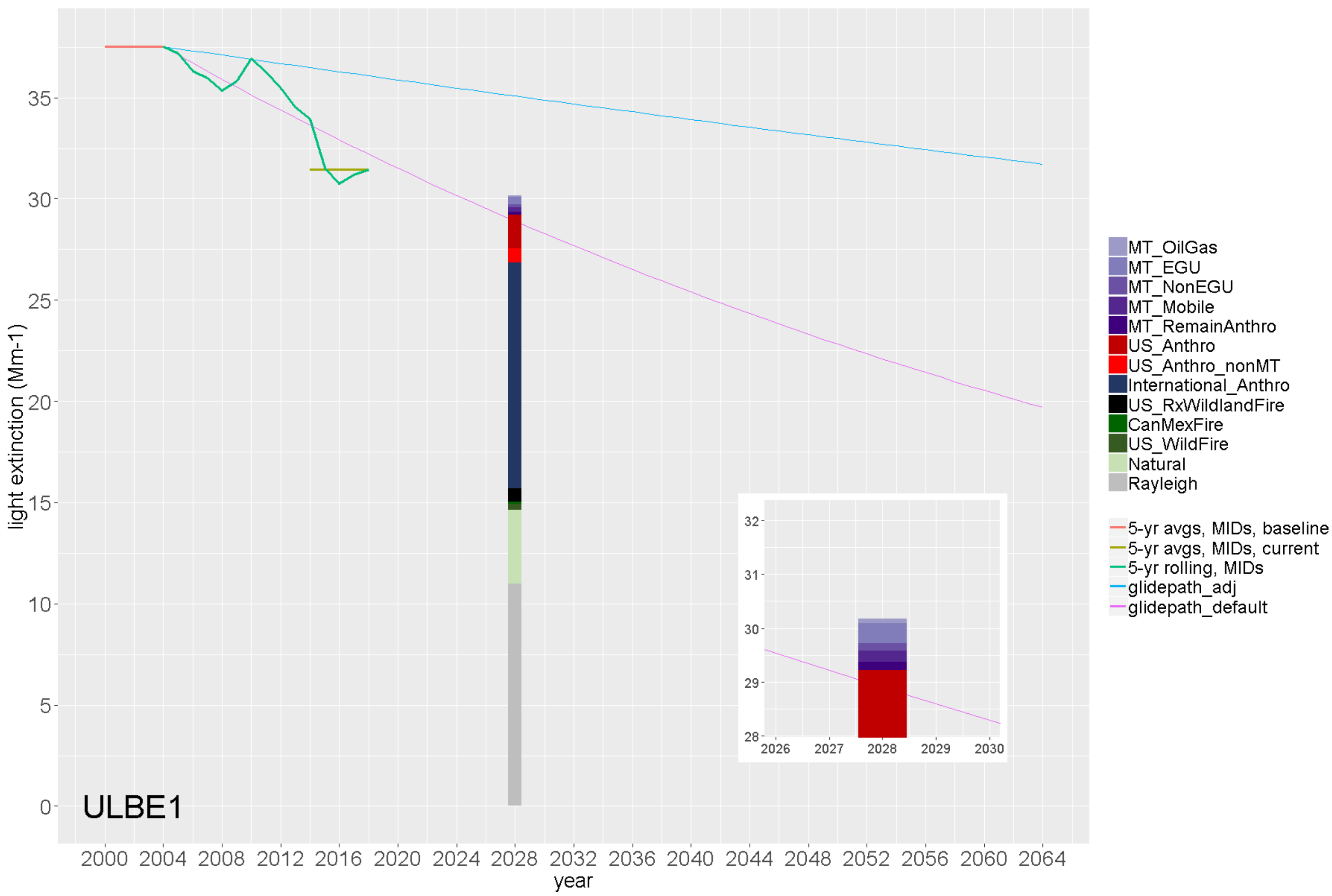


Table 4-20.ULBE1 - percent breakdown of 2028 projected visibility impairment

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
CanMexFire	0.03%	0.15%	0.01%	0.16%	0.31%	0.00%	0.00%	**0.66%**
International_Anthro	21.81%	29.64%	1.90%	2.02%	2.32%	0.00%	0.51%	**58.20%**
MT_EGU	0.32%	1.63%	-	-	-	-	-	**1.94%**
MT_Mobile	1.08%	0.03%	-	-	-	-	-	**1.11%**
MT_NonEGU	0.21%	0.51%	-	-	-	-	-	**0.72%**
MT_OilGas	0.34%	0.10%	-	-	-	-	-	**0.44%**
MT_RemainAnthro	0.25%	0.55%	-	-	-	-	-	**0.81%**
Natural	3.87%	9.28%	1.09%	0.11%	3.96%	0.53%	0.00%	**18.85%**
US_Anthro	-	-	2.59%	0.93%	4.43%	0.00%	0.70%	**8.64%**
US_Anthro_nonMT	1.46%	2.23%	-	-	-	-	-	**3.69%**
US_RxWildlandFire	0.37%	0.49%	0.04%	0.43%	1.98%	0.00%	0.01%	**3.33%**
US_WildFire	0.06%	0.27%	0.02%	0.25%	1.00%	0.00%	0.01%	**1.61%**

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
Total:	**29.80%**	**44.89%**	**5.66%**	**3.90%**	**14.00%**	**0.53%**	**1.23%**	**100.00%**

Figure 4-45. YELL2 - Contributors to visibility impairment, overall progress since baseline period, and 2028 projection

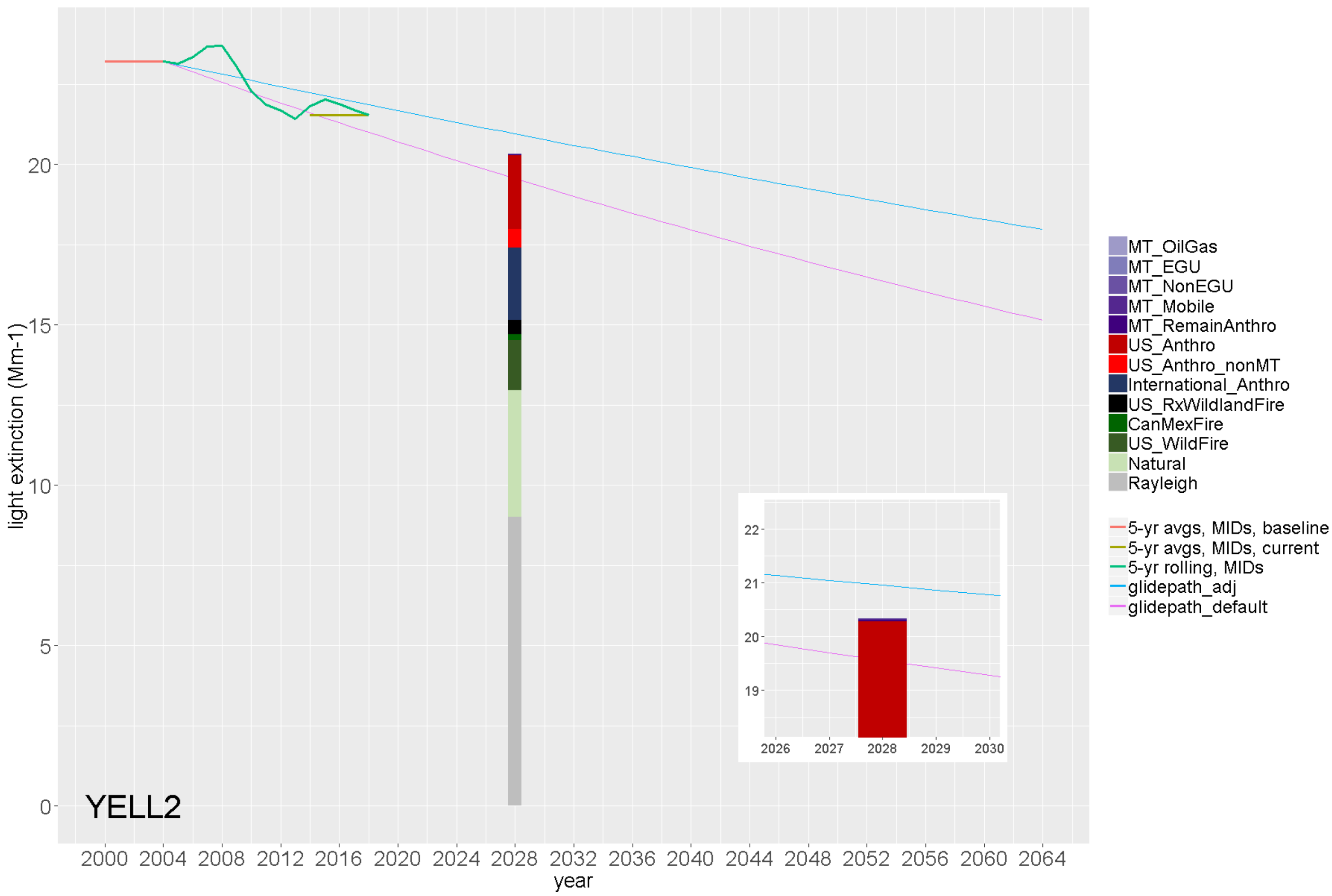


Table 4-21. YELL2 - percent breakdown of 2028 projected visibility impairment

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
CanMexFire	0.01%	0.27%	0.04%	0.41%	0.76%	0.00%	0.01%	**1.50%**
International_Anthro	2.11%	14.17%	0.31%	1.58%	1.55%	0.00%	0.21%	**19.92%**
MT_EGU	0.01%	0.06%	-	-	-	-	-	**0.07%**
MT_Mobile	0.06%	0.01%	-	-	-	-	-	**0.06%**
MT_NonEGU	0.01%	0.05%	-	-	-	-	-	**0.07%**
MT_OilGas	0.00%	0.01%	-	-	-	-	-	**0.02%**
MT_RemainAnthro	0.02%	0.25%	-	-	-	-	-	**0.27%**
Natural	2.28%	7.92%	1.56%	0.21%	22.27%	0.72%	0.00%	**34.96%**
US_Anthro	-	-	10.20%	1.77%	4.89%	0.00%	3.48%	**20.34%**

Source_Cat_combined	AmmNO3	AmmSO4	CM	EC	OMC	SeaSalt	Soil	Total
US_Anthro_nonMT	1.80%	3.30%	-	-	-	-	-	**5.10%**
US_RxWildlandFire	0.08%	0.60%	0.09%	0.51%	2.55%	0.00%	0.03%	**3.86%**
US_WildFire	0.05%	1.78%	0.39%	2.01%	9.50%	0.00%	0.09%	**13.82%**
Total:	**6.42%**	**28.44%**	**12.58%**	**6.49%**	**41.52%**	**0.72%**	**3.83%**	**100.00%**

4.5 WILDFIRE IMPACTS TO CLASS I AREAS

The 2017 metric accounts for elevated carbon impacts and adjusts the MIDs towards the more anthropogenically impaired days, instead of the previously sorted haziest days. As previously discussed, this approach does better to identify anthropogenic MIDs because it attempts to exclude highly episodic impacts, which for Montana, are typically summer days with high carbon, which is an indicator of wildfire. This metric change tends to identify days with more monitored nitrate/sulfate impacts, which are generally considered more controllable as they can be traced to NO_x/SO_2 anthropogenic sources. Even though EPA's metric does well at removing episodic impacts, certain sites in Montana are less responsive to NO_x/SO_2-type reductions because carbon is still a dominant species on the MIDs. This is especially noticeable at western Montana sites, where the absolute impairment is lower to begin with, and the nitrate/sulfate measured impacts are much less than carbon. This section describes how EPA's metric statistically removes wildfire impacts from IMPROVE data that represent Montana's Class I areas, and describes alternate MID metrics considered at sites where the data indicated carbon was still present. This carbon on the MIDs can be further removed by altering the form of EPA's approach, using NOAA's satellite smoke data as an independent check.

4.5.1 Monitoring Data

The monthly impairment trends on all days illuminates the dominant species in the overall haze at Montana's Class I areas and highlights the temporal trends that exist. Figure 4-46 shows the data from the entire data set (not just MIDs), aggregated by month, which contain a few notable features. First, across all Montana (and vicinity) Class I areas, there is a definite temporal pattern showing elevated organic carbon in the July-September timeframes. Visibility in Montana is largely affected by summer month wildfire impacts, both from local fires and fires present in the western U.S. Another pattern seen at Montana Class I areas is spatial, revealing the absolute impairment changes from the western to eastern reaches of Montana's geography. Notably, SULA1, CABI1, GAMO1 show relatively lower impairment during non-wildfire months, with disproportional peaks in August. In contrast, ULBE1, MELA1, and THRO1 show greater impairment overall (including increased nitrate/sulfate contributions) and show less pronounced carbon impacts in the summer.

Figure 4-46. Monthly contributions at MT Class I areas on all days

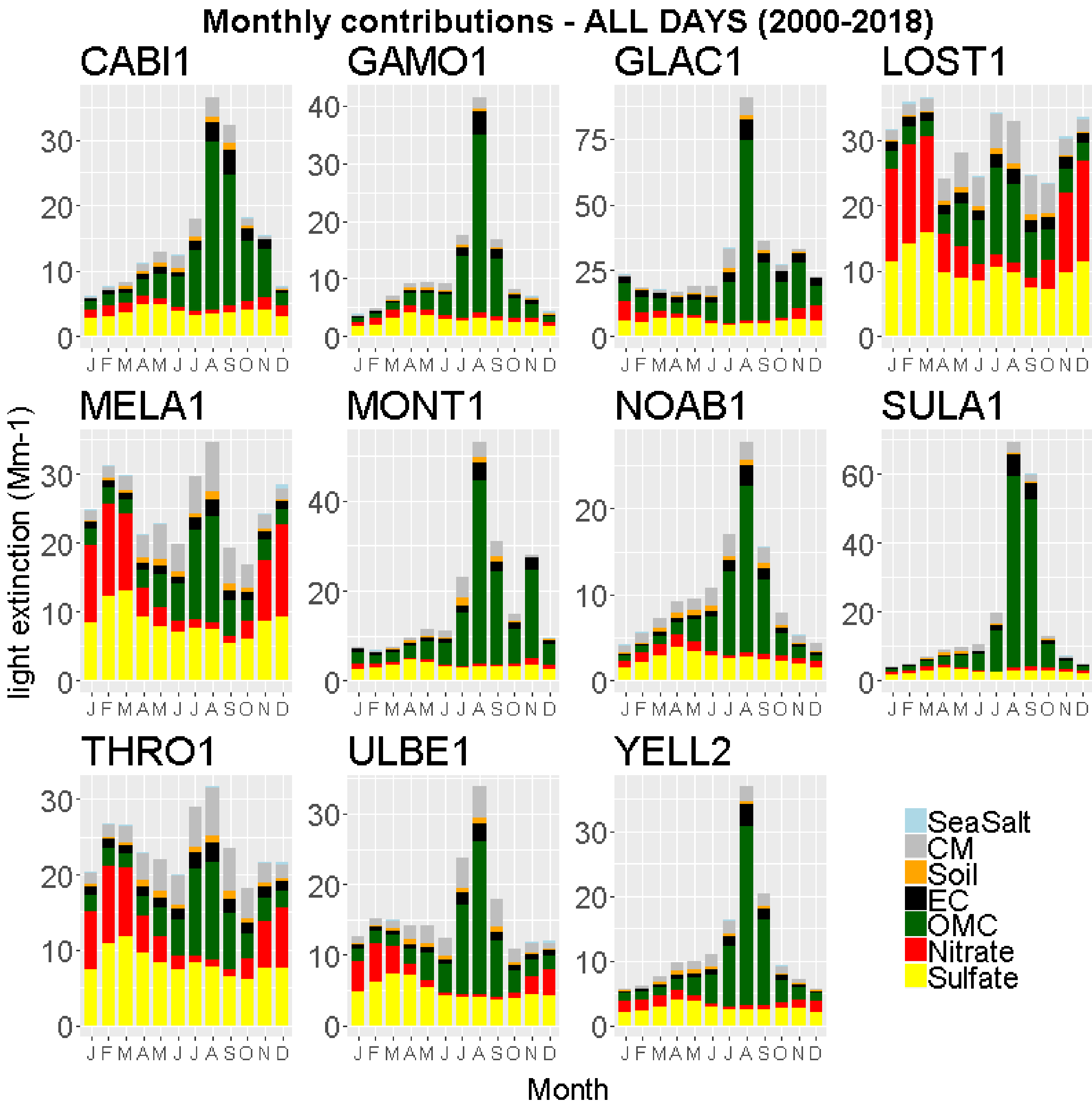
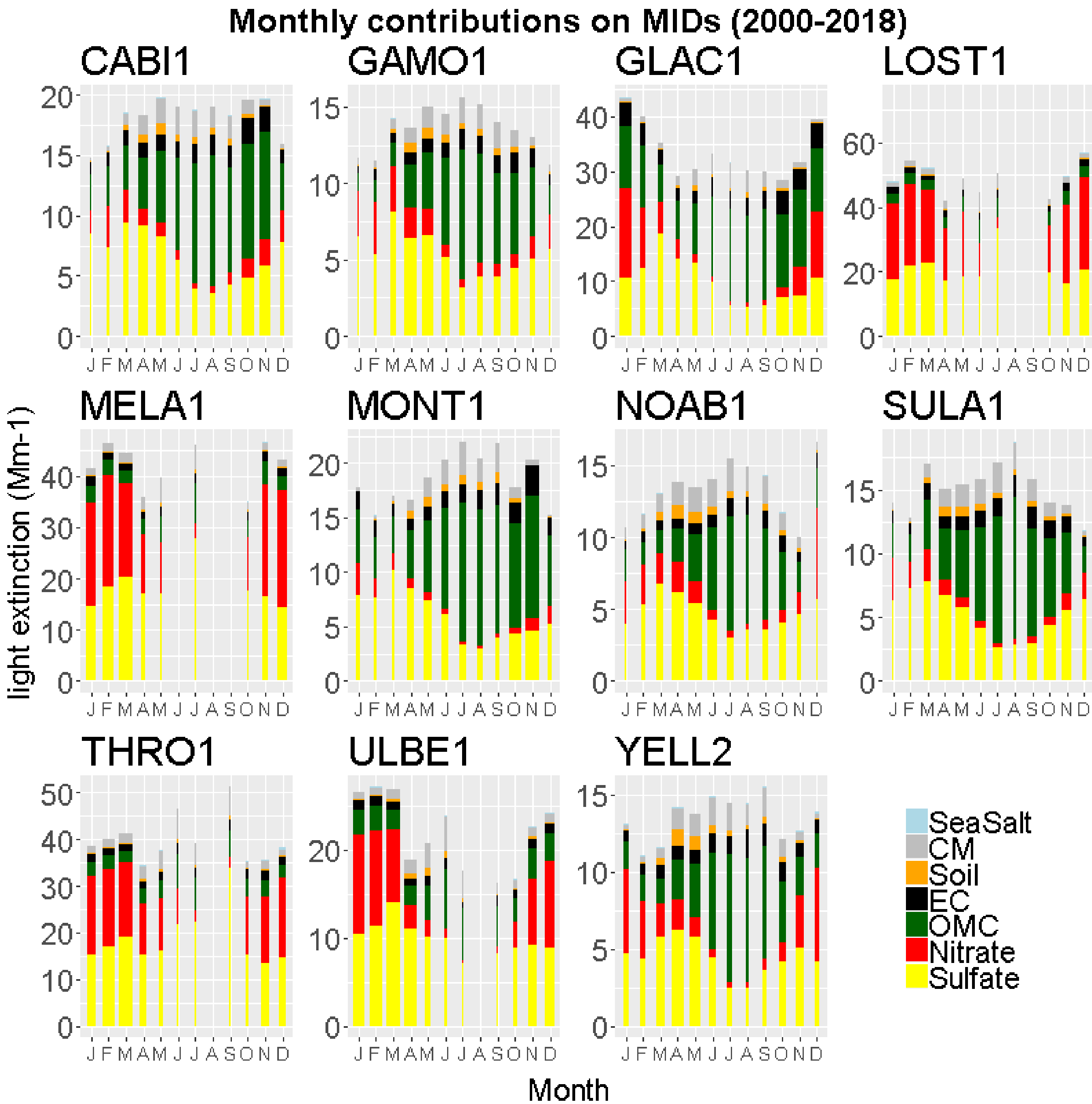


Figure 4-47 shows the same monthly plots, just filtered to the MIDs as determined by the 2017 metric. The width of the bars in the plots are proportional to the number of MIDs that occur in each month. This feature is helpful to highlight just how much weight each month has on the overall MID contribution and which data dominates glidepath progress and the paths to natural improvement by 2064. As can be seen, the effect of EPA's metric is to generally take MID focus off summer carbon-elevated months and to

Figure 4-47. Monthly contributions at MT Class I areas on Most Impaired Days



shift the attention to more nitrate/sulfate impacts during non-summer months. Again, a spatial pattern is notable: the eastern sites generally show very small impacts during summer months while the western sites, while much of the large carbon peaks are removed, still retain an overall large carbon contribution throughout the year compared to other species. This can be attributed to less anthropogenic influences overall, compounded by fire (both wildfire and prescribed fire), which continues to be a large proportion of haze at western Montana Class I areas.

4.5.2 Alternate Metric Considerations

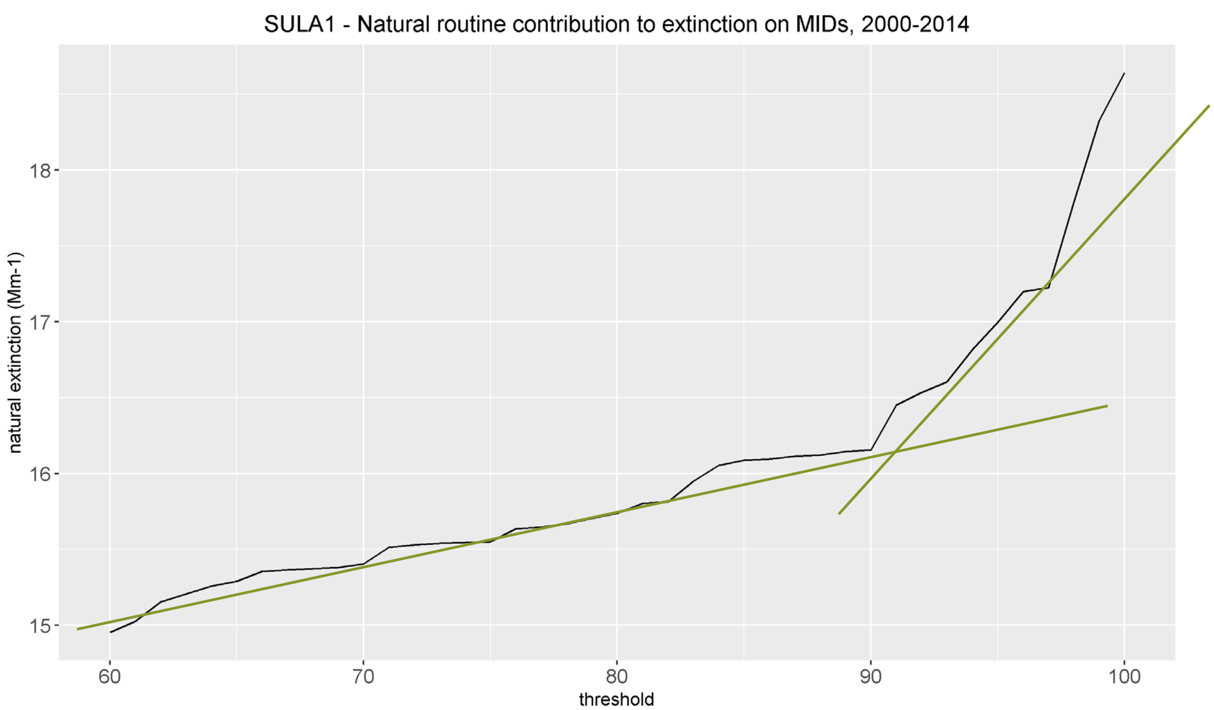
4.5.2.1 Threshold Percentile Adjustment

As described at the beginning of this chapter, EPA's 2017 metric is designed to remove episodic impacts by assigning carbon that exceeds the 95th percentile of the minimum of the fifteen-year period (2000-2014) for each site into a "natural-episodic" bin, while dividing up the remainder between "natural-routine" and "anthropogenic" bins.

One of the goals[83] of the WRAP's Data and Glidepath Subcommittee was to understand the new, restructured metric. The subcommittee also explored alternative percentiles as a way to more appropriately assign the carbon contribution.

The SULA1 site is in an area of western Montana that experiences frequent smoke impacts from regional wildfires; therefore, it is an ideal site on which to test the effect of alternate thresholds. Results for the SULA1 site are discussed below.

Figure 4-48. Alternate Threshold Options Evaluated at SULA1



The monitoring data was processed with EPA's 2017 metric and the threshold was varied from 60-100%-ile to see the variation on MIDs, resulting glidepaths, the split of the bin assignments, and other features. A

83 See Subtask 1.2 of WRAP's Regional Haze Workplan (https://www.wrapair2.org/pdf/2018-2019%20WRAP%20Workplan%20update%20Board%20Approved%20April.3.2019.pdf): The subcommittee was tasked with determining a feasible method for identifying Most Impaired Days, exploring the feasibility of reconstructing the Glide Path by redoing Baseline Conditions and adjusting the Natural Conditions at Class I areas

notable result that was explored as an alternate threshold was to look at the natural routine contribution on MIDs as a function of threshold for the same fifteen-year period and is displayed in Figure 4-48. There appears to be a notable shift when, above 90%-ile in this example, the amount of carbon placed in the natural routine category starts to grow at an increased rate. This can be explained in the following way: above a certain threshold (90%-ile), the selected MIDs begin to include enough elevated carbon contributions, which starts to affect the natural-routine contribution on those days (see equation for natural routine at beginning of chapter). The slope change above 90%-ile in Figure 4-48 could indicate the point when many fire contributions are inadvertently moved to the MIDs. The glidepath for the alternate threshold is shown below in Figure 4-49, alongside EPA's default 95%-ile. The 90%-ile plot shows the 1-year averages dampened compared to the default method, which suggests less elevated impacts included in the MIDs for a reduced threshold.

Figure 4-49. SULA1 Glidepath at 95%-ile and 90%-ile

4.5.2.2 *Use of Satellite Smoke Data*

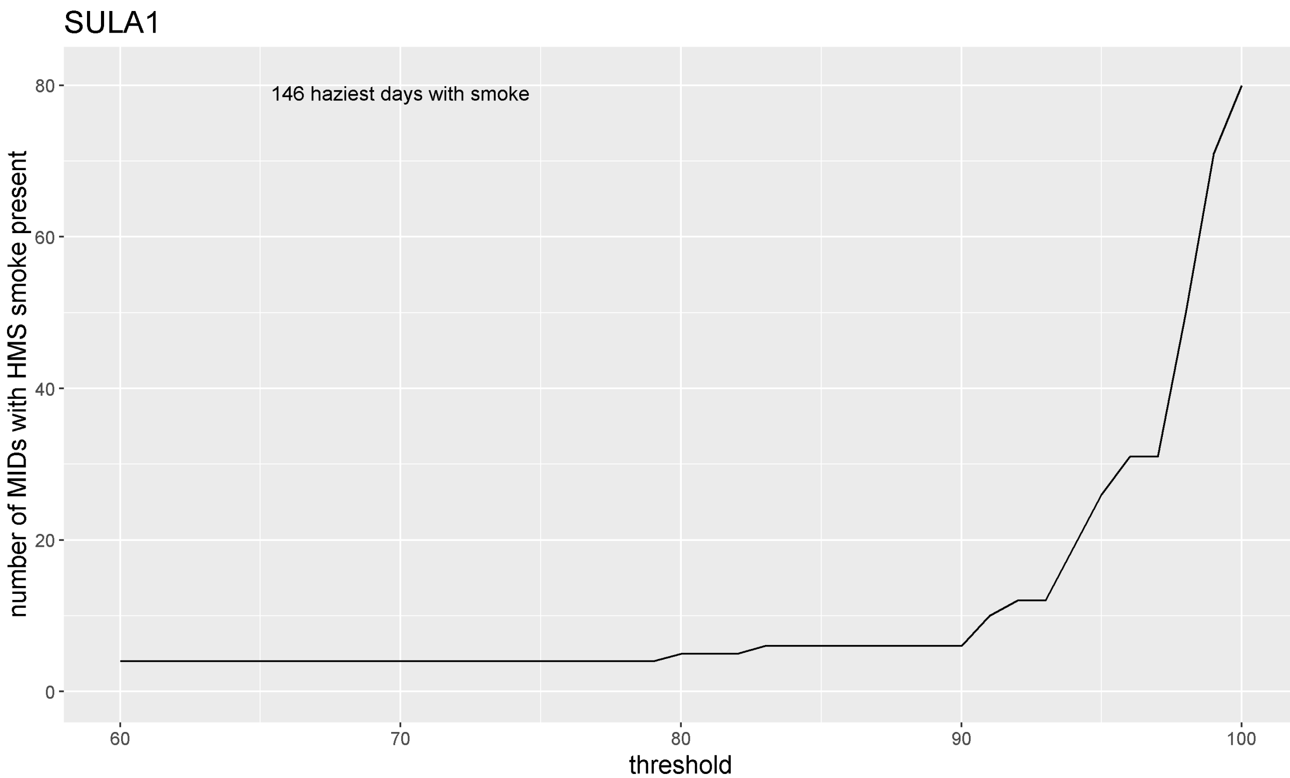
NOAA's Hazard Mapping System (HMS) data[84] was used as an independent check to determine if any correlations existed between the MIDs/threshold and the detected smoke from the satellite analyses. The daily shapefiles were downloaded from the available data (2005-2018) and if a smoke polygon existed "on top of" the IMPROVE monitor, it was assumed that smoke was present that day. This assumption has its limitations, as there are occurrences when smoke is detected but not at ground level, and similarly when

[84]NOAA office of Satellite and Product Operations, Hazard Mapping System Fire and Smoke Product, Available at: https://satepsanone.nesdis.noaa.gov/pub/volcano/FIRE/HMS_ARCHIVE/. (accessed 1/18/2020).

smoke is present at ground level and it is not detected from the satellite observation. However, it was assumed that, on average, the HMS data would serve as a likely indicator of smoke.

To determine if the HMS data could suggest an alternate threshold, an analysis was performed in which the number of MIDs on days with HMS present was looked at as a function of threshold. The results suggested a similar change in behavior above 90%-ile for SULA1, as displayed in Figure 4-50. At and above 90%-ile, the rate at which the MIDs also contain HMS smoke increase rapidly, again suggesting an alternative threshold.

Figure 4-50. Number of MIDs with HMS Smoke Detection vs %-ile Threshold



Another approach using the HMS data was to employ EPA's default 95%-ile with the restraint that a day where HMS smoke was detected during the months of July-September cannot be an MID. This method retained EPA's approach, while manually removing smoky days (and likely wildfire) from the ranking. Additionally, this method served as a way to evaluate the effectiveness of EPA's metric at keeping days dominated by elevated carbon off the MID list and therefore influencing the glidepath progress. As can be seen in Figure 4-51, while this approach did remove smoke days from the MIDs list, it was not enough to significantly change EPA's default approach. An example year for SULA1 (2012) shown in Figure 4-52 illustrates that the default metric removes many of the HMS smoke detected days from the MIDs.

Figure 4-51. Alternate Threshold vs EPA 95%-ile

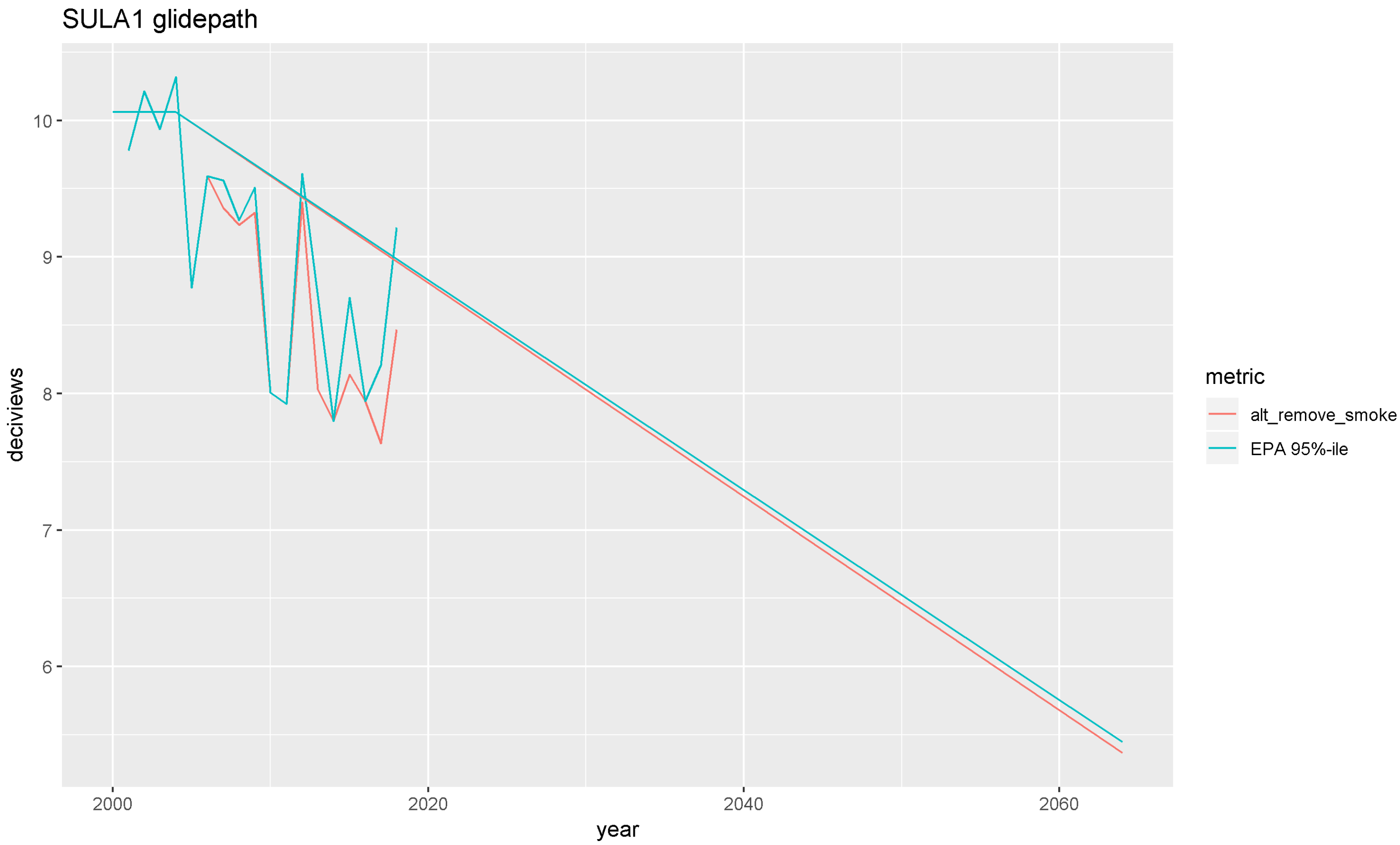
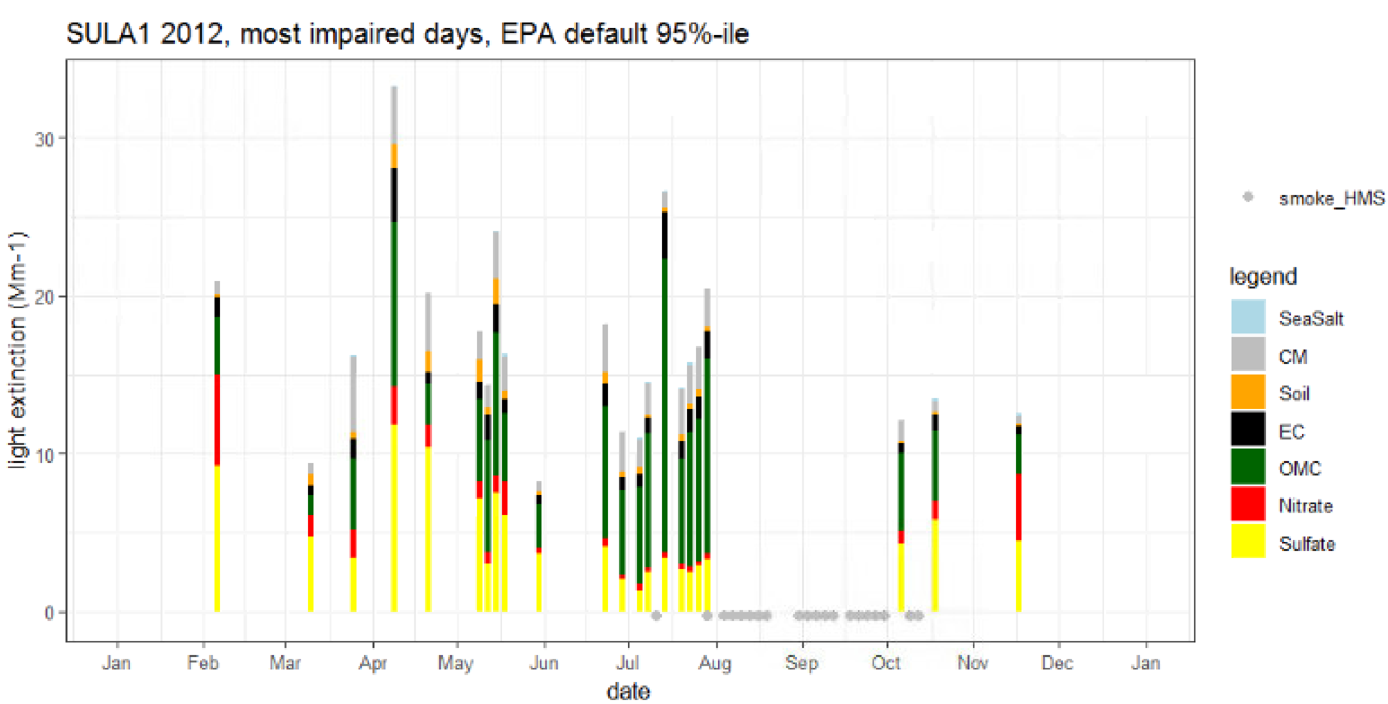


Figure 4-52. 2012 SULA MIDs, EPA 95%-ile



4.5.3 Conclusion

Although metric adjustments were considered for a few Montana sites (SULA1, CABI1, MONT1, GAMO1, GLAC1, and YELL2), there was concern about settling on a method that objectively treated one adjustment methodology across the sites. There are far too many factors at play, making it difficult to choose only one method. It is important to note that anthropogenic, fire (prescribed and wildfire), international, and natural sources all play a role in reducing visibility at Montana Class I areas and affect Montana's Class I areas differently depending on spatial, temporal, meteorological and geographical influences.

The following reasons were offered as to why a simple threshold adjustment did not offer a better approach:

- Montana's NC-II numbers are derived from 1990 estimates of natural levels of species concentrations from across the entire western U.S. Because the NC-II affects the daily natural-routine portion of each sample and ultimately the 2064 endpoint, it is suggested that updated, more regionally relevant, natural conditions be explored.
- The EPA's metric does not simultaneously allow for natural-episodic impacts in future years while also allowing the glidepath's progress to reach natural 2064 targets. Although the natural-episodic portion contributes to the 2064 calculation, the MIDs in future scenarios with anthropogenic reductions applied would inevitably start to migrate towards those days with true episodic impacts, potentially not allowing for 2064 goals to be met, no matter how well controllable emissions' strategies work.

This implementation plan addresses the continued impact of wildfire smoke at Montana Class I areas. On bad wildfire years, the emissions from wildfire smoke from regional and local fires are the largest contributor to haze in Montana's Class I areas. The Montana Forest Action Plan[85] describes that increasing prescribed fire can be a mitigation strategy for reducing emissions from wildfire smoke. An increase in smoke from prescribed fire will occur under this strategy, however through robust smoke management plans, air quality decision makers can control the timing and amount of burning and maintain air quality.

With that in mind, Montana is planning on an increase in prescribed fire emissions in this second implementation period and is one of the reasons why the glidepath for Montana Class I areas is adjusted to account for the prescribed fire impact.

5 EMISSIONS INVENTORY

Along with monitoring data, air emissions inventories are fundamental building blocks in understanding visibility impacts and in developing control strategies to mitigate emissions that cause or contribute to haze in Class I areas. Emissions inventories are compiled for all types of sources, both natural and anthropogenic in origin. The RHR requires the state to provide an emissions inventory of sources, and states use these

[85] Montana Department of Natural Resources (DNRC), Montana Forest Action Plan, Available at: https://www.montanaforestactionplan.org/ (accessed 5/4/2021).

inventories to describe trends, as inputs to regional modeling, and to help inform control strategy decisions. The information in this chapter is referenced in many other sections throughout this document. Table 5-1 provides a crosswalk of the formal RHR requirements for emissions inventories:

Table 5-1. RHR Requirements for an Emissions Inventory

RHR Rule Citation	*RHR Description*
Section 51.308(f)(2)(iii)	Identify the emissions information on which the state's strategies are based and explain how this information meets the RHR's requirements regarding the year(s) represented in the information to the NEI.
Section 51.308(f)(6)(v)	Requires states to submit a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in a Class I area. The inventory must include emissions for the most recent year for which data are available, and estimates for future projected emissions.
Paragraph 51.308(g)(4) of the Regional Haze Rule requires periodic progress reports to contain the following element:	An analysis tracking the change over the period since the period addressed in the most recent plan required under paragraph (f) of this section in emissions of pollutants contributing to visibility impairment from all sources and activities within the State.
Paragraph 51.308(g)(5) requires periodic progress reports to contain the following element:	An assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred since the period addressed in the most recent plan required under paragraph (f) of this section including whether or not these changes in anthropogenic emissions were anticipated in that most recent plan and whether they have limited or impeded progress in reducing pollutant emissions and improving visibility.

The emissions that affect visibility are varied and complex. Emissions from large industrial sources are often measured directly via continuous emissions monitoring equipment or by specific stack tests that measure emissions from the stack. Other source categories, such as mobile emissions from motor vehicles or emissions from fires, are estimated and modeled.

Montana complies with 40 CFR Part 51, Subpart A, Air Emissions Reporting Requirements (AERR) to develop and submit periodic emissions inventories to EPA for inclusion in the National Emissions Inventory (NEI). The 2014 NEI was the starting point to develop a base year emission inventory, used to evaluate the amount of air pollutants known to contribute to poor visibility. A full NEI is created every three years (e.g., 2011, 2014, 2017). The 2014 NEI was the most current and finalized emissions inventory at the beginning of the RH SIP planning for the second implementation period and served as the seed data set for Montana to use in further emission control analyses. However, Section 51.308(f)(2)(iii) requires that states include emissions for the most recent year for which data are available. To meet this requirement, Montana included the 2017 NEI in the tables below.

Montana reviewed the 2014 NEI data and found errors in reporting in the point source emissions submission[86]. The corrected emissions were provided to the RHPWG EI&MP Subcommittee and included as updates to the second planning period's baseline inventory (2014v2). The 2014v2 inventory included emissions from all data categories, providing a snapshot of emissions in Montana and, as Section 2.2.1 described, was used to test model performance. In some cases, the 2014v2 inventory did not accurately portray emissions in certain source categories. A representative baseline, or 'current baseline' was developed to accurately reflect the current emission profile for each source potentially impacting visibility at Class I areas. This inventory is referred to as the RepBase2 and is what was used in the WRAP RepBase2 photochemical grid modeling scenario (Section 2.2.2).

The RepBase2 scenario included emissions of sources not directly measured, such as area sources, mobile sources and wildfire. Due to the high level of processing and analyses involved, estimating these types of emissions is best completed at a regional or national level. Portions of this work was organized through WRAP work groups like the Fire and Smoke and the Oil and Gas workgroups, and other portions were completed through a national initiative.

A key piece necessary to evaluate emissions in the future is the compilation of a forecasted emissions scenario. Projected emissions inventories consider anticipated activity changes and control strategies. For the second implementation period, the RepBase2 inventory was used to create a future year 2028 projected emissions scenario, the "2028 On the Books, On the Way (OTB/OTW)", simply referred to as the 2028OTBa2 inventory. The 2028OTBa2 represents anticipated future emissions and incorporates any changes in emissions between the current representative baseline and 2028 that are expected to result from non-Regional Haze rules and regulations already adopted or anticipated. The 2028 OTBa2 emissions scenario was used to evaluate the feasibility of control technologies selected for the four-factor analyses.

The WRAP began emissions inventory processing prior to the release of the 2017 NEI, which is why the 2014 NEI was used to start RH planning. Since then, the 2017 NEI has been published. Comparing the 204v2 and 2017 emissions inventories in Figure 5-1– Figure 5-4 shows that they are not too different (no major sources of emissions were added after 2014 that could have been missed in the screening for source selection). The following sections detail the emissions information for all sources in Montana, and include comparisons between the 2014v2, RepBase2, 2017 NEI and the 2028 OTBa2 emissions scenarios.

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[86]WRAP Regional Haze Planning Workgroup Emissions Inventory & Modeling Protocol Subcommittee Recommendations for Base Year Modeling (1 Feb. 2019), Available at: https://www.wrapair2.org/pdf/WRAP%20Regional%20Haze%20SIP%20Emissions%20Inventory%20Review%20Documentation_for_Docket%20Feb2019.pdf

5.1 POINT SOURCES

Montana collects annual emissions inventories from permitted point sources and reports these to EPA via the Emission Inventory System (EIS) annually. Point sources are the only EIS data category that Montana collects, QAs and reports to EPA. The remaining data categories are estimated by EPA.

However, in some cases, the 2014 year may not have been representative of typical operations at certain facilities that Montana was considering for additional screening. As further discussed in 6.1 - Source Screening, Montana proposed to use an average of 2014-2017 emissions from the large point sources that were considered for additional four-factor analyses. This average was intended to represent baseline emissions that were closer to more typical operational conditions. The average emissions from these years were used as a screening mechanism and used as a basis for projecting future emissions scenarios. Many screened in facilities chose the 2014-2017 average emissions as being representative. Others chose a different averaging period such as 2017-2018. Montana worked with these stakeholders individually to determine the most representative point-source emission period (see Appendix A for Source Communications) and submitted these updated emissions to the RHPWG EI&MP Subcommittee to be included in the RepBase2 emissions scenario. The 2014v2 emissions were held constant in both the RepBase2 and 2028OTBa2 emissions scenarios for point sources that were not screened-in for additional analyses. Table 5-2 lists the baseline selected for screened-in sources.

Table 5-2. Screened Sources RepBase2 Period

COMPANY	FACILITY_NAME	Baseline?
TALEN MONTANA LLC	COLSTRIP STEAM ELECTRIC STATION #4	2014-2016
TALEN MONTANA LLC	COLSTRIP STEAM ELECTRIC STATION #3	2014-2016
WEYERHAEUSER NR - COLUMBIA FALLS	WEYERHAEUSER-CFALLS	2014-2017
ASH GROVE CEMENT COMPANY	ASH GROVE CEMENT	2017-2018
MONTANA DAKOTA UTILITIES CO	MDU - LEWIS & CLARK STATION	2017-2018
GCC TRIDENT, LLC	TRIDENT FACILITY	2017-2018
YELLOWSTONE ENERGY LIMITED PARTNERSHIP	YELLOWSTONE POWER PLANT	2014-2017
ROSEBURG FOREST PRODUCTS CO	ROSEBURG FOREST PRODUCTS	2014-2017
COLSTRIP ENERGY LTD PARTNERSHIP	COLSTRIP ENERGY LTD PARTNERSHIP	2014-2016
MONTANA SULPHUR & CHEMICAL CO	MONTANA SULPHUR & CHEMICAL	2017-2018
GRAYMONT WESTERN US INC	GRAYMONT WESTERN US INC	2017-2018
EXXONMOBIL FUELS & LUBRICANTS COMPANY	EXXONMOBIL BILLINGS REFINERY	2015-2016
CENEX HARVEST STATES COOPERATIVE INC	CHS INC REFINERY LAUREL	2017-2018
F H STOLTZE LAND & LUMBER CO	F.H. STOLTZE LAND AND LUMBER CO	2017-2018
SIDNEY SUGARS INC	SIDNEY SUGAR FACILITY	2017-2018
PHILLIPS 66 CO	BILLINGS REFINERY	2017-2018
WEYERHAEUSER NR - KALISPELL	WEYERHAEUSER-EVERGREEN	2014-2017
NORTHERN BORDER PIPELINE CO	N. BORDER PIPELINE CO STA. 3	2017-2018

Figure 5-1 shows the visibility-impairing pollutants from all of Montana's point sources, by inventory scenario. Table 5-3 presents the same information in tabular form. Montana chose to focus on these point sources for additional screening, as described in Section 6.1 of this document.

Figure 5-1. Montana Point Emissions by Emissions Scenario

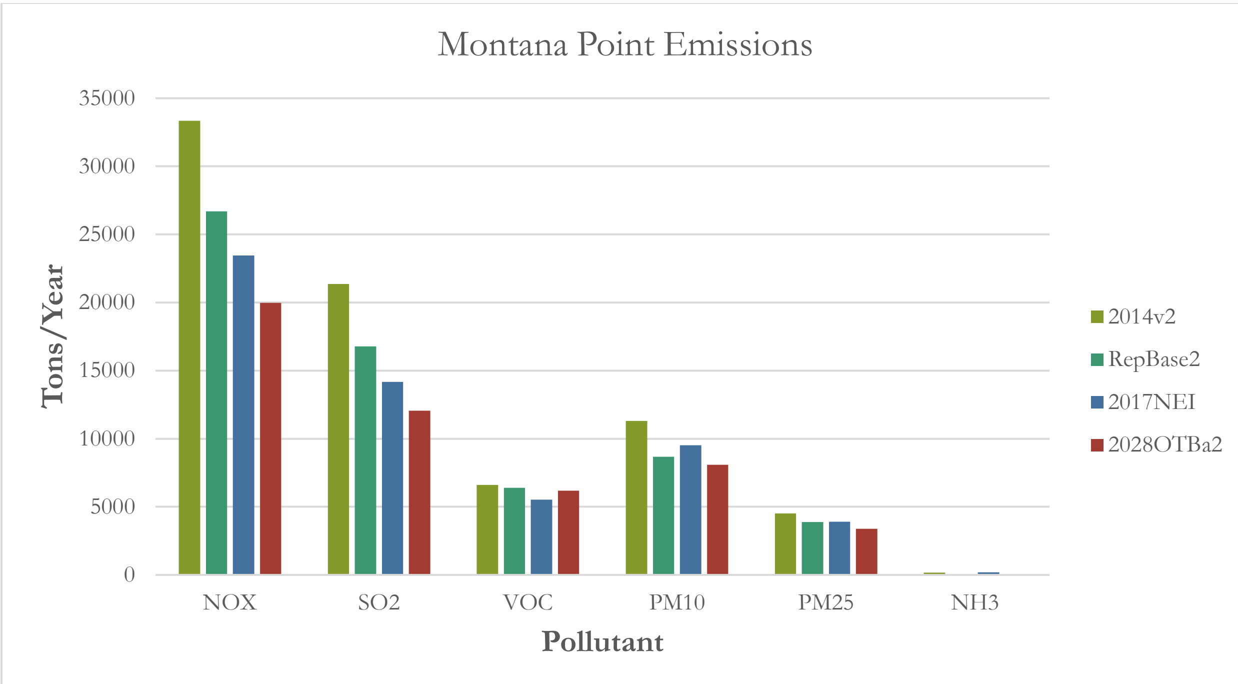

Table 5-3. Montana Point Source Emissions (tons/year)

Pollutant	2014v2	RepBase2	2017NEI	2028OTBa2
NO_X	33,333	26,688	23,459	19,967
SO_2	21,373	16,781	14,168	12,061
VOC	6,595	6,399	5,520	6,179
PM_{10}	11,313	8,677	9,522	8,090
$PM_{2.5}$	4,524	3,880	3,913	3,389
NH_3	168	15	189	15

Figures 5-2–5-3 split Montana's data into EGU emissions and non- EGU emissions sources (including oil and gas point sources). EGU emissions account for a large percentage of emissions in Montana yet have been on a steady decline as shown in Figure 5-2. This is in large part due to the closures of Colstrip's Units 1 and 2, J.E. Corette, and the boiler at MDU Lewis & Clark.

Figure 5-2. Montana NO_x and SO_2 EGU Emissions by Emissions Scenario

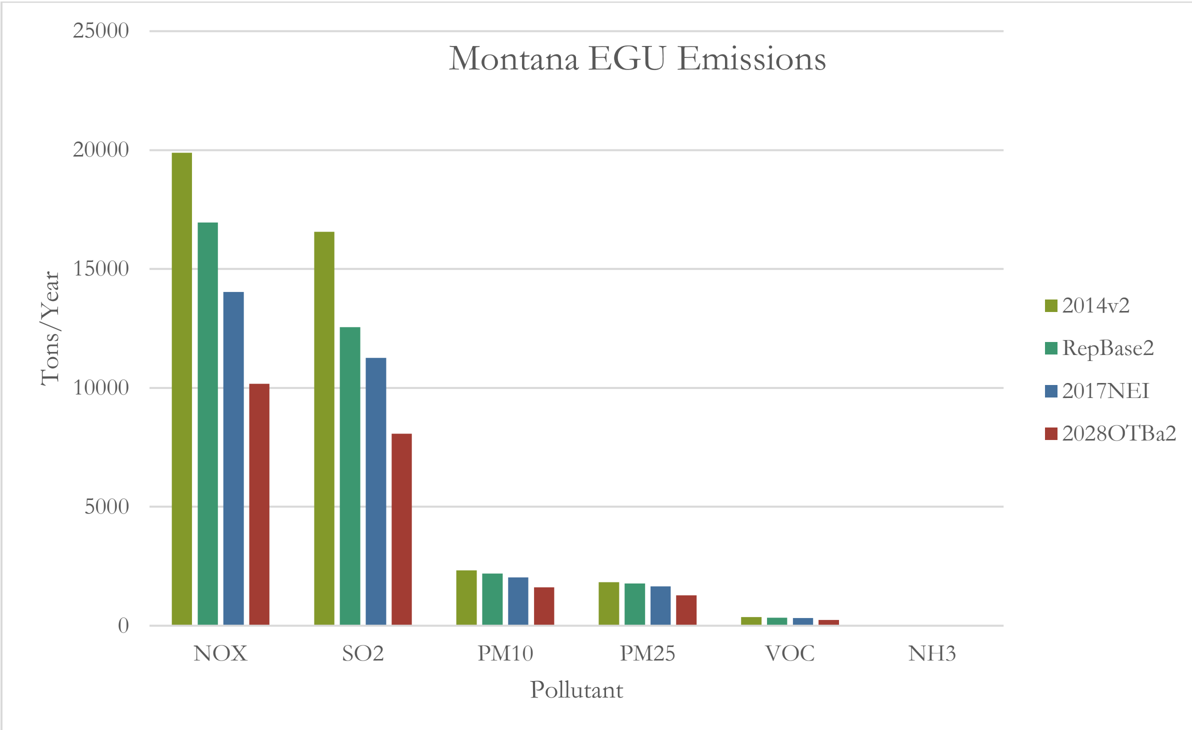

Table 5-4. Montana Coal-fired EGU Emissions (tons/year)

Pollutant	2014v2	RepBase2	2017NEI	2028OTBa2
NO_X	19,885	16,958	14,036	10,167
SO_2	16,566	12,549	11,260	8,079
PM_{10}	2,326	2,195	2,029	1,611
$PM_{2.5}$	1,829	1,771	1,654	1,283
VOC	366	341	325	247
NH_3	6	0	0.4	0

Figure 5-3. NO_x and SO_2 Emissions from Non-EGU Sources by Emissions Scenario

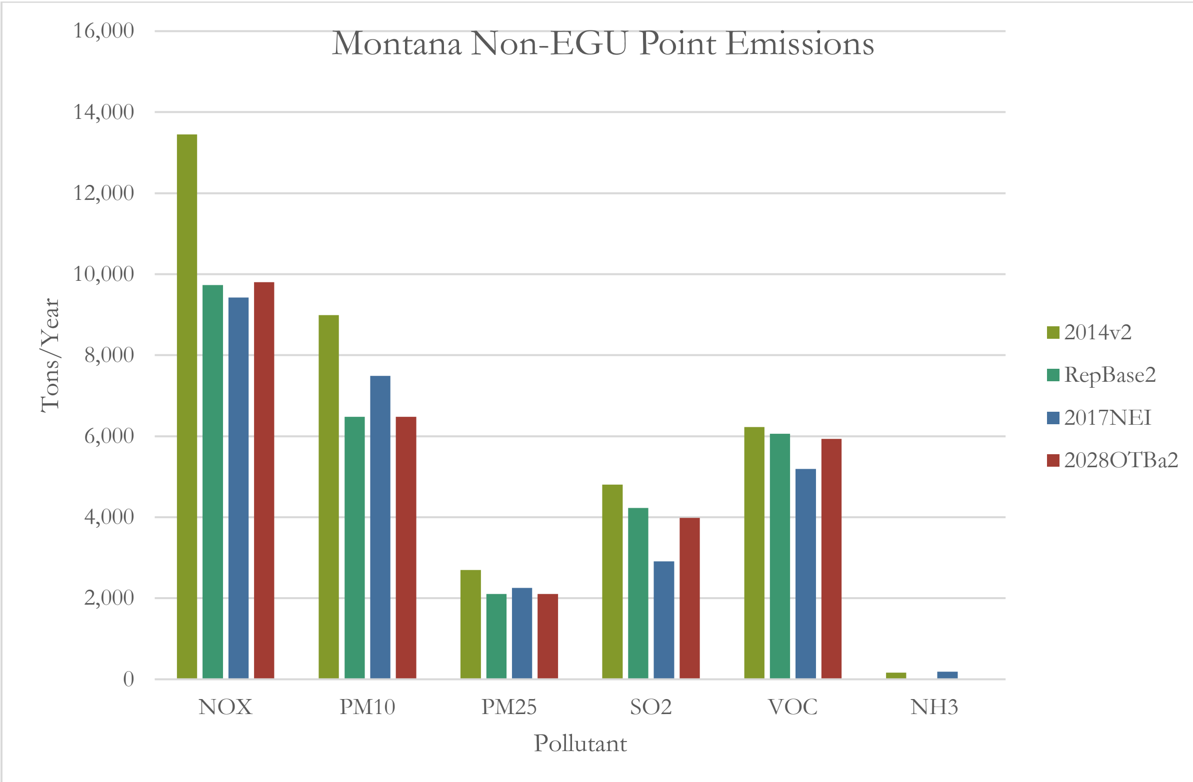

Table 5-5. Montana Non-EGU Emissions (tons/year)

Pollutant	2014v2	RepBase2	2017NEI	2028OTBa2
NO_X	13,448	9,730	9,422	9,800
PM_{10}	8,987	6,482	7,493	6,479
PM2.5	2,695	2,109	2,259	2,106
SO_2	4,807	4,232	2,909	3,982
VOC	6,229	6,058	5,195	5,932
NH_3	162	15	189	15

5.2 Area Sources

Area sources (nonpoint sources) are individual sources that are small and numerous, and that have not been inventoried as mobile, biogenic or specific point sources. These small sources are typically grouped by source classification code, so that emissions can be estimated collectively using one methodology. Montana does not estimate these emissions and instead accepts EPA's estimates.

Montana is a mostly rural state with a small area source emission impact. Figure 5-4 lists the area source emissions by emissions scenario. Of note, Figure 5-4 does not include nonpoint oil and gas sources which are covered separately in Section 5.3. As described in Section 6.1, nonpoint sources were not considered for additional controls, in part because potential control strategies focused on reducing NO_x and SO_2 and, as Figure 5-4 shows, VOC is the main visibility impairing pollutant from nonpoint sources in Montana.

Figure 5-4. Montana Nonpoint Emissions by Emissions Scenario

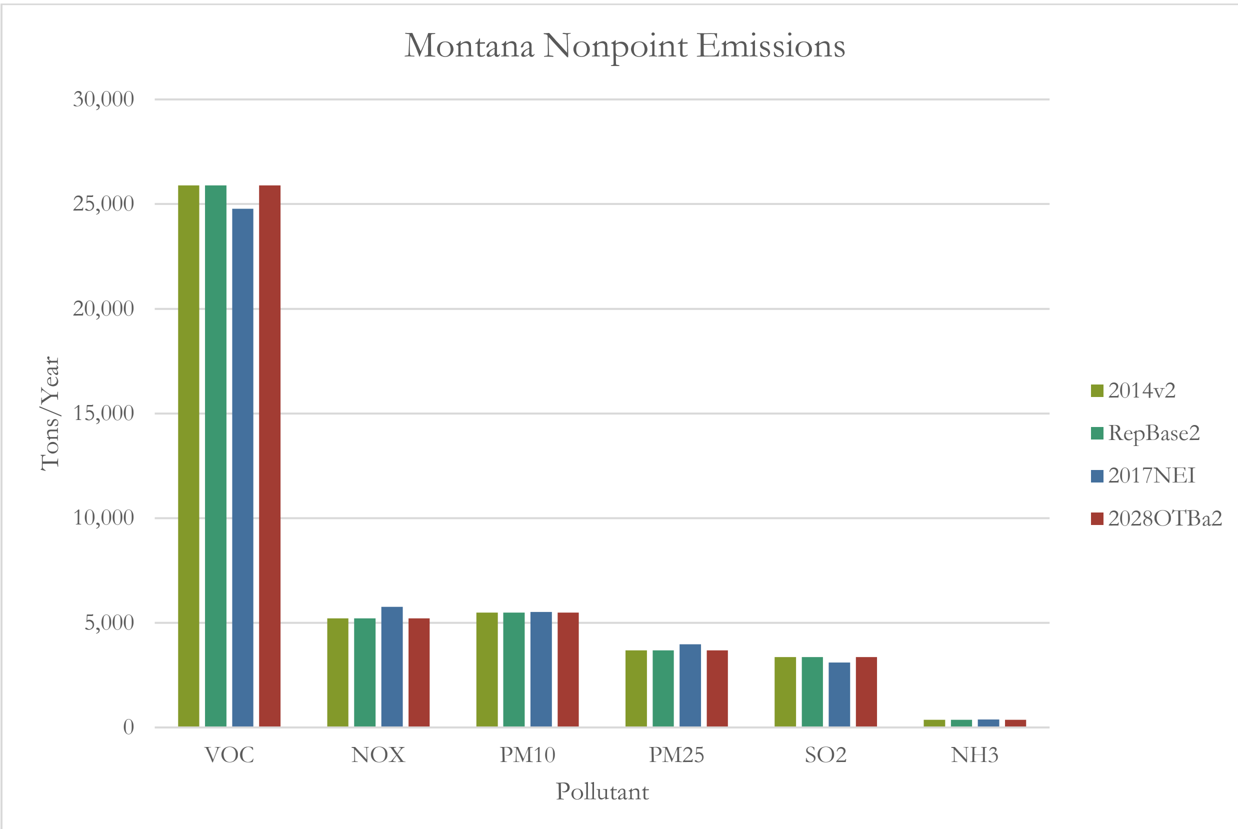

Table 5-6. Montana Nonpoint Emissions (tons/year)

Pollutant	2014v2	RepBase2	2017NEI	2028OTBa2
VOC	25,901	25,901	24,771	25,901
NO_X	5,218	5,218	5,767	5,218
PM_{10}	5,489	5,489	5,521	5,489
$PM_{2.5}$	3,684	3,684	3,979	3,684
SO_2	3,366	3,366	3,095	3,366
NH_3	358	358	381	358

5.3 OIL AND GAS SOURCES

Within the Williston Basin sits the Bakken Formation – a rock formation that contains vast amounts of producible petroleum reserves. Portions of the Bakken Formation run through eastern Montana, although to date, the best production volumes have been generated in the middle portion of the formation located to the west in North Dakota. Therefore, emissions from North Dakota oil and gas sources are substantially larger than those in Montana.

The WRAP Oil and Gas Work Group sponsored the development of oil and gas area source emission inventories as part of efforts to support regional haze planning in the WRAP region. The emission inventory includes emissions from upstream and midstream oil and gas sources, including wellsite, gathering, and processing subsectors. The oil and gas area source emissions included in the 2014v2 emissions scenario were developed for a 2014-2016 baseline period.

The baseline 2014-2016 WESTAR-WRAP region emission inventory was developed using the base year 2014 emissions compiled from existing emission inventory sources.[87] Before compilation of the base year 2014 emission inventory, outreach was conducted to gather additional data from regulatory agencies and upstream O&G operators to enhance the emissions inventory and, to the extent that data was provided, make the inventory applicable to the 2014-2016 baseline period.[88]

The baseline emission inventory was used to create a 2028 future year emissions inventory, termed the Continuation of Historical Trends scenario. This scenario forecasts oil and gas activity for the basins within the WESTAR-WRAP region.[89] The forecasts were developed by well type (oil, gas, and coalbed methane) and spud type (vertical, directional, horizontal) for activity parameters, including spuds, active well count, oil production, and gas production. The Continuation of Historical Trends scenario made the following assumptions:

- Oil development and production continues to be prioritized over gas development and production.
- Development is primarily focused on horizontal wells in tight oil formations such as the Denver Basin Permian Basin, and Williston Basin. Limited exploration activity for vertical wells.
- Production from legacy vertical wells continues to decline and these wells are gradually taken offline.

In the 2028OTBa2 scenario, Williston Basin activity in Montana was unchanged from the base year based on limited recent drilling and recent activity declines. The exception is Williston Basin spudding activity in

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[87] For the Williston Basin, Ramboll used the 2014 Intermountain West O&G Basin Emission Inventory (Parikh et al., 2017) to compile the 2014 base year O&G emissions inventory

[88] Ramboll, Revised Final Report: Circa-2014 Baseline Oil and Gas Emission Inventory for the WESTAR-WRAP Region (Sept. 2019), Available at: https://www.wrapair2.org/pdf/WRAP_OGWG_Report_Baseline_17Sep2019.pdf

[89] Ramboll, Revised Final Report: 2028 Future Year Oil and Gas Emission Inventory for WESTAR-WRAP States – Scenario #1: Continuation of Historical Trends, (March 2019), Available at: https://www.wrapair2.org/pdf/WRAP_OGWG_2028_OTB_RevFinalReport_05March2020.pdf

Montana which was estimated to remain at 2017 levels (18 spuds) which were substantially lower than the activity in base year 2014 (134 spuds).

Estimated emissions inventories for Montana oil and gas area sources are shown in Figure 5-5. NO_x emission decreases in Montana are due primarily to declines in oil and gas activity from the baseline year to the future year. VOC emission decreases in Montana result from the assumption that a higher percentage of associated gas is sent to pipeline compared to the baseline (i.e., lower percentage of associated gas is flared or vented) as well as compliance with New Source Performance Standards (NSPS) Subpart OOOO and OOOOa control program requirements for pneumatic controls and completions.

Figure 5-5. Montana Oil and Gas Area Emissions by Emissions Scenario

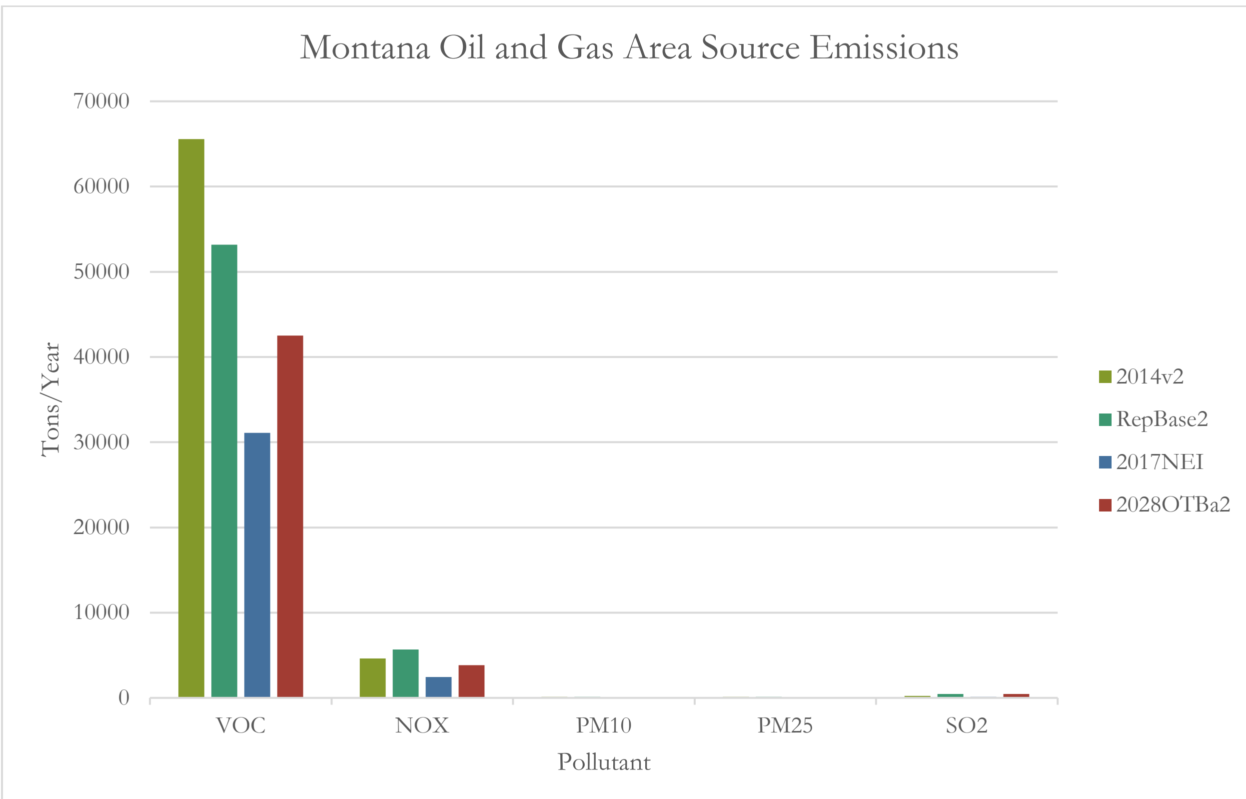


Table 5-7. Montana Oil & Gas Area Emissions (tons/year)

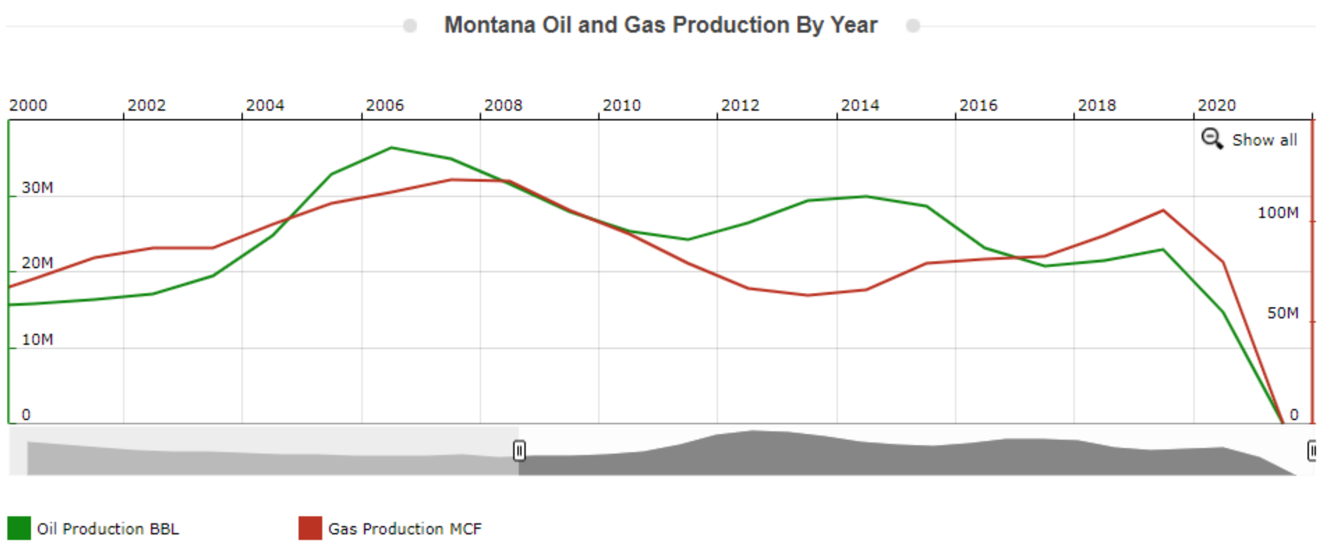
Pollutant	2014v2	RepBase2	2017NEI	2028OTBa2
VOC	65,564	53,188	31,080	42,517
NO_X	4,616	5,660	2,445	3,819
PM_{10}	125	109	88	65
$PM_{2.5}$	125	109	88	65
SO_2	232	440	130	445

Compared to North Dakota, Montana's proven oil and gas reserves are not as prolific as they are across the border. Sections 5.3.1 and 5.3.2 describe in more detail the varying degree of oil and gas production between Montana and North Dakota.

5.3.1 Montana

Montana oil and gas production by year is shown in Figure 5-6 starting in the 2000 base year through the end of 2020.[90] In the graphs, gas production is shown in million cubic feet (MCF) and oil production in barrels (BBL).

Figure 5-6. Changes in Montana Oil & Gas Production



In 2019, Montana's annual oil production increased slightly for the second year in a row, rising to 63,000 barrels per day. However, the state's oil production declined in 2020 along with the decline in petroleum demand and oil prices resulting from the economic effects of the COVID-19 pandemic, with the state's oil output at the lowest level in nearly two decades.[91]

5.3.2 North Dakota

In North Dakota, total oil production was nearly 10 times higher and total gas production was 18 times higher in 2019 than in the baseline period. The state's oil output fell by 17%, or 244,000 barrels per day, in 2020 from 2019's record volume. The decline was mainly due to the drop in oil prices and petroleum demand during the COVID-19 pandemic. However, the state's crude oil production was still almost four times higher than in 2010.[92] Figure 5-7 shows that production has increased dramatically in the past decade.

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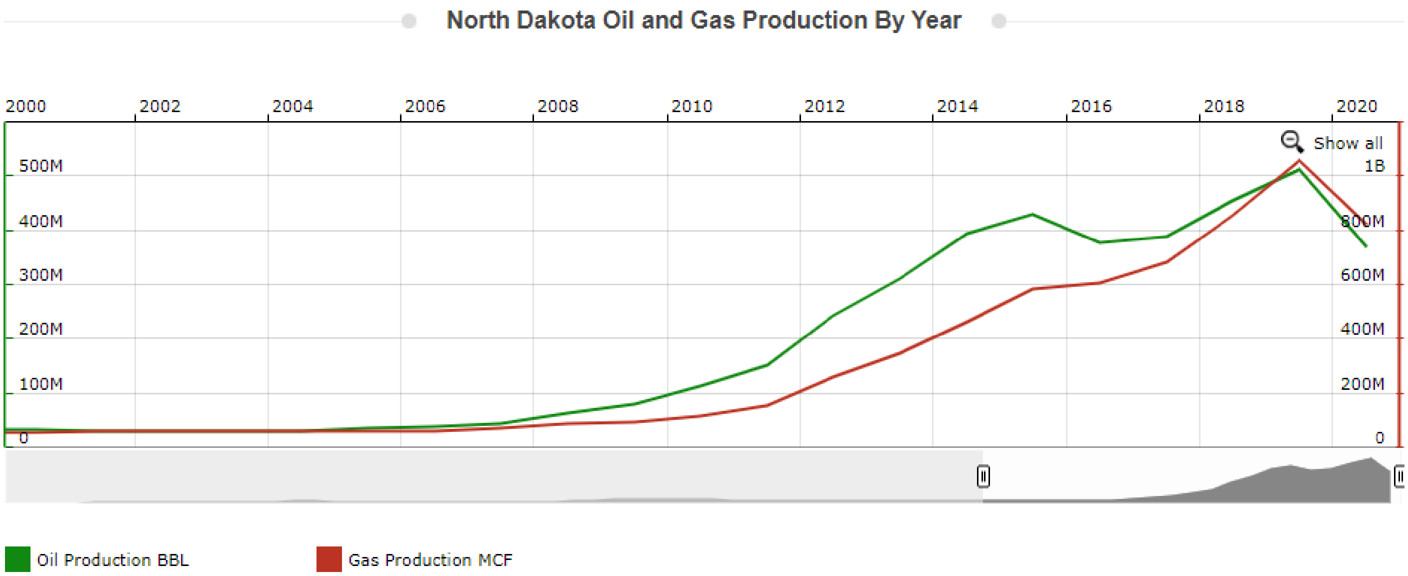
[90] All production data and charts from Drilling Edge, Oil and Gas Data across the United States, www.drillingedge.com (accessed 12/12/2020).

[91] U.S. EIA, Montana Field Production of Crude Oil, Monthly, Thousand Barrels per Day, 1981-2020.

[92] North Dakota Industrial Commission, Department of Mineral Resources, ND Monthly Bakken Oil Production Statistics, (accessed 4/5/2021).

Figure 5-7. Changes in North Dakota Oil & Gas Production[93]



Emissions from oil and gas sources in North Dakota are represented in Figure 5-8. The 2028OTBa2 scenario projects emissions of VOC to be over 400,000 tpy, 10 times the emissions predicted from Montana oil and gas sources in 2028.

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[93] Drilling Edge, North Dakota, www.drillingedge.com/north-dakota.

Figure 5-8. North Dakota Oil and Gas Area Emissions by Emissions Scenario

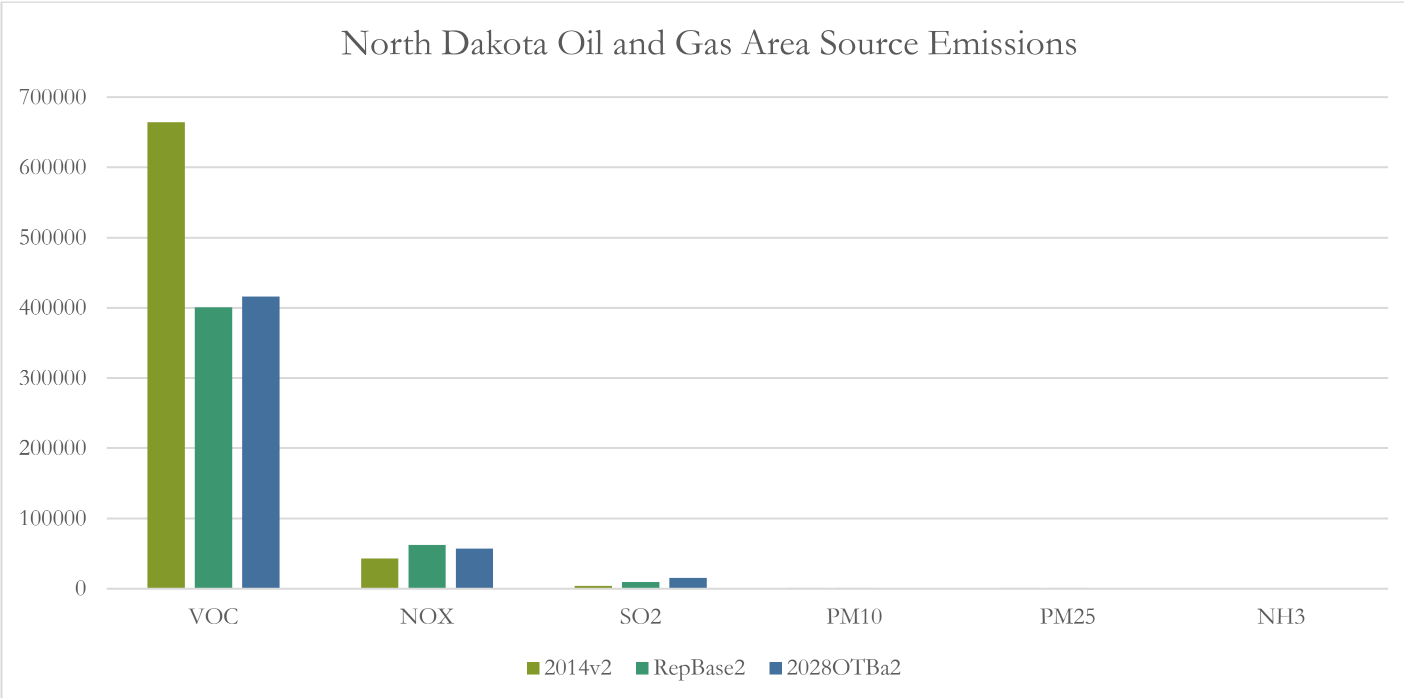


Table 5-8. North Dakota Oil & Gas Area Emissions (tons/year)

Pollutant	2014v2	RepBase2	2028OTBa2
VOC	664,297	400,646	416,111
NO_X	43,237	62,190	57,269
SO_2	4,043	9,391	15,203
PM_{10}	1,129	1,116	562
$PM_{2.5}$	1,129	1,116	562

5.4 Fire

Fire, both wildfire and prescribed fire, is a significant source of visibility-impairing pollutants in Montana Class I areas. Although the revised tracking metric does well to remove extreme episodic events for the most impaired days data set, the fact is that fire emissions are a large source of visibility impairment, during peak tourism season at Class I areas. The following table shows the amount of visitors monthly to Glacier NP from 2014 – 2020, the highest to date occurring in July and August of 2017:

Table 5-9. Monthly Visitation at Glacier NP – 2014 - 2020

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2020	13,651	18,020	24,377	0	0	202,701	453,977	459,121	343,911	125,544	29,366	28,196
2019	13,581	11,240	23,989	35,491	167,403	544,088	879,711	771,874	488,909	78,408	20,008	15,137
2018	12,222	11,847	21,758	28,404	195,116	556,304	905,959	667,688	434,600	91,973	20,657	18,781
2017	14,690	13,802	19,336	38,323	177,787	620,962	1,009,665	908,479	389,137	84,469	15,594	13,268
2016	15,674	16,548	21,257	55,125	183,925	485,017	818,481	748,565	482,592	75,797	30,823	12,877
2015	12,087	14,530	18,139	48,270	134,741	414,671	689,064	579,007	351,388	71,297	19,505	13,357
2014	12,111	10,242	13,214	28,667	112,187	334,074	699,650	675,119	353,497	72,694	15,706	11,367

Record number of visitors in Glacier N.P. coincided with one of the worst wildfire seasons Montana has experienced. Figure 5-9 and Figure 5-10 show impacts from large wildfires that burned in the western U.S. in summer of 2017. These fires generated smoke plumes that were transported across North America, resulting in measured $PM_{2.5}$ concentrations that, for weeks at a time, registered at Unhealthy to Hazardous levels in many areas, based on U.S. Air Quality Index definitions.

Figure 5-9. September 3, 2017 – Wildfire Smoke Impacts Across the West

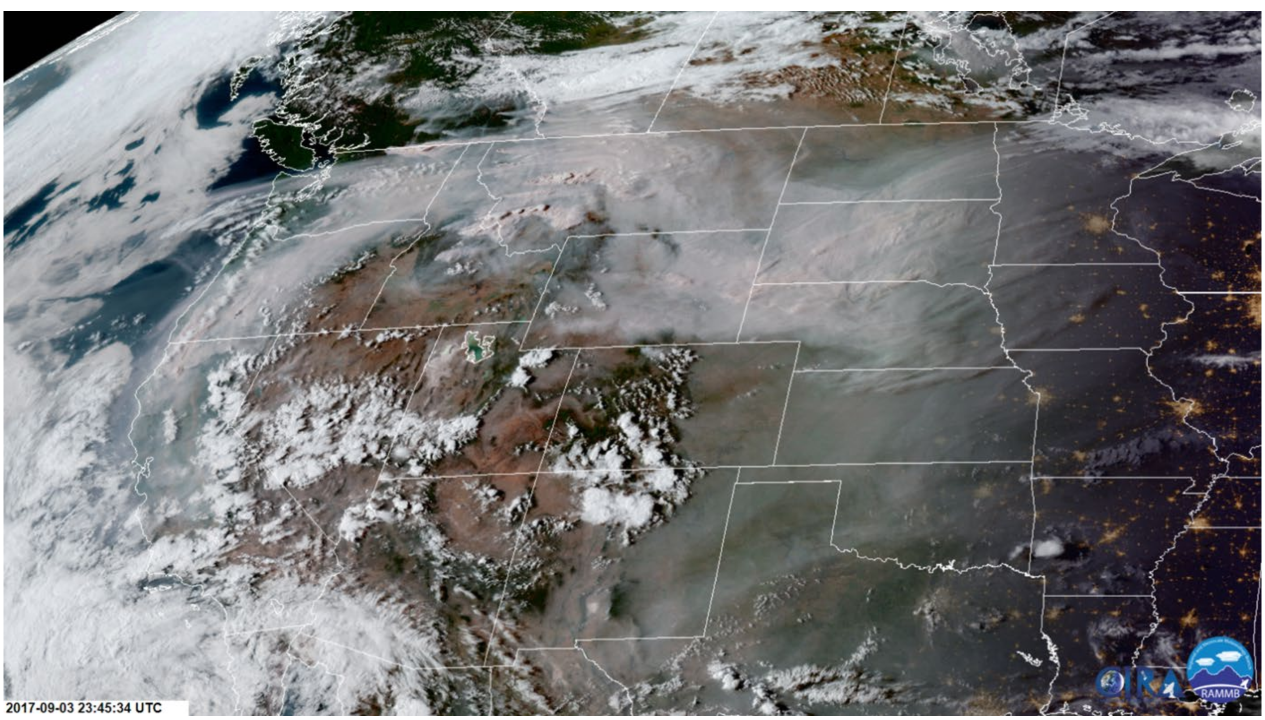
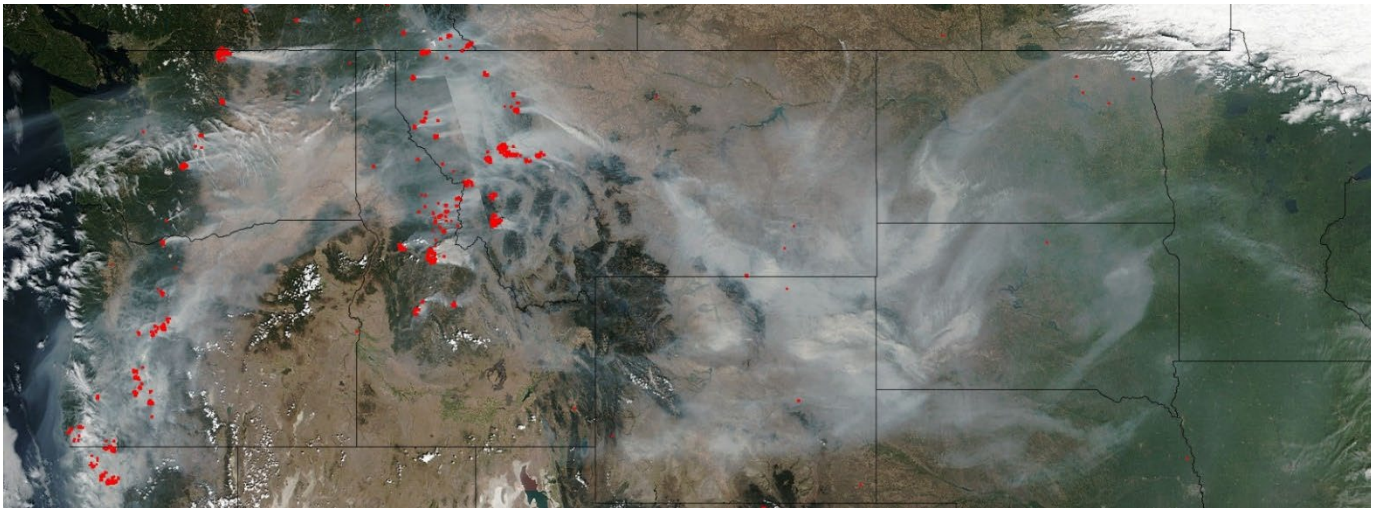


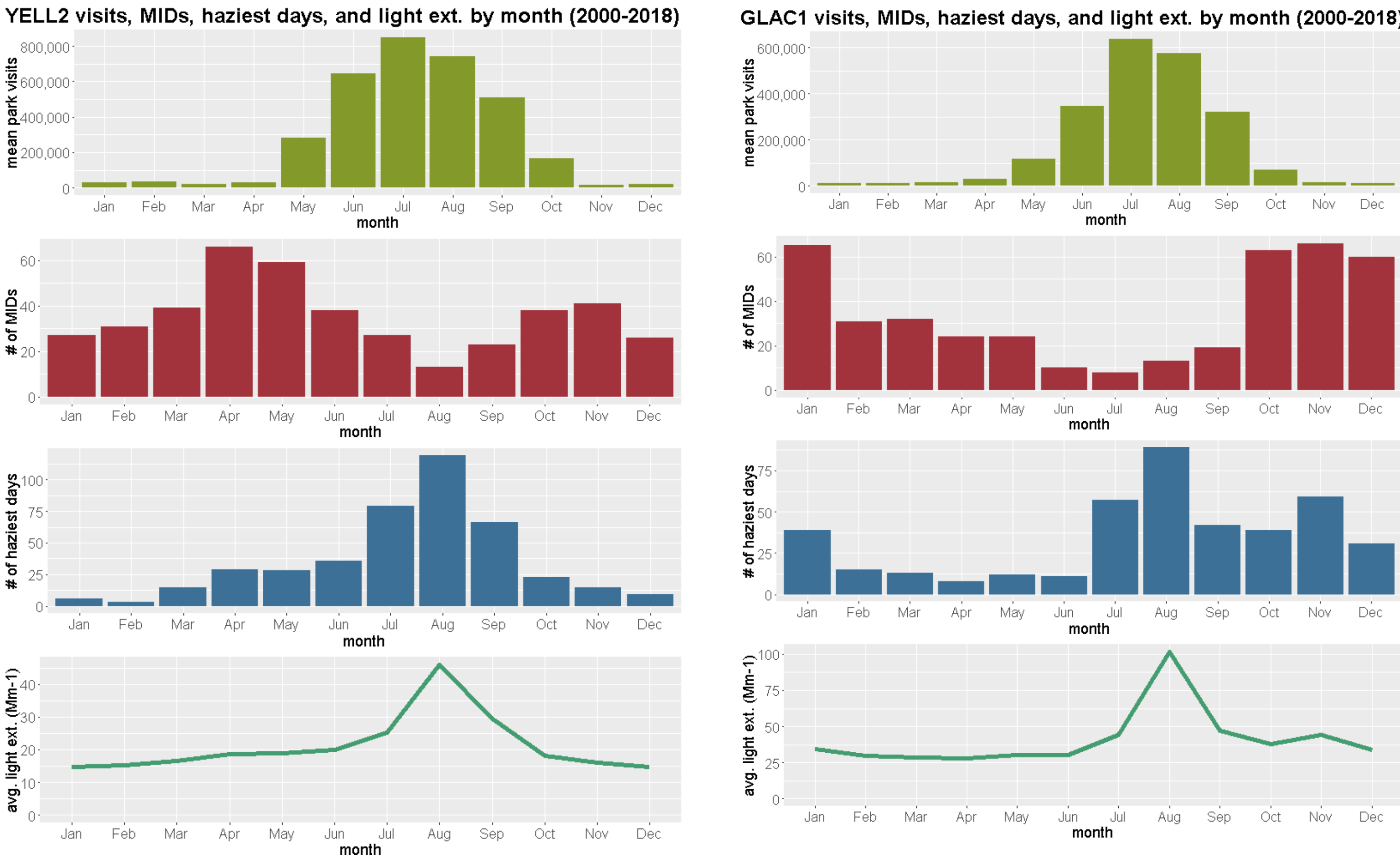
Figure 5-10. September 5, 2017 - MODIS Imagery: Active Fires & Resultant Smoke Plumes



Until recently, 2017 was considered one of the most active fire years in recent history in Montana and throughout the West. In 2020, the West - namely California - faced another record year in terms of acres burned from wildfire.

Figure 5-11 graphs a few different items. The mean park visits to both Yellowstone NP and Glacier NP from 2000-2018 are listed in the top two green bar charts. Underlying this information are the number of MIDs (in red), the number of haziest days (in blue) and the average light extinction (teal line). The message this data conveys is that most people visit these two parks during a time of year where we can expect to see hazy skies, namely due to wildfire smoke impacts.

Figure 5-11. Yellowstone & Glacier NP visitation, MIDs, haziest days and average light extinction (2000-2018)



Recent dramatic increases in wildfire activity have increased attention on the causes of wildfires, their consequences, and how risk from wildfire might be mitigated. One solution is to increase prescribed fire as a means to reduce subsequent wildfire activity. Although smoke is an impact of both wildfire and prescribed burning, prescribed fires are regulated and monitored by state and local government agencies and subject to strict air-quality standards.[85] Emissions from prescribed fires can be mitigated by ensuring burning is conducted on days with good to excellent dispersion. In contrast, wildfires burn uncontrolled, often in areas with heavy fuels built up over decades. National forest management messaging is to increase the use of prescribed fire, not only to improve the ecological integrity of forest, but as a means toward reducing the severity of wildfire.[94] Despite changes in federal fire management policy meant to increase prescribed fire use, the western U.S. is not conducting enough prescribed burns to ward off the potential for more

[94] Courtney Schultz, Sarah McCaffrey, and Heidi Huber-Stearns, "Policy barriers and opportunities for prescribed fire application in the western United States", International Journal of Wildland Fire, 2019, 28, 874-884, (3 Sept. 2019), Available at: https://www.fs.fed.us/rm/pubs_journals/2019/rmrs_2019_schultz_c002.pdf

wildfire.[95] This is due in part to negative public perception in the west regarding prescribed fire, shorter burn seasons, and remote and varied terrain that can be difficult to access. However, Montana anticipates that prescribed fire activity will increase in the future, thereby increasing emissions in seasons outside of the typical summer wildfire season.

The following graphs and tables show emissions from prescribed and wildfire activities in Montana. For comparison, Table 5-12 lists emissions from fire throughout the West.

Figure 5-12. Montana Rx Fire Emissions by Emissions Scenario

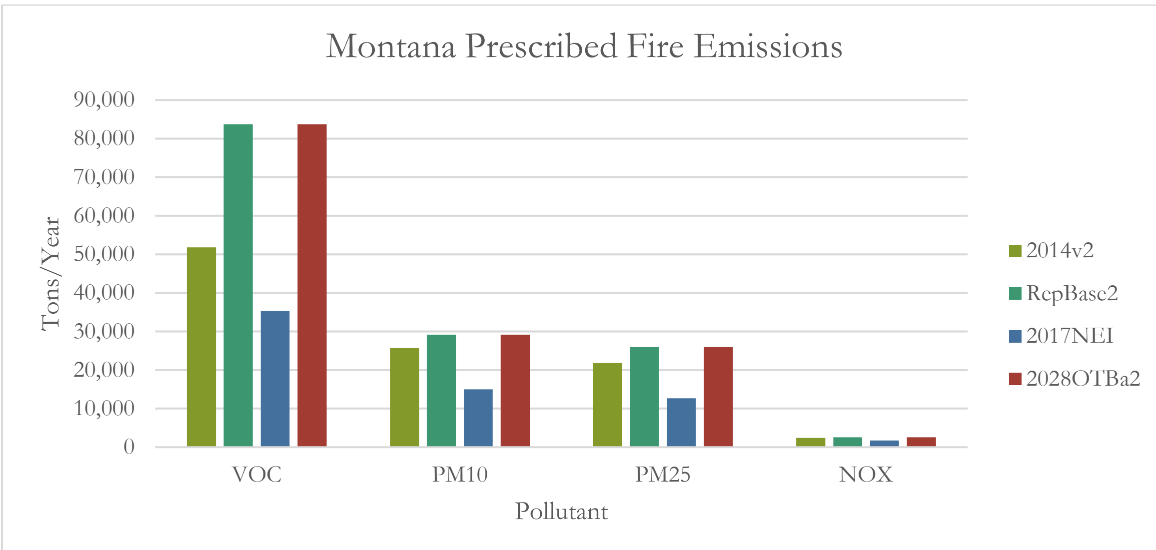


Table 5-10. Montana Prescribed Fire Emissions (tons/year)

Pollutant	2014v2	RepBase2	2017NEI	2028OTBa2
VOC	51,796	83,751	35,320	83,751
PM_{10}	25,723	29,143	15,000	29,143
$PM_{2.5}$	21,799	25,914	12,712	25,914
NO_X	2,448	2,562	1,751	2,562

[95] Crystal A. Kolden, Department of Forest, Rangeland, and fire Sciences, University of Idaho. "We're not doing enough prescribed fire in the Western United States to mitigate wildfire risk", Fire, (29 May 2019), Available at: https://www.mdpi.com/2571-6255/2/2/30/htm

Figure 5-13. Montana Wildfire Emissions by Emissions Scenario

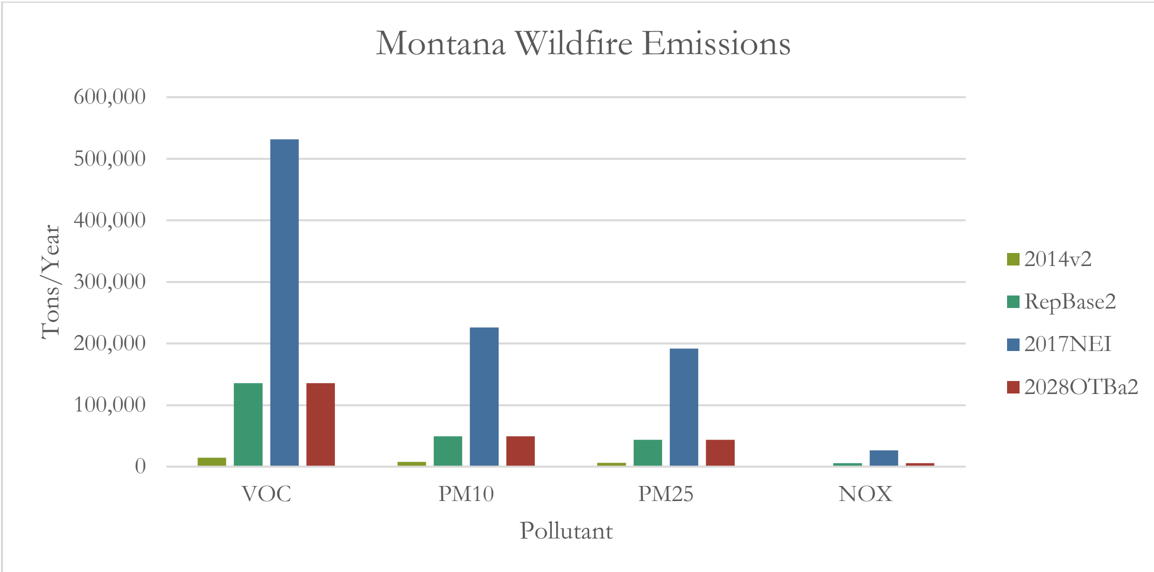


Table 5-11. Montana Wildfire Emissions (tons/year)

Pollutant	2014v2	RepBase2	2017NEI	2028OTBa2
VOC	14,519	135,502	531,402	135,502
PM_{10}	7,553	49,466	225,991	49,466
$PM_{2.5}$	6,401	43,838	191,518	43,838
NO_X	723	5,915	26,735	5,915

Table 5-12. Western States' Wildfire and Rx Fire Emissions - RepBase2 Scenario

AZ

Pollutant	rxfire	wildfire
NO_X	995	981
PM_{10}	15,311	8,619
$PM_{2.5}$	13,522	7,230
VOC	44,672	22,318

CA

Pollutant	rxfire	wildfire
NO_X	2,280	32,477
PM_{10}	34,294	510,987
$PM_{2.5}$	30,141	450,518
VOC	100,086	1,501,452

CO

Pollutant	rxfire	wildfire
NO_X	517	6,429
PM_{10}	7,988	102,919
$PM_{2.5}$	7,047	90,939
VOC	23,215	302,963

ID

Pollutant	rxfire	wildfire
NO_X	1,995	3,614
PM_{10}	31,161	46,254
$PM_{2.5}$	27,494	40,131
VOC	91,219	132,774

MT

Pollutant	rxfire	wildfire
NO_X	2,562	5,915
PM_{10}	29,143	49,466
$PM_{2.5}$	25,914	43,838
VOC	83,751	135,502

NV

Pollutant	rxfire	wildfire
NO_X	91	1,754
PM_{10}	1,046	10,641
$PM_{2.5}$	898	8,344
VOC	2,951	25,760

NM

Pollutant	rxfire	wildfire
NO_X	574	3,098
PM_{10}	8,506	18,938
$PM_{2.5}$	7,495	15,094
VOC	24,854	45,934

ND

Pollutant	rxfire	wildfire
NO_X	593	221
PM_{10}	2,542	564
$PM_{2.5}$	2,369	541
VOC	6,605	1,518

OR

Pollutant	rxfire	wildfire
NO_X	4,961	11,871
PM_{10}	71,980	176,734
$PM_{2.5}$	63,095	155,221
VOC	208,921	516,471

SD

Pollutant	rxfire	wildfire
NO_X	1,445	8,049
PM_{10}	15,778	33,282
$PM_{2.5}$	14,152	30,800
VOC	43,629	84,371

UT

Pollutant	rxfire	wildfire
NO_X	572	2,063
PM_{10}	8,097	20,318
$PM_{2.5}$	7,092	17,381
VOC	23,415	54,614

WA

Pollutant	rxfire	wildfire
NO_X	1,614	9,347
PM_{10}	24,800	151,506
$PM_{2.5}$	21,860	133,868
VOC	72,388	445,834

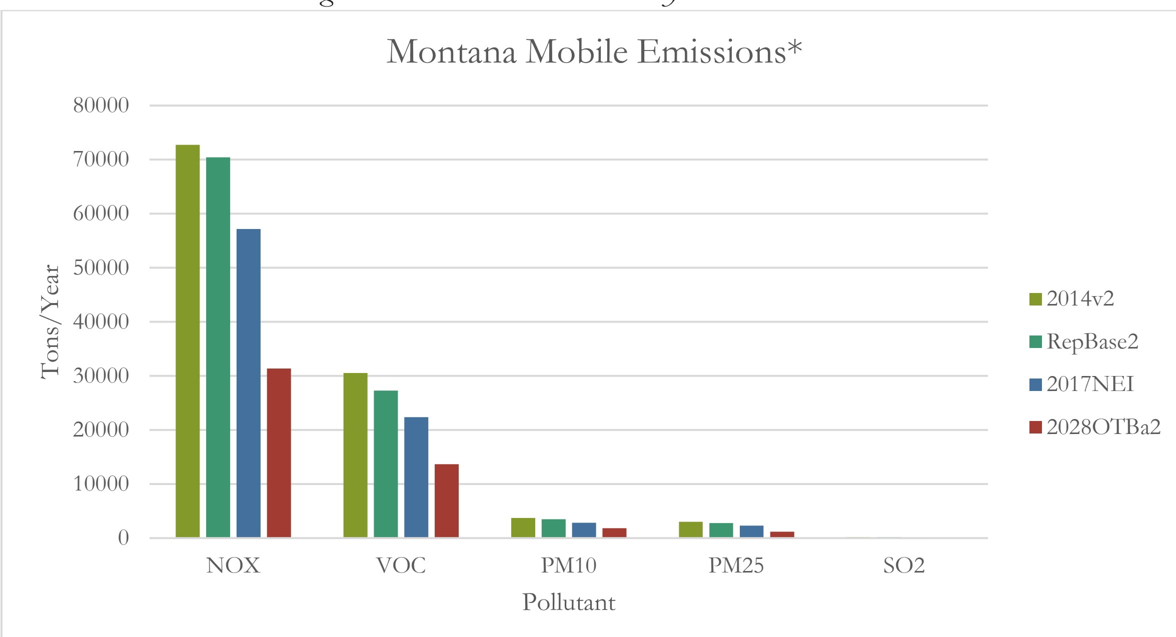
WY

Pollutant	rxfire	wildfire
NO_X	606	7,359
PM_{10}	7,794	32,137
$PM_{2.5}$	6,881	28,563
VOC	22,475	80,425

5.5 MOBILE (ONROAD & NONROAD)

Mobile sources include vehicles, engines and equipment, that can be categorized as either on-road mobile sources (e.g. trucks, buses, passenger cars, and motorcycles) or non-road mobile sources (e.g. locomotives, marine vessels, construction equipment, lawn, garden and snow equipment, personal recreation equipment, etc.). WRAP contracted Ramboll to develop the mobile (onroad and nonroad) source emissions inventory for use in RH planning.[96] As Figure 5-14 shows, NOx emissions are expected to decrease 57 percent from 2014 to 2028. Mobile emissions in Montana, and across the country, have been declining since the early 2000s, mainly due to federal standards such as diesel fuel standards and the Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements[97]. In 2014, EPA published the Tier 3 Motor Vehicle Emission and Fuel Standards, with additional reductions beginning in 2017. In Montana, mobile source NOx emissions made up 60 percent of total NOx emissions (72,706 total mobile vs 119,676 statewide total NOx). In 2028, mobile sources make up 45 percent of total NOx emissions (31,394 total mobile vs 69,507 statewide total NOx).

Figure 5-14. Mobile Emissions by Emissions Scenario*



*In this graph, mobile includes emissions from onroad, nonroad and rail sources

[96] Ramboll to WESTAR-WRAP Memorandum - Mobile Source Emissions Inventory Development for Implementation in WRAP Regional Haze modeling (13 Mar. 2020), Available at: https://views.cira.colostate.edu/docs/wrap/mseipp/WRAP_MSEI_Summary_Memo_13Mar2020.pdf (accessed October, 2020)

[97] Available at https://www.govinfo.gov/content/pkg/FR-2000-02-10/pdf/00-19.pdf (accessed October, 2020)

Table 5-13. Montana Onroad Mobile Emissions (tons/year)

Pollutant	2014v2	RepBase2	2017NEI	2028OTBa2
NO_X	38,220	38,220	27,635	12,767
PM_{10}	1,798	1,798	1,330	1,065
$PM_{2.5}$	1,224	1,224	847	463
SO_2	117	117	89	62
VOC	20,065	20,065	15,813	9,019

Table 5-14. Montana Nonroad Mobile Source Emissions (tons/year)

Pollutant	2014v2	RepBase2	2017NEI	2028OTBa2
NO_X	34,486	32,180	29,517	18,627
PM_{10}	1,919	1,677	1,507	752
$PM_{2.5}$	1,815	1,585	1,454	722
SO_2	37	29	29	24
VOC	10,467	7,220	6,577	4,651

5.6 International Emissions

Section 3.1.5 and Section 4.3.1 both describe international emissions and their impact to Montana's Class I areas. In this section, we present more information on Canadian emissions, specifically British Columbia, Alberta, and Saskatchewan, the provinces that abut Montana.

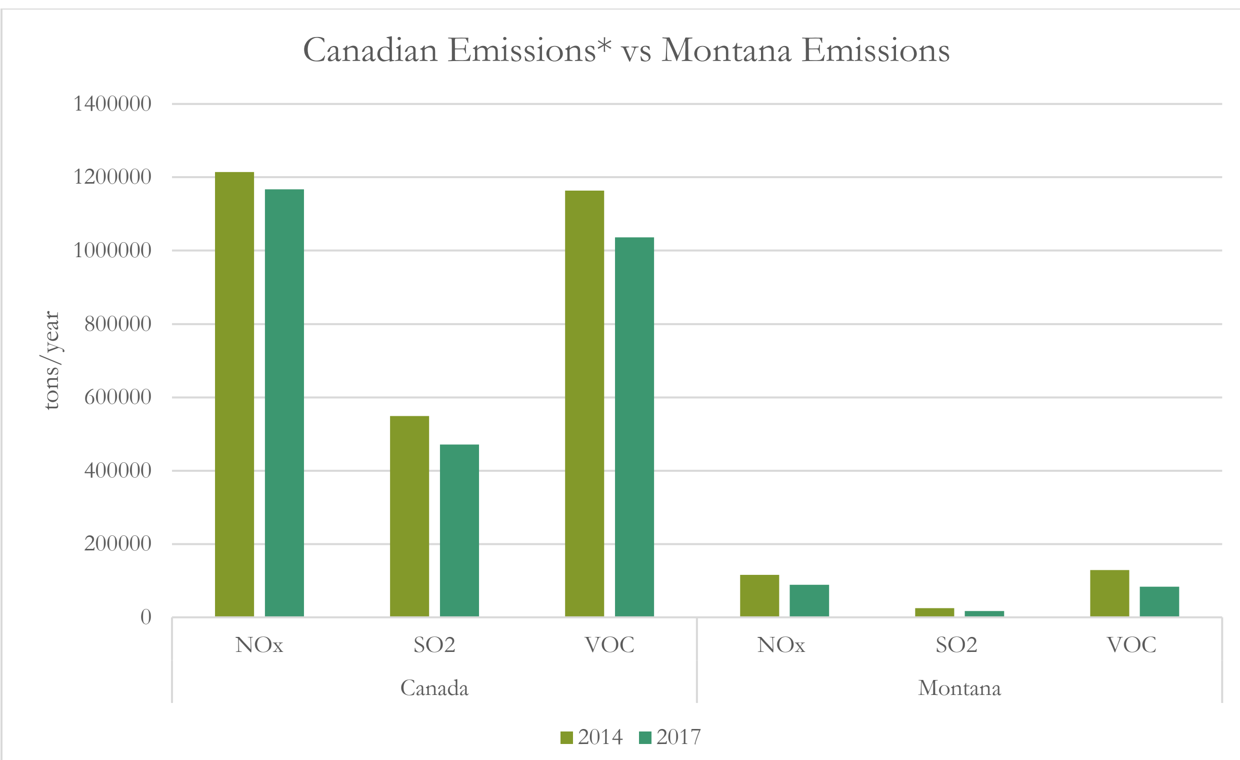
The anthropogenic NOx, SO_2 and VOC emissions from these provinces are summarized in Table 5-15 and are included here as a comparison to Montana emissions. Canada's 2014 and 2017 emissions are similar to the 2014v2 and RepBase2 scenario, respectively. The magnitude of the 2017 international emissions helps support the use of an adjusted glidepath for Montana Class I areas (Section 4.3.1). Montana obtained the Canadian emissions data online from the government of Canada website.[98]

[98] Government of Canada, Air Pollutants Emissions Inventory online search. Available at: https://pollution-waste.canada.ca/air-emission-inventory/ (accessed 6/8/2021).

Table 5-15. Total Canadian Anthropogenic Emissions (tons/year)

		Year	
	Pollutant	2014	2017
Alberta	NOx	750,454	703,884
	SO_2	318,555	264,988
	VOC	722,539	595,413
British Columbia	NOx	298,608	303,225
	SO_2	113,350	80,728
	VOC	180,296	168,170
Saskatchewan	NOx	164,949	159,831
	SO_2	116,920	125,633
	VOC	260,964	272,978
Total of four the Canadian Provinces	NOx	1,214,011	1,166,940
	SO_2	548,825	471,349
	VOC	1,163,799	1,036,561
Montana	NOx	115,873	88,824
	SO_2	25,125	17,512
	VOC	128,592	83,762

Figure 5-15. Montana and Canadian Anthropogenic Emissions*



*British Columbia, Alberta & Saskatchewan Provinces

5.6.1 Nearby Canadian Coal-Fired EGUs

Table 5-16 compares Montana coal-fired EGU emissions to nearby Canadian coal-fired EGUs. The three nearby Canadian facilities were included in this analysis since Montana's Class I areas are likely impacted by emissions from these sources because they have significant NO_X and SO_2 emissions, are near Montana Class I areas, and are upwind in the local prevailing wind direction. The locations of Boundary Dam Power Station (813 MWe), Shand Power Station (279 MWe), and Poplar River Power Station (630 MWe) are displayed in Figure 5-16 along with the Montana four factor sources.

Figure 5-16. Canadian coal-fired EGUs and select Montana Four-Factor sources

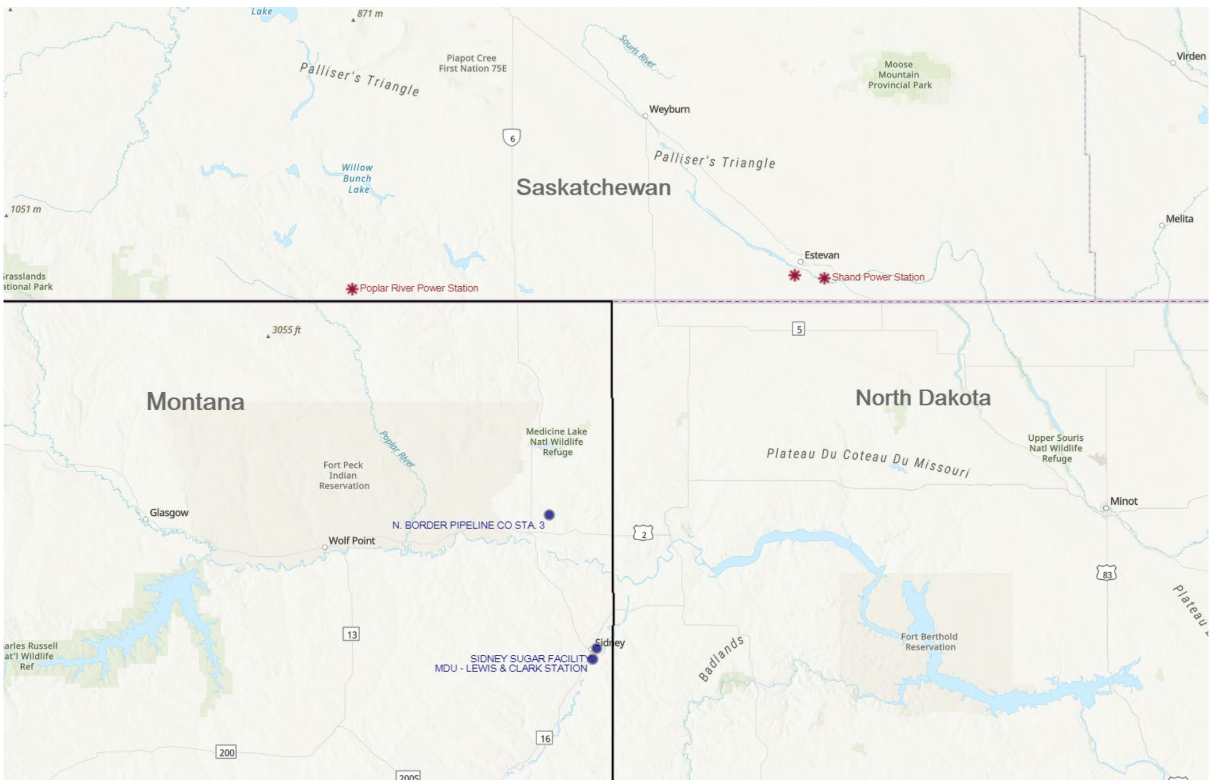


Table 5-16. Nearby Canadian and Montana Coal-Fired EGU Emissions (tons/year)

Source	Pollutant	2014	2017
Boundary Dam Power Station	SO_2	28,183	30,037
	NO_x	14,306	14,009
Poplar River Power Station	SO_2	46,923	44,589
	NO_x	17,403	13,574
Shand Power Station	SO_2	12,567	10,507
	NO_x	2,204	3,419
Total of three nearby Canadian Coal-Fired EGUs	SO_2	87,673	85,133
	NO_x	33,913	31,002
Total From Montana Coal-Fired EGUs	SO_2	16,566	11,260
	NO_x	19,885	14,036
Difference (Canada vs Montana)	*SO_2*	*71,107*	*73,873*
	NO_x	*14,028*	*16,966*

As displayed in Table 5-16, Montana's emissions of both SO_2 and NO_x have been reduced from 2014 to 2017, namely due to the closure of J.E. Corette Steam Electric station. The difference between coal-fired EGU NO_x and SO_2 emissions in Montana compared to 2017 emissions of NO_x and SO_2 from the three nearby coal-fired EGUs in Canada is considerable: Canadian sources emit 16,966 tpy more NO_x and 73,873 tpy more SO_2 than all of Montana EGUs combined. In fact, in 2017, the three Canadian coal-fired EGUs emitted 83 percent more SO_2 and 24 percent more NO_x than all Montana point sources combined.

5.6.2 Canadian Upstream Oil and Gas

Table 5-17 draws a comparison between Montana upstream oil and gas emissions and Canadian upstream oil and gas emissions. Montana's Class I areas are likely impacted by emissions from these Canadian sources since they have significant VOC, NO_X and SO_2 emissions and are upwind from the prevailing wind direction. The data were gathered from the Environment and Climate Change Canada website.[99] Emissions attributable to natural gas production and processing, natural gas transmission and storage, petroleum liquids storage and petroleum liquids transportation were not included in Table 5-17 because these subsectors are not included Montana's upstream oil and gas inventory. Montana's emissions from these activities are quantified in the point and nonpoint emissions.

[99] Government of Canada, Air Pollutants Emissions Inventory online search, Available at: https://pollution-waste.canada.ca/air-emission-inventory/ (accessed 6/8/21)

Table 5-17.Canadian and Montana Upstream Oil and Gas Emissions (tons/year)

	Pollutant	2014	2017
		Year	
Alberta	NOx	109,341	119,402
	SO_2	102,532	90,700
	VOC	507,921	300,851
British Columbia	NOx	4,227	3,548
	SO_2	1,337	1,188
	VOC	27,338	5,196
Saskatchewan	NOx	10,403	10,876
	SO_2	10,616	12,483
	VOC	192,416	171,528
Total of the three Canadian Provinces	NOx	123,972	133,826
	SO_2	114,485	104,371
	VOC	727,675	477,575
Montana Total	NOx	4,616	2,445
	SO_2	232	130
	VOC	65,564	31,080
Difference (Canada vs Montana)	*NO_x*	*119,356*	*131,381*
	SO_2	*114,253*	*104,241*
	VOC	*662,111*	*446,495*

As shown in Table 5-17, most of the Canadian upstream oil and gas emissions come from Alberta and Saskatchewan. Alberta and Saskatchewan account for over 97% of all SO_2, NO_X, and VOC emissions from the Canadian upstream oil and gas sector. These emissions primarily result from the Canadian oil sands, which is the third-largest proven oil reserve in the world.[100]

Emissions from upwind international sources are considerable. Yet, as this section presents, international emissions are just one contributor to visibility impairment in Montana Class I areas. Although there are sources of emissions that are beyond Montana's control (e.g., international emissions, mobile sources) Montana anthropogenic emissions, although small in comparison to other source categories, are within Montana's purview and are analyzed further in this second planning period for potential additional controls.

In the next chapters of this demonstration, we present our screening and subsequent four-factor analyses, our long-term strategy, and our projected reasonable progress goals.

[100] Government of Canada, "What are the oil sands?", Available at: https://www.nrcan.gc.ca/our-natural-resources/energy-sources-distribution/clean-fossil-fuels/what-are-oil-sands/18089 (accessed 6/11/2021).

6 EMISSION CONTROL ANALYSIS

6.1 SOURCE SCREENING

Section 51.308(f)(2)(i) of the RHR states that *"the State must include in its implementation plan a description of the criteria it used to determine which sources or groups of source it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy*". In this chapter, we outline the criteria used to determine which sources could be evaluated further. To start, we examined the ambient monitoring data, collected at IMPROVE sites in Montana and in nearby states. Reviewing the extinction budgets helps not only reveal the relative importance of each PM species to total light extinction, but also helps identify the suite of potential contributing sources.

EPA guidance states that "IMPROVE data and a 2018 EPA technical guidance document on tracking visibility progress can be used directly to develop light extinction budgets (i.e., pie charts showing the light extinction contribution from each ambient PM species) for single days and average budgets for the 20 percent most anthropogenically impaired days. These budgets reveal the relative importance of each PM species to total light extinction. As such, they may be used by a state to focus its SIP development work on the pollutants that matter most."[47]

Montana calculated light extinction budgets, in percent of total. Table 6-1 shows the total light extinction, separated into each species' percent contribution on the MIDs, Table 6-2 shows the anthropogenic extinction only, again, separated into each species' percent contribution on the MIDs (based on the revised RH metric used to allocate and sort days into most anthropogenically impaired days).

Table 6-1. 2014-2018 Species' Relative Percent Contribution on MIDs

sitecode	$AmmNO_3$	$AmmSO_4$	OMC	EC	Soil	CM	Sea Salt
CABI1	6.9%	24.6%	47.9%	9.2%	2.6%	8.3%	0.4%
GAMO1	9%	29.9%	40.5%	7.6%	3.3%	9.4%	0.2%
GLAC1	22.5%	19.4%	40.7%	11%	1%	4.9%	0.4%
LOST1	47%	35.3%	7.4%	4.8	0.6%	4.4%	0.6%
MELA1	45.6%	36.8%	7.2%	4%	0.8%	5.3%	0.3%
MONT1	3.9%	19.1%	55.9%	10.3%	2.4%	8.3%	0.2%
NOAB1	7.6%	30.2%	37.7%	6.9%	4.2%	13.2%	0.2%
SULA1	4.8%	25.2%	46.8%	8.7%	2.9%	11.4%	0.3%
THRO1	38.7%	41.2%	8.1%	3.9%	0.8%	6.7%	0.5%
ULBE1	30.6%	44%	14.2%	4.4%	1.1%	5.2%	0.5%
YELL2	8.4%	26.7%	41.6%	8.3%	3.4%	11%	0.6%

Table 6-2. 2014-2018 Species' Relative Percent Anthropogenic Contribution on MIDs

sitecode	$AmmNO_3$	$AmmSO_4$	OMC	EC	Soil	CM	Sea Salt
CABI1	3%	34.1%	50.5%	12.3%	0.1%	0.1%	0
GAMO1	2.8%	51.2%	35.3%	10.7%	0	0	0

sitecode	$AmmNO_3$	$AmmSO_4$	OMC	EC	Soil	CM	Sea Salt
GLAC1	19.7%	21.8%	43.2%	14.1%	0	1.2%	0
LOST1	49.9%	38.2%	4.4%	5%	0	2.5%	0
MELA1	48.3%	40.5%	4.1%	3.9%	0.2%	2.9%	0
MONT1	0.2%	24.8%	61.4%	13.7%	0	0	0
NOAB1	2.4%	57.5%	30.3%	9.8%	0	0	0
SULA1	0.4%	39.8%	47.4%	12.5%	0	0	0
THRO1	40.6%	46.7%	4.8%	4%	0	3.9%	0
ULBE1	29.5%	56%	9.6%	4.5%	0	0.4%	0
YELL2	5.8%	43.7%	38.8%	11.8%	0	0	0

Table 6-2 shows that ammonium nitrate and ammonium sulfate contribute most to eastern IMPROVE sites (MELA1 (in MT), LOST1 and THRO1 (in ND)). Organic mass carbon is higher at the western IMPROVE sites (CABI1, GAMO1, GLAC1, MONT1, NOAB1, SULA1, and YELL2). This is in keeping with the understanding that western sites are more impacted by smoke from fires. Table 6-3 includes ammonium nitrate and ammonium sulfate combined.

Table 6-3. $AmmNO_3$ and $AmmSO_4$ cumulative percent contribution to light extinction on MIDs

sitecode	$AmmNO_3$ + $AmmSO_4$ (% total extinction)
CABI1	37.1%
GAMO1	54.0%
GLAC1	41.6%
LOST1	88.1%
MELA1	88.8%
MONT1	25.0%
NOAB1	59.9%
SULA1	40.2%
THRO1	87.3%
ULBE1	85.5%
YELL2	49.5%

Figures 6-1 through 6-11 identify the annual extinction concentrations by particulate species from 2001 – 2020. In nearly all Montana Class I areas, the relatively largest components of anthropogenic visibility impairment are sulfate and nitrate, caused primarily by PM precursors SO_2 and NO_x, respectively. Most of Montana's Class I areas also have significant organic mass extinction attributable to fires; however, Montana chose to focus on visibility-impairing pollutants that can be controlled.

Figure 6-1. Annual Extinction Composition MID - CABI1

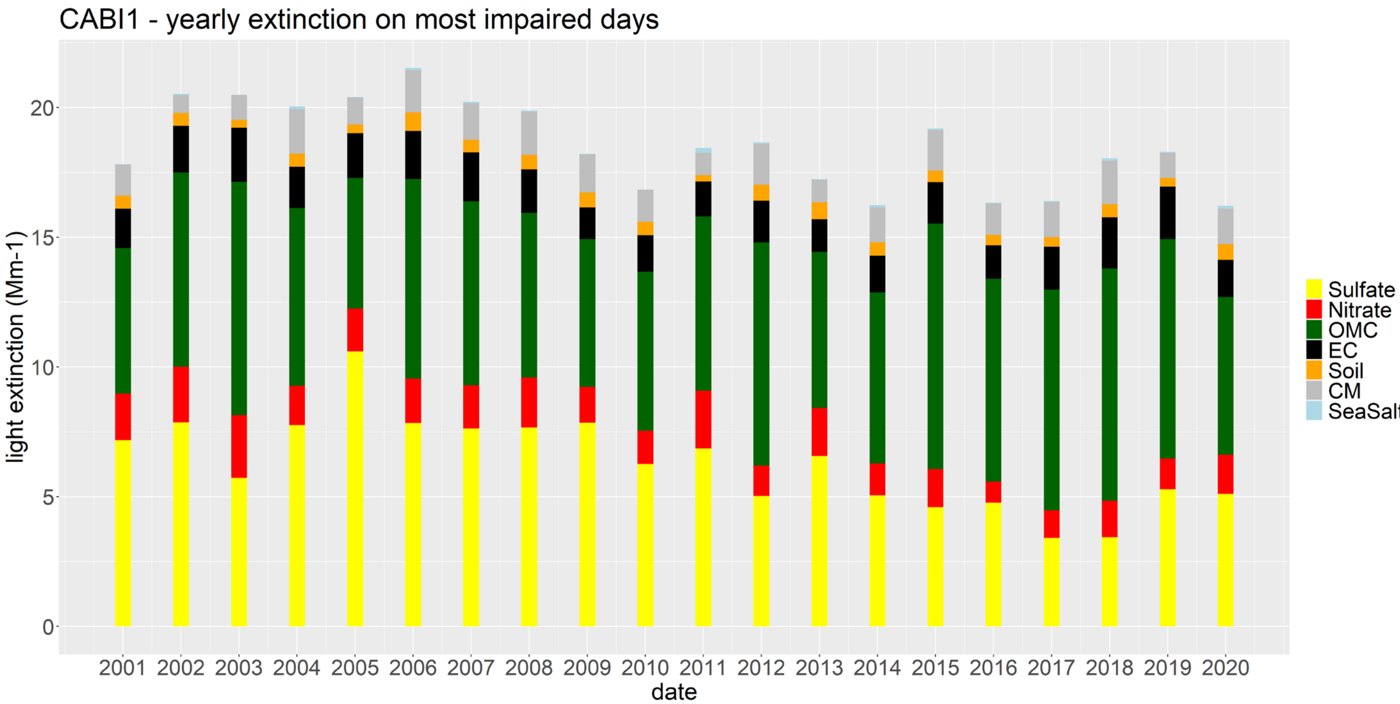


Figure 6-2. Annual Extinction Composition, MID - GAMO1

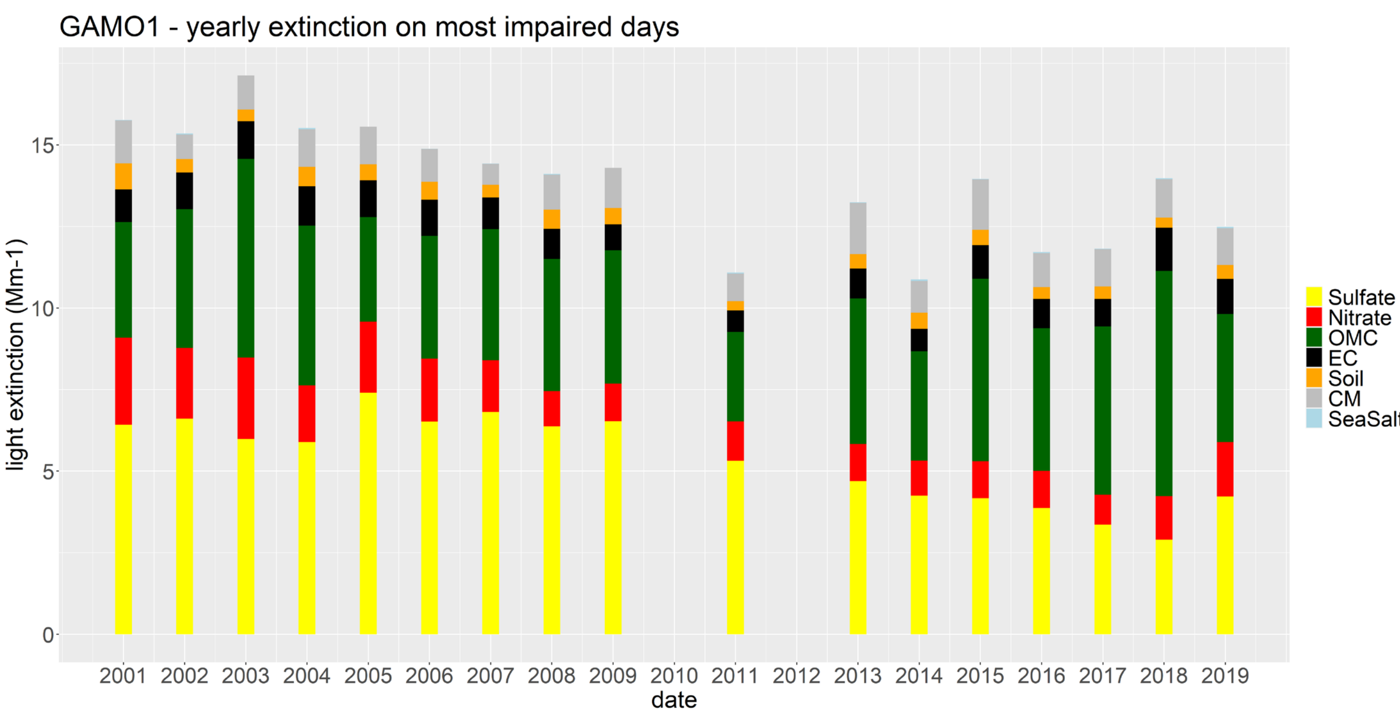


Figure 6-3. Annual Extinction Composition MID - GLAC1

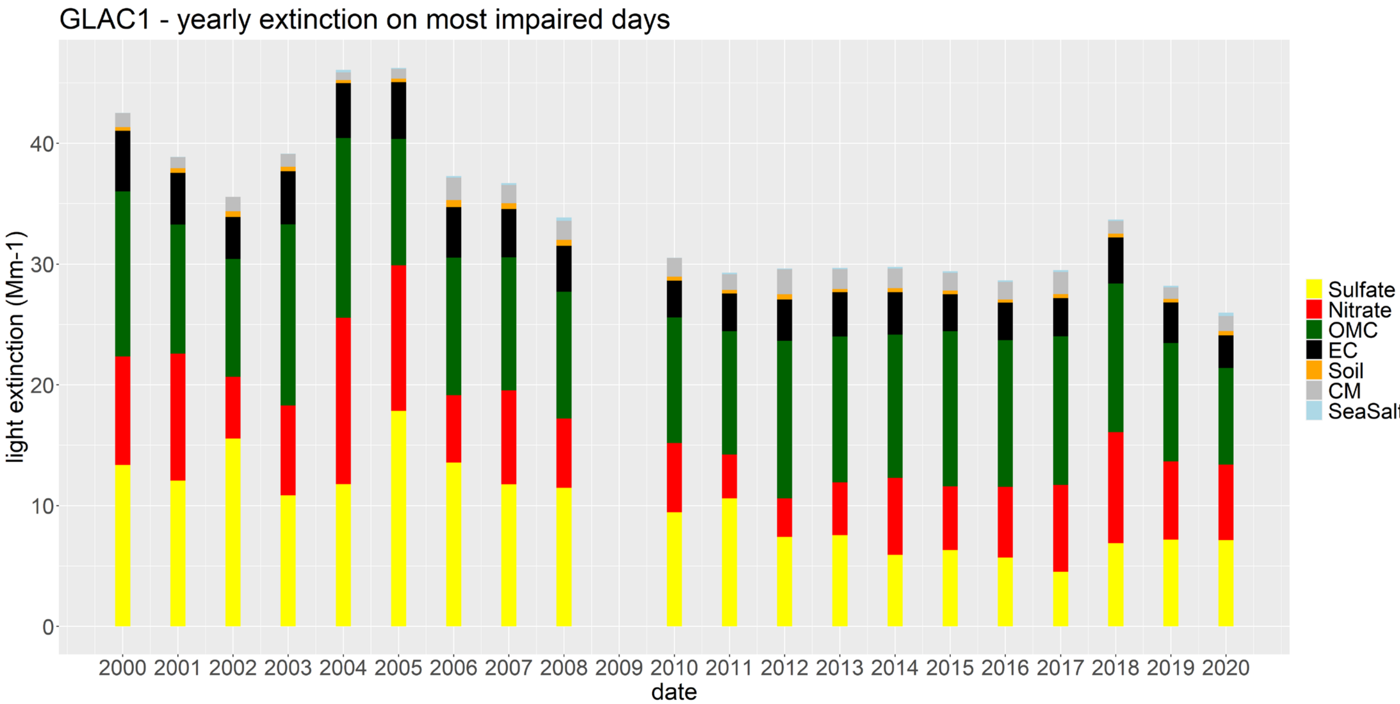


Figure 6-4. Annual Extinction MID – LOST1

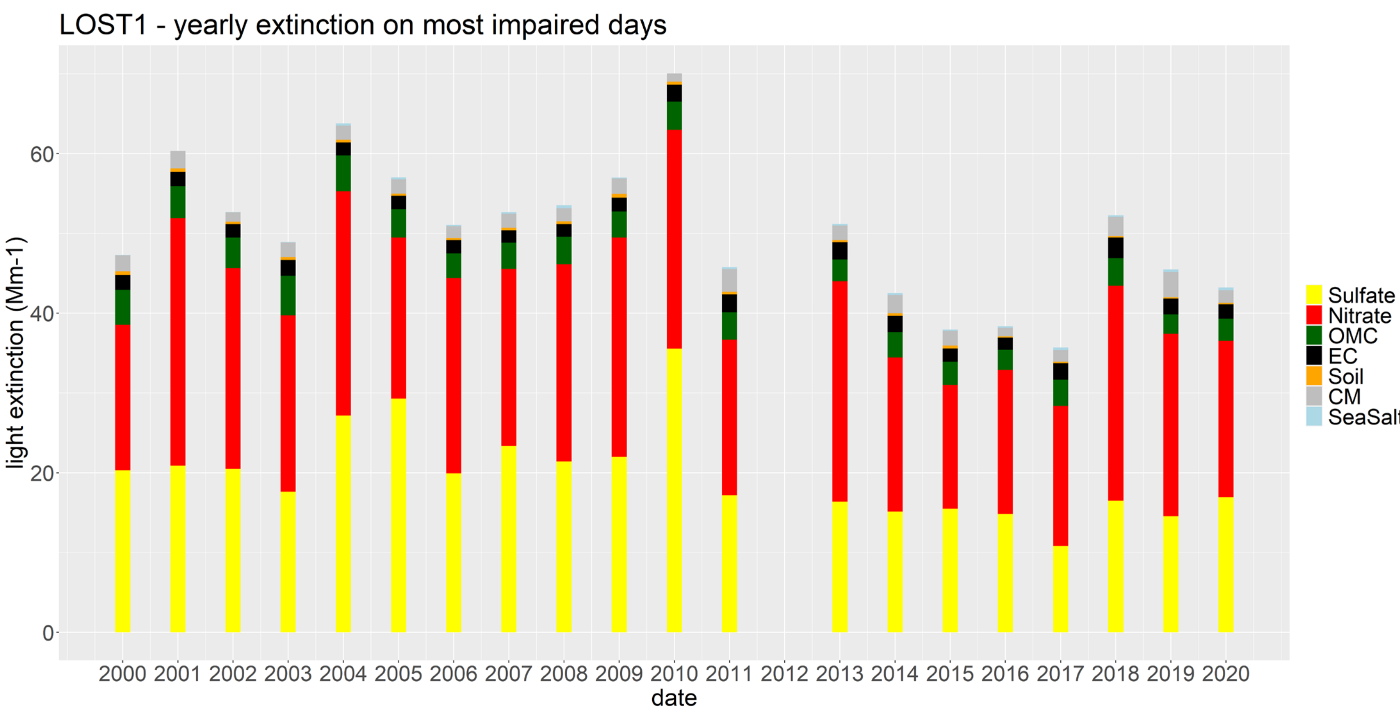


Figure 6-5. Annual Extinction MID - MELA1

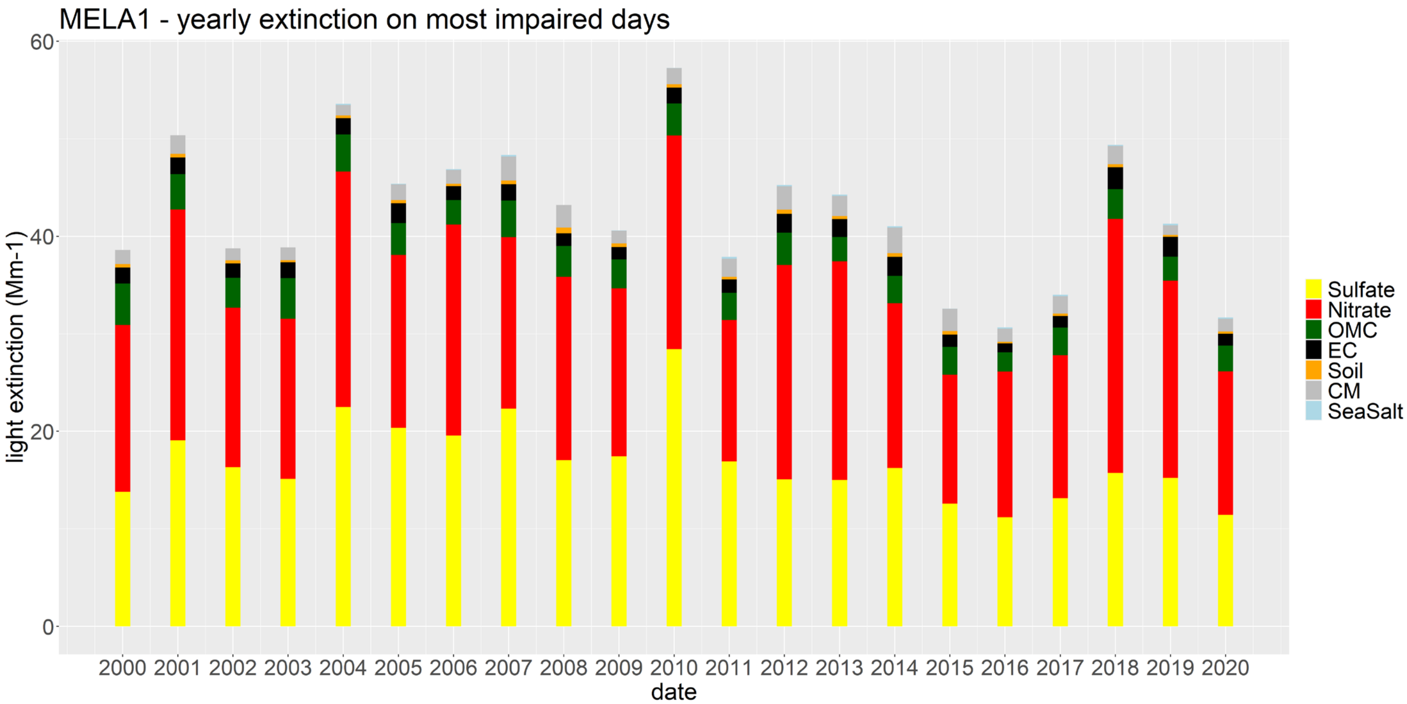


Figure 6-6. Annual Extinction MID - MONT1

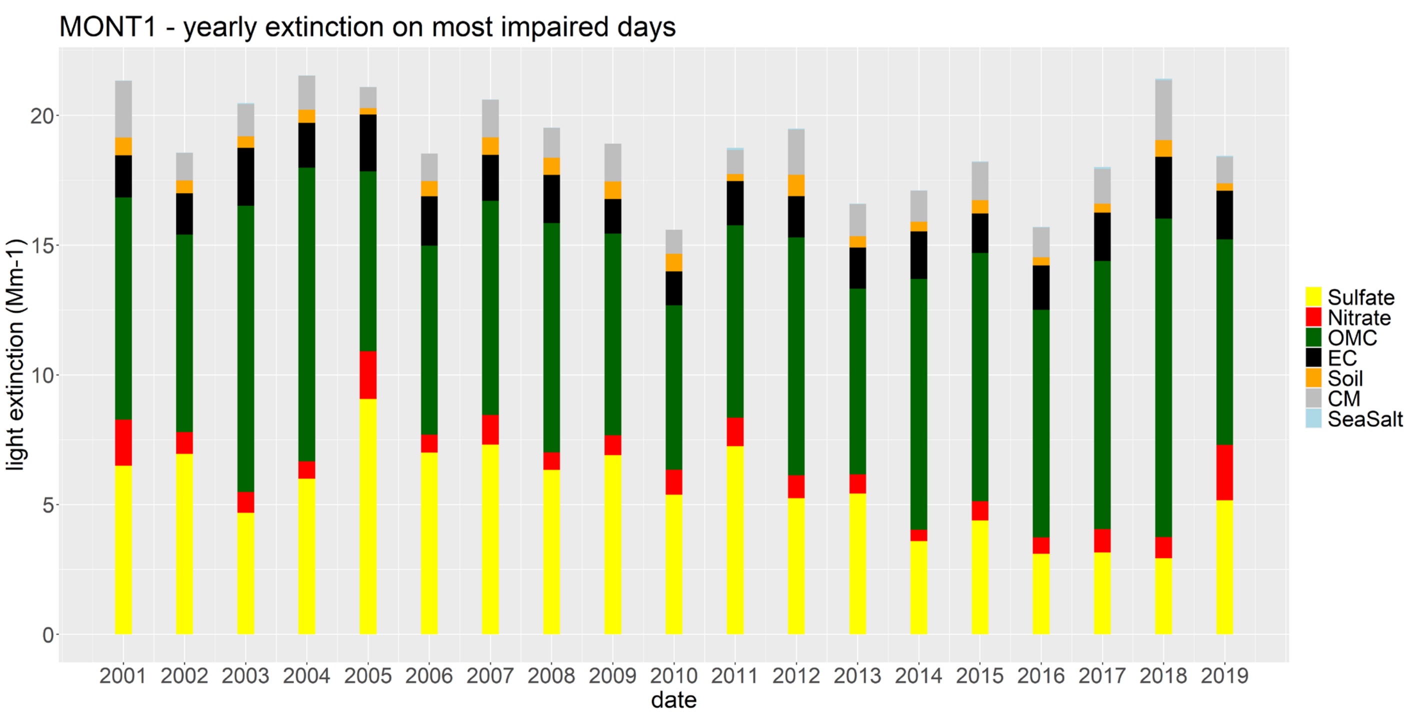


Figure 6-7. Annual Extinction MID - NOAB1

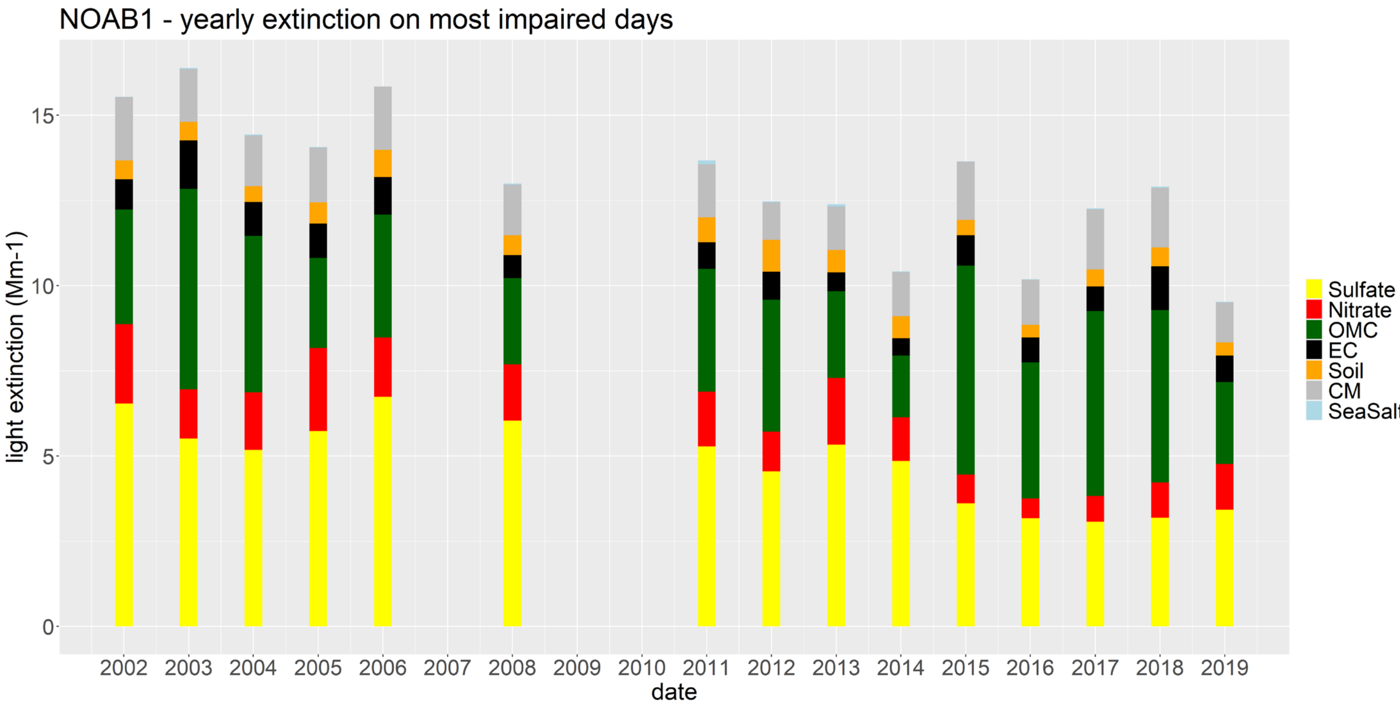


Figure 6-8. Annual Extinction MID - SULA1

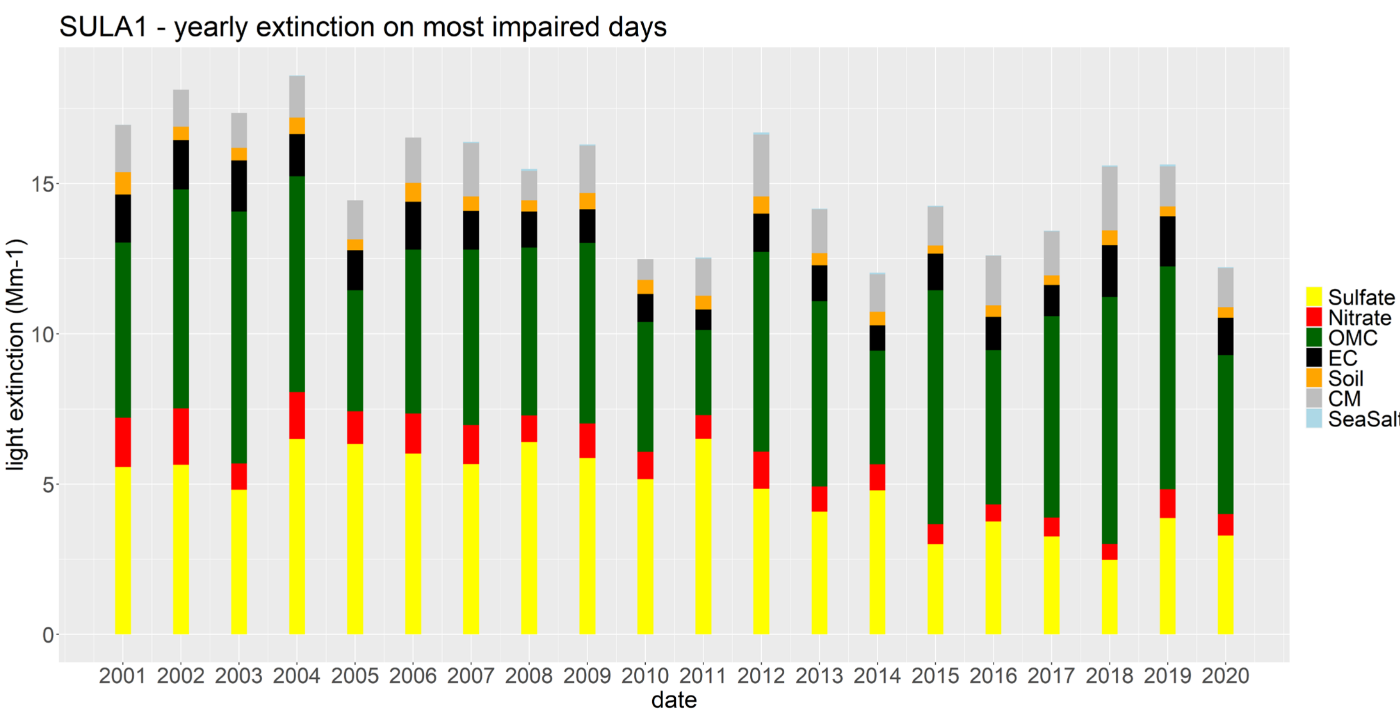


Figure 6-9. Annual Extinction Composition MID - THRO1

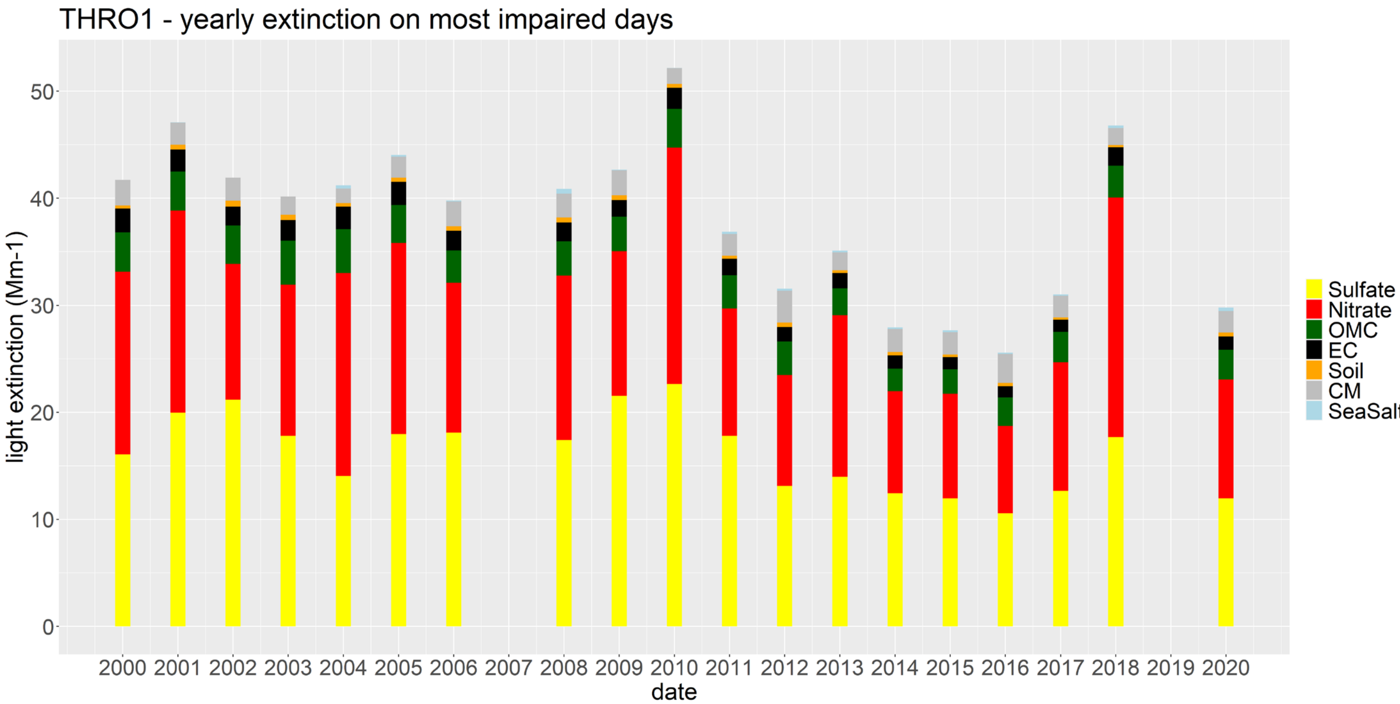


Figure 6-10. Annual Extinction Composition MID - ULBE1

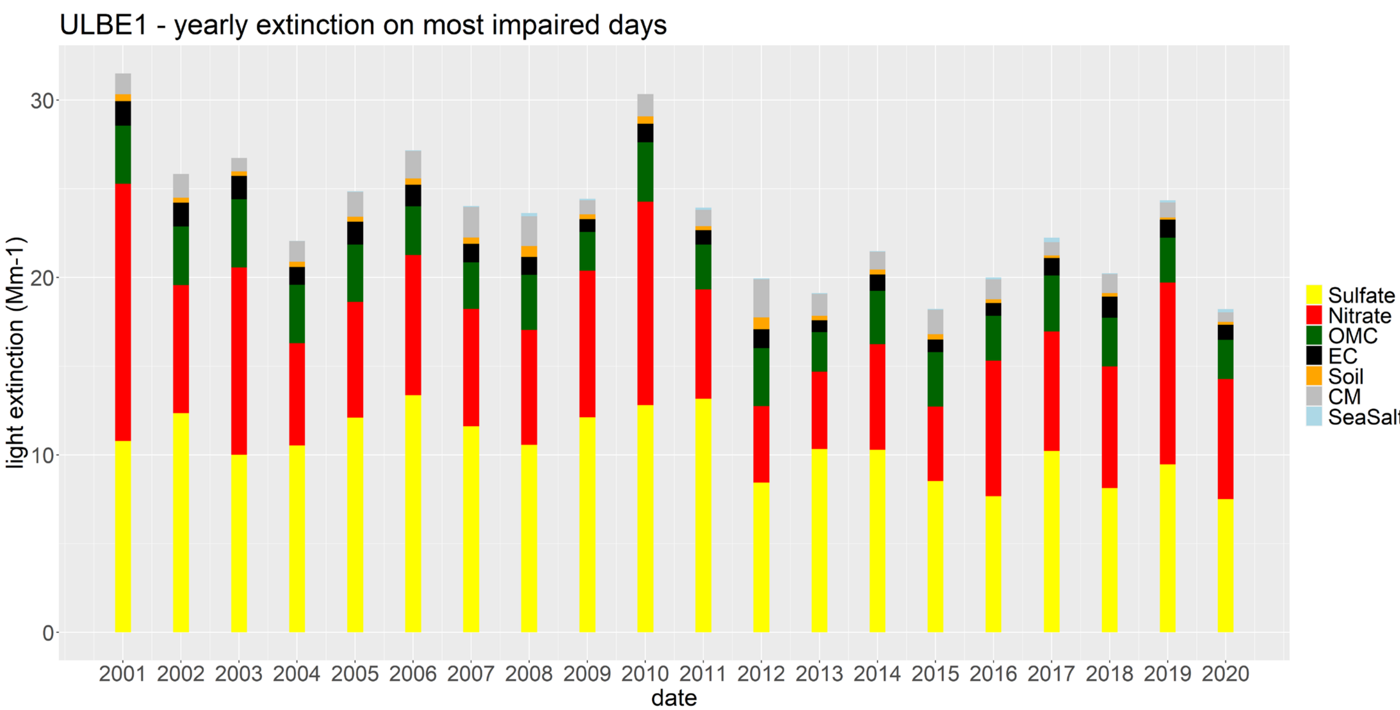
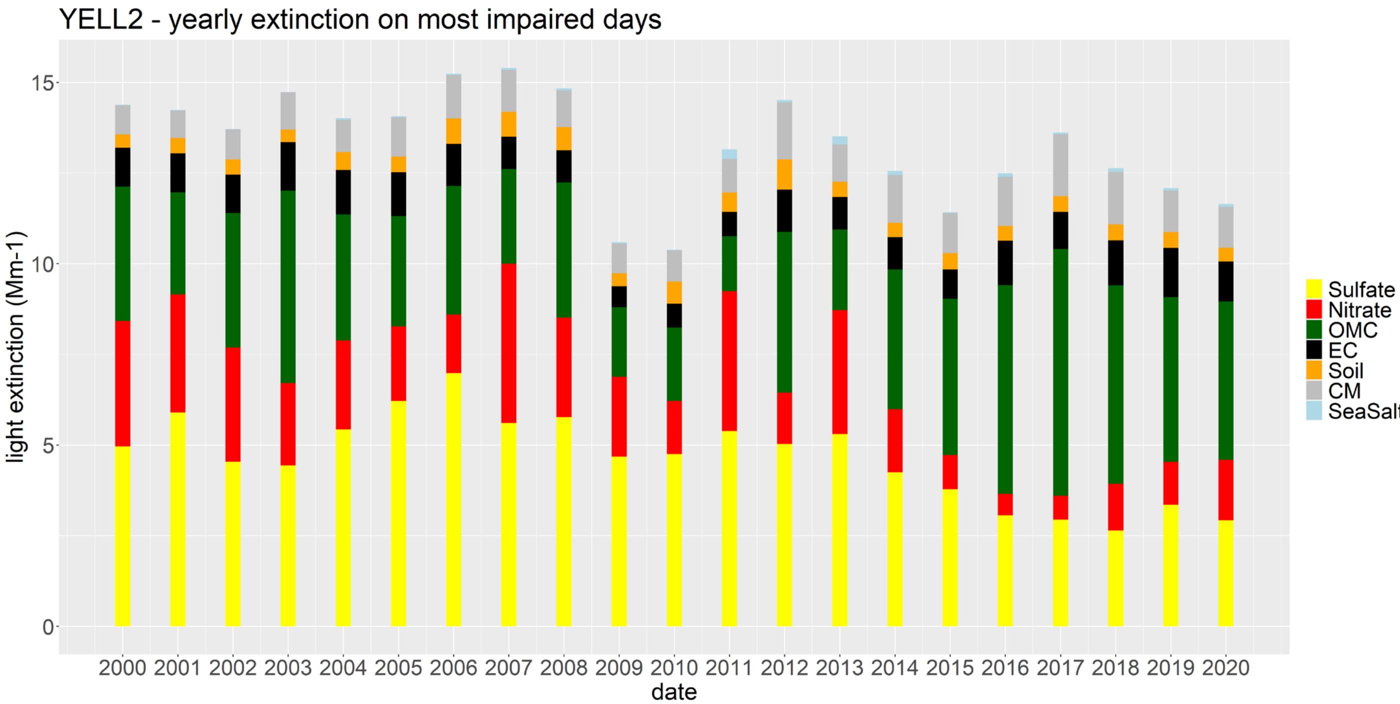


Figure 6-11. Annual Extinction Composition MID - YELL2

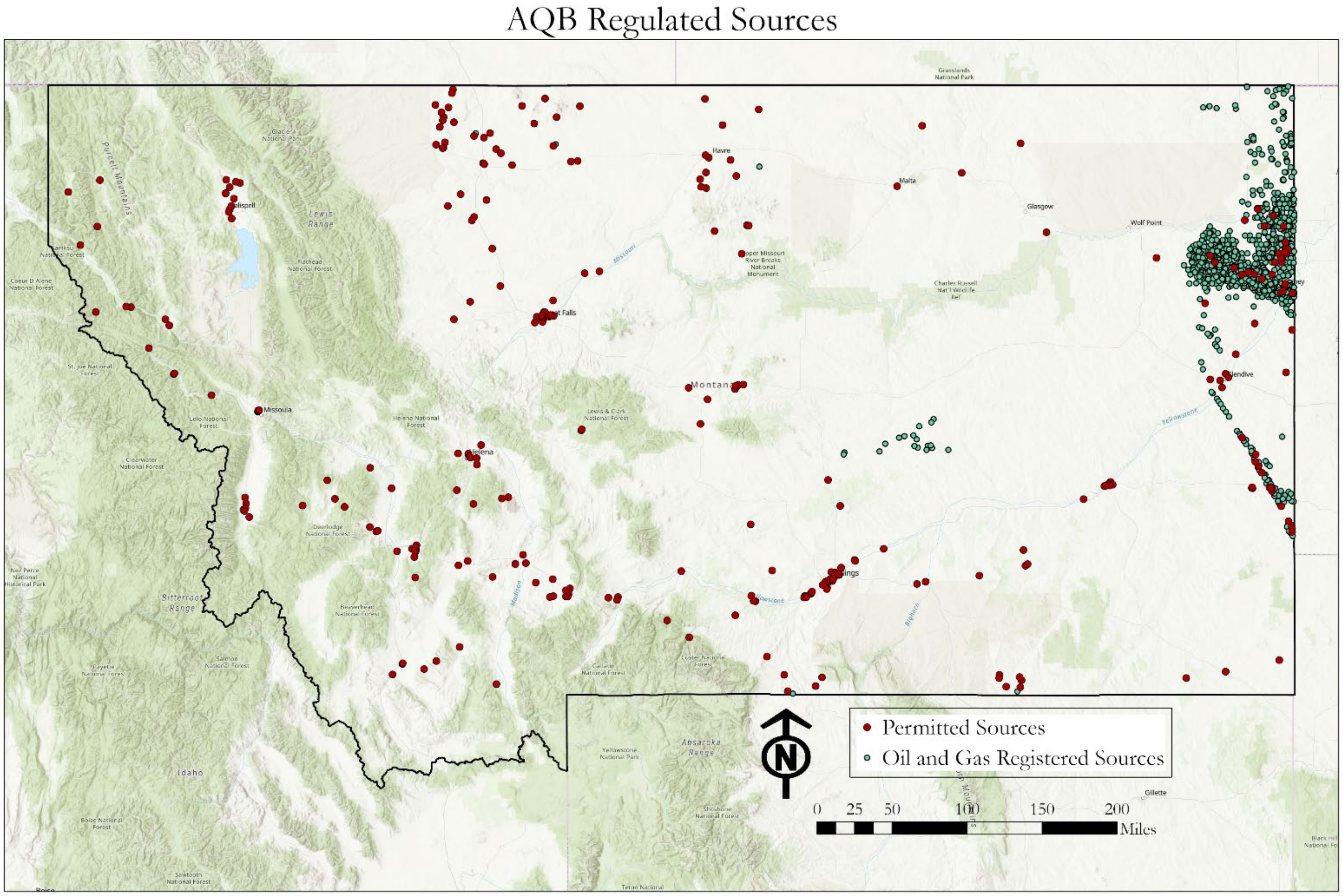


EPA guidance states, "When selecting sources for analysis of control measures, a state may focus on the PM species that dominate visibility impairment at the Class I areas affected by emissions from the state and then select only sources with emissions of those dominant pollutants and their precursors. Also, it may be reasonable for a state to not consider measures for control of the remaining pollutants from sources that have been selected on the basis of their emissions of the dominant pollutants."[47]

Table 6-1, Table 6-2, and Table 6-3 show that haze at Montana Class I areas is comprised mostly of ammonium nitrate, ammonium sulfate and organic mass carbon. As mentioned earlier, the primary precursors of nitrates and sulfates are emissions of NO_x and SO_2. Pollutant precursors to organic mass carbon include $PM_{2.5}$ and VOCs, with large amounts of emissions stemming from fires. As the graphs and tables in sections 5.1 - 5.6 indicate, NO_x and SO_2 emissions are largest from international sources, mobile sources and point sources. Montana has no authority over international sources and does not regulate mobile source emissions; therefore, these sources were not included in source screening (Montana adjusted the URP to account for international anthropogenic emissions and we discuss federal mobile programs in Section 7.1.1.5). The remaining sources that could be evaluated for reasonable progress controls are sources regulated by Montana (e.g., point sources and oil and gas sources).

The universe of regulated sources in Montana includes 301 stationary sources, 1182 registered oil and gas sources, and portable registered sources. A map of the sources in Montana is below:

Figure 6-12. Map of Montana Air Quality Bureau's Regulated Sources



EPA guidance states, "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 source for an analysis of control measures."[47] In the RepBase2 planning inventory, Montana oil and gas sources were estimated to emit 5,660 tpy NO_x and 440 tpy SO_2, while point source emissions over the same period were emitted 26,688 NO_x and 16,781 tpy SO_2. SO_2 emissions from oil and gas are very low because the Bakken formation contains sweet oil and gas with very low sulfur content. NO_x emissions are low (comparatively), and mostly come from combustion sources at the site (engines, glycol dehydrators, flares and vehicles). These sources are well-controlled via New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards which help limit NO_X emissions.

The main pollutant of concern at oil and gas sources is VOC; however, this pollutant was not evaluated as a haze-causing pollutant in Montana in this planning period. VOC emissions lead to organic carbon (OC) formation and most OC particulates are associated with fires or biogenic sources. Past modeling suggests the anthropogenic VOC emission source contribution to OC is typically very small (~2-4%) and therefore not considered a significant contributor to visibility impairment at most Class I areas[101]. Additionally, federal policy for regulating emissions (mostly methane) from oil and gas sources has swung considerably in the past eight years, and only very recently shifted toward more stringent approaches.

In 2016, EPA promulgated a NSPS addressing methane emissions from new, modified and reconstructed facilities in the oil and gas sector. In 2020, the rule was rescinded, yet by 2021, policy shifted again and Congress passed a Congressional Review Act resolution disapproving the rescission. The 2016 NSPS is back in effect for oil and gas sources, and will likely be updated, as explained in the Congressional Research Service Legal Sidebar[102]:

> "As directed by Executive Order (E.O.) 13990[103], EPA has begun the process to propose rules to reduce methane and VOCs emissions from the oil and gas sector. E.O. 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," instructs EPA to consider taking two actions by September 2021: (1) strengthen 2016 methane and VOC emission standards for new sources, and (2) propose emission guidelines for existing sources in the oil and gas sector."

The proposed rule would go beyond the 2016 NSPS in both scope and stringency, and would have a substantial monitoring program requiring companies to detect and repair emission leaks. EPA has also established a protocol for using optical imaging to detect VOC and greenhouse gas (GHG) leaks.[104] In Montana, compliance assistance, an increased field presence, and updated rules and monitoring techniques will provide additional VOC emission reductions. Due to the iterative planning process, Montana has elected to consider whether measures for oil and gas sources are necessary to make reasonable progress in later implementation periods. Montana will evaluate changes in the oil and gas source category in the next progress report.

Based in emission trend analysis and light extinction budgets in Table 6-2, Montana chose to focus the potential additional control analysis on point source emissions of NO_x and SO_2 that are regulated by Montana. Like the analysis conducted in the first planning period, Montana determined that, while there are

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[101] WRAP Reasonable Progress Source Identification and Analysis Protocol for Second 10-year Regional Haze State Implementation Plans. WRAP Regional Haze Planning Work Group – Control Measures Subcommittee, 27 Feb. 19. Available at: https://www.wrapair2.org/pdf/final%20WRAP%20Reasonable%20Progress%20Source%20Identification%20and%20Analysis%20Protocol-Feb27-2019.pdf

[102] Looking Ahead: Regulating Methane from the Oil and Gas Natural Gas Sector, Congressional Research Service, 14 Jul. 21. Available at: https://crsreports.congress.gov/product/pdf/LSB/LSB10622

[103] Exec. Order No. 13990, 20 Jan 21, Available at: https://www.federalregister.gov/documents/2021/01/25/2021-01765/protecting-public-health-and-the-environment-and-restoring-science-to-tackle-the-climate-crisis

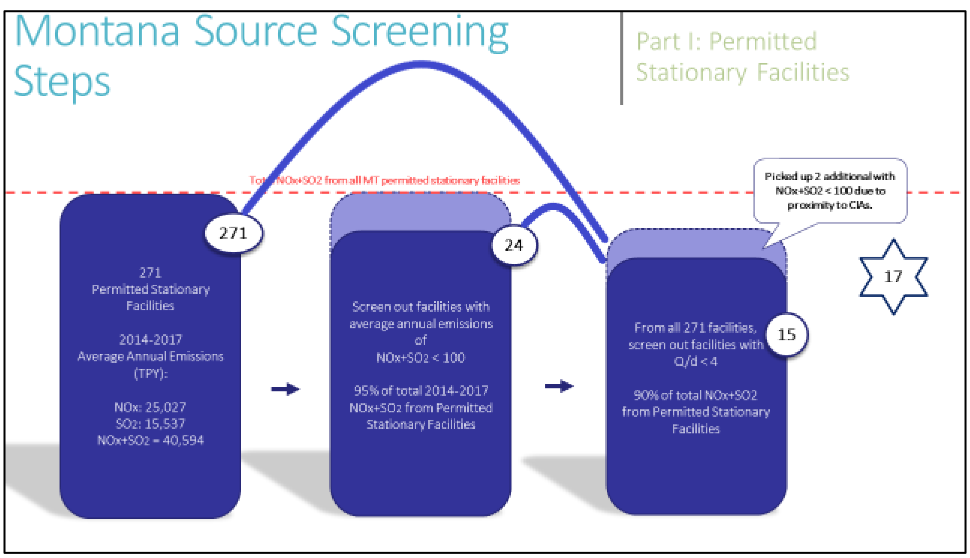
[104] Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging. Nov. 2021. Available at: https://www.epa.gov/system/files/documents/2021-11/40-cfr-part-60-appendix-k-proposal_0.pdf

some particulate matter species impacting the Class I areas, focusing on sources of NO_x and SO_2 would provide a greater haze reduction in this planning period. However, as NO_x and SO_2 emissions decline into the future, the sources of other visibility-impairing pollutants, such as PM_{10} and $PM_{2.5}$ (and VOC), will have to be analyzed and assessed in future planning periods for potential additional controls.

At the time Montana was initiating source screening, EPA had released a Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period in July 2016[105]. This draft guidance recommended that states evaluate about 80 percent of emissions coming from anthropogenic, non-mobile sources that are impacting each Class I area. The final version of this guidance, released in September 2019[47], did not include the 80 percent threshold. However, Montana had already completed the initial screening and determined the 80 percent threshold would ensure an adequate analysis of emission sources.

The RHR is flexible in that it does not explicitly list factors that a state must consider when selecting sources; instead, states may apply a variety of factors for selecting source to analyze. EPA guidance mentions using a surrogate metric for baseline source visibility impacts. The surrogate metric is quantitative and is correlated to some degree with visibility impacts as they would be estimated via air quality modeling. A simple surrogate metric is emissions in tons/year divided by distance to an affected Class I area in kilometers, also known as Q/d. Montana used the 2014-2017 average annual emissions of NO_x and SO_2 in tons divided by distance in kilometers between a source and the nearest Class I area as a surrogate for baseline visibility impact. Figure 6-13 describes the source screening steps:

Figure 6-13. Montana Source Screening Steps for Permitted Facilities



Montana used the annual point source emission inventories from 2014 – 2017 and averaged NO_x and SO_2 emissions over those four years, totaling 40,594 tons per year (tpy) of combined NO_x and SO_2 emissions

105 EPA, Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, (July 2016).

from all permitted stationary sources in the state. As previously mentioned, at the time of this analysis, Montana considered 80% to be a reasonably large fraction of emissions. Montana first separated the 271 sources into two groups: those facilities with average annual NO_x and SO_2 emissions combined that exceeded 100 tpy and those facilities that were below 100 tpy. The first group (>100 tpy NO_x +SO_2) resulted in 24 sources, and represented .95% of the total 2014-2017 NO_x and SO_2 emissions.

Montana then used the Q/d visibility surrogate to identify the sources impacting nearby Class I areas. Montana selected a Q/d of 4 or greater to adequately represent the point source emissions impacting Montana Class I areas. The remaining list included 15 sources from the 24 sources of NO_x and SO_2 emissions combined over 100 tpy. Then, Montana evaluated the second group (sources <100 tpy of NO_x + SO_2) under the Q/d = 4 threshold. Doing so picked up two sources that had less than 100 tpy of NO_x and SO_2 combined, but were very close to a Class I area. In total, these 17 point sources contribute on average 36,620 tpy of NO_x and SO_2 emissions; comprising about 90% of total NO_x and SO_2 emissions in the state from point sources. A comprehensive list of sources evaluated is included in Appendix C.

Of note, this screening criteria included Colstrip's Units 1 & 2, in part because it wasn't clear at the time whether those units should be screened in, knowing that a full four-factor analysis would not be necessary based on the planned shutdown. On July 20, 2021, Montana received feedback from EPA Region 8 staff clarifying that, based on the RH guidance, the units should not be screened in. From the guidance (page 20):

> *States may consider enforceable shutdowns that will occur by 2028 when determining whether to select those sources for further analysis, and if a state does not select a source for a four-factor analysis on the basis that the source has an enforceable shutdown in place is determining that the shutdown is necessary for reasonable progress and must include the enforceable shutdown as a measure in the SIP, if the shutdown is not already federally enforceable and permanent.*

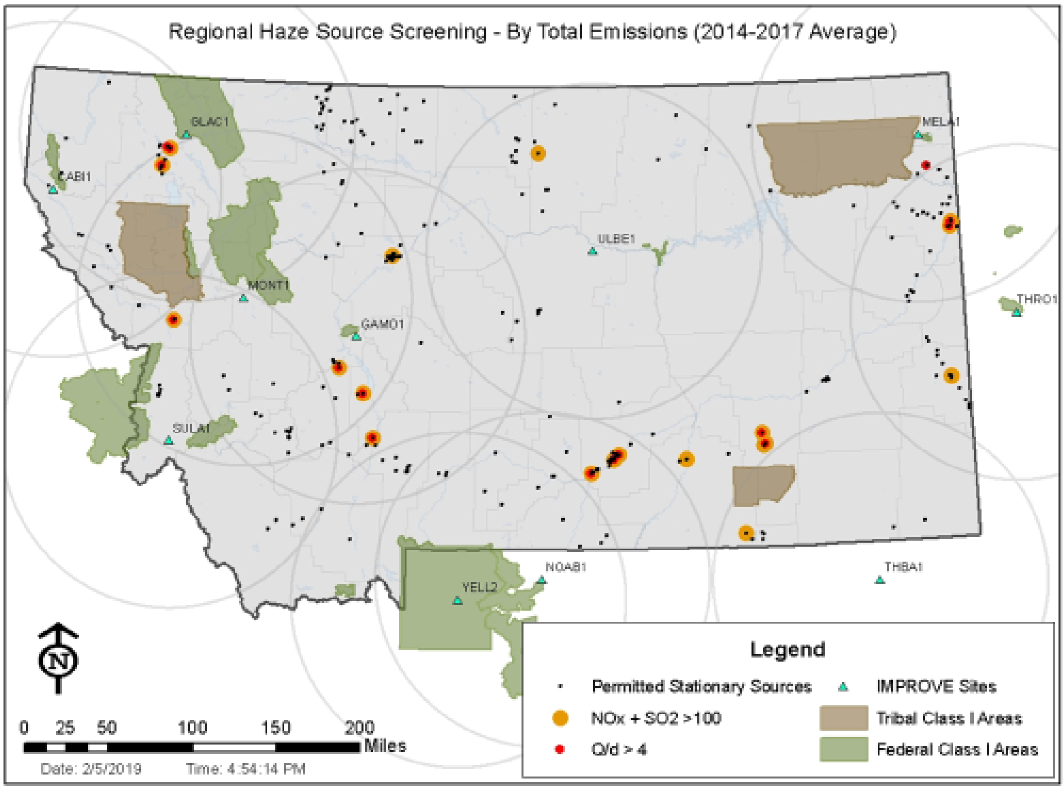
Therefore, Montana removed Colstrip's Units 1 & 2 from the original screened sources list. Table 6-4 contains the final screening list of stationary sources with a Q/d greater than 4. Figure 6-14 shows the locations of these screened in facilities in relation to the Class I areas.

Table 6-4. Montana Q/d Screened Sources

Source	NOx Avg. 2014-2017	SO_2 Avg. 2014-2017	2014-2017 Avg. Emissions NOx+SO_2	Nearest ClA	Distance to ClA (km)	Q/d Q = NOx+SO_2
Weyerhaeuser NR - Columbia Falls Facility	969.60	14.77	984.36	Glacier	13.3	74.01
Talen Montana LLC - Colstrip Steam Electric Station Units #3 and 4	8,133.01	4,583.56	12,716.57	U.L. Bend	198.9	63.93
Ash Grove Cement Company	1,029.91	205.21	1,235.11	Gates of the Mountains	30.6	40.36
Montana Dakota Utilities CO - Lewis & Clark Station	604.67	447.60	1,052.28	Teddy Roosevelt	51.8	20.31
GCC Trident, LLC	1,473.87	14.52	1,488.39	Yellowstone	97.4	15.28

Source	NOx Avg. 2014-2017	SO_2 Avg. 2014-2017	2014-2017 Avg. Emissions $NOx+SO_2$	Nearest ClA	Distance to ClA (km)	Q/d Q = $NOx+SO_2$
Yellowstone Energy Limited Partnership - Yellowstone Power Plant	404.32	1,732.01	2,136.33	Absaroka	143.8	14.86
Roseburg Forest Products CO	299.28	3.33	302.61	Selway Bitterroot	26.6	11.38
Colstrip Energy Ltd Partnership	811.68	1,123.92	1,935.61	U.L. Bend	188.7	10.26
Montana Sulphur & Chemical CO	4.74	1,305.53	1,310.27	Absaroka	137.5	9.53
Graymont Western US Inc - Indian Creek Facility	363.06	161.17	524.23	Gates of the Mountains	57.1	9.18
Exxonmobil Fuels & Lubricants Company - Exxonmobil Billings Refinery	435.75	598.65	1,034.41	Absaroka	143.7	7.20
Cenex Harvest States Cooperative Inc - CHS Inc Refinery Laurel	420.60	208.13	628.73	Absaroka	113.5	5.54
F H Stoltze Land & Lumber CO	68.62	6.60	75.22	Glacier	14	5.37
Sidney Sugars Inc - Sidney Sugar Facility	210.75	58.04	268.79	Teddy Roosevelt	51.9	5.18
Phillips 66 CO - Billings Refinery	540.05	104.87	644.92	Absaroka	143	4.51
Weyerhaeuser NR Kalispell - Weyerhaeuser Evergreen Facility	129.45	4.87	134.32	Glacier	30.5	4.40
Northern Border Pipeline CO - N. Border Pipeline CO Station #3	91.50	4.25	95.76	Medicine Lake	22.8	4.20

Figure 6-14. Map of Montana Screened Sources and Class I areas



The sources listed in Table 7-1 submitted four-factor analyses to Montana for review and the information was considered in the further analysis.

6.1.1 Source Contribution Analysis as part of the Source Screening Criteria

Another approach to source screening is the WEP/AOI and Rank Point analyses described in Section 2.2.7. For the Rank Point analyses, facility-level 2028OTBa2 emissions are overlaid with the corresponding Extinction Weighted Residence Time (EWRT) for the ammonium nitrate and ammonium sulfate species at each Class I Area. Combining the facility-level emissions with the EWRT with the facility-level emissions (divided by the distance to the CIA monitor, Q/d) approximates the relative contribution of each facility to each CIA, calculated from the air parcel trajectories. The resulting data is the Weighted Emissions Potential (WEP) and when sorted for each CIA, it will illustrate the general "rank" of each facility for the given Class I area.

Montana facilities were sorted based on the WEP for NO_x and SO_2 for each of the 11 Class I areas and were used to "check" that the appropriate Montana facilities were screened from the Q/d analysis described previously. For this check, the top 10 *Montana* facilities were retained for each Class I area, then combined to make the list of facilities showed in Table 6-5 and Table 6-6 below. The tables show the rank that each facility falls in for each Class I area, for both NO_x and SO_2, with the green cells highlighted at being in the top 10. For simplicity, facilities with WEP < 1 were filtered out before this aggregation, as they are considered insignificant to the Class I area, and noted with a dash.

The facilities shown in Table 6-5 and Table 6-6 contain all the screened in sources derived above (see Table 6-4), and an additional five sources. Three of the sources were considered but did not meet the Q/d >4 cutoff (Western Sugar Q/d=2.6; Calumet Q/d=2.25; and Blaine County #1 Compressor Station, Q/d=3.82). The remaining two sources had less than 100 tons of NO_x+SO_2.The cells highlighted in green indicate the source is in the top 10 ranking.

Table 6-5. Montana Rank Point Sources (CABI1, GAMO1, GLAC1, LOST1, MELA1, MONT1)

	CABI1 - Rank		GAMO1 - Rank		GLAC1 - Rank		LOST1 - Rank		MELA1 - Rank		MONT1 - Rank	
FacilityName	NOX	SO2	NOX	SO2	NOX	SO2	NOX	SO2	NOX	SO2	NOX	SO2
ASH GROVE CEMENT	63	71	1	2	65	33	144	151	56	88	3	8
BILLINGS REFINERY	272	198	14	32	290	105	85	94	32	53	134	142
BLAINE COUNTY #1	121	-	37	-	363	-	45	-	22	797	112	-
CALUMET MONTANA REFINING	212	130	5	7	136	74	128	125	111	107	42	18
CHS INC REFINERY LAUREL	333	156	22	18	379	77	99	59	55	42	149	73
COLSTRIP ENERGY LTD PARTNERSHIP	216	49	82	25	1209	133	38	20	21	14	502	136
COLSTRIP STEAM ELECTRIC STATION	83	21	10	11	465	66	9	10	9	8	226	65
COMPRESSOR STATION #103	460	-	170	-	1601	-	334	-	226	-	429	-
EXXONMOBIL BILLINGS REFINERY	299	100	18	8	321	37	94	41	37	21	162	54
F.H. STOLTZE LAND AND LUMBER CO	31	25	83	107	2	2	256	282	215	240	83	84
FLATHEAD ELECTRIC LFGE FACILITY	134	45	362	157	6	4	1140	386	831	328	314	125
GRAYMONT WESTERN US INC	112	56	2	1	132	25	263	111	104	64	14	5
MDU - LEWIS & CLARK STATION	472	-	134	245	-	-	8	34	3	18	-	-
MONTANA SULPHUR & CHEMICAL	-	63	427	5	-	23	1174	27	528	15	-	26
N. BORDER PIPELINE CO STA. 3	-	-	470	565	-	-	35	97	10	27	-	-
OLDCASTLE - TRIDENT PLANT	104	350	3	34	91	242	104	414	45	302	24	148
ROSEBURG FOREST PRODUCTS	47	157	4	57	5	84	228	701	134	409	1	12
SIDNEY SUGAR FACILITY	662	480	240	161	-	-	17	21	11	9	-	-
WESTERN SUGAR COOPERATIVE	366	189	39	26	426	91	127	84	68	49	213	129
WEYERHAEUSER-CFALLS	2	18	7	70	1	1	52	208	39	178	5	51
WEYERHAEUSER-EVERGREEN	15	42	32	134	3	5	223	381	173	350	12	52
YELLOWSTONE POWER PLANT	305	55	20	3	337	19	103	24	44	13	168	22

Table 6-6. Montana Rank Point Sources (NOAB1, SULA1, THRO1, ULBE1, YELL2, and 2028 Emissions)

FacilityName	NOAB1 - Rank		SULA1 - Rank		THRO1 - Rank		ULBE1 - Rank		YELL2 - Rank		2028 Emissions	
	NOX	SO2	NOX	SO2	NOX	SO2	NOX	SO2	NOX	SO2	NOX	SO2
ASH GROVE CEMENT	13	39	2	6	86	125	21	35	23	42	982.6	120.9
BILLINGS REFINERY	5	22	-	-	65	70	17	28	55	52	556.1	100.7
BLAINE COUNTY #1	159	-	203	-	57	-	1	288	589	-	531.3	0.1
CALUMET MONTANA REFINING	68	72	85	57	123	120	11	23	98	77	138.8	32.1
CHS INC REFINERY LAUREL	9	11	-	-	109	66	34	20	67	32	385.7	215
COLSTRIP ENERGY LTD PARTNERSHIP	22	14	-	-	22	11	28	8	1410	193	892.6	1232.6
COLSTRIP STEAM ELECTRIC STATION	2	5	-	-	7	8	2	1	436	115	7866.9	4700.2
COMPRESSOR STATION #103	597	-	470	-	365	-	8	385	2130	-	19.8	0
EXXONMOBIL BILLINGS REFINERY	7	6	-	-	75	31	22	9	63	22	427	539.4
F.H. STOLTZE LAND AND LUMBER CO	455	265	82	139	327	360	100	139	536	555	74	7.1
FLATHEAD ELECTRIC LFGE FACILITY	1384	366	334	203	1376	503	428	190	-	-	5.7	3.3
GRAYMONT WESTERN US INC	30	26	9	3	139	85	48	25	46	27	367.8	238.4
MDU - LEWIS & CLARK STATION	207	276	-	-	8	23	18	80	761	626	580.6	22.6
MONTANA SULPHUR & CHEMICAL	184	4	-	-	826	22	393	5	680	13	5.6	1232.6
N. BORDER PIPELINE CO STA. 3	441	431	-	-	36	105	101	169	-	-	56.2	2.6
OLDCASTLE - TRIDENT PLANT	4	69	4	124	72	351	20	150	2	70	1339.4	7.7
ROSEBURG FOREST PRODUCTS	115	278	3	63	163	561	36	204	69	212	306	3
SIDNEY SUGAR FACILITY	339	190	-	-	11	14	46	46	1509	414	224	61.7
WESTERN SUGAR COOPERATIVE	10	18	-	-	103	65	40	27	99	48	242	122.9
WEYERHAEUSER-CFALLS	100	201	8	105	87	276	10	99	144	412	969.6	14.8
WEYERHAEUSER-EVERGREEN	286	326	91	202	240	423	57	165	289	362	129.4	3.9
YELLOWSTONE POWER PLANT	8	2	-	-	78	19	27	4	68	9	404.3	1732

6.2 Four-Factor Analyses for Montana Point Sources

Under 40 CFR 51.308(f)(2)(i), states must consider the four statutory factors to decide what emission control measures are necessary to make reasonable progress toward natural visibility conditions at Class I areas. The four statutory factors are: 1) cost of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts of compliance, and 4) remaining useful life of any potentially affected major or minor stationary source or group of sources.

The 17 sources selected (see Table 6-4) conducted a four factor analysis that evaluated controls for NO_x and/or SO_2. Oftentimes, the control equipment available for sources is very similar. Descriptions of the more common controls evaluated and the sources for which these controls were considered are described in Section 6.2.4. Less common controls or controls specific to a facility are described in the individual facility section(s) that follow.

6.2.1 Source Communications and Guidance

In early 2019, Montana provided screened sources with additional guidance and clarification of requirements for creating four-factor analyses. Prior to engaging sources in communications, Montana reached out to EPA Region 8, consulted draft guidance, and participated in WRAP Control Strategies discussions to build a foundation of knowledge of requirements and processes that could be shared with sources.

Montana worked closely with and provided guidance to sources preparing four-factor reports, such as developing cost of control estimates using EPA's Cost Control Manual[106]. Montana also explained to sources the need to provide facility-specific data that represents current emissions, projected future emissions and potential future control scenarios to ensure the accuracy and representativeness of emissions data for modeling.

As previously discussed in Chapter 5, the representative baseline emissions that accurately reflect the current emissions profile for each source are referred to as RepBase2 emissions and are the basis for the projected 2028 emissions scenario. The 2028OTBa2 emissions scenario accounts for emission changes 'on-the-books', (e.g. permit conditions and shutdowns) and phased reductions 'on-the-way' from known control measures applied to growth categories (e.g. mobile fleet changes, performance standards applied to growth categories, expected/planned future operational rates).

Sources used the 2028OTBa2 scenario emissions to calculate the cost per ton of emission reduction achieved from applying controls. The future potential additional controls (PAC) modeling run utilized the 2028OTBa2 scenario minus any reductions that are likely to occur due to required controls. If no additional controls are required, the 2028PAC2 modeling run used the 2028OTBa2 emissions in the modeling analysis. The 2028OTBa2 estimates may also incorporate emission increases over the representative baseline if emitting units had particularly low output due to market/product demand and/or uncommonly low runtime.

Additional information on source communications can be found in Appendix A.

6.2.2 Reasonable Cost of Compliance

Cost of compliance has historically been viewed as the monetary cost a source has to undertake to achieve a regulatory objective, such as installing a specific pollution control technology. The analysis is most often summarized as the cost per ton of emission reduction that can be achieved beyond any current controls already in place. The numerator portion of the analysis is based on the annual operating costs plus the annualized capital cost spread over a financing period, often twenty to thirty years.

Montana must determine what a "reasonable" cost of compliance is and if a given technology or additional controls are required to make reasonable visibility progress during each planning period. In attempt to do so, Montana has considered the following:

- In the first planning period, the BART requirement directed states to identify whether emissions from sources subject to BART were well controlled, or whether retrofit measures were available to

[106] EPA, EPA Air Pollution Control Cost Manual, Available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual. EPA is in the process of updating what will be the Seventh Edition of this document and some updates have already been finalized. Sources were asked to refer to the most current finalized versions.

reduce emissions in order to achieve reasonable progress. In the BART analyses, often the monetary cost of compliance was the dominant factor for states' determination of what was reasonable in the first planning period. However, what may have been reasonable in terms of BART may not be reasonable for sources this planning period, as much has changed over the past decade. EPA guidance states "*If a state applies a threshold for cost/ton to evaluate control measures, we recommend that the SIP explain why the selected threshold is appropriate for that purpose and consistent with the requirement to make reasonable progress. As explained below, a cost/ton metric and comparisons to the cost/ton values for measures that have been previously implemented may or may not be useful in determining the reasonableness of compliance costs.*"[107] Montana believes that focusing strictly on past costs incurred by BART sources is not appropriate for determining reasonable costs for these sources in Montana for the second planning period.

- Electrical generation and oil and gas markets have changes considerably over the last ten years and significant changes are expected to occur in to the future. Many coal-fired EGUs across the West are being shuttered, and more are planned for shutdown within the next ten years. [108] Although Montana did not secure federally-enforceable limited operations or shutdown dates beyond Colstrip's Units 1 and 2, MDU Lewis & Clark, and JE Corette, research into energy portfolio modeling plans indicate end years for coal-fired EGUs within this planning period.[109] The changing landscape of power generation, and movement toward renewables, is important to consider when defining reasonableness of cost.

- The RHR focuses on preventing any future and remedying any existing visibility impairment from anthropogenic air pollution in Class I areas. Although visibility improvement is not one of the statutory factors, the EPA has indicated states may consider the amount of visibility improvement when making reasonable progress determinations.[110] Montana believes that due to source retirements and closures alone, visibility will improve considerably and additional controls, although costs may seem reasonable this round, are not necessary to make visibility improvement in this planning period.

- Montana is in compliance with all health based ambient air quality standards. Many of Montana's non-attainment areas have already been or are in the process of being redesignated to maintenance status. Additional controls would not have the added benefit of helping Montana comply with the existing health based ambient air quality standards.

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[107] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 2019, p.39–40.

[108] U.S. Energy Information Administration, Today in Energy, "As U.S. coal-fired capacity and utilization decline, operators consider seasonal operation", (1 Sept. 2020), Available at: https://www.eia.gov/todayinenergy/detail.php?id=44976

[109] Northwestern Energy presentation at Montana's Energy and Telecommunications Interim Committee (ETIC) meeting, 23 Feb. 2022. Available at: https://www.northwesternenergy.com/docs/default-source/default-document-library/about-us/regulatory/irp/etac-2022.02.23-presentation.pdf?sfvrsn=cddcc7bd_7

[110] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 2019, p.34-35.

These considerations do not summarily dismiss four-factor analyses, and the rationale for control determination is chosen based on four-factor analysis. However, the determination and how Montana defines reasonableness of cost is flexible and states must be able to balance a wider variety of issues beyond just a low cost. Additionally, setting a cost/ton threshold can be an option to help define reasonableness of cost; however, neither the CAA nor its implementing regulations require that states set a cost-effectiveness threshold. While EPA guidance says "that a state may find it useful to develop thresholds for single metrics to organize and guide its decision-making," it does not require states to set a threshold. During the first regional haze planning period, EPA completed the BART and reasonable progress analysis. EPA did not use a specific cost per ton threshold but rather made a site-by-site determination to decide on final control requirements. For the second planning period, Montana did not identify any cost threshold. Rather, sources were told to make sure all relevant technologies were included in the analysis to provide for a robust evaluation.

6.2.3 Interest Rates and Amortization Periods

Two factors in the cost calculation are the interest rate and amortization period to be used in four-factor analyses. EPA Region 8 and EPA Headquarters recommends that states use the current bank prime interest rate, unless the facility had more specific information relative to their ability to obtain funding. For the better part of 2019, the Federal Bank prime rate was 5.5 percent. Interest rates did not begin to drop until most sources had completed and submitted their four-factor analyses to Montana for review. Although rates had dropped dramatically starting in the fall of 2019 and continued to drop through 2021, based on the historical bank prime rate over the past 50 years, these low rates were unlikely to be maintained. Rates have since increased from their record lows, and as of June 2022, the bank prime interest rate is 4.75%. Further rate increases are expected as the federal government works to control inflation. The difference remaining between the current bank prime rate and the bank prime rate (5.5%) at the time Montana requested four factor summaries is not significant enough to change the outcome of a particular cost per ton analysis.

Montana sources followed EPA draft guidance that recommended a default 20-year amortization period for evaluating control options, unless there were unique cases where the 20-year period exceeded the remaining useful equipment life (see 2019-04_ReasonableProgressGuidanceLetter example in Appendix A). In September 2020, Montana received feedback from the National Park Service and EPA Region 8 that some technology amortization spreadsheets within the EPA Air Pollution Cost Control Manual do use a 30-year period for the analysis. In light of this feedback, Montana considered adjusting the amortization period to determine if costs would change enough to be reasonable.

To understand the effect of changing both the interest rate and amortization period, a demonstration of the impact of changing these variables is provided.

<u>Consideration of Amortization Periods</u>

- o A two-million-dollar capital project at a 5.5% interest rate and a 20-year amortization period results in an annual cost of $167,359.
- o The same million-dollar capital project at a 5.5% interest rate and a 30-year amortization period results in an annual cost of $137,611.

- This change results in an 18 percent annual cost reduction. For any analyses that used a 20 year amortization period, converting the cost per ton calculation downward by 18 percent did not result in a change in the conclusion regarding reasonable cost. Specific comments have been included to highlight how these changes would have impacted particular facility emitting units.

Consideration of Interest Rate

- A two-million-dollar capital project at 5.5% interest rate and a 20-year amortization period results in an annual cost of $167,359.
- The same two-million-dollar capital project at 3.5% interest rate and a 20-year amortization period results in annual cost of $140,722.
- This change results in a 16 percent annual cost reduction.

A summary of interest rate and amortization periods are shown below. Rather, a general understanding of adjusting can be discussed qualitatively.

Table 6-7. Impact of Capital Cost, Interest Rate, and Amortization Period on Annualized Total Cost

Capital	**Interest Rate**	**Period**	**Annual Cost**
2,000,000	0.03	20	134,431
2,000,000	0.035	20	140,722
2,000,000	0.04	20	147,164
2,000,000	0.045	20	153,752
2,000,000	0.05	20	160,485
2,000,000	0.055	20	167,359
2,000,000	0.06	20	174,369
2,000,000	0.065	20	181,513
2,000,000	0.07	20	188,786
2,000,000	0.03	30	102,039
2,000,000	0.035	30	108,743
2,000,000	0.04	30	115,660
2,000,000	0.045	30	122,783
2,000,000	0.05	30	130,103
2,000,000	0.055	30	137,611
2,000,000	0.06	30	145,298
2,000,000	0.065	30	153,155
2,000,000	0.07	30	161,173

Montana stands by its decision to use an interest rate of 5.5% for the second planning period as this was the bank prime rate at the time these analyses were prepared. The interest rates are returning to historic norms and may well end up above the 5.5% bank prime rate, further increasing the cost per ton calculations. Also as demonstrated, changing the amortization period does not significantly alter the outcome of the cost per ton analysis. Therefore, Montana has concluded that to adjust the interest rate and amortization period is not efficacious and does not require updates to the originally submitted four-factor submittals, summarized in Sections 6.2.5 - 6.2.21.

6.2.4 Control Equipment Descriptions

6.2.4.1 Available NOx Reduction Strategies and Technologies[111]

The following represents proven, available NOx-reduction strategies and technologies for four-factor sources.

Fuel switching. Fuel switching is the simplest and potentially the most economical way to reduce NOx emissions. Fuel-bound NOx formation is most effectively reduced by switching to a fuel with reduced nitrogen content. No. 6 fuel oil or another residual fuel, having relatively high nitrogen content, can be replaced with No. 2 fuel oil, another distillate oil, or natural gas (which is essentially nitrogen-free) to reduce NOx emissions.

Flue-gas recirculation (FGR). Flue gas recirculation involves extracting some of the flue gas from the stack and recirculating it with the combustion air supplied to the burners. The process, by diluting the combustion air with flue gas, reduces both the oxygen concentration at the burners and the temperature. Reductions in NOx emissions ranging from 30 to 60% have been achieved.

Low NOx burners. Installation of burners especially designed to limit NOx formation can reduce NOx emissions by up to 50%. Greater reduction efficiencies can be achieved by combining a low-NOx burner with FGR—though not additive of each of the reduction efficiencies. Low-NOx burners are designed to reduce the peak flame temperature by inducing recirculation zones, staging combustion zones, and reducing local oxygen concentrations.

Derating. Some industrial boilers can be derated to produce a reduced quantity of steam or hot water. Derating can be accomplished by reducing the firing rate or by installing a permanent restriction, such as an orifice plate, in the fuel line.

Steam or water injection. Injecting a small amount of water or steam into the immediate vicinity of the flame will lower the flame temperature and reduce the local oxygen concentration. The result is to decrease the formation of thermal and fuel-bound NOx. Be advised that this process generally lowers the combustion efficiency of the unit by 1 to 2%.

Staged combustion. Either air or fuel injection can be staged, creating either a fuel-rich zone followed by an air-rich zone or an air-rich zone followed by a fuel-rich zone. Staged combustion can be achieved by

[111] Pollution Online, NOx Emission Reduction Strategies, (16 June 2000), Available at: https://www.pollutiononline.com/doc/nox-emission-reduction-strategies-0001

installing a low-NOx staged combustion burner, or the furnace can be retrofitted for staged combustion. NOx reductions of more than 40% have been demonstrated with staged combustion.

Fuel reburning. Staged combustion can be achieved through the process of fuel reburning by creating a gas-reburning zone above the primary combustion zone. In the gas-reburning zone, additional natural gas is injected, creating a fuel-rich region where hydrocarbon radicals react with NOx to form molecular nitrogen. Field evaluations of natural gas reburning (NGR) on several full-scale utility boilers have yielded NOx reductions ranging from 40 to 75%.

Reduced-oxygen concentration. Decreasing the excess air reduces the oxygen available in the combustion zone and lengthens the flame, resulting in a reduced heat-release rate per unit flame volume. NOx emissions diminish in an approximately linear fashion with decreasing excess air. However, as excess air falls below a threshold value, combustion efficiency will decrease due to incomplete mixing, and CO emissions will increase. The optimum excess-air value must be determined experimentally and will depend on the fuel and the combustion-system design. A feedback control system can be installed to monitor oxygen or combustibles levels in the flue gas and to adjust the combustion-air flow rate until the desired target is reached. Such a system can reduce NOx emissions by up to 50%.

Selective catalytic reduction (SCR). SCR is a post-formation NOx-control technology that uses a catalyst to facilitate a chemical reaction between NOx and ammonia to produce nitrogen and water. An ammonia/air or ammonia/steam mixture is injected into the exhaust gas, which then passes through the catalyst where NOx is reduced. To optimize the reaction, the temperature of the exhaust gas must be in a certain range when it passes through the catalyst bed. Typically, removal efficiencies greater than 80% can be achieved, regardless of the combustion process or fuel type used. Among its disadvantages, SCR requires additional space for the catalyst and reactor vessel, as well as an ammonia storage, distribution, and injection system. Also, a Risk Management Plan (RMP) in compliance with Federal Accidental Release Prevention rules may have to be prepared and submitted for ammonia storage. Precise control of ammonia injection is critical. An inadequate amount of ammonia can result in unacceptable high NOx emission rates, whereas excess ammonia can lead to ammonia "slip," or the venting of undesirable ammonia to the atmosphere. As NH_3 is both a visibility impairing air pollutant and a wastewater regulated pollutant, air emissions and water discharges can be impacted. Excess ammonia in the presence of other pollutants still remaining in the flue gas can also form species such as ammonium-sulfate which can create visible plumes downwind of the stack discharge.

Selective non-catalytic reduction (SNCR). Selective non-catalytic NOx reduction involves injection of a reducing agent—ammonia or urea—into the flue gas. The optimum injection temperature when using ammonia is 1850ºF, at which temperature 60% NOx removal can be approached. The optimum temperature range is wider when using urea. Below the optimum temperature range, ammonia forms, and above, NOx emissions actually increase. The success of NOx removal depends not only on the injection temperature but also on the ability of the agent to mix sufficiently with flue gas.

6.2.4.2 Available SO_2 Reduction Strategies and Technologies

The following represents proven, available SO_2-reduction strategies and technologies for four-factor sources.

Choice of Fuel. Since sulfur emissions are proportional to the sulfur content of the fuel, an effective means of reducing SO_2 emissions is to burn low-sulfur fuel such as natural gas, low-sulfur oil, or low-sulfur coal. Natural gas has the added advantage of emitting no particulate matter when burned.

Sorbent Injection. Sorbent injection involves adding an alkali compound to the combustion gases for reaction with the sulfur dioxide. Typical calcium sorbents include lime and variants of lime. Sodium-based compounds are also used. Dry sorbent injection systems are simple systems, and generally require a sorbent storage tank, feeding mechanism, transfer line and blower, and injection device. Sorbent injection processes remove 30–60% of sulfur oxide emissions; however, if the sorbent is hydrated lime, then 80% or greater removal can be achieved. These systems are commonly called lime spray dryers.

Flue Gas Desulfurization (FGD). FGD may be carried out using either of two basic systems: regenerable and throwaway. Both methods may include wet or dry processes. Currently, more than 90% of utility FGD systems use a wet throwaway system process. Throwaway systems use inexpensive scrubbing mediums that are cheaper to replace than to regenerate. Regenerable systems use expensive sorbents that are recovered by stripping sulfur oxides from the scrubbing medium. These produce useful by-products, including sulfur, sulfuric acid, and gypsum. Regenerable FGDs generally have higher capital costs than throwaway systems but lower waste disposal requirements and costs.

In wet FGD processes, flue gases are scrubbed in a liquid or liquid/solid slurry of lime or limestone. Wet processes are highly efficient and can achieve SO_2 removal of 90% or more. With dry scrubbing, solid sorbents capture the sulfur oxides. Dry systems have 70–90% sulfur oxide removal efficiencies and often have lower capital and operating costs, lower energy and water requirements, and lower maintenance requirements, in addition to which there is no need to handle sludge. Examples of FGD include:

Dual Alkali Wet Scrubber. Dual-alkali scrubbers use a sodium-based alkali solution to remove SO_2 from the combustion exhaust gas. The process uses both sodium-based and calcium-based compounds. The sodium-based reagents absorb SO_2 from the exhaust gas, and the calcium-based solution (lime or limestone) regenerates the spent liquor. Calcium sulfites and sulfates are precipitated and discarded as sludge, and the regenerated sodium solution is returned to the absorber loop.

Spray Dry Absorber. The typical spray dry absorber (SDA) uses lime slurry and water injected into a tower to remove SO_2 from the combustion gases. The towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry to produce a relatively dry by-product. The process equipment associated with an SDA typically includes an alkaline storage tank, mixing and feed tanks, atomizer, spray chamber, particulate control device, and recycle system. The recycle system collects solid reaction products and recycles them back to the spray dryer feed system to reduce alkaline sorbent use. SDAs are the commonly used dry scrubbing method in large industrial and utility boiler applications. SDAs have demonstrated the ability to achieve greater than 95% SO_2 reduction.

Circulating Dry Scrubber. The circulating dry scrubber (CDS) uses a circulating fluidized bed of dry hydrated lime reagent to remove SO_2. Flue gas passes through a venturi at the base of a vertical reactor tower and is humidified by a water mist. The humidified flue gas then enters a fluidized bed of powdered hydrated lime where SO_2 is removed. The dry by-product produced by this system is routed with the flue gas to the particulate removal system.

Hydrated Ash Reinjection. The hydrated ash reinjection (HAR) process is a modified dry FGD process developed to increase utilization of unreacted lime (CaO) in the circulating fluidized bed combustion (CFBC) ash and any free lime left from the furnace burning process. The hydrated ash reinjection process will further reduce the SO_2 concentration in the flue gas. The actual design of a hydrated ash reinjection system is vendor-specific. In a hydrated ash reinjection system, a portion of the collected ash and lime is hydrated and re-introduced into a reaction vessel located ahead of the fabric filter inlet. In conventional boiler applications, additional lime may be added to the ash to increase the mixture's alkalinity. For CFBC boiler applications, sufficient residual CaO is available in the ash and additional lime is not required.

Each of the screened-in sources were asked to conduct a four-factor analysis which covers the emitting units with the highest emissions for each facility. The discussion below represents information taken directly from those submittals and summaries of the analyses prepared by Montana.

6.2.5 Talen Montana LLC - Colstrip Steam Electric Station Units #3 and #4[112]

Talen Montana LLC – Colstrip Steam Electric Station (Colstrip) submitted their four-factor analysis and supporting information on September 30, 2019. The Colstrip facility is in Colstrip, MT. Units #3 and #4 were analyzed for control options to meet reasonable progress requirements under the RHR. Unit #3 is a tangentially-fired CE boiler that burns low sulfur, sub-bituminous northern Powder River Basin (PRB) coal. Unit #3 is rated at 805 MW gross output and started operation in 1984. Unit #4 is also a tangentially-fired CE boiler that burns low sulfur, sub-bituminous northern PRB coal rated at 805 MW gross output and started operation in 1986. Both units are considered Prevention of Significant Deterioration (PSD) sources for SO_2 and NOx. The operations of Unit #3 and Unit #4 are nearly identical and, as is the case with many EGUs, operate at very high rates throughout the year providing baseload power for Montana and the Northwest.

Unit #3 RepBase and 2028 OTB/OTW Scenarios

Talen selected an average of 2014-2016 emissions as their representative baseline. Talen also selected a future year 2028 OTB/OTW scenario that would incorporate any emissions changes likely to occur regardless of any controls that may be required.

Talen provided Montana with a justification for the emissions used in their four-factor analysis and subsequently used in the regional modeling scenarios (RepBase2 and 2028OTBa2), as summarized below:

> *For baseline emissions, we believe the 2014 – 2016 period provides the most representative period. This period is recent and includes an overhaul period for each of the Units. Typically, Colstrip has conducted a maintenance overhaul every three years for 6-7 weeks. We don't believe the 2018 period is representative of Units 3 and 4 operations because of PM compliance issues and associated downtime during the summer of 2018. From June 28 – September 5 in 2018, Units 3&4 operated at a capacity factor of about 35% when normally the capacity factor during this time of year would be about 92%.*

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[112] Talen Montana LLC, Colstrip Steam Electric Station, Regional Haze Reasonable Progress Analysis (30 Sept. 2019), Available at: http://deq.mt.gov/Portals/112/Air/AirQuality/Documents/Planning/PDF/Talen%20Colstrip%204%20Factor%20Analysis%20(2019-0930).pdf?ver=2020-02-03-161435-860

Recent emission reduction rationale incorporated in the emission determination includes SmartBurn installation on Unit #3 in 2017, which reduced NOx emissions by approximately 10 percent. The incorporation of SmartBurn technology is the primary reason why the 2028 OTB/OTW NOx estimate is below the 2014-2016 Representative Baseline.

The following table lists the NOx and SO_2 emissions for Unit #3 for the representative baseline period and the projected emissions used in the 2028 OTB/OTW scenario:

Table 6-8. Colstrip Unit #3 RepBase and 2028 OTB/OTW emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2014-2016	4228.0	2359.0	3833.0	2350.0

SO_2 Evaluation

The current SO_2 control consists of digital boiler controls, the use of low-sulfur coal (<1% sulfur) and wet scrubbers with additional lime injection to reduce SO_2 emissions. Unit #3 uses eight wet venturi scrubbers that provide compliance with the emission rate equivalent of 0.10 lb SO_2/MMBtu. Per the PSD permitting requirements, the SO_2 control system is a two-staged venturi scrubber/spray tower absorbers module, utilizing the lime addition and the alkalinity of the collected fly ash for SO_2 removal. The scrubbing system includes the past use of hydrated dolomitic lime (containing a mixture of calcium and magnesium hydroxides) and current use of calcium-only lime as the scrubbing reagent. The scrubber system was designed and certified in Talen's Montana Facility Siting Certificate to achieve 95 percent control.

Unit #3 has maintained compliance with the SO_2 emission standards through firing low-sulfur coal and the use of the scrubber system. The current process design allows for a 95 percent SO_2 reduction and includes no provisions for bypassing scrubbers. The process also includes a spare scrubber vessel for system reliability.

Step 1 – Identify All Available Technologies

The 95 percent control level currently being achieved is considered to represent the best control measure available for SO_2 and therefore, no additional detailed analysis for SO_2 is discussed. Any additional SO_2 removal that might be achieved with some process reconfiguration is either already incorporated into the existing scrubber controls or was previously identified as not being effective with the current two stage scrubber design. Such additional technologies include: Elimination of Bypass Reheat (incorporated), Installation of Liquid Distribution Rings (incorporated), Installation of Perforated Trays (incorporated), Use of Organic Acid Additives (ineffective), Improve or Upgrade Scrubber Auxiliary System Equipment (incorporated) and Redesign Spray Header or Nozzle Configuration (ineffective). None of these technologies would be cost effective given the already high control efficiency of 95 percent.

A review of the EPA's RACT/BACT/LAER/ Clearinghouse (RBLC) database for SO_2 add-on controls also indicated the current design already incorporates the add-on controls known for tangential coal-fired boilers. No further analysis was conducted for additional SO_2 control.

NOx Evaluation

The current NO_x controls considered are combustion controls and include low NO_X burners, separate overfire air (SOFA), and Smartburn® technology to lower NO_x emissions. Smartburn® technology was voluntarily installed on Unit #3 in late 2017. Therefore, year 2018 is the only year that represents a full year of emissions with the current NO_x controls in operation. If Smartburn® technology had not been voluntarily installed in 2017, it would be an additional combustion technology for consideration in implementing this planning period. Current NO_x emission rates being achieved with the baseline controls are 0.15 lb/MMBtu based on heat input generation.

Step 1 – Identify All Available Technologies

Selective Noncatalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR) were identified as post-combustion technologies available to control NO_x. These post-combustion technologies were also identified in the first planning period. No additional technologies were listed for consideration.

Step 2: Eliminate Technically Infeasible Options

Both SNCR and SCR require additional reagent beyond stoichiometric requirements to effectively drive the reaction to atmospheric nitrogen and water. This can create a condition identified as "ammonia slip". Excess unreacted ammonia has been known to contribute to the formation of ammonium bisulfate and ammonium sulfate within the exhaust plume, typically an issue at coal-fired power plants and Portland cement kilns. However, neither technology can be eliminated from consideration on the basis of either catalyst life or ammonia slip.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The current baseline control effectiveness is compared to the addition of both SNCR and SCR to the baseline case. The resulting emission rates are shown in Table 6-9.

Table 6-9. NOx Emission Control Rates for Colstrip Unit #3

Pollutant	Control Technology	Controlled Emission Rate
NOx	SCR + LNB SOFA	0.06 lb/MMBtu
	SNCR + LNB	0.13 lb/MMBtu
	SOFA LNB and SOFA*	0.15 lb/MMBtu*

*This is the baseline control scenario

Estimated emission rate reductions are estimated at 13 percent for SNCR and 60 percent for SCR versus the base case. These would provide theoretical NO_x emission reductions of 433 tpy for SNCR and 2,159 tpy for SCR. The reduction for SCR is significantly better than SNCR, although, as previously discussed and further described in Table 6-10 below, SCR carries significantly higher capital costs, operating costs, and additional risk related to catalyst concerns.

Step 4 – Evaluate Impacts and Document Results

<u>Factor 1: Cost of Compliance</u>

Table 6-10 and Table 6-11 provide summaries of estimated annual costs for the various control options.

Table 6-10. Colstrip Unit #3 NOx Control Annualized Costs

Control option	Capital Costs	Annualized Capital Cost	Annual Operation & Maintenance	Total Annualized Cost
SCR	$310,946,279	$6,347,422	$21,414,3489	$27,761,811
SNCR	$17,750,899	$2,937,728	$1,493,738	$4,431,466

Table 6-11. Colstrip Unit #3 NOx Cost Effectiveness Analysis

Control option	Emission Reduction Estimate (TPY)	Cost effectiveness ($/ton)
SCR	2159	$12,858
SNCR	433	$10,234

The capital cost of SCR is estimated at over 310 million dollars and carries an estimate of over 21 million in annual operation and maintenance costs, resulting in a total annual cost exceeding 27 million dollars. SNCR on the other hand, has a capital cost over 17 million, with an annual operation and maintenance cost of approximately 1.5 million providing an annualized cost of approximately 4.5 million.

When evaluated on a cost effectiveness per ton, of NOx reductions, SCR is $12,858 and SNCR is $10,234. It should be noted that the retrofit factor used in the EPA Cost Control Manual for this analysis was 1.3 rather than 1.0 to characterize the relatively limited physical space that is available for the infrastructure for each control technology. Specifically, the current control technologies for particulate matter and SO_2, reduce the available space that would be required for reagent infrastructure and injection to Unit #3.

<u>Factor 2: Time Necessary for Compliance</u>

EPA guidance suggests that, for the second planning period, installation of controls is not necessarily required within 5 years of SIP approval. Therefore, control equipment that becomes operational any time prior to the end of the second planning period (2028) would satisfy the requirements in the RHR. If SCR or SNCR were required, the necessary design, installation, and shakedown period could be complete within this time frame. From a practical standpoint, from the time a decision was made to move ahead with either SCR or SNCR, either technology could be implemented within a three to five-year period.

<u>Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance</u>

As previously discussed, both SCR and SNCR require reagent injections that are above the stoichiometric requirements to achieve the desired reaction rates. The excess reagent can combine with high concentrations of sulfate and nitrate to form solid species within the exhaust plume. These conditions are also dependent upon ambient conditions and can lead to plume visibility issues sporadically during the year. The formation of these species can themselves contribute to haze. Potential haze impacts from ammonia slip should not be overlooked as a future concern with use of SCR and SNCR. Additionally, for SCR, the catalyst required can have relatively short service life due to fouling and plugging and these issues create additional waste disposal streams and can cause additional unit downtime including startup and shutdown events which often result in higher short-term emission rates.

Factor 4: Remaining Useful Life

Unit #3 is expected to have a remaining useful life of at least 20 years although market conditions and policy decisions in the states receiving power from Colstrip may impact the viability of future power operations. These policies may impact operations by the end of the second planning period and provide for a better understanding of remaining useful life for the third planning period.

Step 5: Select Reasonable Progress Control

Montana has determined that the current control technologies of digital boiler controls, low NOx burners, SOFA, and Smartburn® low NOx combustion burners are providing effective NOx control. Furthermore, both SCR and SNCR do not provide a reasonable cost effectiveness to justify either add-on control technology for the second planning period. The enforceable shutdown date of July 1, 2022 for Units #1 and #2 would have provided estimated annual NOx reductions of approximately 4,961 tpy NOx. Due to economic reasons, these units were shut down in January 2020, over two years earlier than the required shutdown date. This permanent reduction outweighs the combined emissions reduction that would occur from both Unit #3 and Unit #4, if the most stringent evaluated technology (SCR) were incorporated at the site. If SCR was installed on both Units #3 and #4, it would provide an overall reduction of 4,318 tpy NOx (2014-2016 baseline) while the total reduction from the Units #1 and #2 provides an annual reduction of 5,835.7 tpy NOx (2014-2017 baseline). Therefore, the reduction from shuttering Units #1 and #2 exceeds the reduction amount that would have occurred from SCR installation on both Units #3 and #4 by 1,517 tpy NOx.

No additional controls for SO_2 or NOx are required for the second planning period. Voluntary NOx reductions have already occurred as demonstrated in the lower NOx emission rates. Add-on NOx controls are not cost effective at this time, and current SO_2 controls incorporate known controls for tangential boilers while already achieving high SO_2 control.

Unit #4

Unit #4 is essentially identical to Unit #3 in controls and operation. Therefore, the analysis and conclusions for Unit #3 are identical to the analysis and conclusions for Unit #4. No additional controls for NOx or SO_2 are required for the second planning period.

For completeness, Unit #4 emissions for the RepBase and future 2028 OTB/OTW are included below.

Table 6-12. Colstrip Unit #4 RepBase and 2028 OTB/OTW emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2014-2016	4228.0	2359.0	3833.0	2350.0

6.2.6 Weyerhaeuser NR – Columbia Falls Facility[113]

Weyerhaeuser NR – Columbia Falls facility (Weyerhaeuser CF), submitted analysis and supporting information on September 30, 2019. Montana did not request that Weyerhaeuser CF evaluate SO_2 at the facility as the SO_2 emissions are extremely low. Therefore, the Weyerhaeuser CF four-factor analysis did not include any discussion of SO_2.

The facility is in Columbia Falls, Montana and consists of a sawmill, a planer, and plywood and medium density fiberboard (MDF) processes. The MDF plant has two production lines: Line 1 manufactures MDF through a batch press process and Line 2 manufactures by using a continuous press. The analysis presented by Weyerhaeuser CF included both the Columbia Falls Facility and the Evergreen Facility in Kalispell, MT. The elements specific to the Columbia Falls facility are highlighted in this section.

Weyerhaeuser CF RepBase and 2028 OTB/OTW Scenarios

Weyerhaeuser CF selected an average of 2014-2017 emissions as their representative baseline. Weyerhaeuser CF also selected a future year 2028 OTB/OTW scenario that was used to calculate the cost per ton of emission reduction achieved from applying controls.

Weyerhaeuser CF chose not to scale the representative baseline emissions to the future 2028 OTB/OTW scenario. Thus, the 2028 OTB/OTW emissions are equivalent to the representative baseline emissions.

Weyerhaeuser CF provided Montana with a justification for the emissions used in their four-factor analysis and subsequently used in the regional modeling scenarios (RepBase2 and 2028OTBa2), and Montana concurred that the four-year period was reflective of recent normal operation. Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 6-13. Weyerhaeuser CF RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2014-2017	969.6	14.8	969.6	14.8

This four-factor analysis focuses on four emitting units at the Columbia Falls facility: the Riley-Union Stoker hog fuel boiler (Riley-Union Boiler), two sanderdust burners located on Line 1 MDF dryer (Line 1 MDF dryers) and the Line 2 MDF Fiber Dryer (Line 2 sanderdust burner).

The Riley-Union Boiler was manufactured in 1973 and is rated at 170,00 pounds per hour (pph) steam. It supplies steam heat to the dry kilns, plywood press, log vats and MDF platen press. The Riley-Union Boiler uses wood waste supplemented with natural gas as a fuel. Downstream from the spreader-stoker grate, there

[113]Weyerhaeuser, Columbia Falls and Evergreen Facilities, Regional Haze 2nd Planning Period Four-Factor Analysis, (Sept. 2019), Available at: http://deq.mt.gov/Portals/112/Air/AirQuality/Documents/Planning/PDF/2019%20Evergreen%20Columbia%20Falls%204FA%20v2.0.pdf?ver=2020-02-03-161831-050

are sanderdust burners that are capable of supplementing 10% of the heat rate capacity of the boiler. These burners are normally fired with sanderdust, but can fire natural gas during sanderdust shortages and startup.

The Line 1 MDF dryers include two direct-contact dryers. The Core dryer consists of a sanderdust Coen burner with a heading capacity of 50 MMBtu/hr. The other dryer is a face dryer heated by one Coen burner with a capacity of 50 MMBtu/hr. The Line 2 MDF consists of a sanderdust burner.

The Riley-Union Boiler includes both multiclones (primary) and a dry electrostatic precipitator (ESP) (secondary) for PM control. The ESP was manufactured in 1993 by PPC Industries and has an estimated control efficiency of 99% PM. The Line 1 MDF dryers are controlled with 4 GeoEnergy E-tube wet ESPs. Each ESP is designed to accommodate a stack flow of 70,000 acfm (280,000 acfm total). The Line 2 sanderdust burner exhausts to a Venturi scrubber installed in 2001.

<u>Riley-Union Boiler</u>

The Riley-Union Boiler does not currently have post-combustion or low NOx combustion technology. The Riley-Union Boiler does use a process similar to fuel staging by design. The sanderdust burners, which typically supply approximately 10 percent of the heat to the boiler, are located downstream of the primary wood-fired flame. This configuration helps reduce thermal NOx by breaking the combustion event into multiple stages. Weyerhaeuser follows a maintenance program to maintain the boiler's burners, hog fuel feed system, fans, and other equipment. The boiler is also equipped with a computer control system used to maintain optimum air-to-fuel ratios and fuel feed rates.

The Riley-Union Boiler at CF combusts wood residue, primarily as bark from the log debarking process, and is load-following, meaning its firing rates are adjusted to meet the changing steam demand of various process operations. Sanderdust burners supplement the hog fuel firing downstream of the spreader-stoker grate in the boiler. The sanderdust burners are also capable of firing natural gas, with a design capacity of approximately 10 percent of the total boiler capacity. Natural gas firing only occurs during startup and rare events of sanderdust shortage.

The load of the Weyerhaeuser CF Riley Stoker Boiler fluctuates between 50,000 lb/hr steam and 150,000 lb/hr steam. These widespread load changes often occur rapidly, sometimes swinging from the minimum load to the maximum load within thirty minutes. The average low-end temperature of the flue gas from the boiler is 350º F.

A high-level summary of the analysis presented by Weyerhaeuser is presented below. Weyerhaeuser indicated the information provided was based on a search of the EPA RBLC for similar units.

Step 1 – Identify All Available Technologies

The control technologies for combustion modification described below decrease NOx emissions by preventing NOx formation during the combustion process, rather than by reducing NOx concentrations in the exhaust.

The following retrofit technologies were evaluated for the Riley-Union Boiler: Flue Gas Recirculation (FGR), Fuel Staging, Low NOx Burner (LNB), Low Excess Air (LEA) and Staged Combustion

Post-combustion techniques that can be employed for NOx controls include SCR and SNCR.

Step 2: Eliminate Technically Infeasible Options

Minimal thermal NOx is formed in wood-fired spreader stoker boilers due to the high moisture content of the wood, and the spreader stoker firing configuration. Therefore, combustion modification technologies that are aimed at reducing thermal NOx formation, such as FGR, are not considered. Additionally, combustion modification technologies used with traditional gas and oil burners, such as LNB, are not available for wood- fired boilers. Similarly, since the boiler is of spreader stoker design, they need high excess air levels for proper fuel burning. As such, combustion modifications like LEA are not practical to employ on spreader stoker boilers.

Many wood-fired spreader stoker boilers include overfire air systems by design. The overfire air combustion configuration reduces NOx through staged combustion technology. Because overfire air systems are commonly employed in spreader stoker boilers, retrofitting an overfire air system on the Weyerhaeuser CF Riley-Union Boiler has been identified as a combustion modification improvement option.

After accounting for the physical and operational characteristics of the Riley-Union Boiler, the post-combustion and combustion modification control technologies and strategies considered in this analysis for controlling NOx emissions include the following:

- Staged Combustion (OFA)
- Good Operating Practices (base case)
- Selective Catalytic Reduction
- Regenerative Selective Catalytic Reduction (RSCR)
- Selective Non-Catalytic Reduction

<u>SCR</u>

Implementing SCR on industrial hog fuel boilers poses several technical challenges. First, size constraints often make retrofitting an SCR system near the boiler impossible. Second, most hog fuel boilers' temperature profiles are not appropriate for SCR, and the SCR system pressure drop requirements create sizing concerns related to existing boiler fans. Third, the National Council for Air and Stream Improvement (NCASI) notes that the high PM concentrations upstream of the PM control equipment (Hot-side/High-dust) would impede catalyst effectiveness and could result in deactivation or poisoning of the catalyst, which requires downtime to clean and/or replace the catalyst. The installation of SCR downstream of the PM control equipment (Cold-side/Tail- end SCR) would render the gas stream too cold for an effective reaction with the catalyst to reduce NOx. In biomass boilers, plugging and fouling of the catalyst can occur due to large amounts of fly ash generated by the biomass.

The desired minimum temperature for SCR application to achieve 70% control is 575°F 13. The maximum exhaust temperature of the Riley-Union Boiler at Weyerhaeuser CF is 500°F. While the exhaust temperatures of the boiler are close to the range of operation of the SCR system, higher temperatures would be needed for optimum control efficiency for tail-end SCR application.

<u>RSCR</u>

In an RSCR system, the regenerative heating reduces the required heat input; however, this reheating of the flue gas still represents a significant amount of auxiliary fuel that would be necessary for successful operation.

Moreover, it is not considered available as RSCR has not been previously demonstrated on load-following industrial boilers. As noted above, locating the SCR in a higher temperature region (Hot-side/High-Dust SCR) to avoid the issue with use of auxiliary fuel would result in exposure to high particulate emissions from hog fuel combustion that could significantly damage the catalyst.

The technical difficulties described above apply generally to biomass boilers, and recent applications indicate that advanced technologies and auxiliary heating of the tail-end flue gas may overcome these difficulties.

However, the wide load swings experienced by the Weyerhaeuser boilers result in unstable exhaust temperatures and would make it particularly difficult to control the reagent injection rate needed to ensure appropriate NO_X reductions while avoiding excessive ammonia slip. For these reasons, SCR technology has not been successfully demonstrated for a load-following spreader-stoker boiler with load swings comparable to the Riley-Union Boiler at Weyerhaeuser CF.

Regional Haze guidelines state that technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; thus, technologies that have not been successfully implemented on a comparable emission unit, such as SCR on a load-following spread-stoker boiler, are considered to be technically infeasible. Nevertheless, Weyerhaeuser CF did provide an economic analysis for a tail-end SCR on the boiler at Weyerhaeuser CF.[113]

SNCR

While there have been recent advancements in SNCR technology, such as setting up multiple injection grids and the addition of sophisticated Continuous Emissions Monitoring Systems (CEMS)-based feedback loops, implementing SNCR on industrial load-following hog fuel boilers continues to pose several technical challenges. In a SNCR system, the injection of the reagent must be applied in a narrow temperature window for the reduction reaction to successfully complete. High temperatures, normally between 1,600 and 2,100°F, promote the reaction between urea or ammonia and NOx to form N_2 and water. In a load-following boiler, the region of the boiler where the optimal temperature range is present would vary depending on the firing rate, making it very difficult to control the SNCR reaction temperature. Modeling studies performed for the Riley-Union Boiler indicate that the boiler grate is the only location that reaches even the low end of this temperature range. Therefore, no locations exist within the boilers with high enough temperature for SNCR to be technically feasible.

Another factor preventing proper implementation of SNCR technology in load-following biomass boilers is inadequate reagent dispersion in the injection region, which can lead to significant amounts of unreacted ammonia exhausted to the atmosphere (i.e., large ammonia slip). At least one pulp mill wood-fired boiler had to abandon their SNCR system due to problems caused by poor dispersion of the reagent within the boiler.

SNCR has yet to be successfully demonstrated for a hog fuel boiler with swing loads comparable to the Riley-Union Boiler at Weyerhaeuser CF. Therefore, SNCR is considered to be technically infeasible.

Staged Combustion

Implementing staged combustion technology would require installation of OFA injection ports, which poses several site-specific technical obstacles for the Riley-Union Boiler. The ports would need to be installed at the exact location where the current sanderdust burners are located, and installing OFA in the boilers' small combustion chambers would likely result in flame impingement on boiler walls, leading to tube wall overheating and mechanical failure. Flame impingement can also result in premature flame quenching and increased soot and CO emissions. Staged combustion generally lengthens the flame configuration so the applicability is limited to installations large enough to avoid flame impingement on internal surfaces.

Other issues related to general OFA retrofit installations include penetration of the boiler walls, which may affect the structural integrity of the unit, and which would require re-routing of the steam tubes. The reducing atmosphere created in the fuel-rich primary combustion zone may also result in accelerated corrosion of the furnace. Additionally, grate corrosion and overheating may occur in stokers as primary air flow is diverted to the overfire ports for air introduction.

Retrofitting the Riley Stoker Boilers with OFA injection ports is not technically feasible due to the numerous technical issues described above. Therefore, OFA technology is considered to be technically infeasible and is not considered further in the analysis.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The only remaining technology available for the Riley-Union Boiler is best operating practices which represents the base case for the boiler.

Base case control scenario	
Best operating practices	134.50 lbs/hr NOx

Step 4 – Evaluate Impacts and Document Results

All control technology options are considered technically or economically infeasible for these boilers. Good combustion and boiler operation practices constitute the most suitable control option for the Riley Stoker Boilers.

Factor 1: Cost of Compliance

All retrofit and add-on technologies were eliminated. Weyerhaeuser CF did provide cost estimates even though they were technically eliminated.

Factor 2: Time Necessary for Compliance

Since the existing base case of best operating practices is already in place, Weyerhaeuser is expected to continue to comply with their existing NOx limit.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

Since the existing base case of best operating practices is already in place, Weyerhaeuser is expected to have the same energy and non-air quality related impacts of operation in the second planning period.

Factor 4: Remaining Useful Life

Weyerhaeuser CF has confirmed the remaining useful life of the Riley-Union Boiler is at least 20 years. If new controls are identified in future planning periods, further evaluations of those controls may be necessary to determine additional NOx controls.

Step 5: Select Reasonable Progress Control

Montana has determined that control technology of "best operating practices", that includes a computer control system used to maintain optimum air-to-fuel ratios and fuel feed rates, remains the only technically available retrofit and/or post combustion technology. To incorporate both retrofit and post combustion technologies within the wood products industry remains challenging. More cost-effective strategies are possible when the existing process equipment reaches the end of its useful life and replacement processes go through BACT evaluations. Therefore, no additional NOx controls for the Riley-Union Boiler are reasonable this planning period.

<u>Line 2 MDF Dryer Sanderdust Burners</u>

The Line 2 MDF Dryers at Weyerhaeuser CF are direct-contact dryers. The flue gas from the combustion chamber, rated at 85 MMBtu/hr, feeds a two-stage flash tube dryer (the first stage dryer and the second stage dryer). The Line 2 Dryers are equipped with venturi scrubbers, followed by biofilters for particulate and VOC control. The burner that supplies the heat to the dryers is fired with sanderdust from the process and employs staged combustion to limit NOx formation. The combustion for the Line 2 MDF Fiber Dryers employs a staged combustion design. First, the burners fire sanderdust at less than stoichiometric oxygen to fuel ratio. The primary combustion stage is "fuel rich", which limits formation of fuel NOx. As the flame progresses in the firebox, additional air is added to complete the combustion process. Due to the lower temperature required in the secondary combustion zone, thermal NOx formation is also reduced.

Most of the NOx emissions from wood-fired units arise from the fuel nitrogen. As such, combustion modification technologies aimed at reducing thermal NOx formation, such as FGR, are not considered. Since the dryers burn wood residue in a small combustion chamber with no available footprint for a secondary combustion zone, fuel staging is not an available combustion modification option (as the technology involves the diversion of fuel to a secondary combustion zone). Additionally, fuel staging primarily reduces thermal NOx as opposed to fuel NOx (the primary component of the dryers' exhaust). LEA is also not an available control alternative as high excess air levels are needed for proper fuel burning in MDF dryers due to limited thermal decomposition of wood furnish components in the drying process. Therefore, no combustion modification improvements are identified for the Line 2 Dryers.

Step 1 – Identify All Available Technologies

- SCR and SNCR
- Staged combustion (currently in use; considered the base case).

Step 2: Eliminate Technically Infeasible Options

<u>SCR</u>

SCR technology has not been previously demonstrated on a wood product dryer. This control option does not appear in the RBLC search results for similar units. SCR technology is not technically feasible for wood products dryers because of the direct contact of the combustion air with the wood product material. If the reagent were to be injected in the optimal temperature range directly after the burner (hot-side SCR), the ammonia in the flue gas would deposit on the wood fibers (due to the direct-fired nature of the burners where the combustion gases come in contact with the material being dried), causing product damage. Specifically, the ammonia would tie up the formaldehyde in the urea-formaldehyde resin, altering the resin chemistry and causing structural defects.

Furthermore, for a hot-side SCR, the SCR system is located prior to the particulate control processing. Such a design is technically difficult due to the small size of the combustion chamber. It also poses the risk of damage to the catalysts in the bed due to the large amount of particulates in the gas.

An alternative to avoid product fouling issues is to place the SCR system post particulate control (tail-end SCR). As mentioned previously, the Line 2 Dryers are currently equipped with venturi scrubbers followed by biofilters. For a tail-end SCR application, the flue gas from the dryers would need to be reheated to a temperature optimal for the injection of the ammonia reagent. The reheating cost alone is a significant hurdle in the application of this technology for these dryers.

The tail-end SCR can be located after the venturi scrubbers, prior to the biofilter. However, this system design would require a modification to the biofilters to accommodate increased flow and heat. A large volume of cooling air is added to the dryer exhaust stream prior to the biofilter in order to cool the flue gas to the biofilter's optimum temperature of 104 °F. Hence, the temperature is considerably lower and the flow is considerably higher post-biofilter. The size of the SCR system will also be significantly larger in such a scenario.

For the reasons mentioned above, SCR has not been successfully demonstrated on wood products dryers. Therefore, it is considered technically infeasible. However, a demonstration of the economic infeasibility of the tail-end SCR technology is included under Step 3 of this section.

SNCR

As previously discussed for the Riley-Union Boiler, SNCR systems are installed where the temperature in the combustion zone of the unit reaches the optimum range for operation of the SNCR of 1600 to 2100 °F. The combustion zone for the Line 2 Dryers reaches a maximum temperature of approximately 1500 °F, which is lower than the minimum temperature needed for SNCR. Moreover, as for SCR, if the reagent were to be injected near the optimal temperature range within the combustion chamber, the reagent in the flue gas would deposit on the wood fibers and cause product damage due to altering the chemistry of the resin process. Due to these reasons, SNCR has not been successfully demonstrated on wood products dryers. Therefore, SNCR is considered technically infeasible and is not considered further.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Since both SCR and SNCR were eliminated, no further discussion is warranted. Weyerhaeuser CF did provide additional economic analysis, but since the technology has not been demonstrated as evidenced by no entries in the RBLC, those results are not presented here in detail. Reheating costs associated with installing an SCR ahead of the existing biofilter results in over $31,000 per ton of NOx removed. This scenario would also require significant modification to the biofilter which is not included in the cost per ton of $31,000. Staged combustion remains a technology and is currently the method used on the Line 2 MDF Dryers.

Step 4 – Evaluate Impacts and Document Results

Since SCR and SNCR were eliminated, the existing control of staged combustion remains the only available control option.

Factor 1: Cost of Compliance

All retrofit and add-on technologies were eliminated. Weyerhaeuser CF did provide cost estimates even though they were eliminated but those costs are not provided here.

Factor 2: Time Necessary for Compliance

Since the existing base case of staged combustion is already in place, Weyerhaeuser is expected to continue to comply with their existing NOx limit.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

Since the existing base case of staged combustion is already in place, Weyerhaeuser is expected to have the same energy and non-air quality related impacts of operation in the second planning period.

Factor 4: Remaining Useful Life

Weyerhaeuser CF has confirmed the remaining useful life of the Line 2 MDF Dryers is at least 20 years. If new controls are identified in future planning periods, further evaluations of those controls may be necessary to determine additional NOx controls.

Step 5: Select Reasonable Progress Control

Montana has determined that control technology of "staged combustion" remains the only technically available technology for NOx control. To incorporate both retrofit and post combustion technologies within the wood products industry remain challenging. More cost-effective strategies are possible when the existing process equipment reaches the end of its useful life and replacement processes go through BACT evaluations. Therefore, no additional NOx controls for the Line 2 MDF Dryers are reasonable this planning period.

Line 1 MDF Dryer Sanderdust Burners

The Line 1 MDF Fiber Dryers at Weyerhaeuser CF include a core dryer and a face dryer, each installed with a sanderdust burner with a capacity of 50 MMBtu/hr for each unit. The dryers can process up to 57 tons/hr of bone-dry fiber.

Step 1 – Identify All Available Technologies

Similar to the Line 2 MDF analysis, control technologies determined to not be available include FGR and LEA and are not considered in this analysis. However, since Line 2 includes staged combustion, the use of staged combustion is also considered for the Line 1 MDF Dryer. Additionally, "good operating practices" are considered to be in place for minimizing NOx formation. Weyerhaeuser CF defines good operating practices as following a documented maintenance program for the Line 1 MDF Fiber Dryers. Maintaining the burners and other dryer equipment in good condition promotes proper combustion and supports good operating practices, including computer-controlled optimization of air to fuel ratios and firing rates. The burners are also computer monitored for combustion zone temperatures. After accounting for the physical and operational characteristics of the Line 1 MDF Fiber Dryers, the control technologies and strategies considered in this analysis for controlling NOx emissions include the following:

- SCR and SNCR
- Staged Combustion / Low NOx Burners (LNB)
- Good Operating Practices (baseline)

The size of the combustion chambers in the Line 1 Dryers is approximately one-fourth that of the combustion chamber for the Line 2 Dryers. This size difference is a direct result of the Line 2 Dryers including a staged combustion design requirement from the permitting process of the second line. The staged combustion technology implemented on the Line 2 Dryers requires four times the space to complete the combustion process.

Because staged combustion technology has been demonstrated as a technically feasible combustion technology for the Line 2 dryers, retrofitting a staged combustion system on Weyerhaeuser's Line 1 Dryers has been identified as a combustion modification improvement option.

Step 2: Eliminate Technically Infeasible Options

As described in the Line 2 analysis, SCR has not been demonstrated to be used on MDF process lines and is eliminated for the same reason here.

<u>SNCR</u>

As described in the Line 2 analysis, SNCR has not been demonstrated to be on MDF process lines and is eliminated for the same reason here.

The available technique for application of staged combustion / LNB technology for the combustion of sanderdust involves the same staged combustion process described for the Line 2 MDF Fiber Dryers. This technique involves firing the sanderdust at sub-stoichiometric levels at the burners, and adding air through separate ports for air introduction to complete the combustion process. The type of LNB technology that can be applied for natural gas or fuel oil combustion is not applicable for the combustion of sanderdust.

The application of staged combustion is limited by the longer and cooler flames produced as a consequence of improved air distribution control. The Line 1 MDF Fiber Dryers have a combustion chamber that is size-restricted. The firebox is one-fourth the size of that of the Line 2 MDF Fiber Dryers combustion chamber. The small size of the combustion chamber makes it impossible to retrofit the Line 1 MDF Fiber Dryers with a staged combustion technology. Weyerhaeuser CF has also identified that it is possible to replace the existing Line 1 burners with an entirely new, larger firebox needed to accommodate staged combustion. The location of the current burners is restricted by the footprint size, so the larger combustion chambers would need to be relocated further away from the dryer, which would also involve adding significant ducting to accommodate the existing Line 1 Dryers footprint.

Good operating practices also remain a methodology to minimize NOx emissions.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Staged combustion remains a technology that could be incorporated on Line 1 MDF. Best combustion practices (baseline control scenario) also remains a control to minimize NOx emissions.

Step 4 – Evaluate Impacts and Document Results

Incorporating staged combustion on Line 1 is further analyzed.

<u>Factor 1: Cost of Compliance</u>

Weyerhauser CF did evaluate costs to incorporate either SCR or SNCR, however these technologies were determined not to be technically feasible; therefore, these costs are not included here. Weyerhaeuser CF estimated the cost to install two new burners with a larger firebox for the Line 1 Dryers. It is estimated that the capital cost of the equipment with ducting would be approximately $4,379,811 in 2018 dollars, resulting in a cost of $4,751 per ton of NOx removed. Any other annualized costs associated with this change were not documented, so only the annualized capital cost is included.

Table 6-14. Line 1 MDF Dryer Sanderdust Burners - Staged Combustion NOx Control Annualized Costs

Control option	Capital Costs	Annualized Capital Cost
Staged Combustion	$4,379,811	$358,936

Table 6-15. Line 1 MDF Dryer Sanderdust Burners - Staged Combustion NOx Cost Effectiveness

Control option	Emission Reduction Estimate (TPY)	Cost effectiveness ($/ton)
Staged Combustion	76	$4,751

Best combustion practices and existing maintence activities would continue at the current costs incurred by the facility.

Factor 2: Time Necessary for Compliance

Weyerhaeuser CF has determined that, if staged combustion were required to be incorporated, the installation could be completed by 2028. Maintaining their existing best combustion practices would continue throughout the planning period.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

Montana determined that there are no energy and non-air quality environmental impacts associated with staged combustion.

Factor 4: Remaining Useful Life

Weyerhaeuser CF has confirmed the remaining useful life of the Line 1 MDF Dryers is at least 20 years. If new controls are identified in future planning periods, further evaluations of those controls may be necessary to determine additional NOx controls.

Step 5: Select Reasonable Progress Control

Montana has determined that control technology of "best combustion practices" remains a reasonable control technology for NOx control. To incorporate both retrofit and post combustion technologies within the wood products industry remain challenging. More cost-effective strategies are possible when the existing process equipment reaches the end of its useful life and replacement processes go through BACT evaluations. Incorporating a staged combustion on Line 1 MDF, replicating the design on Line 2, will be considered in future planning periods. No additional NOx controls for the Line 1 MDF Dryers are reasonable this planning period.

6.2.7 Weyerhaeuser NR – Evergreen Facility[113]

Weyerhaeuser NR – Evergreen facility (Weyerhaeuser EF), submitted an analysis and supporting information on September 30, 2019. Montana did not request that Weyerhaeuser EF evaluate SO_2 at the facility as the SO_2 emissions are extremely low. Therefore, the Weyerhaeuser EF four-factor analysis did not include any discussion of SO_2.

The facility is located in Evergreen, MT and consists of a Riley-Union Stoker hog fuel boiler (rated at 196 MMBtu/hr and 140,000 lb/hr steam) that supplies steam for process operations such as the dry kilns, veneer dryers, plywood presses, and the medium density overlay (MDO) press. This four-factor analysis focuses on the Riley-Union Stoker Boiler (Riley-Union Boiler).as it is the main source of NOx at the facility.

The analysis presented by Weyerhaeuser included both the Columbia Falls Facility and the Evergreen Facility. The elements specific to the Evergreen facility are highlighted here.

Weyerhaeuser EF RepBase and 2028 OTB /OTW Scenarios

Weyerhaeuser EF chose to use the 2014-2017 period and use the average emissions from that period as their representative baseline. Weyerhaeuser EF also selected a future year 2028 OTB/OTW scenario that was used to calculate the cost per ton of emission reduction achieved from applying controls.

Weyerhaeuser EF chose not to scale the representative baseline emissions to the future 2028 OTB/OTW scenario. Thus, the 2028 OTB/OTW emissions are equivalent to the representative baseline emissions.

Weyerhaeuser EF provided Montana with a justification for the emissions used in their four-factor analysis and subsequently used in the regional modeling scenarios (RepBase2 and 2028OTBa2), and Montana concurred that the four-year period was reflective of recent normal operation. Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 6-16. Weyerhaeuser EF RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2014-2017	129.5	4.9	129.5	4.9

Riley-Union Boiler

The Riley-Union Boiler at the Evergreen facility was installed in 1971. The Riley-Union Boiler combusts wood residue, primarily as bark from the log debarking process, and is load-following, meaning its firing rates are adjusted to meet the changing steam demand of various process operations.

The boiler's average firing rate from 2017 to 2018 was 96 MMBtu/hr. The Riley-Union boiler's load varies between 30,000 lb/hr steam and 70,000 lb/hr steam. These widespread load changes often occur rapidly, sometimes swinging from the minimum load to the maximum load within thirty minutes. The average low-end temperature of the flue gas from the boilers is 350º F. The Riley-Union boiler uses wood waste supplemented with natural gas as a fuel. Downstream from the spreader-stoker grate, there are sanderdust burners that are capable of supplementing 10 percent of the heat rate capacity of the boiler. These burners are normally fired with sanderdust, but can fire natural gas during sanderdust shortages and startup.

The Riley-Union Boiler includes both multiclones (primary) and a dry electrostatic precipitator (ESP) (secondary) for PM control.

The Riley-Union Boiler does not currently have post-combustion or low-NOx combustion technology. The Riley-Union Boiler uses a process similar to fuel staging by design. The sanderdust burners are located downstream of the primary wood-fired flame. This configuration helps reduce thermal NOx by breaking the combustion event into multiple stages. Weyerhaeuser EF follows a maintenance program to maintain the boiler's burners, hog fuel feed system, fans, and other equipment. The boiler is also equipped with a computer control system used to maintain optimum air-to-fuel ratios and fuel feed rates.

The Weyerhaeuser EF Riley-Union Boiler is very similar in operation to the Riley-Union Boiler at Weyerhaeuser CF and the analysis presented here is nearly identical to the analysis for Weyerhaeuser CF. Like the Weyerhaeuser CF analysis, the Weyerhaeuser EF analysis searched the EPA RBLC database for similar units. A high-level summary of the analysis presented by Weyerhaeuser EF is presented below.

Step 1 – Identify All Available Technologies

The following retrofit technologies were evaluated for the Riley-Union Boiler

- Flue Gas Recirculation (FGR),
- Fuel Staging,
- Low NOx Burner (LNB)
- Low Excess Air (LEA)
- Staged Combustion (OFA)
- Good Operating Practices (base case)
- Post-Combustion Controls including SCR, RSCR and SNCR

Step 2 - Eliminate Technically Infeasible Technologies

Minimal thermal NOx is formed in wood-fired spreader stoker boilers due to the high moisture content of the wood and the spreader stoker firing configuration. Therefore, combustion modification technologies that are aimed at reducing thermal NOx formation, such as FGR, are not considered. Additionally, combustion modification technologies used with traditional gas and oil burners, such as LNB, are not available for wood- fired boilers. Similarly, since the boiler is of spreader stoker design, they need high excess air levels for proper fuel burning. As such, combustion modifications like LEA are not practical to employ on spreader stoker boilers.

<u>SCR</u>

Implementing SCR on industrial hog fuel boilers poses several technical challenges. First, size constraints often make retrofitting an SCR system near the boiler impossible. Second, most hog fuel boilers' temperature profiles are not appropriate for SCR and the SCR system pressure drop requirements create sizing concerns related to existing boiler fans. Third, the NCASI notes that the high PM concentrations upstream of the PM control equipment (Hot-side/High-dust) would impede catalyst effectiveness and could result in deactivation or poisoning of the catalyst, which requires downtime to clean and/or replace the catalyst. The installation of SCR downstream of the PM control equipment (Cold-side/Tail- end SCR) would render the gas stream too cold for an effective reaction with the catalyst to reduce NOx. In biomass boilers, plugging and fouling of the catalyst can occur due to large amounts of fly ash generated by the biomass.

The desired minimum temperature for SCR application to achieve 70% control is 575°F The maximum exhaust temperature of the Riley-Union Boiler at Weyerhaeuser EF is 430°F. While the exhaust temperatures of the boiler are close to the range of operation of the SCR system, higher temperatures would be needed for optimum control efficiency for tail-end SCR application.

<u>RSCR</u>

In a Regenerative Selective Catalytic Reduction system, the regenerative heating reduces the required heat input; however, this reheating of the flue gas still represents a significant amount of auxiliary fuel that would be necessary for successful operation.

Moreover, it is not considered available as RSCR has not been previously demonstrated on load-following industrial boilers. As noted above, locating the SCR in a higher temperature region (Hot-side/High-Dust SCR) to avoid the issue with use of auxiliary fuel would result in exposure to high particulate emissions from hog fuel combustion that could significantly damage the catalyst.

The technical difficulties described above apply generally to biomass boilers, and recent applications indicate that advanced technologies and auxiliary heating of the tail-end flue gas may overcome these difficulties.

However, the wide load swings experienced by the Weyerhaeuser EF Riley Stoker Boiler result in unstable exhaust temperatures and would make it particularly difficult to control the reagent injection rate needed to ensure appropriate NOx reductions while avoiding excessive ammonia slip. For these reasons, SCR technology has not been successfully demonstrated for a load-following spreader-stoker boiler with load swings comparable to the Riley-Union Boiler at Weyerhaeuser EF.

Regional Haze guidelines state that technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; thus, technologies that have not been successfully implemented on a comparable emission unit, such as SCR on a load-following spread-stoker boiler, are considered to be technically infeasible. Nevertheless, Weyerhaeuser EF did provide an economic analysis for a tail-end SCR on the boiler at Weyerhaeuser EF which can be found in the Weyerhaeuser EF completed four-factor analysis.

<u>SNCR</u>

While there have been recent advancements in SNCR technology, such as setting up multiple injection grids and the addition of sophisticated CEMS-based feedback loops, implementing SNCR on industrial load-following hog fuel boilers continues to pose several technical challenges. In a SNCR system, the injection of the reagent must be applied in a narrow temperature window in order for the reduction reaction to successfully complete. High temperatures, normally between 1,600 and 2,100°F, promote the reaction between urea or ammonia and NOx to form N_2 and water. In a load-following boiler, the region of the boiler where the optimal temperature range is present would vary depending on the firing rate, making it very difficult to control the SNCR reaction temperature. Modeling studies performed for the Weyerhaeuser EF Riley-Union Boiler indicate that the boiler grate is the only location that reaches even the low end of this temperature range. Therefore, no locations exist within the boiler with high enough temperature for SNCR to be technically feasible.

Another factor preventing proper implementation of SNCR technology in load-following biomass boilers is inadequate reagent dispersion in the injection region, which can lead to significant amounts of unreacted ammonia exhausted to the atmosphere (i.e., large ammonia slip). At least one pulp mill wood-fired boiler had to abandon their SNCR system due to problems caused by poor dispersion of the reagent within the boiler.

SNCR has yet to be successfully demonstrated for a hog fuel boiler with swing loads comparable to the Riley-Union Boiler at Weyerhaeuser EV. Therefore, SNCR is considered to be technically infeasible.

<u>Staged Combustion</u>

Implementing staged combustion technology would require installation of OFA injection ports, which poses several site-specific technical obstacles for the Riley Stoker Boiler. The ports would need to be installed at the exact location where the current sanderdust burners are located, and installing OFA in the boilers' small combustion chambers would likely result in flame impingement on boiler walls, leading to tube wall overheating and mechanical failure. Flame impingement can also result in premature flame quenching and increased soot and CO emissions. Staged combustion generally lengthens the flame configuration so the applicability is limited to installations large enough to avoid flame impingement on internal surfaces.

Other issues related to general OFA retrofit installations include penetration of the boiler walls, which may affect the structural integrity of the unit, and which would require re-routing of the steam tubes. The reducing atmosphere created in the fuel-rich primary combustion zone may also result in accelerated corrosion of the furnace. Additionally, grate corrosion and overheating may occur in stokers as primary air flow is diverted to the overfire ports for air introduction.

Retrofitting the Riley Stoker Boiler with OFA injection ports is not technically feasible due to the numerous technical issues described above. Therefore, OFA technology is considered to be technically infeasible and is not considered further in the analysis.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The only remaining technology available for the Riley-Union Boiler is best operating practices which represents the base case for the boiler.

Base case control scenario	
Best operating practices	104 lbs/hr NOx

Step 4 – Evaluate Impacts and Document Results

All control technology options are considered technically or economically infeasible for these boilers. Good combustion and boiler operation practices constitute the most suitable control option for the Riley Stoker Boiler.

<u>Factor 1: Cost of Compliance</u>

All retrofit and add-on technologies were eliminated. Weyerhaeuser EF did provide cost estimates even though they were technically eliminated, but those costs are not provided here.

<u>Factor 2: Time Necessary for Compliance</u>

Since the existing base case of best operating practices is already in place, Weyerhaeuser EF is expected to continue to comply with their existing NOx limit.

<u>Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance</u>

Since the existing base case of best operating practices is already in place, Weyerhaeuser EF is expected to have the same energy and non-air quality related impacts of operation in the second planning period.

Factor 4: Remaining Useful Life

Weyerhaeuser EF has confirmed the remaining useful life of the Riley-Union Boiler is at least 20 years. If new controls are identified in future planning periods, further evaluations of those controls may be necessary to determine additional NOx controls.

Step 5: Select Reasonable Progress Control

Montana has determined that control technology of "best operating practices", which includes a computer control system used to maintain optimum air-to-fuel ratios and fuel feed rates, remains the only technically available retrofit and/or post combustion technology. Processes within the wood products industry remain challenging to incorporate both retrofit and post combustion technologies. More cost-effective strategies are possible when the existing process equipment reaches the end of its useful life and replacement processes go through BACT evaluations. No additional NOx controls for the Riley-Union Boiler are reasonable this planning period.

6.2.8 Ash Grove Cement Company[114]

Ash Grove submitted their four-factor analysis (in conjunction with Trinity Consultants) and supporting information on September 30, 2019. Trinity Consultants assisted both of Montana's Portland cement facilities in compiling the four-factor analyses; therefore, the analyses are very similar. The Ash Grove facility is located in Montana City, Montana, and consists of a long wet kiln for producing Portland cement. Nearly all the NOx and SO_2 emissions at the facility are associated with the kiln; therefore, the kiln is the single emitting unit located at Ash Grove requiring a four-factor evaluation. The Ash Grove facility has been in operation since 1963 and is currently owned by CRH but continues to operate under the Ash Grove name. For consistency, "Ash Grove" will be used throughout this discussion.

Ash Grove RepBase and 2028 OTB/OTW Scenarios

Ash Grove selected the two-year average from 2017-2018 as representative of baseline emissions and Montana concurred that this two-year period was reflective of recent normal operation. Ash Grove also selected a future year 2028 OTB/OTW scenario that was used to calculate the cost per ton of emission reduction achieved from applying controls.

Ash Grove chose to scale the 2017-2018 representative baseline for future possible market growth and that resulted in the 2028 OTB/OTW scenario being approximately 20 percent higher than the 2017-2018 representative baseline. Representative baseline and 2028 OTB/OTW emissions are as follows:

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[114] Ash Grove Cement, Regional Haze 2nd Implementation Period Four-Factor Analysis, (September 2019), Available at: http://deq.mt.gov/Portals/112/Air/AirQuality/Documents/Planning/PDF/2019%2009-30%20MON%20Regional%20Haze%204-Factor%20Analysis.pdf?ver=2020-02-03-161450-953

Table 6-17. Ash Grove RepBase2 and 2028OTBa2 Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2017-2018	810.3	101.6	981.5	120.8

SO_2 Evaluation

The consent decree *United States v. Ash Grove Cement Co.*[48] required semi-dry scrubbing to be installed by September 10, 2014. The current permit limit [115]for SO_2 is limited to 2.0 lb/ton of clinker, which Ash Grove has been successfully achieving since 2015. Based on EPA guidance, a source with flue gas desulfurization, (e.g., the semi-dry scrubber installed on the Ash Grove kiln) that operates year-round with an effectiveness of at least 90 percent, is considered to be effectively controlled.[47]

Step 1 – Identify All Available Technologies

In the first planning period, several technologies were evaluated for SO_2 removal. These included fuel substitution, raw material substitution, dry absorbent addition, semi-wet scrubbing and wet scrubbing. The following are considered in this planning period:

- Fuel Substitution. Any substitute fuel that is used must provide adequate heat content from combustion to properly heat the kiln. Fuels must also be available at a competitive comparison to existing fuels used at the site and in quantities that allow continuous operation. A substitute fuel must also not impact product quality. Currently, the fuels that the plant is permitted to use and that are available in continuous quantities include coal and coke. The ratio of coal/coke usage can be optimized to minimize SO_2 emissions. Natural gas can also be considered as a substitute alternate fuel.
- Wet Scrubbing
- Semi-Dry Scrubbing. The consent decree *United States v. Ash Grove Cement Co.*[48] required semi-dry scrubbing to be installed by September 10, 2014. The incorporation of semi-dry scrubbing provided an annual SO_2 reduction of approximately 800 tpy. Some portion of the 800 tpy reduction has come as Ash Grove has continued to optimize the semi-dry scrubbing system from the initial installation in 2012 through the current time period.

The remaining representative baseline emissions of just over 100 tpy are unlikely to be significantly reduced without the addition of a different control technology.

[115] Montana Air Quality Permit MAQP #2008-16, (22 Oct. 2021), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/ARMpermits/2005-16.pdf

Step 2: Eliminate Technically Infeasible Options

Fuel Substitution

In the 2007 analysis supporting the first planning period, Ash Grove evaluated the coal/coke blend to determine if revising the blend could provide SO_2 reductions. Between 2007 and 2011, Ash Grove reduced baseline emissions by 369 tpy by changing the coal/coke ratio. Ash Grove continues to evaluate fuel blends in an effort to reduce SO_2; however, Ash Grove determined that any continued modification to the coal/coke ratio would be nearly insignificant in SO_2 reductions. Therefore, further changes to the ratio of coal/coke are considered unlikely to provide significant emission reductions in the future.

Natural gas can also be considered as a technically feasible replacement for coal/coke as the primary fuel source at this facility, and can be evaluated further. For natural gas to be a technically feasible option, the supply of natural gas must be reliable on a continuous basis. While the Ash Grove facility uses natural gas for startup, the facility has been curtailed by the natural gas supplier the last two winters. Consequently, natural gas is not considered available on a continuous basis, and relying on natural gas to be the sole fuel source for the facility is not feasible.

Wet Scrubbing

In the first planning period, wet scrubbing did not provide any higher estimated controls than that of 90 percent which has already been achieved with the Consent Decree requirement to install semi-dry scrubbing. Therefore, wet scrubbing would not provide a higher estimate of control than the semi-dry scrubbing technology which is already operating and in place. Wet scrubbing is not evaluated further as the current dry scrubbing technology is as effective as wet scrubbing.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The baseline control scenario is semi-dry scrubbing which is providing a 90 percent reduction in SO_2 emissions. Controls using wet scrubbing are not estimated to significantly increase the SO_2 removal efficiency over the current 90 percent reduction being achieved. No further analysis is necessary as Ash Grove plans to continue, as required by permit, to operate the semi-dry scrubbing technology.

Step 4 – Evaluate Impacts and Document Results

Semi-dry scrubbing was evaluated in the first planning period and has proven to have had significant SO_2 reductions since installation in 2014. Ongoing optimization of the semi-dry scrubbing may also provide some minor future SO_2 reductions. No further four-factor analysis is included in this demonstration as Ash Grove is currently using an effective technology to reduce SO_2 at the facility. Ash Grove plans to continue, as required by permit, to operate the semi-dry scrubbing technology.

Step 5: Select Reasonable Progress Control/Final State Recommendations:

Montana concurs with the four-factor analysis that the current semi-dry scrubbing technology at Ash Grove, installed as part of the Consent Decree, continues to provide the best reduction for SO_2 control. No additional SO_2 control is required for the second planning period. Any further future reductions are limited to less than the remaining approximately 120 tpy. It is worth noting that the current 2.0 lb/ton SO_2 limit is significantly below the first round BART limit of 11.5 lb/ton which was set by EPA.

NOx Evaluation

The current NOx control consists of low NOx burner operation and SNCR. Both low NOx burners and SNCR were selected in the first planning period as BART for NOx reductions, and were installed in 2014. These NOx controls have been operating since 2016 with reduction levels similar to what EPA had predicted in the first planning period. Ash Grove is currently permit-limited to 7.5 lb/ton of clinker.

Step 1 – Identify All Available Technologies

Both SNCR and SCR are technologies considered in the first planning period. In the first planning period, there wasn't much data available on the full cost analysis for incorporating SCR on cement kilns. In this planning period, while there is some more information available on facilities that are working on SCR, the data is largely not available to the public. Therefore, the viability of incorporating SCR, including having an accurate understanding of catalyst life, cost of ammonia/urea injection and actual NOx reduction levels, is not well-understood. SNCR is in operation at both Ash Grove and the second Montana Portland cement plant (GCC Trident). Each of these facilities were required to install SNCR in the first planning period and did so according to the schedules provided in the BART determinations.

Step 2: Eliminate Technically Infeasible Options

SNCR is currently operating and has successfully reduced emissions at Ash Grove.

<u>SCR</u>

The second control option remaining is SCR. As mentioned above, SCR has seen some continued advancement both internationally and at a few locations within the United States. However, based on the limited use of SCR on cement kilns in the U.S., this technology has been technically eliminated from consideration. There is not enough information available on the technical success or on the actual costs required for construction and operation. Montana has determined that, for this planning period, SCR is infeasible; however, as more facilities analyze and subsequently install SCR, it is likely to become a viable option in future planning periods. A more rigorous SCR evaluation is likely in the third planning period, if the technology has advanced and more information is publicly available to perform a proper assessment.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Ash Grove continues to successfully operate the SNCR system achieving NOx reductions of approximately 30 to 40 percent.

Step 4 – Evaluate Impacts and Document Results

SNCR continues to operate and achieve the previously established BART limits. There remains some concern around the possibility of a detached plume under certain ambient conditions, as not long after initial start-up, a plume was documented from the facility.

Step 5: Select Reasonable Progress Control/Final State Recommendations:

Montana concurs with the four-factor analysis that the current technology of a low NOx burner and the operation of SNCR at Ash Grove, earlier determined to represent BART, continues to provide the best reduction for NOx control. No additional NOx control is required for the second planning period.

6.2.9 Montana Dakota Utilities Co. – Lewis & Clark Station[116]

Montana Dakota Utilities Co. (MDU) submitted their four-factor analysis and supporting information on March 16, 2020. The MDU Lewis and Clark facility is located in Sidney, Montana, and, prior to 2021, contained a dry-bottom, tangentially-fired boiler that had been in operation since before 1968. This boiler is identified by MDU and Montana as Boiler #1. The boiler was permitted to burn lignite coal, which was supplemented as needed with subbituminous coal and natural gas. MDU has one steam turbine with a capacity of up to 56 megawatts. Nearly all the NOx and SO_2 emissions at the facility were associated with the boiler, and therefore the boiler was the single emitting unit located at MDU that required evaluation.

Communications with MDU indicated that the existing boiler would be shuttered before 2028 (MDU's Integrated Resource Plan described MDU's intent to shut down the boiler in 2021). However, the retirement date for the boiler was not certain when Montana conducted source screening and four-factor analyses; thus, Montana included MDU in the source screening and subsequent four-factor analyses.

MDU was a reasonable progress source in the first implementation period and, in 2011, had submitted a four-factor report to EPA for review. MDU relied on the 2011 analysis for this second implementation period, choosing not to modify the report to account for the recent 2017-2018 representative baseline, citing EPA's guidance.[47]:

> *"The EPA's "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" explains that it may be appropriate for a state to rely on a previous BART analysis or reasonable progress analysis for the characterization of a factor, for example information developed in the first implementation period on the availability, cost, and effectiveness of controls for a particular source, if the previous analysis was sound and no significant new information is available. Based on this guidance document, Montana-Dakota believes this submittal meets MDEQ's request. The controls review in Lewis & Clark Station's Round 1 four-factor analysis included some site-specific review by Montana-Dakota and our engineering consultants and we believe this information remains relevant today. Based on the Federal Implementation Plan (FIP) final rule from Round 1, EPA ultimately adopted no emission controls for Lewis & Clark Station.*

Montana reviewed the 2011 analysis and developed conclusions consistent with the other facilities analyzed for the second planning period. On July 21, 2021, Montana received a request for an administrative amendment to Montana Air Quality Permit (MAQP) #0691-07 to remove all permit references to Boiler #1 as the boiler had been permanently removed from service as of April 1, 2021. MAQP #0691-07 was

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[116] Emissions Control Analysis for Lewis & Clark Station Unit 1 (Feb. 2011), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/Planning/PDF/MDU_LC_RH_Evaluation_Update_060311.pdf

finalized on September 8, 2021. MDU is now a synthetic minor source with respect to Title V, and on February 22, 2022, Operating Permit OP#0691-08 was revoked (see Appendix D for documentation).

Because the boiler was removed from service, further discussion of MDU's four-factor analysis is no longer relevant. With Boiler #1 removed from operation, emission reductions approaching 600 tpy for NOx and SO_2 combined will occur going forward from April 1, 2021.

MDU Rep Base and 2028 OTB /OTW Scenarios

For purposes of modeling information, Montana used the 2017-2018 period as the representative baseline for MDU. At the time Montana was working with sources to develop 2028 OTB/OTW emission estimates, discussions with MDU indicated a federally-enforceable shutdown date of March 31, 2021, would be agreed upon. Montana submitted emissions information to the EI&MP subcommittee that 'zeroed out' the facility for the PAC2 modeling scenario. Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 6-18. MDU RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2017-2018	579.4	22.6	579.4 (modeled as 0 tpy in PAC2 run)	22.6 (modeled as 0 tpy PAC2 run)

The removal of emissions from the boiler at MDU are not reflected in the modeled 2028 RPGs, and therefore, are a conservative projection estimate.

6.2.10 GCC Trident, LLC.[117]

GCC Trident, LLC (GCC) submitted their four-factor analysis (in conjunction with Trinity Consultants) and supporting information on September 30, 2019. Because Trinity Consultants was used by both GCC and Ash Grove, the resulting four-factor analyses are very similar. The GCC facility is located in Three Forks, Montana, and consists of a long wet kiln for producing Portland cement. Nearly all NOx and SO_2 emissions at the facility are associated with the kiln, and therefore the kiln is the single emitting unit located at GCC requiring evaluation. In the first planning period, the plant was often referred to as the Trident or Three Forks Plant. The GCC facility has been in operation since 1972 and is currently owned by Grupo Cementos de Chihuahua GCC and is referenced as GCC throughout.

[117] GCC Three Forks, LLC Trident Plant Four-Factor Analysis (30 Sept. 2019), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/Planning/PDF/GCC_Trident_4_Factor_Analysis_2019-0930.pdf

GCC RepBase and 2028 OTB /OTW Scenarios

GCC selected the two-year average of 2017-2018 as their representative baseline emissions. GCC also selected a future year 2028 OTB/OTW scenario used to calculate the cost per ton of emission reduction achieved from applying controls.

GCC chose to scale the 2017-2018 representative baseline for future possible market growth, resulting in the 2028 OTB/OTW scenario being approximately 10 percent higher than the 2017-2018 representative baseline.

GCC provided Montana with a justification for the emissions used in their four-factor analysis and subsequently used in the regional modeling scenarios (RepBase2 and 2028OTBa2), and Montana concurred that this two-year period was reflective of recent normal operation. Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 6-19. GCC RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2017-2018	1204.8	7.5	1338.0	7.5

SO_2 Evaluation

The emissions of SO_2 at GCC are inherently low due to the chemistry of raw materials used in the kiln; therefore, no four-factor analysis was required. SO_2 emissions remain below 10 tpy. There is no reason to believe future emissions of SO_2 will change with the current kiln and similar use of raw materials.

NOx Evaluation

The current NOx control consists of SNCR, which was selected in the first planning period as BART for NOx reductions, and was installed in 2017. SNCR controls have been operating since 2016 with reduction levels similar to what was predicted by EPA in the first planning period. GCC is currently permit-limited to 7.6 lb/ton of clinker and has been achieving an emission rate below that limit. GCC also installed indirect coal firing, providing further reductions in NOx control beyond what was being achieved with SNCR using ammonia injection. GCC continues to invest resources to better understand the window of operation for NOx control, given the facility is concerned about ammonia slip. While GCC has been successful at achieving the NOx limit of 7.6 lb/ton clinker, there remains concern that atmospheric ambient conditions could result in a detached plume from the facility as the result of condensation of ammonium nitrate.

Step 1 – Identify All Available Technologies

SNCR and SCR were determined to be available, and both had been considered in the first planning period. In the first planning period, there wasn't much data available on the full cost analysis for incorporating SCR on cement kilns. In this planning period, while there is some more information available on facilities that are working on SCR, the data is largely not available to the public. Therefore, the viability of incorporating SCR is not well enough understood to have an accurate understanding of catalyst life, cost of ammonia/urea injection and actual NOx reduction levels. SNCR is in operation at both GCC and Ash Grove. Each of these facilities were selected in the first planning period to install SNCR and did so according to the schedules provided in the BART determinations.

Step 2: Eliminate Technically Infeasible Options

SNCR is currently operating and has successfully reduced emissions at GCC. The second control option remaining is SCR. As mentioned above, based on the limited use of SCR on cement kilns in the U.S., this technology has been technically eliminated from consideration. There is not enough information available on the technical success or on the actual costs required for construction and operation. Montana has determined that SCR is infeasible in this planning period; however, as more facilities analyze and subsequently install SCR, it is likely to become a viable option in future planning periods. A more rigorous SCR evaluation is likely in the third planning period, if the technology has advanced and more information is publicly available to perform a proper assessment.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

SNCR continues to operate and achieve the previously established BART limits. As long as GCC continues to operate the SNCR system, no further controls are required for NOx control at this time.

Step 4 – Evaluate Impacts and Document Results

GCC continues to operate the SNCR system and has demonstrated it can achieve the applicable permit limits. Additionally, the current inherent scrubbing for SO_2 removal proves to be optimal in SO_2 reduction.

Step 5: Select Reasonable Progress Control

NOx

Montana determined that the current technology of SNCR at GCC, earlier determined to represent BART, continues to provide the best reduction for NOx control. No additional NOx controls are reasonable for the second planning period.

6.2.11 Yellowstone Energy Limited Partnership[118]

Yellowstone Energy Ltd Partnership (YELP) submitted their four-factor analysis (in conjunction with Bison Engineering Inc.) on September 30, 2019. Bison Engineering Inc. (Bison) prepared both the YELP and Colstrip Energy Ltd. Partnership (CELP) four -factor analyses. Both YELP and CELP have circulating fluidized bed boilers, so these analyses are very similar. YELP is located in Billings, Montana where the primary operation is the production of energy in the form of steam. The plant, a 65 Megawatt electric generating facility, uses both petroleum coke and coker gas supplied by the ExxonMobil Billings Refinery as the primary fuels to fire two circulating fluidized bed combustion (CFBC) boilers that vent to a single baghouse. These boilers in turn produce steam, of which a portion is provided to the Exxon Refinery, a small portion is used to run various fans and pumps at the site, and the remainder is used to generate

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[118]Yellowstone Energy Limited Partnership – Yellowstone Power Plant Regional Haze Four-Factor Analysis (Sept. 2019), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/Planning/PDF/YELP_Four-Factor_RH_Analysis_Sept%2019.pdf?ver=2020-02-04-130959-290

electricity through a steam turbine. The CFBCs are the only emitting unit at the site that require an evaluation for this demonstration.

YELP Rep Base and 2028 OTB/OTW Scenarios

YELP chose to use the average of 2014-2017 emissions as their representative baseline. YELP also selected a future year 2028 OTB/OTW scenario that was used to calculate the cost per ton of emission reduction achieved from applying controls. YELP chose to use the 2014-2017 representative baseline for the 2028 OTB/OTW scenario.

YELP provided Montana with a justification for the emissions used in their four-factor analysis and subsequently used in the regional modeling scenarios (RepBase2 and 2028OTBa2), and Montana concurred this four-year period was reflective of recent normal operation. Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 6-20. YELP RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2014-2017	404.3	1,732	404.3	1,732

SO_2 Evaluation

YELP currently controls SO_2 emissions using limestone injection. Limestone is injected with the petroleum coke prior to its combustion in the CFBC boilers. In the CFBC boilers, the limestone calcines to lime and reacts with SO_2 to form calcium sulfates and calcium sulfites. The calcium compounds are removed as particulate matter by the baghouses. Depending on the fuel fired in the boilers and the total heat input, YELP must control SO_2 from 92% reduction for all boilers operating hours per Montana Operating Permit #OP2650-03[119]. The current limestone injection system is reported to be operating at or near its maximum capacity and increasing limestone injection beyond the current levels may result in plugging of the injection lines, increased bed ash production which can reduce combustion efficiency, and increased particulate loading to the baghouses. Increasing limestone injection beyond its current level would require major upgrades to the limestone feeding system and the baghouses. Furthermore, an upgrade to the existing limestone injection system would expect only modest increases in SO_2 removal efficiency compared to add-on SO_2 control systems which were further analyzed within this section. Therefore, upgrading the existing system is not considered further. This analysis will focus on add-on control systems for SO_2 control, as those are expected to be significantly more cost effective.

[119] Operating Permit #OP2650-03, (3 Dec. 2019), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/ARMpermits/OP2650-03.pdf

Step 1 – Identify All Available Technologies

As YELP's fuel type (petroleum coke and coker gas), type of boiler (Circulating Fluidized Bed), and the limestone system are operating at current maximum capacity, this cost analysis will focus on post-combustion controls to further reduce sulfur dioxide emissions beyond the existing limestone injection control. The post-combustion controls that are potentially technically feasible in this application are flue gas desulfurization (FGD) systems. FGD options for the CFBC boiler include: Wet Lime Scrubber, Wet Limestone Scrubber, Dual-Alkali Scrubber, Spray Dry Absorber, Dry Sorbent Injection, Circulating Dry Scrubber, and Hydrated Ash Reinjection.

Step 2: Eliminate Technically Infeasible Options

CDS systems result in high particulate loading to the unit's particulate control device. Because of the high particulate loading, the pressure drop across a fabric filter would be unacceptable; therefore, electrostatic precipitators (ESP) are generally used for particulate control. YELP has high efficiency fabric filters in place. Based on limited technical data from non-comparable applications and engineering judgment, it has been determined that CDS is not technically feasible with a CFBC boiler equipped with a fabric filter for particulate control. Therefore, the CDS will not be evaluated further.

The YELP facility has a very limited area to install additional SO_2 controls and manage waste materials. The wet FGD scrubber systems with the higher water requirements (Wet Lime Scrubber, Wet Limestone Scrubber, Dual Alkali Wet Scrubber) would require an on-site dewatering pond or landfill to dispose of scrubber sludge. Due to YELP's limited space requirements, its proximity to the Yellowstone River, and limited water availability for these controls, these technologies are considered technically infeasible and will not be evaluated further.

The three remaining technically feasible control options for the YELP facility were determined to be HAR, SDA, and DSI.

The ability of the existing fabric filter baghouses at YELP to accommodate additional particulate resulting from HAR, SDA or DSI is in question based on prior conversations with a vendor of these systems. The vendor previously indicated that the baghouse design must be matched with the add-on control systems and its resulting particulate loading. Therefore, the existing baghouse system would need to be replaced or potentially redesigned significantly to accommodate the increase in particulate in the flue gas stream. As a result, a redesigned (new) fabric filter baghouse is included in the cost for each SO_2 control technology.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Specific estimated removal efficiencies for HAR, SDA and DSI, are 50 percent for both HAR and DSI and 80 percent for SDA. These approximate control efficiencies are used in determining the cost of compliance.

Step 4: Evaluate Impacts and Document Results

__Factor 1: Cost of Compliance__

The cost-effectiveness of each of the technically feasible SO_2 control technologies was estimated based on the methodologies developed and provided in EPA's Air Pollution Control Cost Manual.[106] (Control Cost Manual) Each cost analysis is based on the methodology described in the Control Cost Manual, Section 5.2, Chapter 1- Wet Scrubbers for Acid Gas Removal. The cost effectiveness was estimated using the example for Acid Gas Removal because it most closely reflected the control methods being assessed when compared to the other choices. This same methodology was utilized in the first planning period analysis.

Equipment and system operations have remained the same at YELP since the first planning period analysis was accepted by the EPA in 2011. EPA guidance states that a state may rely on previous BART analysis or reasonable progress analysis for the characterization of a factor, for example information developed in the first implementation period on the availability, cost and effectiveness of controls for a particular source, if the previous analysis was sound and no significant new information is available.[47] The four-factor analysis for YELP used the first planning period cost analysis, but updated for this cost of compliance demonstration by revising the calculation parameters to account for a 20-year life expectancy, 5.5% interest rate, and adjusting 2011 prices to 2019-dollar values due to inflation.

The 2028 OTB/OTW emissions were used to estimate the cost-effectiveness of the technically feasible control options. All three control options include the cost of installing the designated control option as well as installing an upgraded baghouse system.

Table 6-21. Estimated Costs of SO_2 Control Options for YELP

SO_2 Control Option	% Control	Total Capital Investment	Total Annual Cost	Annual Emission Reduction (tpy)	Annual Emissions After Control (tpy)	Average Annual Cost Effectiveness ($/ton)
Hydrated Ash Reinjection and Baghouses	50%	$35,816,983	$5,796,240	866	866	$6,693
Spray Dry Absorbers and Baghouses	80%	$45,276,409	$7,509,313	1,386	346	$5,420
DSI and Baghouses	50%	$23,446,964	$5,062,421	866	866	$5,846

The costs for additional control of the boiler are considered moderate. Although Montana did not set a threshold for cost-effectiveness for RH planning, Montana is very familiar with cost effectiveness benchmarks prepared under BACT reviews. As previously discussed, the calculated costs above incorporate the additional cost of an upgraded baghouse system. Generally, these costs are higher than BACT level cost per ton values at recently permitted units.

Factor 2: Time Necessary for Compliance

The addition of HAR, SDA, or DSI would each take approximately the same amount of time. However, as stated previously, the addition of SO_2 controls would likely require complete replacement or major modifications to the existing baghouses. The installation of the new SO_2 controls and baghouses should be staggered to allow one boiler to remain in operation while the retrofits are applied to the other boiler. Bison estimates that the time necessary to complete the modifications to one boiler would be approximately four to six months. A boiler outage of approximately two to three months per boiler would be necessary to perform the installation of both control systems. The total time necessary to install the controls would be approximately one year.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

HAR, SDA and DSI installed systems require electricity to operate. SDA, DSI, and HAR systems have been estimated to consume 0.1% to 0.5% of total plant generation. These control systems being analyzed use electricity primarily for the ID fan, lime/limestone handling equipment and baghouse blowers. The addition of the SO_2 controls would result in increased ash production at the YELP facility. Boiler ash is currently either sent to a landfill or sold for beneficial use, such as oil well reclamation. Changes in ash properties due to increased calcium sulfates and calcium sulfites could result in the ash being no longer suitable to be sold for beneficial uses. The loss of this market would cost YELP approximately $2,300,000 year at the current ash value and production rates (approximately 170,000 tons of ash/year). The loss of this market would also result in YELP having to dispose of the ash at its current landfill, which is approximately 80 miles from the YELP plant. YELP currently pays a fixed fee of approximately $500,000 a year to manage this landfill. YELP incurs a fee of $3.56/ton on ash taken to the pit that is in excess of 140,000 tons/year. At its current production and ash disposal costs, this would result in an increased cost to YELP of approximately $96,000/year. The total cost from the loss of the beneficial use market and the increase in ash disposal costs would be a total of $2,400,000/year.

Another potential impact would an increase in mercury emissions. YELP has recently determined that mercury content in its limestone feed has contributed to a violation of the federal Mercury Air Toxics Standard. Additional use of limestone (which is included in the SO_2 controls listed above) would trigger added costs and control to address potential mercury emissions resulting from that limestone.

Factor 4: Remaining Useful Life

The CFBC boilers at YELP are not planned for retirement at this time. The remaining useful life of the sources is assumed to be 20 years.

Step 5: Select Reasonable Progress Control

Montana has determined that, while the costs for retrofit are considered moderate and the annual SO_2 emissions remain over 1,700 tpy, additional SO_2 controls are not reasonable in this implementation period. The rationale for this decision takes into account the four-factors as well as five additional considerations. Limestone injection technology currently in place at YELP is providing an effective control of SO_2..

NOx Evaluation

During the first planning period analysis, YELP consulted with Bison, the Harris Group, and Metso to estimate the cost-effectiveness of installing SCR or SNCR at the facility. Metso and the Harris Group have extensive experience building CFBCs with NOx controls. Their expertise was utilized to develop as close to an estimate of each control technology as possible.

Again, equipment and system operations have remained the same at YELP since the first planning period analysis was accepted by the EPA in 2011. The first planning period cost analysis for NOx was updated for this cost of compliance demonstration by revising the calculation parameters to account for a 20-year life expectancy, 5.5% interest rate, and adjusting 2011 prices to 2019-dollar values due to inflation.

The average of YELP NOx emissions from 2014-2017 was used to estimate the cost-effectiveness of the technically feasible control options. Both control options include the cost of installing the designated control option but do not account for the cost of facility downtime.

YELP currently controls NOx emissions using good combustion practices in the CFBC boilers. Emissions are controlled through the boiler design and its lower operating temperatures, and a recirculation of fuel and ash particles through the combustion boiler. The lower operating temperature in a CFBC boiler already reduces the formation of thermal NOx emissions in the range of 50% or more compared to other boiler designs. YELP must meet emission limits of 0.400 lb/MMBtu and 319.0 pounds per hour per Title V Operating Permit #OP2650-03[119].

Step 1 – Identify All Available Technologies

As YELP is currently using boiler design to control NOx emissions, only post-combustion controls were considered for this analysis. The post-combustion controls that are initially technically feasible in this application are Low Excess Air (LEA), Flue Gas Recirculation (FGR), Overfire Air (OFA), Low NOx Burners (LNB), Selective Catalytic Reduction (SCR), and Selective Non-Catalytic Reduction (SNCR).

<u>Low Excess Air</u>

Emissions reductions achieved by LEA are limited by the need to have sufficient oxygen present for flame stability and to ensure complete combustion. As excess air levels decrease, emissions of CO, hydrocarbons and unburned carbon increase, resulting in lower boiler efficiency. Other impediments to LEA operation are the possibility of increased corrosion and slagging in the upper boiler because of the reducing atmosphere created at low oxygen levels.

This technology is typically utilized on Pulverized Coal (PC)-fired units. This option cannot be utilized on CFBC boiler due to air needed to fluidize the bed.

<u>Flue Gas Recirculation</u>

This technology is typically utilized on PC-fired units. This option cannot be utilized on CFBC boilers due to air needed to fluidize the bed.

<u>Overfire Air</u>

Poorly controlled OFA may result in increased CO and hydrocarbon emissions, as well as unburned carbon in the fly ash. These products of incomplete combustion result from a decrease in boiler efficiency. OFA may also lead to reducing conditions in the lower furnace that in turn may lead to corrosion of the boiler.

This technology is typically utilized on PC-fired units. This option cannot be utilized on CFBC due to air needed to fluidize the bed.

<u>Low NOx Burners</u>

This technology is typically utilized on PC-fired units. This option cannot be utilized on CFBC boilers because the combustion occurs within the fluidized bed.

<u>Selective Catalytic Reduction</u>

<u>Selective Non-Catalytic Reduction</u>

Step 2: Eliminate Technically Infeasible Options

Because OFA, LEA, and FGR are used to reduce flame temperature and reduce the thermal NOx, these control options are technically ineffective on a CFBC boiler that has inherently low combustion temperatures and relatively lower thermal NOx. Further, a CFBC boiler does not use burners like a PC boiler, limiting the available combustion control options. The remaining post combustion NOx control options are considered technically feasible.

SCR and SNCR are considered technically feasible options for NOx control of the YELP boilers for the purpose of this analysis. However, both control technologies have difficulties in design, construction, and implementation. Most notably, SCR control creates a high risk of causing superheater damage due to the interaction of vanadium in petroleum coke and the SCR catalyst. Likewise, the YELP facility has a very limited area to install additional controls and manage waste materials. These space limitations also apply to the potential installation of SCR and SNCR. However, both control technologies were still evaluated. The technical limitations are described further in the energy and non-air environmental compliance section (Factor 3) and the summary.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

SCR

Theoretically, SCR systems can be designed for NOx removal efficiencies up close to 100 percent. In practice, new commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent. However, the reduction may be less than 90 percent when SCR follows other NOx controls such as LNB or FGR that achieve relatively low emissions on their own (including CFBC boiler technology). The outlet concentration from SCR on a utility boiler is rarely less than 0.04 pounds per MMBtu (lb/MMBtu)[120]. Based on that limitation, which is particularly applicable to a retrofit unit, the proposed reduction associated with SCR for the YELP boilers is 80% as provided by vendor data detailed in Factor 1.

The control technology works best for flue gas temperatures between 575°F and 750°F. Excess air is injected at the boiler exhaust to reduce temperatures to the optimum range, or the SCR is located in a section of the boiler exhaust ducting where the exhaust temperature has cooled to this temperature range. Technical factors that impact the effectiveness of this technology include inlet NO_X concentrations, the catalyst reactor design, operating temperatures and stability, type of fuel fired, sulfur content of the fuel, design of the ammonia injection system, catalyst age and reactivity, and the potential for catalyst poisoning.

In retrofit installations, new ductwork would be required to integrate the SCR system with the existing equipment. In low-dust SCR systems for utility and industrial boilers, the SCR reactor would be located between the outlet duct of the particulate control device and the air heater inlet duct.

Retrofit of SCR on an existing unit has higher capital costs than SCR installed on a new system. There is a wide range of SCR retrofit costs due to site-specific factors, scope differences, and site congestion.

[120] YELP analyses footnote: Data in the Clean Air Markets Division (CAMD) database also suggest SCR units rarely achieve emissions less than 0.04 lb/MMBtu.

SNCR

SNCR involves the noncatalytic decomposition of NOx in the flue gas to nitrogen and water using a reducing agent (e.g., ammonia or urea). The reactions take place at much higher temperatures than in an SCR, typically between 1,550°F and 1,950°F, because a catalyst is not used to drive the reaction. The efficiency of the conversion process diminishes quickly when operated outside the optimum temperature band and additional ammonia slip or excess NOx emissions may result.

The process has been used in North America since the early 1980s and is most common on utility boilers, specifically coal-fired utility boilers. Removal efficiencies of NOx vary considerably for this technology, depending on inlet NOx concentrations, fluctuating flue gas temperatures, residence time, amount and type of nitrogenous reducing agent, mixing effectiveness, acceptable levels of ammonia slip and the presence of interfering chemical substances in the gas stream.

Reagent costs currently account for a large portion of the annual operating expenses associated with this technology, and this portion has been growing over time. Ammonia is generally less expensive than urea because urea is derived from ammonia. However, the choice of reagent is based not only on cost but also on physical properties and operational considerations. Ammonia was employed as the reagent in the YELP SNCR cost analysis because it was determined to be the most appropriate reagent by the vendors and was included in the vendor quote. An average reduction of 50% was used in the cost efficiency calculations because that was selected/determined to be feasible in the vendor quote.

For SNCR retrofit of existing boilers, optimal locations for injectors may be occupied with existing boiler equipment such as the watertubes. The primary concern is adequate wall space within the boiler for installation of injectors. The injectors are installed in the upper regions of the boiler, the boiler radiant cavity, and the convective cavity. Existing watertubes and asbestos may need to be moved or removed from the boiler housing. In addition, adequate space adjacent to the boiler must be available for the distribution system equipment and for performing maintenance. This may require modification or relocation of other boiler equipment, such as ductwork. The estimated costs on a $/kW basis increase sharply for small boilers due to both economies of scale and to account for the more difficult installation conditions that are often encountered for the small boilers. The YELP boilers combine for 65 MW and therefore are considered small boilers.

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

The cost-effectiveness of the technically feasible NOx control technologies was estimated using the first planning period total capital and operating cost estimates developed by Metso, the Harris Group, and EPA's Air Pollution Control Cost Manual, 6th Edition.**Error! Bookmark not defined.** [121] The newly published 2019 control cost manual analyses for SCR and SNCR were not utilized in this demonstration, since the YELP boilers are not accurately represented within the spreadsheet calculations. The YELP boilers are dual purpose and create steam for the ExxonMobil Billings Refinery as well as power generation. It is difficult to provide

[121] EPA Air Pollution Control Cost Manual, Sixth Edition (2002 January). Available at: https://www.epa.gov/sites/default/files/2020-07/documents/c_allchs.pdf

accurate input data for the YELP boilers within the utility or industrial functions of the spreadsheet. The 2019 calculations also do not provide representative fuel characteristics for the utilization of petroleum coke and coker gas at YELP. The Metso and Harris Group cost estimates were provided specifically for the YELP facility and provide the most reasonable estimate for this stage of planning. Therefore, the 2011 analyses were revised utilizing the vendor specific cost estimates.

The equipment and system operations have remained the same at YELP since the first planning period analysis was accepted by the EPA in 2011. The first planning period cost analysis for NOx was updated for this cost of compliance demonstration by revising the calculation parameters to account for a 20-year life expectancy, 5.5% interest rate, and adjusting 2011 prices to 2019-dollar values due to inflation. Montana accepted this approach because the facility-specific vendor costs are assumed to be more accurate than generic facility calculations from EPA's Control Cost Manual.

The results of the analysis are summarized below. Both control options include the cost of installing the designated control option but do not account for the cost of facility downtime.

Table 6-22. Estimated Costs of NO2 Control Options for YELP

NOx Control Option	% Control	Total Capital Investment	Total Annual Cost	Annual Emission Reduction (tpy)	Annual Emissions After Control (tpy)	Average Annual Cost Effectiveness ($/ton)
Selective Catalytic Reduction	80%	$32,460,400	$4,153,623	323	81	$12,841
Selective Non-Catalytic Reduction	50%	$1,020,800	$597,303	202	202	$2,954

The costs for additional NOx control of the boilers vary and are difficult to accurately estimate at a preliminary design stage. Due to space limitations causing constraints in design capabilities, these proposed costs are an initial estimate for installing the add-on control systems with limited knowledge of the YELP network equipment (i.e., plant piping, cable piping, etc.). As noted in the Metso report, this is an order of magnitude estimate because there could be interferences and significant unknowns that would alter Metso's cost estimates. Additional investment would be required from YELP to determine a more refined cost estimate.

Additionally, the vendor cost estimates do not account for lost revenue due to facility downtime. The time necessary for compliance is detailed in Factor 2 and describes YELP's operating relationship with the ExxonMobil Billings Refinery. Lost revenue due to facility downtime would increase the total annual costs associated with adding on emissions controls.

Factor 2: Time Necessary for Compliance

Due to the complexity of the existing infrastructure and severely limited space, the installation of SCR is estimated to take approximately 26 months. The installation of SNCR is less complex and would take approximately 24-30 weeks.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

The energy impacts from an SNCR are minimal and an SNCR does not cause a loss of power output from the facility. On the other hand, SCR would cause a significant backpressure in the CFBC boiler leading to lost boiler efficiency and, thus, a loss of power production. Along with the power loss, YELP would be subject to the additional cost of reheating the exhaust gas, which is an inefficient use of energy and additional fuel.

The addition of chemical reagents in SNCR and SCR controls would add equipment for its storage and use. The storage of on-site ammonia would pose a risk from potential releases to the environment. An additional concern is the loss of ammonia, or "slip" into the emissions stream from the facility; this "slip" contributes another pollutant to the environment, which has been implicated as a precursor to fine particulate formation in the atmosphere. The additional costs of chemicals and catalysts have been included in the cost analysis.

SCRs can also contribute to equipment fouling due to ammonia bisulfate formation. Equipment fouling can reduce unit efficiency and increase flue gas velocities. Additionally, the ammonium sulfate can corrode downstream exhaust handling equipment, as well as increase the opacity or visibility of the exhaust plume.

In addition, SCR would require disposal or recycling of catalyst materials, which may require handling in a specific landfill for hazardous waste. On some installations, catalyst life is very short, and SCRs have fouled in high dust environments. This had led to boiler downtime in some installations. The presence of vanadium in the petroleum coke fuel has also led to reduced catalyst life on SCR units. A detailed assessment of catalyst life cost would require further analysis by a catalyst vendor.

Fouling of petroleum coke-fired units occurs on superheater surfaces. The superheater is upstream of this SCR. The fouling will likely cause plugging and blinding of the SCR catalyst when it breaks loose from the superheater surfaces. This will increase maintenance costs at this facility and subject the unit to increased downtime.

Factor 4: Remaining Useful Life

As previously stated in the SO_2 analysis, YELP is not planned for retirement at this time. A remaining useful life of the sources is assumed to be 20 years.

Step 5: Select Reasonable Progress Control/Final State Recommendations:

Montana has determined that, while the costs for SNCR are considered moderate, additional NOx controls are not reasonable in this implementation period. The rationale for this decision takes into account the four-factors as well as five additional considerations.

6.2.12 Roseburg Forest Products Co.[122]

Roseburg Forest Products (Roseburg) submitted their four-factor analysis (in conjunction with Maul Foster and Alongi Inc.) on September 30, 2019. Roseburg was evaluated in the first planning period and the four-factor analysis submitted is very similar to the technology discussions from that period. Roseburg is located in Missoula, Montana, in Missoula County and consists of three emitting units that are each evaluated for reasonable progress controls. The three emitting units are related to combustion devices which provide heat for the particleboard manufacturing production line as described below.

The facility has historically had two production lines, one with a multi-platen batch press (Line 1) and one with a continuous press (Line 2). Roseburg went through a Line 1 modernization project to increase the production efficiency of the facility. As part of the Line 1 modernization project, the facility went from the historic two-line production configuration to a single production line configuration. Line 1 historically consisted of four dryers (dryer 100 through dryer 103, referred to by the facility as dryers 1 through 4) which dry both face and core material. All four dryers continue to exhaust through a single, common stack.

The Line 2 production line had consisted of two dryers, dryer 200 and dryer 201 (referred to as dryers 5 and 6). Dryer 5 was reconfigured to supply the Line 1 storage bins, and Dryer 6 was removed from service. Dryer 5 exhausts to atmosphere through a dedicated stack.

A pre-dryer is used to reduce the moisture of green wood materials received at the facility and was unchanged during the Line 1 modernization project. Heat for the pre-dryer is provided by a 45 MMBtu/hr SolaGen sanderdust burner.

Heat input for the five final dryers associated with Line 1 (post Line 1 modernization project; dryers 1 through 5) is provided by the combined exhaust of a 50 MMBtu/hr ROEMMC sanderdust burner and a sanderdust-fired Babcock & Wilcox low NOx suspension-type boiler, which also provides steam for facility processes. The ROEMMC burner was installed in 1979. The sole purpose of this burner is to provide heat input for the final dryers. The newer Babcock & Wilcox boiler was installed in 2015. It was subsequently upgraded, also in 2015, with a low-NOx burner which resulted in a decrease in heat input rating from 55 MMBtu/hr to the current 52 MMBtu/hr. Unlike the other facility sanderdust burners, the Babcock & Wilcox boiler serves the function of producing steam for facility processes in addition to providing heat input to the final dryers. A third burner, the SolaGen, provides heat input to the pre-dryer. The SolaGen burner was installed in 2006. For purposes of clarity, the three units are identified as ROEMMC, Babcock boiler, and SolaGen. More information on the unit configurations are below:

> Boiler-ROEMMC Configuration: A horizontal manifold connects the boiler and ROEMMC burner exhaust stacks to provide combined exhaust to the five final dryers for the single manufacturing Line 1. Both the boiler and ROEMMC burner stacks allow exhaust to be diverted to atmosphere in the event of an emergency or upset condition. Line 1 dryers (Dryers 1-4) exhaust to multi-clones for

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[122] Roseburg Forest Products – Missoula Particleboard, Four-Factor Reasonable Progress Analysis (30 Sept. 2019), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/Planning/PDF/Rf_BART%20Report.pdf?ver=2020-02-04-131029-430

particulate control. The multi-clone exhaust is combined and released from a single Line 1 dryer stack. Dryer 5 exhausts to a multi-clone, which emits to atmosphere.

SolaGen Burner Configuration: The SolaGen burner exhaust is utilized to dry green furnish materials in the pre-dryer. Green materials are typically about 50% moisture, so the primary purpose of the pre-dryer is to reduce the moisture by approximately 80% or more so that the pre-dried material is suitable for final drying in the Line 1 dryers. The SolaGen burner is equipped with a low-NOx burner and flue gas reinjection to reduce NOx emissions. Exhaust from the pre-dryer is controlled by a cyclone, a wet electrostatic precipitator (WESP) and a regenerative thermal oxidizer (RTO). These controls significantly reduce emissions of particulate matter.

Roseburg RepBase and 2028 OTB/OTW Scenarios

Roseburg selected the four-year average from 2014-2017 for their representative baseline and Montana concurred that this four-year period was reflective of recent normal operation. Roseburg also selected a 2028 OTB/OTW scenario that was used to calculate the cost per ton of emission reduction achieved from applying controls.

Roseburg chose to use the 2014-2017 representative baseline for the 2028 OTB/OTW scenario. Roseburg was not asked to conduct an analysis for SO_2 reductions as their baseline emissions for SO_2, like most wood products facilities, are very low.

Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 6-23. Roseburg RepBase and 2028 OTB/OTW Emissions

Baseline Period	**Rep. Baseline NOx**	**Rep. Baseline SO_2**	**2028 OTB/OTW NOx**	**2028 OTB/OTW SO_2**
2014-2017	299.3	3.3	299.3	3.3

NOx Evaluation

NOx emission controls were analyzed for the Babcock boiler, ROEMMC, and SolaGen sanderdust combustion devices. Currently there are no NOx add-on emission controls on these devices. However, the SolaGen burner was installed in 2006 with a low-NOx burner and flue gas recirculation, and the Babcock boiler was upgraded with a low-NOx burner in 2015. Each of the units can be fired upon natural gas and/or sanderdust, although NOx emissions increase significantly from the firing of sanderdust.

Step 1 – Identify All Available Technologies

NOx control technologies identified include SNCR, SCR, RSCR and low-NOx burners.

<u>SNCR</u>

SNCR systems have been widely employed for biomass combustion systems globally. SNCR is relatively simple because it utilizes the combustion chamber as the control device reactor, achieving control efficiencies of 30-70%.

SCR

Unlike SNCR, SCR reduces NOx emissions with ammonia in the presence of a catalyst. The major advantages of this are the higher control efficiency (70%-90%) and the lower temperatures at which the reaction can take place (400°F to 800°F, depending upon the catalyst selected). SCR is widely used for combustion processes where the type of fuel produces a relatively clean combustion gas, such as natural gas turbines.

SCR is not widely used with wood-fired combustion units due to the amount of particulate that is generated by combustion of wood. The particulate, if not removed completely, can cause plugging in the catalyst and coat the catalyst such that the surface area for reaction is reduced. Another challenge with wood-fired combustion is the presence of alkali metals such as sodium and potassium, which are commonly found in wood, but not fossil fuels. Sodium and potassium will poison catalysts and the effects are irreversible. Other naturally occurring catalyst poisons found in wood are phosphorous and arsenic.

To prevent the plugging, blinding, and/or poisoning of the SCR catalyst, it is necessary to first remove particulate from the exhaust gases. It is not considered technically feasible to place an SCR unit upstream of the particulate control device in a wood-fired boiler or burner application due to the potential for decreasing the useful life of the catalyst and decreasing the control efficiency, which can happen relatively quickly. Use of SCR on a wood-fired boiler or burner application requires a high temperature particulate control device so that the downstream temperature is still in the range of 400°F to 800°F, which is necessary for the reduction of NOx in the presence of the catalyst. In situations where NOx emissions are being controlled downstream of a dryer where the outlet temperature is well below 200°F, the catalyst is essentially ineffective at reducing emissions.

RSCR

RSCR is a commercially available add-on control technology by Babcock Power Inc. that combines the technology of a regenerative thermal oxidizer device and SCR. An RSCR unit is approximately 95% efficient at thermal recovery. The exhaust is heated to a temperature in the range optimal for catalytic reduction (600°F to 800°F) prior to entering an SCR unit. These systems have been shown to reduce NOx emissions to less than 0.075 lbs/MMBtu and can achieve emission reductions to as low as 0.05 lbs/MMBtu.

Low-NOx Burner

Low-NOx burners are a viable technology for many fuels including sanderdust and gasified biomass. Generally, staged combustion and sub-stoichiometric conditions can be used to limit the amount of NOx formation. The SolaGen burner and the Babcock boiler at the Missoula facility both already utilize low-NOx burners.

Step 2: Eliminate Technically Infeasible Options

SNCR relies on the injection of ammonia in the combustion chamber of the sanderdust fired devices. The ROEMMC and SolaGen burners do not have the residence time needed at the critical temperatures for the reaction to take place. It is unknown whether sufficient residence time would occur in the Babcock boiler combustion zone. Because these combustion units provide exhaust to the dryers, there is concern about the impact of ammonia on the wood furnish. In making particleboard, the wood furnish is combined with a formaldehyde-based resin. Ammonia acts as a scavenger of free formaldehyde, which could have some effect on resin curing if ammonia is trapped within the furnish during forming.

Another concern is that ammonia can darken or blacken certain wood species. It is unknown what impact ammonia would have on the wood species being used by Roseburg, given the following: period of time wood would be exposed, the concentrations of excess ammonia, and at the elevated temperatures that occur in the dryers. As part of developing the reasonable progress analysis, the National Council of Air and Stream Improvement was contacted to inquire as to whether they were aware of any installations where ammonia was injected upstream of a wood particle dryer. No instances where ammonia injection was conducted upstream of a wood particle dryer were identified.

Due to the uncertain impact that ammonia could have on wood furnish and resin curing, SNCR is not considered an applicable technology with proven feasibility for any of the sanderdust combustion devices due to their location upstream of the wood particle dryers.

Where wood combustion is concerned, SCR requires a clean exhaust stream with temperatures between 400°F and 800°F. PM in the exhaust from wood combustion can poison, blind, or plug catalyst beds very rapidly in certain conditions. As a result, it is industry practice to have a good PM control device upstream of the catalyst bed. For the Backcock boiler, SolaGen burner, and ROEMMC burner there is not sufficient room for particulate controls and a catalyst bed upstream of the particle dryers. Additionally, the exhaust temperature exiting the catalyst bed would be significantly cooler, which would provide less heat to the dryers. The SCR unit could be located downstream of the dryers and particulate controls, but the dryer exhaust temperature is well below 400°F. Additionally, the location of an SCR unit upstream of any of the dryers would result in ammonia slip into the dryers. The presence of ammonia slip into the dryers could have unintended consequences for the wood furnish, thereby affecting the manufacturing process. For these reasons, SCR is not considered an applicable technology with proven feasibility for any of the sanderdust combustion devices.

The RSCR control device was assessed in the 2011 reasonable progress analysis. In that assessment, issues with technical feasibility of the RSCR on wood combustion units were raised. These concerns were based on direct comments from the RSCR vendor and were specific to catalyst performance. The vendor would not guarantee the catalyst life due to potential blinding. The 2011 reasonable progress analysis states;

> *"It should be noted that the RSCR vendor would not guarantee catalyst life beyond three years due to the potential for poisoning and blinding associated with the combustion products of wood fuels."*

Additionally, the 2011 reasonable progress analysis describes the challenges encountered with trying to obtain a quote from the RSCR vendor. RSCR units were being heavily marketed at the time but concerns across the air pollution control industry relating to the catalyst performance, unit cost, and thermal efficiency inhibited widespread adoption.

The work related to the 2011 reasonable progress analysis was conducted almost 10 years ago. In that time, one might expect that, if technical feasibility issues had been addressed, then RSCR units would appear in the RBLC. The RBLC was queried for any BACT, RACT or LAER determinations in the past 10 years for NOx emissions resulting from combustion of wood, wood products, or biomass. This RBLC search criteria were left purposely broad to gather as many NOx determinations as possible.

No determinations made in the past 10 years for control of NOx emissions from units combusting wood, wood products, or biomass included an RSCR unit. This supports a determination that the RSCR unit is not feasible for wood combustion units. Based on the comments from the RSCR vendor relating to catalyst poisoning, and the fact that RSCR units do not appear in the RBLC search for NOx controls, the RSCR unit is deemed to be technically infeasible.

A low-NOx burner technology is already in use for the SolaGen sanderdust burner as well as the Babcock boiler. The ROEMMC burner does not have low-NOx burner technology and could be a candidate for an upgrade if it were a much newer unit. It was installed in 1979 and a retrofit to low NOx burner technology is not considered cost effective. If the ROEMMC burner is replaced it would include low-NOx burner technology that would provide NOx emission reductions.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Since there were no NOx control devices deemed technically feasible, control effectiveness was not determined for any NOx control device.

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

Cost impacts were not assessed for any NOx control devices since no unit was found to be technically feasible.

Factor 2: Time Necessary for Compliance

No new controls were brought forward. The Babcock boiler and SolaGen are equipped with low-NOx burners and these will continue to provide low NOx emissions as long as the units are in operation.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

Energy impacts were not assessed for any NOx control devices since no unit was found to be technically feasible. However, it should be noted that the RSCR units require both fossil fuel and electricity. Fossil fuel would be used to reheat the dryer exhaust gas from approximately 140°F to 600°F or higher. Additionally, electricity is used to operate the fans required to overcome the pressure drop across the catalyst bed.

Another less quantifiable impact from energy use is the impact from producing the electricity and mining the fossil fuel. Both the production of electricity and the use of fossil fuel for combustion would result in greenhouse gases and other pollutant emissions.

It should be noted that RSCR units require the use of catalysts that must be disposed of. The catalysts will most likely be considered a hazardous waste. Additionally, SNCR, SCR, and RSCR units all require the use of ammonia injected into the exhaust stream and unreacted excess ammonia would be released to the atmosphere. Ammonia slip to the atmosphere is a contributor to fine particle formation, which further exacerbates the regional haze issue. Therefore, there is a trade-off between maximizing NOx emission reductions and minimizing ammonia slip. The use of ammonia or urea also introduces certain transportation and handling risks that also can have safety and environmental concerns.

Factor 4: Remaining Useful Life

Useful life was not assessed for any of the NOx control devices since none were found be technically feasible.

Step 5: Select Reasonable Progress Control

None of the control options identified in this analysis were deemed technically feasible. No additional NOx controls for the boilers are reasonable this planning period. The current controls include the newer sanderdust boiler installed in 2015 with a low-NOx burner, which has contributed to a decrease in the NOx emission rate from the facility since the first planning period.

6.2.13 Colstrip Energy Ltd Partnership[123]

Colstrip Energy Ltd Partnership (CELP) submitted their four-factor analysis (in conjunction with Bison Engineering Inc.) on September 30, 2019. CELP was evaluated in the first planning period and the four-factor analysis submitted is very similar to the technology discussions from that period. The CELP facility is very near to Colstrip, Montana, in Rosebud County and consists of a single circulating fluidized bed combustion (CFBC) boiler. The facility is often referred to as the Rosebud Power Plant. The CFBC is the only emitting unit at the site that requires an evaluation for this demonstration. The CELP facility combusts waste coal mined from the Westmoreland Rosebud coal mine. Waste coal is generally described as a low-grade BTU value coal.

CELP RepBase and 2028 OTB/OTW Scenarios

CELP selected the 2014-2016 three-year average of emissions as their representative baseline and Montana concurred that this three-year period was reflective of recent normal operation. CELP used the 2028 OTB/OTW scenario emissions to calculate the cost per ton of emission reduction achieved from applying controls.

CELP chose to use the 2014-2016 representative baseline for the 2028 OTB/OTW scenario. Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 6-24. CELP RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2014-2016	892.6	1232.6	892.6	1232.6

SO_2 Evaluation

CELP currently controls SO_2 emissions using limestone injection. Limestone is injected with the waste coal prior to its combustion in the CFBC boiler. In the CFBC boiler, the limestone calcines to lime and reacts

[123] Colstrip Energy Limited Partnership – Rosebud Power Plant Regional Haze Four-Factor Analysis (September 2019), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/Planning/PDF/CELP%20Four-Factor%20RH%20Analysis_Sept%202019.pdf?ver=2020-02-03-161311-357

with SO_2 to form calcium sulfates and calcium sulfites. The calcium compounds are removed as particulate matter by the baghouse. Depending on the fuel fired in the boiler and the total heat input, CELP must control SO_2 between a 70% to 90% reduction per Montana Operating Permit #OP2035-04[124]. The current limestone injection system is reported to be operating at or near its maximum capacity and increasing limestone injection beyond the current levels may result in plugging of the injection lines, increased bed ash production which can reduce combustion efficiency, and increased particulate loading to the baghouses. Increasing limestone injection beyond its current level would require major upgrades to the limestone feeding system and the baghouses. Furthermore, an upgrade to the existing limestone injection system would expect only modest increases in SO_2 removal efficiency compared to add-on SO_2 control systems which were further analyzed within this section. Therefore, upgrading the existing system is not considered further. This analysis will focus on add-on control systems for SO_2 control, as those are expected to be significantly more cost effective.

Step 1 – Identify All Available Technologies

As CELP's fuel type (waste coal), type of boiler (Circulating Fluidized Bed), and the limestone system are operating at current maximum capacity, this cost analysis will focus on post-combustion controls to further reduce sulfur dioxide emissions beyond the existing limestone injection control. The post-combustion controls that are potentially technically feasible in this application are flue gas desulfurization (FGD) systems. FGD options for the CFBC boiler include:

- Wet Lime Scrubber
- Wet Limestone Scrubber
- Dual Alkali Wet Scrubber
- Spray Dry Absorber
- Dry Sorbent Injection
- Circulating Dry Scrubber
- Hydrated Ash Reinjection

Step 2: Eliminate Technically Infeasible Options

CDS systems result in high particulate loading to the unit's particulate control device. Because of the high particulate loading, the pressure drop across a fabric filter would be unacceptable; therefore, electrostatic precipitators (ESP) are generally used for particulate control. CELP has a high efficiency fabric filter (baghouse) in place. Based on limited technical data from non-comparable applications and engineering judgment, it has been determined that CDS is not technically feasible with a CFBC boiler equipped with a fabric filter for particulate control. Therefore, CDS will not be evaluated further.

The CELP facility has a limited area to install additional SO_2 controls that would require high quantities of water and dewatering ponds. The wet FGD scrubber systems with the higher water requirements (Wet Lime Scrubber, Wet Limestone Scrubber, Dual Alkali Wet Scrubber) would require an on-site dewatering pond or

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[124] Operating Permit #OP2035-04, (30 November 2020), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/ARMpermits/OP2035-04.pdf

an additional landfill to dispose of scrubber sludge. Due to CELP's limited available space, its proximity to the East Armels Creek to the east of the plant and an unnamed creek to the south of the plant, and limited water availability for these controls, these technologies are considered technically infeasible and will not be evaluated further.

The three remaining technically feasible control options for the CELP facility were determined to be HAR, SDA, and DSI.

The ability of the existing fabric filter baghouses at CELP to accommodate additional particulate resulting from HAR, SDA or DSI is in question based on prior conversations with a vendor of these systems. The vendor previously indicated that the baghouse design must be matched with the add-on control systems and its resulting particulate loading. Therefore, the existing baghouse system would need to be replaced or potentially redesigned significantly to accommodate the increase in particulate in the flue gas stream. As a result, a redesigned (new) fabric filter baghouse is included in the cost for each SO_2 control technology.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Specific estimated removal efficiencies for HAR, SDA and DSI, are 50 percent for both HAR and DSI and 80 percent for SDA. These approximate control efficiencies are used in determining the cost of compliance.

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

The cost-effectiveness of each of the technically feasible SO_2 control technologies was estimated based on the methodologies developed and provided in EPA's Control Cost Manual.[106] Each cost analysis is based on the methodology described in the Control Cost Manual, Section 5.2, Chapter 1- Wet Scrubbers for Acid Gas Removal. The cost effectiveness was estimated using the example for Acid Gas Removal because it most closely reflected the control methods being assessed when compared to the other choices. This same methodology was utilized in the first planning period analysis.

Equipment and system operations have remained the same at CELP since the first planning period analysis was accepted by the EPA in 2011. EPA guidance states that a state may rely on previous BART analysis or reasonable progress analysis for the characterization of a factor, for example information developed in the first implementation period on the availability, cost and effectiveness of controls for a particular source, if the previous analysis was sound and no significant new information is available.[47] The four-factor analysis for CELP used the first planning period cost analysis has been updated for this cost of compliance demonstration by revising the calculation parameters to account for a 20-year life expectancy, 5.5% interest rate, and adjusting 2011 prices to 2019-dollar values due to inflation.

The 2028 OTB/OTW emissions were used to estimate the cost-effectiveness of the technically feasible control options. All three control options include the cost of installing the designated control option as well as installing an upgraded baghouse system.

Table 6-25. Estimated Costs of SO_2 Control Options for CELP

SO_2 Control Option	% Control	Total Capital Investment	Total Annual Cost	Annual Emission Reduction (tpy)	Annual Emissions After Control (tpy)	Average Annual Cost-Effectiveness ($/ton)
Hydrated Ash Reinjection and Baghouses	50%	$22,177,580	$3,669,038	616	616	$5,961
Spray Dry Absorbers and Baghouses	80%	$28,435,354	$4,814,409	985	246	$4,889
DSI and Baghouses	50%	$13,994,337	$2,848,330	616	616	$4,628

The costs for additional control of the boiler is considered moderate. Although Montana did not set a threshold for cost-effectiveness for RH planning, Montana is very familiar with cost effectiveness benchmarks prepared under BACT reviews. As previously discussed, the calculated costs above incorporate the additional cost of an upgraded baghouse system. Generally, these costs generally are higher than BACT level cost per ton values at recently permitted units.

Factor 2: Time Necessary for Compliance

The addition of HAR, SDA, and DSI would each take approximately the same amount of time. As stated previously, the addition of SO_2 controls are assumed to require complete replacement or major modifications to the existing baghouse. The four-factor analysis estimated that the time necessary to complete the modifications to the CELP facility would be approximately four to six months. A boiler outage of approximately two to three months would be necessary to perform the installation of control systems.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

HAR, SDA and DSI installed systems require electricity to operate. SDA, DSI, and HAR systems have been estimated to consume 0.1% to 0.5% of total plant generation. If CELP had to dispose of the unsalable ash, the increased cost would be approximately $62,000/year. The total cost from the loss of the beneficial use market and the increase in ash disposal costs would be a total of $1,082,000/year.

Factor 4: Remaining Useful Life

The CFBC boiler at CELP is not planned for retirement at this time. The remaining useful life of the sources is assumed to be 20 years.

Step 5: Select Reasonable Progress Control

SO_2

Montana concurs with the CELP prepared and submitted four-factor analysis that the current limestone technology in place at CELP is providing an effective control of SO_2. No additional SO_2 control is required for the second planning period. The costs for retrofit are considered moderate but annual SO_2 emissions remain over 1200 tpy, and no facility reductions appear to have occurred recently.

NOx Evaluation

Applicable NOx control technologies can be divided into two main categories: combustion controls, which limit NOx production, and post-combustion controls, which destroy NOx after formation. CELP currently controls NOx emissions using good combustion practices in the CFBC boilers. Emissions are controlled through the boiler design and its lower operating temperatures, and a recirculation of fuel and ash particles through the combustion boiler. The lower operating temperature in a CFBC boiler already reduces the formation of thermal NOx emissions in the range of 50% or more compared to other boiler designs. CELP must meet NOx emission limits of 328.0 lbs/hr, 7,864 lbs/day, and 1,435 tpy (#OP2035-04[124]). CELP demonstrates compliance with these limits using continuous emission monitors and EPA Method 7.

Step 1 – Identify All Available Technologies

As CELP is currently using boiler design to control NOx emissions, only post-combustion controls were considered for this analysis. The post-combustion controls that are initially technically feasible in this application are Low Excess Air (LEA), Flue Gas Recirculation (FGR), Overfire Air (OFA), Low NOx Burners (LNB), Selective Catalytic Reduction (SCR), and Selective Non-Catalytic Reduction (SNCR).

<u>Low Excess Air</u>

This technology is typically utilized on Pulverized Coal (PC)-fired units. This option cannot be utilized on CFBC boiler due to the air needed to fluidize the bed.

<u>Flue Gas Recirculation</u>

This technology is typically utilized on PC-fired units. This option cannot be utilized on CFBC due to the air needed to fluidize the bed.

<u>Overfire Air</u>

This control option cannot be utilized on CFBC due to the air needed to fluidize the bed.

<u>Low NOx Burners</u>

This technology is typically utilized on PC units. This option cannot be utilized on CFBC because the combustion occurs within the fluidized bed.

<u>Selective Catalytic Reduction</u>

<u>Selective Non-Catalytic Reduction</u>

Step 2: Eliminate Technically Infeasible Options

Because OFA, LEA, and FGR are used to reduce flame temperature and reduce the thermal NOx, these control options are technically ineffective on a CFBC boiler that has inherently low combustion temperatures and relatively lower thermal NOx. Further, a CFBC boiler does not use burners like a PC boiler, limiting the available combustion control options. The remaining post-combustion NOx control options are considered technically feasible.

SCR and SNCR are considered technically feasible options for NOx control of the CELP boiler for the purpose of this analysis. However, both control technologies have difficulties in design, construction, and implementation. The CELP facility has a limited area to install additional controls and manage waste materials. These space limitations also apply to the potential installation of SCR and SNCR. Both control technologies are continuing to be evaluated; however, these technical limitations are described further in the energy and non-air environmental compliance section.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

<u>SCR</u>

Theoretically, SCR systems can be designed for NOx removal efficiencies close to 100 percent. In practice, new commercial coal-, oil-, and natural gas-fired SCR systems are often designed to meet control targets of over 90 percent. However, the reduction may be less than 90 percent when SCR follows other NOx controls such as LNB or FGR that achieve relatively low emissions on their own (including CFBC boiler technology). The outlet concentration from SCR on a utility boiler is rarely less than 0.04 pounds per MMBtu (lb/MMBtu). Based on that limitation, which is particularly applicable to a retrofit unit, the proposed reduction associated with SCR for the CELP Boiler is 80% as provided by vendor data.

In retrofit installations, new ductwork would be required to integrate the SCR system with the existing equipment. In low-dust SCR systems for utility and industrial boilers, the SCR reactor would be located between the outlet duct of the particulate control device and the air heater inlet duct.

Retrofit of SCR on an existing unit has higher capital costs than SCR installed on a new system. There is a wide range of SCR retrofit costs due to site-specific factors, scope differences, and site congestion.

<u>SNCR</u>

This technology is often used for mitigating NOx emissions since it requires a relatively low capital expense for installation, albeit with relatively higher operating costs. The conventional SNCR process occurs within the combustion unit, which acts as the combustion chamber.

Reagent costs currently account for a large portion of the annual operating expenses associated with this technology, and this portion has been growing over time. Ammonia is generally less expensive than urea because urea is derived from ammonia. However, the choice of reagent is based not only on cost but also on physical properties and operational considerations. Ammonia was employed as the reagent in the CELP SNCR cost analysis because it was determined to be the most appropriate reagent by the vendors and was included in the vendor quote. An average reduction of 50% was used in the cost efficiency calculations because that was selected/determined to be feasible in the vendor quote.

For SNCR retrofit of existing boilers, optimal locations for injectors may be occupied with existing boiler equipment such as the watertubes. The primary concern is adequate wall space within the boiler for installation of injectors. The injectors are installed in the upper regions of the boiler, the boiler radiant cavity, and the convective cavity. Existing watertubes and asbestos may need to be moved or removed from the boiler housing. In addition, adequate space adjacent to the boiler must be available for the distribution system equipment and for performing maintenance. This may require modification or relocation of other boiler equipment, such as ductwork. The estimated costs on a $/kW basis increase sharply for small boilers

(<50 MW) due to both economies of scale and to account for the more difficult installation conditions that are often encountered for the small boilers. The CELP boiler is nominally rated at 43 MW and is considered a small boiler.

During the first planning period analysis, CELP consulted with Bison, the Harris Group, and Metso to estimate the cost-effectiveness of installing SCR or SNCR at the facility. Metso and the Harris Group have extensive experience building CFBCs with NOx controls. Their expertise was utilized to develop as close to an estimate of each control technology as possible.

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

The equipment and system operations have remained the same at CELP since the first planning period analysis was accepted by the EPA in 2011. The first planning period cost analysis for NOx was updated for this cost of compliance demonstration by revising the calculation parameters to account for a 20-year life expectancy, 5.5% interest rate, and adjusting 2011 prices to 2019-dollar values due to inflation. Montana accepted this approach because the facility-specific vendor costs are assumed to be more accurate than generic facility calculations from EPA's Control Cost Manual.

The results of the analysis are summarized below. Both control options include the cost of installing the designated control option but do not account for the cost of facility downtime.

Table 6-26. Estimated Costs of NOx Control Options for CELP

NOx Control Option	% Control	Total Capital Investment	Total Annual Cost	Annual Emission Reduction (tpy)	Annual Emissions After Control (tpy)	Average Annual Cost-Effectiveness ($/ton)
Selective Catalytic Reduction	80%	$15,650,550	$2,269,256	714	178	$3,179
Selective Non-Catalytic Reduction	50%	$1,020,800	$601,808	202	202	$1,527

The costs for additional NOx control of the boiler varies and is difficult to accurately estimate at a preliminary design stage. Due to space limitations causing constraints in design capabilities, these proposed costs are an initial estimate for installing the add-on control systems with limited knowledge of the CELP network equipment (i.e., plant piping, cable piping, etc.). As noted in the Metso report, this is an order of magnitude estimate because there could be interferences and significant unknowns that would alter Metso's cost estimates. Additional capital investment would be required from CELP to determine a more refined cost estimate.

Additionally, the vendor cost estimates do not account for lost revenue due to facility downtime. The time necessary for compliance is detailed in Factor 2. Lost revenue due to facility downtime would increase the total annual costs associated with adding on emissions controls.

Factor 2: Time Necessary for Compliance

Due to the complexity of the existing infrastructure and limited space, the installation of SCR is estimated to take approximately 26 months. The installation of SNCR is less complex and would take approximately 24-30 weeks.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

The energy impacts from an SNCR are minimal and an SNCR does not cause a loss of power output from the facility. On the other hand, SCR would cause a significant backpressure in the CFBC boiler leading to lost boiler efficiency and a loss of power production. Along with the power loss, CELP would be subject to the additional cost of reheating the exhaust gas, which is an inefficient use of energy and would incur additional fuel costs.

The addition of chemical reagents in SNCR and SCR controls would add equipment for its storage and use. The storage of on-site ammonia would pose a risk from potential releases to the environment. An additional concern is the loss of ammonia, or "slip" into the emissions stream from the facility; this "slip" contributes another pollutant to the environment, which has been implicated as a precursor to fine particulate formation in the atmosphere. The additional costs of chemicals and catalysts have been included in the cost analysis.

SCRs can contribute to airheater fouling due to ammonia bisulfate formation. Airheater fouling could reduce unit efficiency, increase flue gas velocities in the airheater, and cause corrosion and erosion.

On some installations, catalyst life is very short and SCRs have fouled in high dust environments. This had led to boiler downtime in some installations. A detailed assessment of catalyst life cost would require further analysis by a catalyst vendor.

Factor 4: Remaining Useful Life

As previously stated in the SO_2 analysis, CELP is not planned for retirement at this time. A remaining useful life of the sources is assumed to be 20 years.

Step 5: Select Reasonable Progress Control/Final State Recommendations:

NOx

Limestone injection technology currently in place at YELP is providing an effective control of SO_2..

Montana has determined that, while the costs for the technologies evaluated for NOx reductions are considered moderate and NOx emissions remain at nearly 900 tpy, additional NOx control are not reasonable for the second planning period. The rationale for this decision takes into account the four-factors as well as five additional considerations.

6.2.14 Graymont Western US Inc.[125]

Graymont Western US Inc. (Graymont) submitted their four-factor analysis (in conjunction with Trinity Consultants) and supporting information on September 30, 2019. The Graymont Western US, Inc. Indian Creek Plant is located in Broadwater County near Townsend, Montana, approximately 25 miles southeast of Helena.

The facility operates two horizontal rotary preheater lime kilns. The two kilns are nearly identical in design and operations, although constructed at different times. Kiln #1 was installed in 1982 and Kiln #2 was installed in 1990. Each kiln has a nominal lime production rate of 500 tons per day.

Both kilns can utilize coal and petroleum coke as fuels for the lime production process. Typical annual fuel usage rates for both kilns combined are approximately 40,000 tons per year of coal (at 8,600 Btu/lb) and 20,000 tons per year of coke (at 14,400 Btu/lb). Fuels typically used for kiln startup include diesel and propane. Natural gas is not available at the plant.

Graymont RepBase and 2028 OTB /OTW Scenarios

Graymont selected the 2017-2018 two-year average emissions as their representative baseline. Montana concurred that this two-year period was reflective of recent normal operation. Graymont also selected a future year 2028 OTB/OTW scenario that was used to calculate the cost per ton of emission reduction achieved from applying controls.

Graymont chose not to scale the representative baseline emissions to the future OTB/OTW scenario. Thus, the 2028 OTB/OTW emissions are equivalent to the 2017-2018 representative baseline emissions.

Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 6-27. Graymont RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2017-2018	367.8	238.4	367.8	238.4

SO_2 Evaluation

Step 1 – Identify All Available Technologies

SO_2 is generated during fuel combustion in a lime kiln, as the sulfur in the fuel is oxidized by oxygen in the combustion air. Sulfur in the limestone raw material can also contribute to a kiln's SO_2 emissions, though the proportion of sulfur contained in the raw material is much less than that of the fuel.

[125] Graymont Western US, Inc., Reasonable Progress Four-Factor Analysis, (September 2019), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/Planning/PDF/2020-0731_Graymont_IC_4_Factor_Analysis_CBI_Excluded.pdf

The retrofit controls include both add-on controls that eliminate SO_2 after it is formed and switching to lower sulfur fuels which reduces the formation of SO_2. Available technologies for SO_2 were identified as: Inherent Dry Scrubbing, Alternative Low Sulfur Fuels, Wet Scrubbing, and Semi-Wet/Dry Scrubbing.

<u>Inherent Dry Scrubbing</u>

SO_2 is inherently scrubbed within a lime kiln system due to the presence of large volumes of alkaline materials in the system, including limestone in the preheater that all kiln exhaust gases pass through. A typical kiln system scrubs approximately 90% of SO_2 (originating from both fuel sulfur and raw material sulfur) that would otherwise leave the stack. This in-situ scrubbing mechanism is commonly determined as BACT for preheater rotary kilns being permitted today. Dry sorbent injection operates under a similar principle, using the injection of lime particulate into the process stream to initiate the same reaction. Dry sorbent injection is not considered an available control methodology, because the reaction is already taking place inherently as part of the lime kiln process.

<u>Alternative Low Sulfur Fuels</u>

Fuels that can be considered for use in the lime kilns must have sufficient heat content and be dependable and readily available locally in significant quantities so as not to disrupt continuous production. Also, they must not adversely affect product quality. Currently, the Graymont Indian Creek kilns utilize coal and petroleum coke during normal operations. Alternative lower-sulfur fuels that can be considered include natural gas and diesel, as well as an operating scenario using exclusively coal.

Currently, there is no natural gas supplied to the facility. The nearest natural gas pipeline is on the east side of Helena, Montana, approximately 30 miles from the plant, and there are no plans to run a pipeline towards the area of the plant. Therefore, natural gas is not considered an available alternative control method at this time.

There are no examples of kilns that fire 100% diesel fuel for lime production. Therefore, the use of diesel fuel is not a commercially established emission reduction method and is not considered an available, feasible option at this time.

The all-coal scenario will be considered going forward.

<u>Wet Scrubbing</u>

A wet scrubber is an add-on technology that may be installed downstream of the kilns.

Step 2: Eliminate Technically Infeasible Options

Inherent dry scrubbing occurs in the lime kiln systems and is particularly effective in rotary preheater type kilns. Baseline emissions account for this form of SO_2 control. All alternative methods of SO_2 control in this analysis conservatively assume that the kilns maintain the current level of inherent dry scrubbing.

<u>Alternative Low Sulfur Fuels</u>

The use of entirely coal as the primary source of fuel is technically feasible and will be considered further.

<u>Wet Scrubbing</u>

A wet scrubbing system utilizes a ground alkaline agent, such as lime or limestone, in slurry to remove SO_2 from stack gas. The spent slurry is dewatered using settling basins and filtration equipment. Recovered water is typically reused to blend new slurry for the wet scrubber. A significant amount of makeup water is required to produce enough slurry to maintain the scrubber's design removal efficiency. Water losses from the system occur from evaporation into the stack gas, evaporation from settling basins, and retained moisture in scrubber sludge.

Graymont estimates that the slurry required per kiln will be approximately 250 gallons per minute (gpm) of water. Approximately 50% of this water can be recovered from dewatering efforts. The remaining 125 gpm per kiln will need to be continuously added to the system. For both kilns, this amounts to 131.4 million gallons per year.

The Indian Creek plant's water rights entitle the plant to use up to 75 million gallons per year. Plant records indicate the facility's current water usage is approximately 5 million gallons per year. Therefore, at most only 70 million gallons are available to the plant for additional needs. Because the facility would need over 131 million gallons per year to operate the wet scrubbers, the facility would need to acquire the rights to more than an additional 61 million gallons of water per year to operate two wet scrubbers and provide for possible other demands by the plant for water. All water rights in that area of Montana have already been appropriated, so the facility does not have the water resources available to operate wet scrubbers at the facility.

Wet scrubbing SO_2 control technology is technically infeasible for this facility because the Indian Creek plant does not have adequate water resources to operate wet scrubbers. Therefore, this technology is not considered further.

<u>Semi-Wet/Dry Scrubbing</u>

Semi-wet/dry scrubbing uses considerably less water than wet scrubbing; therefore, it is technically feasible and will be considered further.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The remaining technologies are estimated as having the following SO_2 control efficiencies.

- Semi-wet/dry Scrubbing 90.0%
- Alternative Low Sulfur Fuel – All Coal 51.8%
- Inherent Dry Scrubbing Base case

The following assumptions have been applied to each of the estimates noted above.

- Assumes 95% control equipment uptime.
- The alternative fuel scenario reduction efficiency is calculated using a material balance on the fuel sulfur, with fuel sulfur emissions reductions assumed to be independent of feed sulfur emissions and inherent dry scrubbing.
- Estimated inherent SO_2 control efficiency is 90%. Additional reductions from alternative control methods are applied to the base case, conservatively assuming that reduction from inherent dry scrubbing is unaffected by the reduction options.

The alternative fuel scenarios have a calculated control efficiency that considers two key assumptions:

- Changing the primary fuel will fully reduce sulfur by the difference in sulfur levels between the fuel types being compared, affecting only the emissions directly resulting from sulfur contained in the fuel. SO_2 emitted from sulfur contained in the raw material that is processed in the kilns is assumed to not be affected.

- The control efficiencies assume the same level of in-situ scrubbing reduction takes place under all fuel scenarios. These alternative fuel efficiency values are the incremental control efficiencies that take place as a result of the fuel switching beyond the inherent control.

Given the complexity of the inherent scrubbing's impact on SO_2 resulting from fuel sulfur vs. raw material sulfur, assuming the fuel switching fully reduces sulfur by the difference in sulfur levels between the fuel types is particularly conservative. In reality, inherent SO_2 reduction would likely be substantially reduced when the SO_2 concentration in the exhaust stream routed through the pre-heater is reduced

For purposes of this four-factor analysis, the capital costs, operating costs, and cost effectiveness of semi-wet/dry scrubbing have been estimated by scaling the capital and operating costs used in the first planning period by the Chemical Engineering Plant Cost Index (CEPCI). The alternative all-coal fuel scenario calculations are determined using the fuel costs associated with plant operations during baseline emission years. Currently, the Indian Creek kilns utilize a combination of approximately 70% coal and 30% coke by mass.

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance[126]

The capital and operating costs of the semi-wet/dry scrubber used in the cost effectiveness calculations are estimated based on vendor quotes obtained during the first planning period for similar sources, along with published calculations methods. The capital cost is annualized over a 20-year period and then added to the annual operating costs to obtain the total annualized cost.

The cost of the fuel switching used in the cost effectiveness calculations is determined by calculating the current annual cost of using a coal and coke blend and determining the increased cost of switching to all coal, all diesel, and all natural gas.

The Graymont Indian Creek plant currently uses a low heat content coal (Powder River Basin [PRB]) that is obtained locally. To bring the kiln system to the required calcination temperature range, Graymont must blend this coal with a higher heat content fuel such as petroleum coke. In considering the all-coal alternative fuel scenario, it would not be technically feasible to use all PRB coal for the analysis. Therefore, Graymont factored in the composition and cost of an appropriate quality coal that would need to be transported to the plant and blended with the PRB coal.

Switching fuel may require changes to the burners and the fuel storage, processing and delivery system. These factors are significant, especially for the all natural gas alternative fuel scenario. For this case, there would be a significant capital cost to establish a line from the nearest pipeline, which is approximately 30 miles from the plant. For this analysis, however, capital expenses are not included.

The cost effectiveness for the two alternatives is shown below.

[126] Graymont commissioned a Class 4 engineering cost estimate for or semi-wet scrubber to control SO_2 and submitted that information to Montana on August 9, 2022. This cost information can be found in Appendix H, Section 10.

Table 6-28. Graymont SO_2 Cost Effectiveness

Control Option	Control Cost ($/yr)	Baseline Emission Level (tons)	SO_2 Reduction (%)	Emission Reduction (tons)	Cost Effectiveness ($/ton removed)
Semi-wet/dry Scrubbing	$3,939,630	238.39	90.0%	203.82	$9,664
Alt. Fuel – All Coal	$1,887,649	238.39	51.8%	123.45b	$15,290

Factor 2: Time Necessary for Compliance

Graymont has indicated that any controls which are identified as part of the analysis, could be implemented by 2028 but believes the base case of inherent scrubbing is providing reasonable SO_2 control.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

The cost of energy required to operate the control devices has been included in the cost analyses. To operate any of the add-on control devices, there would be decreased overall plant efficiency due to the operation of these add-on controls. At a minimum, this would require increased electrical usage by the plant with an associated increase in indirect (secondary) emissions from nearby power stations.

Most of the alternative SO_2 control options that have been considered in this analysis also have additional non-air quality impacts associated with them. A semi-wet/dry hydrated lime control system, for example, will require water to hydrate lime. There will also be additional material collected in the baghouses that will require disposal concerns for water scarcity is a significant concern. This is especially true when weighing the benefits of a wet vs. a semi-wet or dry control technology, as wet scrubbing requires a significant quantity of water. In addition, environmental concerns associated with sludge disposal and visible plumes are distinct possibilities.

Factor 4: Remaining Useful Life

The remaining useful life of the kilns is expected to be at least 20 years.

Step 5: Select Reasonable Progress Control/Final State Recommendations:

SO2

The lime production process inherently removes the majority of SO_2 that is created from the process. This inherent control measure was BACT for these kilns when they were originally constructed. Inherent scrubbing can still be an effective control mechanism to remove the majority of SO_2.

Montana concurs with the Graymont prepared and submitted four-factor analysis that costs for the technologies evaluated for SO_2 reductions are considered high for this planning period. No additional SO_2 control is required for the second planning period. SO_2 emissions remain significant at nearly 238 tpy, and future planning periods will continue to focus on whether the estimated costs are low enough to justify new controls.

NOx Evaluation

Step 1 – Identify All Available Technologies

NOx is produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. Thermal NOx emissions are produced when elemental nitrogen in the combustion air is oxidized in a high temperature zone. Fuel NOx emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

Most of the NOx formed within a rotary lime kiln is classified as thermal NOx. Virtually all the thermal NOx is formed in the region of the flame at the highest temperatures, approximately 3,000 to 3,600 °F. A small portion of NOx is formed from nitrogen in the fuel that is liberated and reacts with the oxygen in the combustion air. The following NOx control technologies were identified for the Graymont kilns; those using combustion controls and those using post-combustion control.

- Reduce Peak Flame Zone Temperature
- Low NOx Burners
- Kiln Operation Preheater Kiln Design
- Selective Catalytic Reduction
- Selective Non-Catalytic Reduction

<u>Reduce Peak Flame Zone Temperature</u>

These are methods of reducing the temperature of combustion products in order to inhibit the formation of thermal NOx. They include (1) using fuel rich mixtures to limit the amount of oxygen available; (2) using fuel lean mixtures to limit amount of energy input; (3) injecting cooled, oxygen depleted flue gas into the combustion air; and (4) injecting water or steam.

<u>Low NOx Burners</u>

<u>Preheater Kiln Design/ Proper Combustion Practices</u>

The use of staged combustion and preheating alone can lead to effective reduction of NOx emissions. By allowing for initial combustion in a fuel-rich, oxygen-depleted zone, necessary temperatures can be achieved without concern for the oxidation of nitrogen. This initial combustion is then followed by a secondary combustion zone that burns at a lower temperature, allowing for the addition of additional combustion air without significant formation of NOx.

<u>Selective Catalytic Reduction</u>

As of this report, there are no known instances of SCRs installed on lime kilns.

<u>Selective Non-Catalytic Reduction</u>

In cement kilns SNCR can be applied as a post combustion technology or in a certain combustion zone of kilns to facilitate SNCR (mid-kiln SNCR). The lime industry has a severely limited track record in determining the feasibility or control level that could be attained if mid-kiln SNCR were attempted on the Indian Creek kilns. The aforementioned technical barriers to SNCR implementation have limited the technology's use in the industry, with temperature, residence time, and lower NOx concentrations distinguishing lime production from the cement production process. A search of the RBLC database indicates that there is only one instance of a lime kiln that was permitted with SNCR as control for NOx emissions. The permit documents indicate that after conducting a trial with the SNCR, a lower limit would be established that considers the control of NOx emissions achieved by the SNCR. Updated permit files have not included a reduced permit limit, and there is no publicly available evidence of the trial results. Based on the record, the SNCR installation and reduction for this RBLC search result has not been demonstrated. Additionally, for the one instance of known SNCR installation on a different lime kiln (which does not appear in RBLC results), very limited information is available on the details of this kiln necessary for Graymont to evaluate whether the application of SNCR in that instance could be implemented at Indian Creek. Therefore, there is not enough information to conclude that SNCR has been demonstrated as a successful control option for NOx emissions from lime kilns.

Step 2: Eliminate Technically Infeasible Options

<u>Reduce Peak Flame Zone Temperature</u>

In a lime kiln, product quality is co-dependent on temperature and atmospheric conditions within the system. Although low temperatures inhibit NOx formation, they also can inhibit the calcination of limestone. For this reason, methods to reduce the peak flame zone temperature in a lime kiln burner are considered concern for lime quality and therefore are eliminated.

<u>Low NOx Burners</u>

The facility currently operates Pillard low NOx burners in the lime kilns. Coal and coke are delivered to the burners using a direct fired system. However, to limit NOx, only enough primary air is used to sweep coal and coke out of the mill. This is similar to using an indirect fired system, which also limits primary air to the burners while delivering fuels. Baseline emissions are based on the operation of these low NOx burners. All alternative methods of NOx control in this analysis will assume that the kilns continue to operate these burners.

<u>Preheater Kiln Design/Proper Combustion Practices</u>

Proper combustion practices and preheater kiln design are considered technically feasible for Graymont and will be considered further.

<u>SCR</u>

Efficient operation of the SCR process requires fairly constant exhaust temperatures. Fluctuations in exhaust gas temperatures reduces removal efficiency. If the temperature is too low, ammonia slip occurs. If the temperature is too high, oxidation of the NH_3 to NO can occur. Also, to achieve higher removal efficiencies, some excess of NH_3 is necessary, thereby resulting in some ammonia slip. Other emissions possibly affected by SCR include increased PM emissions (as ammonia salts result from the reduction of NOx and are emitted in a detached plume) and increased SO_3 emissions (from oxidation of SO_2 on the catalyst).

To reduce fouling the catalyst bed with the PM in the exhaust stream, an SCR unit can be located downstream of the particulate matter control device (PMCD). However, due to the low exhaust gas temperature exiting the PMCD (approximately 350°F), a heat exchanger system would be required to reheat the exhaust stream to the desired reaction temperature range of between 480°F to 800°F. The source of heat for the heat exchanger would be the combustion of fuel, with combustion products that would enter the process gas stream and generate additional NOx. Therefore, in addition to storage and handling equipment for the ammonia, the required equipment for the SCR system will include a catalytic reactor, heat exchanger and potentially additional NOx control equipment for the emissions associated with the heat exchanger fuel combustion.

High dust and semi-dust SCR technologies are still highly experimental. A high dust SCR would be installed prior to the dust collectors, where the kiln exhaust temperature is closer to the optimal operating range for an SCR. It requires a larger volume of catalyst than a tail pipe unit, and a mechanism for periodic cleaning of catalyst. A high dust SCR also uses more energy than a tail pipe system due to catalyst cleaning and pressure losses.

A semi-dust system is similar to a high dust system. However, the SCR is placed downstream of an ESP or cyclone. The main concern with high dust or semi-dust SCR is the potential for dust buildup on the catalyst, which can be influenced by site specific raw material characteristics present in the facility's quarry, such as trace contaminants that may produce a stickier particulate than is experienced at sites where the technology is being demonstrated. This buildup could reduce the effectiveness of the SCR technology, and make cleaning of the catalyst difficult, resulting in kiln downtime and significant costs.

No lime kiln in the United States is using any of these SCR technologies. For the technical issues noted above, post combustion, high dust and semi-dust SCR's are considered technically infeasible at this time.

SNCR

Based on the temperature profile, there are three locations in a rotary preheater lime kiln system where the ammonia /urea injection could theoretically occur: the stone/preheater chamber, the transfer chute, or after the PMCD. A fourth location that will be considered in this analysis is the kiln tube. In order for SNCR to be technically feasible, at least one of these locations must meet the following criteria: placement of injector to ensure adequate mixing of the ammonia or urea with the combustion gases, residence time of the ammonia with the combustion gases, and temperature profile for ammonia injection.

- SNCR Ammonia/Urea Injection Location - Stone Chamber/Preheater

  The required temperature range for the reaction may occur within the preheater. However, the location of the temperature zone varies with time and location as explained below.

  In each Graymont Indian Creek preheater, mechanical rams operate in sequence, transferring limestone, one ram at a time, from the stone chambers into the transfer chute. When a ram is in the "in" position, very little exhaust gas flows through the stone and out the duct. When the ram pulls out, the cold stone drops down and fills the stone heating chamber. The angle of repose of the stone and the configuration of the duct and chamber are such that stone does not continue to fall into the transfer chute. Hot gases, at approximately 1,950°F, then pass through the stone chamber filled with cold stone. The first gas to pass through the chamber exits the chimney at approximately 400°F. As the cold stone heats up, the exit gas temperature increases and reaches a high of approximately 600°F. This fluctuation would likely amount to poor control of NOx and ammonia slip.

- SNCR Ammonia/Urea Injection Location – Transfer Chute

  The temperature in the transfer chute is approximately 1,950°F for typical kilns. These temperatures are in the upper range for the NOx reduction reaction. Temperatures this high reportedly resulted in approximately 30 percent NOx reduction in low dust exhaust streams. Lime kilns do not have clean exhaust streams at this location. Rather, the back end of the transfer chute is an extremely dusty environment, and therefore the exhaust stream is dust-laden. The one SNCR installation in the lime industry has achieved control efficiencies of around 50% with the injection nozzles installed in the bottom of the preheater, at the preheater cone. While this technology is certainly promising, this one example of SNCR installation on a rotary lime kiln does not necessarily transfer to other lime kilns.

Effectiveness of SNCR is highly site-dependent, with a variety of factors having the potential to heavily influence the quantities of NOx controlled. Until such time as more information is available that demonstrate successful operation of SNCR systems on rotary lime kilns, this location is also infeasible.

- SNCR Ammonia/Urea Injection Location - Inside Rotary Kiln

  Ammonia/urea could be injected through a door or port in the kiln shell. Similar to the transfer chute, stone is traveling down the rotary kiln. Consequently, the nozzle would need to be positioned out of the direct path of the flow of the stones. Theoretically, the temperature inside a rotary lime kiln, which is above 2,200 F, would promote the formation of NO from injected ammonia.

  Graymont stated that they were aware that there have been trials at competing lime facilities with mid-kiln ammonia injection and transfer chute ammonia/urea injection for NOx reduction. However, the technology costs and technical details have not become publicly available, so evaluating this further is considered infeasible at this time.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Graymont determined in their four-factor analysis that low NOx burners were feasible. Graymont identified that they currently are using low NOx burners. Graymont also stated they believe SCR and SNCR are not commercially available, although Graymont did provide a cost estimate for SNCR to demonstrate the magnitude of what those costs might be. Montana has not included that analysis within this section (Confidential Business Information Excluded). Future additional technology advancements and further system demonstrations of successful SNCR operations may require further evaluations for the Graymont kilns.

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance[127]

As indicated above, the Graymont four-factor analysis indicates that all options except low NOx burner technology have been eliminated. However, Graymont did bring forward an SNCR cost estimate. That number indicates a cost effectiveness of approximately $13,000 per ton of NOx removed. Even if the technology further develops, and at double the NOx removal rate which was estimated, the cost effectiveness would still be considered moderate. See the Graymont four-factor analysis for further details.

Factor 2: Time Necessary for Compliance

If controls were determined to be necessary, Graymont believes they could be installed by 2028.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

[127] Graymont commissioned a Class 4 engineering cost estimate for SNCR and submitted that information to Montana on March 21, 2022. The updated information can be found in Appendix H, Section 10.

Graymont brought forward a number of other impacts including additional energy usage and concerns for ammonia slip.

Factor 4: Remaining Useful Life

The Graymont kilns are believed to have at least 20 years of remaining useful life.

NOx

Step 5: Select Reasonable Progress Control/Final State Recommendations:

Montana determined that the technologies evaluated for NOx reductions are not adequately demonstrated for rotary lime kilns for SCR and SNCR, and that low NOx burners (currently in operation) are reasonable controls for this planning period. SNCR will be further evaluated in future planning periods if documentation demonstrates that SNCR becomes more widely used. No additional NOx control are reasonable in the second planning period.

6.2.15 Montana Sulfur & Chemical Co.[128]

Montana Sulfur and Chemical Co (MSCC) submitted their four-factor analysis (in conjunction with Bison Engineering Inc) and supporting information on September 30, 2019. MSCC is located in Billings, Montana, and operates in conjunction with ExxonMobil Fuels & Lubricants Co - ExxonMobil Billings Refinery to process sulfur-containing gases. Because the ExxonMobil Billings Refinery does not have a sulfur recovery unit within the refinery, refinery gases high in hydrogen sulfide (H_2S) are piped to MSCC. MSCC extracts sulfur from the sour refinery fuel gas (RFG) and returns sweetened fuel gas to the ExxonMobil Billings Refinery.

This analysis is limited to emissions from the Claus/SuperClaus unit(s) and main stack at the facility since these units are responsible for 99+% of the total sulfur dioxide emissions from the plant. An NOx four-factor analysis was not requested since the MSCC NOx emissions are extremely low.

The existing SRU unit at MSCC controls SO_2 emissions via two steps. The first is a 3-stage Claus process. (On occasion, the unit is operated in a 2-stage fashion, allowing for necessary maintenance). This process converts hydrogen sulfide (H_2S) and SO_2 into elemental sulfur (S) via the 'Claus' reaction. The general reaction is:

$$H_2S + SO_2 \leftrightarrow S + H_2O \text{ (unbalanced).}$$

To achieve additional reduction, the Claus process is followed up by the addition of the "SuperClaus®" technology. This technology uses selective oxidation catalysts to oxidize residual H_2S to elemental sulfur using air. The first SuperClaus unit was installed in 1998. A second (parallel) SuperClaus unit was installed in 2007/2008 as a redundant system to improve system reliability and continue reducing emissions during periods of maintenance on one of the units.

[128] Montana Sulphur & Chemical Co., Regional Haze 4-Factor Analysis, (30 September 2019), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/Planning/PDF/4-Factor_MSCC_2019Report.pdf

Generally, the units collectively control SO_2 emissions by about 97-98% of input sulfur gases. The efficiency was recorded at 98.4% for the baseline period (2017-2018).

MSCC RepBase and 2028 OTB/OTW Scenarios

MSCC selected the 2017-2018 two-year average emissions as representative of a baseline emissions and Montana concurred this two-year period was reflective of recent normal operation.

MSCC also selected a future year 2028 8OTB/OTW scenario that was used to calculate the cost per ton of emission reduction achieved from applying controls. MSCC chose to use the 2017-2018 representative baseline for the 2028 OTB/OTW scenario.

Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 6-29. MSCC RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2017-2018	5.8	1013.5	5.8	1013.5

Step 1 – Identify All Available Technologies

The most common control measures that may be applied to a typical Claus facility are generally categorized as Tail-Gas Scrubbing Treatment units (TGST). These units use either an oxidation or a reduction measure to continue to convert some of the underlying sulfur gases exiting the Claus systems to additional elemental sulfur. Another common measure of removing sulfur dioxide from some gas streams is a traditional FGD unit which is more typically used at coal or oil-fired electrical generating units. However, this is not generally applied to Claus systems in the US.

Oxidation – Reduction Techniques

The TGST control typically adds an additional scrubbing process to the Claus exhaust stream prior to the tail-gas incinerator. The processes classically convert the Claus exhaust to either H_2S (reducing process) or SO_2 (oxidizing process). In most cases, the 'newly created' H_2S or SO_2 is then captured, concentrated and returned to the Claus portion of the facility to extend the elemental sulfur recovery. Alternatively, an oxidizing process selectively converts low-concentration hydrogen sulfide residue from the Claus system directly to elemental sulfur (e.g. SuperClaus).

There are several processes that either achieve oxidations or reductions. Regarding the oxidation method, the exhaust stream from the Claus or SuperClaus® would be treated to oxidize the various residual reduced sulfur compounds to sulfur dioxide (similar to the plant's incinerators). The sulfur dioxide is then captured, concentrated and recycled back to the Claus process itself. There are several varieties of processes within the oxidation method. They include the Stauffer, Wellman- Lord, and Aquaclaus. Only the Wellman-Lord process has been applied successfully in any US refinery.

The reduction process is the more typical refinery-based method of additional sulfur dioxide control. This process catalytically converts the sulfur-containing gases from the Claus back to H_2S. The H_2S-containing gas is then sent to a scrubber for capture prior to routing the remaining gases to a tail-gas incinerator. The

H_2S scrubber typically uses a specialized amine process to selectively capture the H_2S while rejecting carbon dioxide. Then this captured H_2S is regenerated from the specialized amine to produce a suitably concentrated stream and is then sent back to the Claus plant for reprocessing.

Five common systems utilizing the reduction-oxidation control method are the LO- CAT®, Beavon (MDEA), Shell Claus Off Treatment (SCOT), and ARCO. (Additional oxidation-reduction processes for converting H_2S into sulfur include Cold Bed Adsorption (sub dewpoint), Sulferox, Stretford, and Paques biological process.) For the oxidation-reduction processes, LO-CAT®, SCOT and CBA have been among the predominant industry choices. LO-CAT® is a proprietary liquid redox process that converts H_2S in the acid gas to solid elemental sulfur using an aqueous solution of iron as catalyst. LO-CAT® units are in service treating refinery fuel gas, off gas, sour-water- stripper gas, amine acid gas, and Claus tail gas. The SCOT process, however, is the most common in the U.S, and is discussed below.

<u>SCOT</u>

In the Shell Claus Off Treatment (SCOT) process, and numerous variants, tail gas from the SRU is re-heated and mixed with a hydrogen-rich reducing gas stream. Heated oxygen-free tail gas is treated in a catalytic reactor where free sulfur, sulfur dioxide, and reduced sulfur compounds are substantially reconverted to H_2S. The H_2S-rich gas stream is then routed to a cooling/quench system where the gases are cooled, and substantial process water is condensed as sour water. Excess condensed sour water from the quench system is routed to a separate sour water system for further treatment and disposal. The cooled quench system gas effluent is then fed to an absorber section where the acidic gases (H_2S, CO_2), which must be substantially free of SO_2 to prevent damage, comes in contact with a selective amine solution and is absorbed into solution; the amine must selectively reject carbon dioxide gas to avoid problems in the following steps, and must not be exposed to unreduced materials (e.g., unconverted SO_2 or sulfur) or to oxygen that may arise during malfunctions. The rich solution is separately regenerated using steam, cooled. The regenerated amine is cooled and returned to the scrubber/absorber. The cooled H_2S-rich gas released at the regenerator is reprocessed by the SRU.

<u>Cold Bed Adsorption (CBA)</u>

The Cold Bed Adsorption (CBA) process is effectively an extension of the Claus process. The Claus reaction is driven closer to completion by a reduction in temperature over certain catalyst beds/reactors. CBA, of which Sulfreen® is one variant, operates at lower temperatures (260 to 300ºF) to recover tail-gas SO_2 and H_2S as sulfur. Claus plant and very high-quality feeds. AP-42 Chapter 8.13-Sulfur Recovery suggests the upper range is about 99% overall recovery when associated with a modern Claus design and very high-quality stable feeds.

The recovery percentage ranges represent the amount of sulfur removed from the untreated gas stream(s) entering a sulfur recovery facility and not the amount of SO_2 reduction from the existing tail gas stream. The effective reduction to the existing already controlled SO_2 emissions at MSCC would be substantially lower than the theoretically possible overall sulfur recovery rates.

<u>LO-CAT®</u>

The LO-CAT® technology uses a redox process to oxidize H_2S to elemental sulfur. It does so by using an iron based aqueous solution in which the iron acts as a catalyst. An acid gas stream is compressed and fed to an absorber unit where it contacts the dilute, iron chelate catalyst solution and the H_2S is absorbed and then directly oxidized to solid sulfur. Gas leaves the absorber for disposal via a tail gas disposal system. The reduced catalyst solution returns to the oxidizer, where sparged air reoxidizes the catalyst solution. Product water resulting from the reaction must also be removed and treated. The catalyst solution is then returned to the absorber. The presence of SO_2 or other non-H_2S species in the treated gases may make this process impractical. Sulfur is concentrated in the bottom of the oxidizer and sent to a sulfur filter, which produces the solid sulfur filter cake.

A critical concern with this technology for MSCC is the quality of the produced sulfur. Contaminants commonly present in the raw acid gas are not converted to sulfur, may remain with the product sulfur, and may be highly odorous. The catalyst itself also is a source of product contamination. MSCC not only removes sulfur from various streams at the facility, MSCC creates many saleable products. Many of the products require up to 99.9% purity to meet client demands. The LO-CAT® system does not consistently meet this expectation. Therefore, this technology is rejected because it could undermine the fundamental purpose of the facility itself.

After consideration, it was decided to use the SCOT and CBA (Sulfreen®) processes as a reasonable approximation for any and all the oxidation or reduction options discussed above, for economic analysis. MSCC or Bison has, in the past, received some cost estimates information from some designers as well as other information helpful to the process. In addition, the removal efficiency potentials for these two processes are relatively similar. Should either the SCOT or CBA technologies (as a representative of oxidation or reduction option) indicate a low dollar/ton cost effectiveness, then a more detailed review may be appropriate. That review could or would extend to other processes previously mentioned.

<u>Flue Gas Desulfurization Techniques</u>

The second class of sulfur dioxide scrubbing for consideration is the Flue Gas Desulfurization (FGD) unit. As noted earlier, this is the typical sulfur dioxide control system found in most coal and oil-fired electrical generation systems across the U.S. The FGD unit may be configured as a wet, semi-dry, or dry scrubber system. In all cases an alkaline compound (typically $CaCO_3$ or CaO) is used to react with SO_2 (an acidic gas) to form a compound such as CaSO3. The $CaSO_3$ (and its related compounds) are then removed via a particulate control device such as a baghouse.

Step 2: Eliminate Technically Infeasible Options

<u>FGD</u>

To operate an FGD system, it is necessary to place a significant amount of (solid) material handling equipment on site. This would also include a large surface area to store, move and otherwise handle the reagent and spent- reagent materials. This equipment and space might typically be available and designed in an FGD installation such as a new coal-fired electrical generation station which also handles bulk solid materials (coal, e.g.) on routine basis. For this facility, however, none of the required space for solids handling and storage equipment is readily available. There is simply not enough space in MSCC's very narrow footprint to accommodate a significant redesign of the facility in both layout and surface disturbance.

Thus, to install and operate an FGD for this facility, not only is an FGD itself necessary, but a complete particulate removal system will be required as well (typically a fabric filter). Thus, the FGD will add new particulate emission sources at this facility; offsetting some of the reduction achieved by the sulfur-removing FGD system.

FGD systems are not typically designed to process high concentrations streams of SO_2 or containing H_2S. EPA suggests that inlet loading of SO_2 is limited to streams with less than 2,000 ppm[129]. Emissions monitoring data reported to DEQ typically show an average SO_2 concentration between 2,000 and 3,000 ppm, with excursions to higher levels. Thus, Montana concluded this technology is not feasible for use at MSCC.

Any FGD system, regardless of the type, will require disposal of the spent reagent. Since space is limited at this site, the disposal needs to take place at a "new" offsite landfill, able and willing to accept the effluent. Thus, in addition to the cost necessary for the FGD, a suitable landfill site would need to be identified and a permit would need to be obtained. There is, in addition, no available land at MSCC's small site. This would be a significant undertaking and not especially productive given other non-FGD processes are available producing lower levels of solid waste.

As discussed above, for wet scrubber FGD, or any so-called 'dry' or semi-dry system involving quench of the hot-incoming Claus off gases, a complete water system, including disposal off-site, would be required. The water content of Claus off gas is necessarily very high compared to coal firing. This corrosive water system and off-site disposal is deemed unnecessary given other alternatives and the potential environmental consequences.

MSCC indicated that, according to their knowledge, no FGD system has been installed at any acid gas processing facility in the US similar to the MSCC plant. This fact makes it clear that an FGD system is not a viable option for consideration. For all the reasons above, it was decided to not pursue the FGD option further in this study and it was dropped from analyses that follow.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Table 6-30. MSCC SO_2 Control Efficiencies

Source	Potential Control Option	Estimated Control Efficiency (%)	Potential Emission Reduction (tons/year)
100 Meter Stack (Sulfur Recovery Unit)	SCOT	99.3	570
	CBA (Sulfreen®)	99.1	443

Step 4: Evaluate Impacts and Document Results

<u>Factor 1: Cost of Compliance</u>

[129] EPA's Air Pollution Control Technology Fact Sheet, FGD, EPA-452/F-03-034

Table 6-31. MSCC SO_2 Cost of Compliance

Source	Potential Control Option	Potential Emission Reduction (tons/year)	Estimated Capital Cost ($1000)	Estimated Annual Cost including Capital Recovery ($1000/year)	Cost Effectiveness ($/ton)
100 Meter Stack (Sulfur Recovery Unit)	SCOT	570	103,655	15,895	$27,882
	CBA (Sulfreen®)	443	48,963	8,424	$18,999

Factor 2: Time Necessary for Compliance

Montana has concluded that any required controls could be installed by 2028.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

The quench system in the SCOT system produces a sour water waste effluent that requires treatment prior to disposal. This effluent would contain hydrogen sulfide, and may contain sulfur and other troublesome species as well, particularly during upsets. MSCC currently does not have sour water treatment facilities nor access to a public sewer system to accommodate such a waste stream. A permissible solution to this problem would have to be engineered if this system were installed at the facility.

SCOT would also require a few non-fuel consumables of significant cost including: catalyst for the reduction stage, MDEA or proprietary blends of amines, corrosion inhibitors, and water treatment chemicals.

Factor 4: Remaining Useful Life

A brief history of MSCC is critical to a discussion regarding its remaining useful life. As a summary, the facility began construction in 1955, and has operated continuously since 1956. Estimates vary on the typical useful life of SRU equipment; however, it would be typical to expect plants to last about 40 years or more with careful maintenance and operation. The facility has exceeded the typical expectation for useful life, in part due to careful operation, quality maintenance and continual improvements in reliability. No specific additional life of the sulfur recovery plant can be offered. The facility has operated under a succession of essential contracts relating to raw material supply and gas processing. There is no way to assuredly predict if such contracts will continue or will cease. However, for purposes of planning, it would be reasonable to assume that the facility, which remains serviceable, effective and reliable today, would continue to operate at least 15 years into the future.

Step 5: Select Reasonable Progress Control/Final State Recommendations:

Montana determined that the technologies evaluated for SO_2 reductions are not cost effective for the second planning period. MSCC will need to evaluate in future planning periods whether these technologies improve or new technologies become viable. No additional SO_2 control are reasonable for the second planning period.

6.2.16 ExxonMobil Fuels & Lubricants Co – ExxonMobil Billings Refinery[130]

ExxonMobil Billings Refinery (Exxon) submitted their four-factor analysis (in conjunction with Bison Engineering Inc) and supporting information on November 15, 2019. Exxon is located in Billings, Montana, and is one of the four oil refineries in Montana, with three of the four being near Billings, MT. The Exxon Refinery is designed to process a variety of crude slates including those containing high sulfur crude oil. Major process units include: atmospheric and vacuum crude distillation towers, a fluidized catalytic cracking unit (FCCU), a hydrocracker and hydrogen plant, a fluid coker, a naphtha fractionator, a catalytic reformer, an alkylation unit, three hydrotreaters for polishing the naphtha and distillate streams, and a catalytic hydrotreating unit (CHUB). The Exxon Refinery does not have a sulfur recovery unit within the refinery. Refinery gases high in hydrogen sulfide (H_2S) are piped to an off-site sulfur recovery plant owned and operated by the Montana Sulphur and Chemical Company. MSCC extracts sulfur from the sour refinery fuel gas (RFG) and returns sweetened fuel gas to the Billings Refinery. The bulk terminal does not produce SO_2 or NOx emissions and is not considered in this analysis.

The Exxon Refinery encompasses approximately 760 acres, and the location of the main refinery gate is 700 ExxonMobil Road, Billings, Montana. The legal description of the site location is S½ of Section 24 and N½ of Section 25, Township 1 North, Range 26 East, in Yellowstone County, Montana.

As previously discussed in the Source Screening section, Montana screened on a facility basis to determine whether four-factor analyses would be required. However, refineries contain many small emitting units that, in aggregate, contribute to emissions of SO_2 and/or NOx at the facility. Because of this, Montana determined that it was impractical to perform a four-factor analysis on each individual emitting unit. Montana and Exxon agreed on a ranking of the highest emitting units for both NOx and SO_2 that could be evaluated in the four-factor analysis. Doing so provided the information necessary to determine opportunities for emissions reductions at the facility.

The analysis focuses on the following units for NOx: the Coker CO Boiler (KCOB), F-1 Crude Furnace/F-401 Vacuum Heater, and the F-551 Hydrogen Plant. Based on a 2015-2016 emissions baseline, the KCOB, F-1 Crude Furnace/F-401 Vacuum Heater, and F-551 Hydrogen Plant are responsible for approximately 52% of the total NOx emissions at the facility. The F-1 Crude Furnace and F-401 Vacuum Heater are two separate units, but vent to a single stack, so are evaluated as one unit for the purpose of this analysis. To address potential costs and controls associated with the smaller refinery process heaters, this analysis also included the F-201 Hydrofiner Heater as a representative smaller process heater.

For the 2015-2016 baseline summary, 75% of the SO_2 emissions are attributed to the Fluidized Catalytic Cracking Unit (FCCU). At the time Montana was reviewing the submitted four-factor analysis, the Exxon Refinery was engaged in an extended demonstration period on a desulfurization (DeSOx) additive while

[130] ExxonMobil - Billings Refinery, Regional Haze Four-Factor Analysis, (November 2019), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/Planning/PDF/2019.11.15%20Four%20Factor%20Analysis.pdf?ver=2020-02-03-161912-177

operating the FCCU in Full Burn Operation as required under its EPA Refinery Consent Decree for controlling SO_2 emissions from the FCCU. The FCCU SO_2 limit was finalized on June 28, 2021 and incorporated in Exxon Refinery's Operating Permit #OP1564-18[131] and MAQP #1564-35[132]. The limits are 177.3 ppm at 0% O2 on a 365-day rolling average and 300.0 ppm at 0% O2 on a 7-day rolling average.

Since 2012, SO2 emissions from the FCCU have been reduced by almost 4,000 tpy due to the DeSOx additive. The remainder of the SO_2 emissions are attributed to either the KCOB (during YELP downtime, particularly in 2016) or small boilers and heaters subject to NSPS Subpart J or other requirements. No additional control is being considered for these units, given the circumstances of the emissions (for the KCOB) and the existing level of control. Future planning periods may evaluate other emitting units for possible emission reduction opportunities.

Exxon RepBase and 2028 OTB/OTW Scenarios

Exxon selected the two-year average from 2015-2016 as representative of emissions at the refinery. Montana concurred that this two-year period was reflective of recent normal operation.

Exxon also selected a future year 2028 OTB/OTW scenario that was used to calculate the cost per ton of emission reduction achieved if controls were applied.

Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 6-32. Exxon RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2015-2016	427.4	539.4	427.4	539.4

NOx Background

The EPA Refinery Consent Decree, in addition to the significant SO_2 emission reductions for units across the facility, required NOx emissions to be reduced. A NOx Control Plan for heaters and boilers that required NOx controls on at least 30% of the heater and boiler capacity greater than 40 MMBtu/hr was implemented. Additionally, the Consent Decree required SCR to be installed (and associated emission limit) on the FCCU. NOx reductions were evaluated and implemented on units where the investment would provide the most efficient emission reduction value. Exxon has demonstrated progress through the Consent Decree and beyond, to reduce NOx emissions in the recent past.

This NOx analysis focuses on the KCOB, F-1 Crude Furnace/F-401 Vacuum Heater, and F-551 Hydrogen Plant because these four units are responsible for approximately 52% of the NOx emissions from the plant

[131] Operating Permit #OP1564-18, (2 November 2021), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/ARMpermits/OP1564-18.pdf,

[132] Montana Air Quality Permit MAQP #1564-35, (21 September 2021), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/ARMpermits/1564-35.pdf

based on the 2015-2016 emissions baseline. Two other NOx sources have seen recent emissions control upgrades (F-700 heater with ULNB) and replacement (B-8 heater with ULNB and FGR) under the Consent Decree. The F-700 and B-8 heaters result in 3% (13.27 tpy) of the 2015-2016 NOx emissions baseline. Eight other NOx sources (i.e., small refinery fuel gas-fired heaters less than 40 MMBtu/hr) split the remaining 45% of the NOx emissions baseline. As mentioned previously, the F-201 Hydrofiner Heater is included in the analysis to show representative costs and controls for the smaller process heaters units less than 40 MMBtu/hr.

Step 1 – Identify All Available Technologies

There are several ways to control NOx emissions from a boiler or furnace. Some methods utilize combustion modifications that reduce NOx formation in the boiler/furnace itself, while others utilize add-on control devices at various points in the exhaust path to remove NOx after it is formed. Combinations of combustion controls and add-on controls may also be used to reduce NOx. The identified applicable NOx control technologies include:

- Ultra-Low NOx Burners with Flue Gas Recirculation
- SNCR (only applicable for boilers, see explanation below)
- SCR

The NOx basis (the current actual emissions referred to as "uncontrolled emissions" in the EPA cost control spreadsheet) for the KCOB, F-1 Crude Furnace/F-401 Vacuum Heater, F-551 Hydrogen Plant, and F-201 Hydrofiner Heater is 0.191, 0.110, 0.107, 0.115 pound per million British Thermal Unit (lb/MMBtu), respectively. These emissions are derived from the pound per million cubic feet emission factor used in annual reporting converted using actual refinery fuel gas heating values.

<u>ULNB with FGR</u>

Combustion controls are features of the boiler that reduce the formation of NOx at the source. Ultra-Low NOx Burners are a common combustion control, particularly for new boilers, and typically include Flue Gas Recirculation. Because of the intrinsic nature of both controls (often used in conjunction), they are generally installed in new boilers. While retrofits have occurred (and did, in specific instances during the EPA Refinery Consent Decree NOx reductions), they generally occurred on smaller, newer, low burner count units. (Note: the B-8 Boiler was a full replacement with UNLB and FGR).

Based on corporate and unit specific information, F-1 Crude Furnace/F-401 Vacuum Heater would not be candidates for ULNB/FGR because of the age of the furnaces. If such an upgrade were required, the furnaces would be replaced, at an estimated cost of $10-$20 million per boiler (F-1 at the higher end, F-401 at the lower end). The F-551 Hydrogen Plant would also not be a candidate for UNLB/FGR because of the high number of burners (80). Replacement of 80 burners would essentially require a rebuild of the furnace. Retrofitting the KCOB or the F-201 Hydrofiner Heater with UNLB/FGR is a potential option, however cost data is generally unavailable.

For the F-201 Hydrofiner Heater and KCOB, the Billings Refinery provided an estimate of UNLB retrofit installation based on actual average costs incurred for similar refinery units in the ExxonMobil fleet. Incorporation of FGR is not included in the estimate because it would require a boiler reconfiguration (and potentially reconstruction).

SNCR

The viability of SNCR is directly related to combustion temperature (typically between 1,550°F and 1,950°F); therefore, the application of this technology to furnaces/heaters is not technically feasible, as they operate at much lower temperatures (600-700°F). SNCR was analyzed only for the KCOB, and not for the F-1 Crude Furnace/F-401 Vacuum Heater, the F-551 Hydrogen Plant or the F-201 Hydrofiner Heater.

The median reductions for urea based SNCR systems in various industry source categories range from 25 to 60 percent. Additional industry-specific unit information included in the SNCR White Paper[133] provided boiler size and associated NOx reductions; particularly in the "Refinery Process Units and Industrial Boiler" section, for units less than 200 MMBtu/hr (the KCOB is rated at 146 MMBtu/hr). The 200 MMBtu/hr was used as a logical cut-off for smaller industrial boilers, with ranges estimated between 40 and 62.5 percent NOx reduction. An average reduction of 58.5 percent was used in the cost efficiency calculations, for a resulting/predicted exit NOx emission factor of 0.079 lb/MMBtu at the KCOB.

The costs provided for SNCR in the four-factor analysis were calculated using EPA's SNCR Cost Calculation Spreadsheet and use the "retrofit factor" of 1 – average retrofit. The Spreadsheet states that its use is particularly for boilers (coal-, oil-, and natural gas-fired) with maximum heat capacities greater than or equal to 250 MMBtu/hr. The KCOB has additional difficulty with respect to boiler ductwork, etc. because of its direct proximity to the coker unit and shared piping/ductwork with that unit. Based on the boiler size, the less-common refinery-fuel gas, the potential for higher retrofit costs, the involvement with the coker unit, and the economies of scale described above, the Billings Refinery believes that the costs calculated are highly conservative (i.e., costs are estimated low). EPA's estimates compared to actual costs incurred for similar refinery units in the ExxonMobil fleet are quite low and do not consider the significant and unique complexities associated with retrofitting refinery units.

SCR

The controlled SCR emissions rates used in the analysis were based on a 95% control efficiency.

Because ammonia is most commonly used (and is the default for the EPA's SCR Cost Calculation Spreadsheet), it was used in the reagent calculations for the KCOB, F-1 Crude Furnace/F-401 Vacuum Heater, F-551 Hydrogen Plant, and the F-201 Hydrofiner Heater.

As previously discussed for SNCR, there is an efficiency of scale associated with pollution control equipment installation. Because the cost calculator is based on units with a heat capacity greater than 250 MMBtu/hr (and only one unit, the combined F-1 Crude Furnace/F-401 Vacuum Heater is in that size range at 280 MMBtu/hr), those efficiencies are included in the EPA spreadsheet estimates. The costs provided for SCR in the four-factor analysis that follows are calculated using EPA's SCR Cost Calculation Spreadsheet also use the "retrofit factor" of 1 – average retrofit. Based on the boiler size, the less-common refinery-fuel gas, the potential for higher retrofit costs, and the economies of scale described above, the Billings Refinery believes that the costs calculated for SCR are also highly conservative (i.e., costs are estimated low). EPA's

[133] Institute of Clean Air Companies (ICAC), Selective Non-Catalytic Reduction (SNCR) for controlling NOx Emissions; White Paper. Prepared by the SNCR Committee of ICAC. (February 2008), Available at: https://cdn.ymaws.com/icac.siteym.com/resource/resmgr/Standards_WhitePapers/SNCR_Whitepaper_Final.pdf

estimates compared to actual costs incurred for similar refinery units in the ExxonMobil fleet are quite low and do not take into account the significant and unique complexities associated with retrofitting refinery units.

Step 2: Eliminate Technically Infeasible Options

None of the options presented were deemed technically infeasible.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The control effectiveness for the reviewed technologies ranged from approximately 60 percent for SNCR up to 95 percent for SCR. The control efficiencies are shown in Table x.x

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

Costs were expressed in terms of cost-effectiveness in a standardized unit of dollars per ton of actual emissions reduced by the proposed control option. Baseline emissions for the KCOB, F-1 Crude Furnace/F-401 Vacuum Heater, F-551 Hydrogen Plant, and the F-201 Hydrofiner Heater were taken from the baseline 2015 and 2016 annual emission inventory years it relates to this planning period.

The capital recovery factor was applied to the control options based on a 20-year equipment life expectancy and applying the 5.5% as the interest rate. The Exxon cost effectiveness estimates are based on similar unit upgrades (or averages of similar unit upgrades, with allowances for unique Billings space or needs) elsewhere in the ExxonMobil refinery fleet. Specific retrofit costs would require a detailed engineering analysis of the actual site (for space considerations), unit, and process considerations.

Table 6-33. Estimated Costs of NOx Control Options for the Billings Refinery, ranked by Control Efficiency

Source	Potential Control Option	Estimated Control Efficiency (%)	Potential Emission Reduction (tons/year)	EPA Total Annual Cost (in 2018 dollars)[a]	Cost Effectiveness ($/ton) based on EPA spreadsheet/ retrofit factor[a]	Estimated ExxonMobil Retrofit Factor[e]	Anticipated Actual Cost Effectiveness ($/ton) [b]
KCOB (146 MMBtu/hr, refinery fuel gas fired)	SNCR	58.5	30	$231,203	$7,698	--	--
	UNLB	~85	62	--[d]	--[d]	--	$5,800[c]
	SCR	95	67	$438,842	$6,564	3.7	$24,300
F-1/F-401 (280 MMBtu/hr, refinery fuel gas fired, total)	SCR	95	79	$687,812	$8,732	3.7	$32,300
F-551 (160 MMBtu/hr, refinery fuel gas fired)	SCR	95	51	$474,103	$9,290	3.7	$34,400
F-201(36 MMBtu/hr, refinery fuel gas fired)	UNLB	~78	~7	--[d]	--[d]	--	$31,100[c]

Source	Potential Control Option	Estimated Control Efficiency (%)	Potential Emission Reduction (tons/year)	EPA Total Annual Cost (in 2018 dollars)[a]	Cost Effectiveness ($/ton) based on EPA spreadsheet/ retrofit factor[a]	Estimated ExxonMobil Retrofit Factor[e]	Anticipated Actual Cost Effectiveness ($/ton) [b]
	SCR	95	~9	$169,512	$18,919	3.7	$70,000

a. Based on EPA Cost Control Spreadsheets 2019.
b. Based on ExxonMobil corporate project information.
c. The UNLB cost assumes no major physical changes to boiler or boiler configuration (e.g., due to spacing of burners). d. As discussed in Section 5.2.1, EPA does not have ULNB costs in its cost control manual at this time.
e. ExxonMobil retrofit factors ranged from approximately 3.7 to 10.

Factor 2: Time Necessary for Compliance

Exxon relies on the consistent operation of the units which were evaluated for the four-factor analysis. Therefore, any major retrofits or maintenance on major refinery units are scheduled during periodic maintenance turnarounds. Any major control installation at affected units would have to wait until either the estimated 2026 Hydrogen Plant/Hydrocracker turnaround (affecting the F-551 Heater) or the estimated 2025 FCCU/Alkylation Unit turnaround. The retrofit of smaller process heaters (such as the F-201 Hydrofiner Heater) may allow for implementation outside of major turnarounds, but such efforts would require a similar level of planning as the major units because of the interdependence of refinery systems.

EPA does not provide a specific time necessary for compliance basis for replacement of existing burners/boiler configurations with ULNB/FGR. Exxon estimated SNCR would require approximately 3-5 years for design, permitting, financing, etc. through commissioning.

For SCR, EPA states in its Control Cost Manual, "In retrofit installations, new ductwork is required to integrate the SCR system with the existing equipment."[134] Because the KCOB, F-1 Crude Furnace/F-401 Vacuum Heater, F-551, F-201 Hydrofiner Heater are primarily refinery fuel gas-fired units and have negligible particulate emissions, consideration of high-dust SCRs would not be necessary, and the focus would be on either low-dust or tail-end installations (tail-end refers to following all pollution control devices; for the units in question, the options would be essentially the same). Exxon estimated SCR would require approximately 3-5 years months for design, permitting, financing, etc. through commissioning. If PSD permitting is triggered on the basis of formation of condensable particulate matter from the SCR, the timeline would be extended beyond that estimate.

[134] EPA Cost Control Manual (Seventh Edition), Section 4 – NOx Controls, Chapter 2 – Selective Catalytic Reduction (updated on June 12, 2019). Available at: https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

In general, the use of combustion controls for reducing NOx formation can in turn cause an increase in CO emissions.

SCR and SNCR both can result in ammonia slip. Ammonia slip causes the formation of additional condensable particulate matter such as ammonium sulfate, $(NH_4)_2SO_4$. The ammonium sulfate can corrode downstream exhaust handling equipment, as well as increase the opacity or visibility of the exhaust plume. In addition, SCR would require disposal or recycling of catalyst materials, which may require handling in a specific landfill for hazardous waste.

Factor 4: Remaining Useful Life

None of the units considered (KCOB, F-1 Crude Furnace/F-401 Vacuum Heater, F-551, or F-201 Hydrofiner Heater) are planned for retirement at this time. Therefore, the remaining useful life of the sources is assumed to be 20 years.

Step 5: Select Reasonable Progress Control

SO_2

Montana has determined that the SO_2 limit (177.3 ppm at 0% O2 on a 365-day rolling average and 300.0 ppm at 0% O2 on a 7-day rolling average) incorporated in Exxon Refinery's Operating Permit #OP1564-18[135] and MAQP #1564-35[136] will result in significant reductions of SO_2 at the FCCU in this planning period. Therefore, additional controls are not considered reasonable in this planning period.

NOx

Montana determined that that the NOx reduction technologies analyzed, with cost effectiveness ranging from $5800-$70,000, are cost prohibitive at this time. Therefore, additional NOx control is not reasonable for the second planning period.

6.2.17 Cenex Harvest States Cooperative Inc. – CHS Inc. Refinery Laurel[137]

Cenex Harvest States Cooperative Inc. (CHS) submitted their four-factor analysis (in conjunction with RTP Consultants) and supporting information on September 30, 2019. CHS is located in Laurel, Montana, and is one of the four oil refineries in Montana, with three of the four being near Billings, MT, including CHS. Oil refineries represent very complex processes and while all the oil refineries are considered "major" sources, Montana also classifies them as "complex" in terms of managing compliance activities for these sources.

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[135] Operating Permit #OP1564-18, (2 November 2021), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/ARMpermits/OP1564-18.pdf,

[136] Montana Air Quality Permit MAQP #1564-35, (21 September 2021), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/ARMpermits/1564-35.pdf

[137] CHS Inc. – Laurel Refinery, Requested Regional Haze Four-Factor for MDEQ Identified Emissions Units, (September 2019), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/Planning/PDF/1821_2019_09_30_CHS.pdf?ver=2020-02-04-143838-103

As previously discussed in the Source Screening section, Montana screened on a facility basis to determine whether four-factor analyses would be required. However, refineries contain many small emitting units that, in aggregate, contribute to emissions of SO_2 and/or NOx at the facility. Because of this, Montana determined that it was impractical to perform a four-factor analysis on each individual emitting unit. Montana and CHS agreed on a ranking of the highest emitting units for both NOx and SO_2 that could be evaluated in the four-factor analysis. Doing so provided the information necessary to determine opportunities for emissions reductions at the facility.

This analysis focuses on the following subset of emitting units at CHS: Main Crude Heater (NOx), the Platformer Heater (NOx), Boiler #9 (NOx) and the Main Refinery Flare (SO_2). Future planning periods may evaluate other emitting units; however, evaluating the highest existing emitting units provides a reasonable approach to identifying possible emission reduction opportunities in this planning period.

CHS RepBase and 2028 OTB/OTW Scenarios

CHS selected the two-year average from 2017-2018 as representative of baseline emissions. Montana concurred that this two-year period was reflective of recent normal operation. CHS also selected a future year 2028 OTB/OTW scenario that was used to calculate the cost per ton of emission reduction achieved from applying controls.

The specific updates to emitting units that were adjusted to determine the 2028 OTB/OTW scenario and reasoning are as noted:

- Platformer Recycle Compressor: The natural gas fired driver for this compressor was replaced with an electric motor during 2018. This resulted in a reduction in NOx emissions from the 2017-2018 baseline.
- #2 Crude Unit Vacuum Heater: This refinery fuel gas (RFG) fired process heater is nearing the end of its serviceable life. It will be replaced prior to 2028 with a heater that includes ultra-low NOx burners. This will result in a reduction in actual NOx emissions from the 2017-2018 baseline (*The unit was replaced in October 2021, during Montana's formal FLM consultation period and noted here for accuracy).*
- Stationary Emergency Engines: Emissions from stationary emergency engines were first added to the refinery emissions inventory in 2018. A small increase in actual NOx emissions from the 2017-2018 baseline will result because they were not reported in 2017.
- Main Refinery Flare: It is conservatively estimated that SO_2 emissions from the main refinery flare will decrease by 20% from the 2017-2018 baseline by 2028 as a result of ongoing air pollution control programs, including optimization and increased utilization of the FGRS and the ongoing work practices required by applicable regulations

Representative baseline and 2028 OTB/OTW emissions for the facility are as follows:

Table 6-34. CHS RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2017-2018	408.6	251.2	393.0	215.0

To further refine the analysis, the actual base emissions for the four units were evaluated for either NOx or SO_2 reductions. The baseline emissions for the units analyzed are as follows:

Table 6-35. CHS Baseline Emissions by Emitting Unit

Source	Pollutant	2017-2018 Baseline, TPY
Main Crude Heater	NOx	43.6
Platformer Heater	NOx	91.4
#9 Boiler	NOx	29.3
Main Refinery Flare	SO_2	181.6

SO_2 Evaluation

Step 1 – Identify All Available Technologies

The Main Refinery Flare receives flow from two separate flare headers (i.e., the primary and non-recoverable headers) that are designed to safely accumulate and transfer gases from the refinery processes to the flare for combustion. In addition to hard-piped connections that support normal process operating conditions, the flare gas headers also have connections that support equipment depressurization and purging for maintenance activities, such as startups, shutdowns, and maintenance turnarounds.

The primary flare header delivers vent gas from the process units to either the flare gas recovery system (FGRS) or to the flare stack. Under normal refinery operations, the FGRS is used to direct recovered flare gases to an amine unit for removal of H_2S prior to use in the refinery fuel gas (RFG) system. Although the intent is to maximize the amount of flare gas recovered, certain maintenance activities (e.g. steaming, pressure testing, and nitrogen purging equipment to the flare to ensure safe working conditions) may require bypassing the FGRS to avoid upsetting the RFG system. The FGRS is also bypassed during events when the volume of vent gas that is relieved into the flare header system exceeds the capacity of the FGRS. Such events include emergency releases, process upsets, or unit startups/shutdowns. During an event, the pressure of the gases in the flare header exceeds the back-pressure exerted on the header by a liquid seal and the gases bypass the seal to the flare where they are combusted. The frequency and duration of these activities and events are highly variable and may last for several hours to several days or weeks depending on the specific situation.

The non-recoverable flare header is used to transfer hydrogen-rich gases and excess RFG to the flare. The hydrogen-rich streams are considered non-recoverable due to their low net heating value (i.e., Btu/set), which has the potential to cause an upset in the RFG system. The sulfur content of the vent gases in the non-recoverable flare header is minimal. As a result, the amount of SO_2 resulting from the combustion of non-recoverable gases is small.

Collectively, all the equipment that is connected to the FGRS and main flare make up the "system" where SO_2 emissions can be reduced through additional equipment, improved operating procedures and overall better process control.

A review of precedents and requirements for flares in the RBLC database, permits, EPA/DOJ consent decrees, and regulations identified flare gas recovery and work practices as potential SO_2 control measures. Work practices identified include the following:

- Flare management plans
- Waste gas minimization plans
- Root cause/corrective action programs
- Flare monitoring requirements
- Proper equipment design
- Proper maintenance practices

Step 2: Eliminate Technically Infeasible Options

All the identified control measures are considered to be technically feasible for control of SO_2 from the Main Refinery Flare. The FGRS has been in operation on the Main Refinery Flare since November 2015. It was identified as one element of BACT for the Main Refinery Flare during a 2014 minor modification permit action. In addition, each of the identified work practices are already in place due to the various regulations that are applicable to the Main Refinery Flare, as follows:

- NSPS subpart Ja at§ 60.103a(a) and NESHAP subpart CC at§ 63.670(0)(1) each require development of a written flare management plan (FMP). The following information is specifically required to be included in or referenced in the FMP:
  - Listing of all process units, ancillary equipment, and fuel gas systems that are connected to the flare header system;
  - A flare minimization assessment;
  - Descriptions of all flare components and design parameters;
  - Specifications for all required monitoring instrumentation;
  - A baseline flow evaluation; and
  - A description of procedures to reduce flaring during planned startups and shutdowns, during imbalances of the fuel gas system, and during outages of a FGRS.
- A completion of a root cause/corrective action analysis when the 24-hour total SO_2 from the flare exceeds 500 pounds and/or when the 24-hour total flare flow is greater than 0.5 MMSCF above the baseline.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

No control measures beyond what are already in place were identified. Each of the work practices identified above together function as a means of minimizing SO_2 emissions. However, additional SO_2 reductions at the Main Refinery Flare are anticipated as part of ongoing air pollution control programs.

Step 4: Evaluate Impacts and Document Results

Factor 1 – Cost of Compliance Main Refinery Flare SO_2

No control measures beyond what are already in place were identified in this analysis. The total capital cost of the FGRS installed in 2015 was greater than $50MM. Continuing to operate the FGRS with the work practices will continue to provide SO_2 control while also allowing for continued optimization of the entire system as additional process knowledge is incorporated to provide further SO_2 reductions.

Factor 2 – Time Necessary for Compliance Main Refinery Flare SO_2 Controls

The FGRS is already in place and will continue to operate.

Factor 3 - Energy and Non-Air Quality Environmental Impacts of Compliance Main Refinery Flare SO_2

No control measures beyond what are already in place were identified in this analysis and therefore no new additional impacts are identified.

Factor 4 - Remaining Useful Life- Main Refinery Flare SO_2 Controls

No control measures beyond what are already in place were identified in this analysis. The Main Refinery Flare and FGRS began operation in 2015. It is expected that the flare and FGRS have a remaining useful life greater than 20 years.

Step 5: Select Reasonable Progress Control

No control measures beyond those already in place at the Main Refinery Flare were identified in the Four-Factor Analysis. CHS believes that SO_2 emissions from the Main Refinery Flare will decrease by at least 20% from the 2017 - 2018 baseline by 2028 as a result of ongoing programs and work practices. These programs will continue to identify opportunities to reduce vents to the flare and to increase utilization of the FGRS. Following are two examples of recently identified opportunities:

- Evaluation of flare emissions during maintenance activities identified the potential benefit of additional online analyzers to better identify flare gases that may be compatible with the RFG system. These analyzers have been installed.
- A piping modification is being implemented to allow for recovery and amine treatment of certain flare gases that aren't currently being recovered because they don't meet RFG specifications. Although these recovered gases will be returned to the flare after treatment, SO_2 emissions at the flare will be significantly reduced.

As a result of these ongoing programs, it can be concluded that enforceable emissions limitations, compliance schedules, and other measures are already in place, are providing SO_2 emission reductions at the facility.

NOx Evaluation

The Main Crude Heater was installed in 1961 and is located in the #1 Crude Unit. It is a natural draft horizontal cabin type heater with a top mounted convection section and stack and has been retrofitted with an air pre-heat system. It is equipped with 24 burners located along the sidewalls that fire horizontally along the floor of the firebox. It has a design heat input of 142 MMBtu/hr (HHV) and is fired with RPG. In 2012, the burners were replaced with low NOx burners that had a burner vendor guaranteed NOx emissions rate of 0.08 lb/MMBtu (HHV). Because the heater does not have CEMs and stack testing has not been required, a NOx emission rate of 0.1 lb/MMBtu (HHV) has been conservatively used as the basis for emissions calculations since completion of the 2012 burner retrofit.

The Platformer Heater was installed in 1973 and is located in the Platformer Unit. It is a natural draft, four cell heater with a common convection section that generates steam. There are 36 burners fired horizontally in three cells from both end walls (12 burners per cell) and six (6) floor fired burners in the fourth cell. It has a design heat input of 190.4 MMBtu/hr (HHV) and is fired with RFG. The NOx emission rate from the heater has been conservatively assumed to be equal to the AP-42 emissions factor of 280 lb/106 scf (approximately 0.275 lb/MMBtu, HHV) for large wall-fired boilers. A performance test completed in 2002 indicated an actual NOx rate of 0.163 lb/MMBtu.

Boiler #9 was installed in 1978 and is one of four steam generating boilers located at the Laurel refinery. It is a natural gas fired unit with one burner and has a design heat input of 98 MMBtu/hr (HHV). The assumed NOx emissions rate from the boiler is based on the AP-42 emission factors of 100 lb/106 scf (approximately 0.098 lb/MMBtu, HHV) for small boilers. More recently, Boiler #9 is planned for replacement but will continue in operation until a new boiler comes on-line in its place. More importantly, the replacement boiler will be permitted under Montana's PSD program and following BACT.

Step 1 – Identify All Available Technologies

Based on a review of recent NOx control precedents for gas fired process heaters two fundamental categories of NOx controls were identified: low NOx burners (LNB) or ULNB, and post-combustion catalytic control to selectively reduce NOx emissions (SCR). In addition to these controls, external flue gas recirculation (FGR) was identified as a potential NOx control for boilers. The NOx control effectiveness of ULNB technology makes use of what is called internal FGR.

Additional controls that are applied to the control of NOx from other types of combustion sources include: SNCR, nonselective catalytic reduction (NSCR), and EMx™. These controls, which are potentially applicable via technology transfer, are also considered.

Technical Feasibility of Available NOx Control Technologies

LNBs/ULNB, and SCR are considered to be demonstrated on gas fired refinery process heaters. In addition to LNBs/ULNB, and SCR, FGR is also considered demonstrated on boilers. As a result, these controls are considered further by this analysis. The technical feasibility of FGR to process heaters, and SNCR, NSCR, and EMx™ to both process heaters and boilers are evaluated further using the previously discussed criteria: applicability, availability, and demonstrated in practice.

Step 2: Eliminate Technically Infeasible Options

<u>SNCR</u>

Because SNCR's ability to achieve NOx reduction requires operation of the combustion source within specific ranges it has previously only been applied to the control of NOx emissions from sources that operate within well-defined operating ranges and that do not rapidly vary across those ranges such as base-loaded boilers and FCCUs. Refinery process heaters operate across much wider ranges. As a result, SNCR has not been widely applied within the refinery industry and is not considered feasible for the process heaters. Boiler #9 is operated over a wide range of loads. As a result, SNCR is eliminated from further consideration.

NSCR

NSCR is used to reduce NOx emissions in the exhaust of automotive engines and stationary internal combustion engines. NSCR systems are comprised of three different catalyst types used in series. The first catalyst in the series is a reducing catalyst that is used to react unburned hydrocarbon in the exhaust with NOx in the exhaust. Tuning the engine to run fuel rich creates the unburned hydrocarbon. The next catalyst in the series is an oxidizing catalyst that is used to oxidize the unburned fuel to CO and water and the final catalyst, which is also an oxidizing catalyst is used to oxidize any remaining CO. NSCR has only been applied to engines because it is impractical to tune a fired combustion source such as a process heater to combust in a fuel rich manner. As a result, this control type is considered to be infeasible for the proposed application and removed from further review.

EMx™

The EMx™ system (formerly referred to as SCONOX™) is an add-on control device that simultaneously oxidizes CO to CO_2, VOCs to CO_2 and water, NO to NO_2 and then adsorbs the NO_2 onto the surface of a potassium carbonate coated catalyst. The EMx™ system does not require injection of a reactant, such as ammonia, as required by SCR and SNCR and operates most effectively at temperatures ranging from 300°F to 700°F.

The catalyst has a finite capacity to react with NO_2. As a result, to maintain the required NOx/NO_2 removal rate, the catalyst must be periodically regenerated. Regeneration is accomplished by passing a reducing gas containing a dilute concentration of hydrogen across the surface of the catalyst in the absence of oxygen. Hydrogen in the regeneration gas reacts with the nitrites and nitrates adsorbed on the catalyst surface to form water and molecular nitrogen. Carbon dioxide in the regeneration gas reacts with the potassium nitrite and nitrates to form potassium carbonate, the original form of the chemical in the catalyst coating.

The regeneration gas is produced in a gas generator using a two-stage process to produce molecular hydrogen and carbon dioxide. In the first stage, natural gas and air are reacted across a partial oxidation catalyst to form carbon monoxide and hydrogen. Steam is added to the mixture and then passed across a low temperature shift catalyst, forming carbon dioxide and more hydrogen. The regeneration gas mixture is diluted to less than four percent hydrogen using steam. To accomplish the periodic regeneration, the EMx™ system is constructed in numerous modules which operate in parallel so that one module can be isolated and regenerated while the remaining modules are lined up for treatment of the exhaust gas stream.

There are currently six EMx™ units in commercial operation with the U.S. All are on natural gas-fired combustion turbines of 45 MW or less. There are no known installations on process heaters or boilers. There are a number of differences between the operation and flue gas characteristics of combustion turbines and CHS's candidate process heaters and boiler considered by this analysis. Specifically, combustion turbines are essentially constant flue gas flow combustion devices no matter what the load.

Process heater and boiler gas flow rates are directly proportional to load. The impact on the load following ability of the EMx™ is unknown with respect to process heater and boiler applications. Additionally, the concentration of NOx/NO_2 in the flue gases from the process heaters are much higher than that of the combustion turbine flue gases. This is due to the high oxygen content of the combustion turbine flue gas (~15% 0_2) relative to a process heater/boiler flue gas (~3% 0_2). The impact of the flue gas oxygen content and NOx/NO_2 concentration on the EMx™ is unknown. Finally, the combustion turbines where EMx™ has been demonstrated have all been fired with natural gas. Of the CHS sources included in this analysis, only Boiler #9 is natural gas fired. Based on the above factors the use of EMxTM to control NOx emissions from the selected CHS process heaters and boiler is considered technically infeasible and this technology is eliminated from further consideration. The following technologies are carried forward for further consideration.

Table 6-36. CHS Technically Feasible Technologies to Reduce NOx

Process Heaters	**Boilers**
• LNB/ULNB • LNB/ULNB followed by SCR	• FGR • LNB/ULNB • LNB/ULNB followed by SCR

The NOx emission rate achievable as part of a heater or boiler retrofit is dependent upon the inherent design of the heater. Although it may be technically feasible to retrofit an existing heater/boiler with a control, NOx emission rates that are achievable on a new heater/boiler may not be achievable through a retrofit installation. Table 6-37 identifies the NOx emission rates expected to be achievable for the identified process heaters and boiler as a result of installation of ULNB (heater) or FGR+ULNB (boiler). The table also notes the NOx reduction expected from the retrofit.

Table 6-37. CHS ULNB Achievable NOx Levels - Process Heaters and Boilers

	Main Crude Heater	**Platformer Heater**	**Boiler #9**
Baseline NOx, lb/MMBtu	0.1	0.275	0.098
Post Retrofit NOx, lb/MMBtu	0.05	0.04	0.04
Baseline NOx, tons/year	43.6	91.4	29.3
NOx Reduction, tons/year	21.8	78.1	17.3

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

An analysis of recent SCR based precedents for new units where the SCR's placement can be integrated into the heater's design indicated NOx reductions of 85 to 95 percent on an annual average basis. As a result, due to the retrofit related issues of installing an SCR, a design level NOx control of 85% was applied as part of this analysis.

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

CHS calculated the costs for NOx for the two process heaters and boiler evaluated. A summary of the estimated costs is presented in Table 6-38. The costs presented were developed in accordance with EPA's Air Pollution Control Cost Manual methodology. Capital costs were escalated to 2018 dollars using the Chemical Engineering Plant Cost Index.

Table 6-38. Summary of the Cost of Compliance Associated with Application of ULNB and SCR on Identified Process Heaters and Boilers

PARAMETERS	**Main Crude Heater**	**Platformer Heater**	**Boiler #9**
ULNB			
Total Capital Requirement, $[1]	2,826,000	8,488,000	3,249,000
Annual O&M Costs, $	71,000	212,000	81,000
Capital Recovery Costs, $	267,000	801,000	307,000
Total Annual Costs, $	338,000	1,013,000	388,000
SCR			
Total Capital Requirement, $[1]	6,005,000	6,192,000	5,307,000
Annual O&M Costs, $	263,100	283,400	230,000
Capital Recovery Costs, $	566,900	584,500	501,000
Total Annual Costs, $[1]	830,000	867,900	731,000
NOx Emissions, tons/yr			
Actual Emissions (2017-2018)	43.6	91.4	29.3
Emissions w/ULNB	21.8	13.3	12.0
Emissions w/ULNB + SCR	3.3	2.0	1.8
NOx Reductions			
ULNB	21.8	78.1	17.3
ULNB+SCR	40.3	89.4	27.5
Cost Effectiveness, $/ton			
ULNB	15,500	13,000	22,400
ULNB+SCR	27,800	21,000	39,000

Factor 2: Time Necessary for Compliance

Although not specifically noted in the submitted four-factor analysis it is believed that any of the above controls could be implemented by 2028.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

The application of SCR to the candidate process heaters and boiler will result in the emissions of ammonia and additional fine particulate matter in the form of ammonium salts. The emission of ammonia results from incomplete utilization of all of the ammonia injected before the SCR catalyst. This unreacted ammonia will result in ammonia slip, and is either exhausted to the atmosphere as ammonia or combines with sulfur species in the flue gas to form ammonium salts.

The installation of an SCR system increases the pressure drop through the heater flue gas path requiring the installation of an induced draft fan on the Main Crude and Platformer Heaters. The induced draft fan and SCR system power requirements result in an increase in the emission rate of criteria pollutants (NOx, CO, GHGs, etc.) at the location where the power is generated.

The spent catalyst is comprised of metals that are not considered toxic. This allows the catalyst to be handled and disposed of following normal waste procedures.

Energy Impacts: The energy impact of applying SCR to the candidate process heaters and boiler comes from the power required to drive the induced draft fan and operate the ammonia injection and storage equipment.

Factor 4: Remaining Useful Life

CHS believes units such as Boiler #9 and the Platform Heater may be candidates for replacement in the future and with those replacements, reductions are likely due to the controls installed on those units. However, no credit is taken for a shorter remaining useful life and the resulting cost per ton estimates are considered high.

Step 5: Select Reasonable Progress Control

SO_2

Montana concurs with the CHS prepared and submitted four-factor analysis that the existing flare and flare gas recovery system have provided significant SO_2 reductions and the continued optimization of these relatively new systems provide opportunity for future SO_2 reductions.

NOx

Montana has determined that ULNB and ULNB plus SCR are cost prohibitive with a range of $13,000 to $39,000 per ton of emission reduction across the process heaters and Boiler #9. Therefore, additional NOx control is not reasonable for the second planning period. The three units evaluated represent 40 percent of the facility NOx emissions. Future planning periods may look at other smaller emitting NOx units for further emission reductions.

6.2.18 F.H. Stoltze Land & Lumber Co.[138]

F.H. Stoltze Land and Lumber Co. (Stolze) submitted their four-factor analysis (in conjunction with Bison Engineering Inc.) on September 30, 2019. Stoltze owns and operates a sawmill facility located near Columbia Falls, Montana. The sawmill includes a biomass-fired boiler that supplies steam for lumber drying and for steam-powered electrical generation. The boiler was manufactured by Wellons Inc. in 2012 and is referred to as the Wellons boiler.

Stoltze RepBase and 2028 OTB/OTW Scenarios

Stoltze selected the two-year average of 2017-2018 as representative of baseline emissions. Montana concurred that this two-year period was reflective of recent normal operation. Stoltze also selected a future year 2028 OTB/OTW scenario used to calculate the cost per ton of emission reduction achieved from applying controls.

[138] F.H. Stoltze Land & Lumber Co., Columbia Falls Sawmill, Regional Haze Four-Factor Analysis (September 2019), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/Planning/PDF/FH%20Stoltze%20Draft%204-factor%20report_reviewed.pdf?ver=2020-02-03-161247-277

Stoltze chose to use the 2017-2018 representative baseline for the 2028 OTB/OTW scenario. Stoltze was not asked to conduct an analysis on SO_2 but did provide some comments on SO_2 in their four-factor analysis. The SO_2 information is not included here.

Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 6-39. Stoltze RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2017-2018	73.9	7.1	73.9	7.1

Step 1 – Identify All Available Technologies

NOx is formed during the combustion of woody biomass fuel in the Wellons boiler. The Wellons boiler was subject to a BACT analysis during the permit application process when it was permitted in 2012. The BACT analysis included consideration of combustion controls and add-on NOx emissions controls.

The Wellons boiler is equipped with staged combustion flue gas recirculation and over-fire air. These NOx control technologies are required by the Montana air quality permit for the facility.[139]

Additional control could be achieved by add-on emissions control technology as discussed below. The efficiency of the add-on controls would be reduced because of the low NOx concentration emitted from the boiler. Because the Wellons boiler is already equipped with combustion controls, this cost-effectiveness analysis only considers add-on controls including:

- Selective Catalytic Reduction
- Selective Non-catalytic Reduction

SCR control technology works best for flue gas temperatures between 575°F and 750°F. SCR is typically installed upstream of the particulate control equipment where the temperature is high enough to support the process. When the combustion source is a biomass-fired boiler, the SCR must be placed downstream of the particulate control equipment for proper operation. At this point in the exhaust system, the flue gas temperature is lower than required for the SCR to operate effectively. Source tests of the Wellons boiler stack show an average stack exit temperature of 285°F.

Step 2: Eliminate Technically Infeasible Options

The Wellons boiler underwent BACT analysis when it was permitted in 2012. At that time, Wellons stated they had never installed an SCR on a wood-fired boiler this small, and Wellons was not confident that the

[139] Montana Air Quality Permit MAQP #2934-01 (14 May 2012), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/ARMpermits/2934-01.pdf

system could operate effectively as they have no operating experience. Stoltze considers this alternative technically infeasible and SCR is eliminated from any further consideration as a feasible control technology.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The Wellons boiler is currently equipped with combustion controls to minimize the formation of NOx emissions. The permit limit for NOx emissions is 0.26 pounds per million Btu (lb/MMBtu), which is equivalent to 18.2 pounds per hour (lb/hr). The analysis identified SNCR as the only feasible add-on NOx control technology that could potentially be applied to the Wellons boiler. The estimated control efficiency for SNCR is 30%-50%. Because the Wellons boiler is equipped with NOx reduction technology, the lower end of the efficiency range, 30%, is assumed. Based on the assumption of a 30% control efficiency, the NOx emission rate could be reduced to 0.18 lb/MMBtu and 12.7 lb/hr.

Step 4: Evaluate Impacts and Document Results

<u>Factor 1: Cost of Compliance</u>

The cost of compliance analysis was based on a spreadsheet developed by EPA to implement the June 2019 update of the SNCR chapter of the EPA Control Cost Manual.[140]

The SNCR cost estimate spreadsheet is designed for use with coal-fired and oil- and natural gas-fired boilers. The spreadsheet was modified for use with the Wellons boiler by substituting wood fuel characteristics for coal characteristics. The fuel information for the wood/bark fuel is based on fuel analysis for samples collected during the most recent source test on the Wellons boiler.

The Stoltze sawmill cuts green lumber which is dried in lumber kilns. Steam to heat the for the kilns is supplied by the Wellons boiler which has a nominal rated capacity of 40,000 lb/hr and heat input up to 70 MMBtu/hr. Steam from the boiler is used to run a generator which produces 2.5 megawatts (MW) of power.

The steam heat output is converted to MW using the heat content of saturated steam (1,191 Btu/lb steam) and the following conversion:

- 40,000 lb steam/hr * 1,191 Btu/lb steam * 1 MMBtu/(1E6 Btu) = 47.64 MMBtu/hr heat output
- 47.64 MMBtu/hr ÷ 3.412 MW/MMBtu/hr = 13.96 MW
- Additional 2.5 MW Electrical Power
- NPHR = 70 MMBtu ÷ (13.96MW + 2.5MW) = 4.25 MMBtu/MW

The maximum potential inlet NOx emissions to the SNCR are 0.26 lb/MMBtu as limited by the air quality permit. A removal efficiency of 30% is assumed, and the outlet NOx emissions from the SNCR would be 0.182 lb/MMBtu.

The estimated Normalized Stoichiometric Ratio (NSR) was obtained from the EPA Control Cost Manual for SNCR. Figure 1.8 of the control cost manual chapter on SNCR shows the lowest NOx emission rate for

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[140] EPA's SNCR Cost Calculation Spreadsheet, June 2019. Available at: https://www.epa.gov/sites/production/files/2019-06/sncrcostmanualspreadsheet_june2019vf.xlsm

which SNCR control would be applied is 0.40 lb/MMBtu. The corresponding NSR of 1.15 for 0.40 lb/MMBtu and 30% removal efficiency was used in the spreadsheet.

For this application, it was assumed that the SNCR would use urea, and the reagent values for urea in the spreadsheet are the default values. The cost values are based on the 2018 Chemical Engineering Plant Cost Index (CEPCI) value of 603.1, based on the annual average. The spreadsheet default annual interest rate of 5.5% was used. The fuel cost for the hog fuel was estimated to be $2.05/MMBtu based on an assumed cost for handling the fuel of $20 per ton and a fuel high heating value (HHV) of 9.76 MMBtu/ton. Ash disposal cost was not included because the spreadsheet excludes ash removal costs for non-coal fuels. The spreadsheet default costs for reagent, water and electricity were used in the analysis.

The cost calculation results showed that the addition of SNCR to the Wellons boiler would have a cost effectiveness of $8,092 per ton of NOx removed, in 2018 dollars. This value represents the cost of installing and operating SNCR add-on NOx control technology to the Wellons boiler, which is already equipped with combustion controls to reduce the formation of NOx.

For SNCR, EPA states in its Control Cost Manual, "Installation of SNCR equipment requires minimum downtime. Although simple in concept, it is challenging in practice to design an SNCR system that is reliable, economical, and simple to control and that meets other technical, environmental, and regulatory criteria.[141] Based on information provided by Stoltze, Montana concluded that any required controls could be implemented by 2028.

Factor 2: Time Necessary for Compliance

Stoltze estimated that SNCR would require approximately 24 months for design, permitting, financing, etc. through commissioning. Montana has concluded that any required controls could be installed by 2028.

Factor 3: Energy and Environmental Impacts of Compliance

SNCR presents several adverse environmental impacts. Unreacted ammonia in the flue gas (ammonia slip) and the products of secondary reactions between ammonia and other species present in the flue gas will be emitted to the atmosphere. Ammonia slip causes the formation of additional condensable particulate matter such as ammonium sulfate, $(NH_4)2SO_4$. The ammonium sulfate can corrode downstream exhaust handling equipment, as well as increase the opacity or visibility of the exhaust plume.

An SNCR system would have a very small energy penalty on the overall operation cost of the boiler. Costs for this energy expenditure are included in the discussion of Factor 1, cost of compliance.

Factor 4: Remaining Useful Life

The Wellons boiler was manufactured in 2012 and installed at the Columbia Falls facility in 2013. For this four-factor analysis, it has been assumed that the boiler has a remaining useful life of 20 years based on Montana's guidance which stated that a 20-year planning horizon should be assumed for the purpose of the

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[141] EPA Cost Control Manual (Seventh Edition), Section 4 – NOx Controls, Chapter 1 – Selective Non-Catalytic Reduction, April 25, 2019. Available at: https://www.epa.gov/sites/default/files/2017-12/documents/sncrcostmanualchapter7thedition20162017revisions.pdf

requested reasonable progress analysis. The only exception to this horizon is if there is a unit shutdown date identified that will cease operations before 20 years has expired.

Step 5: Select Reasonable Progress Control/Final State Recommendations

Montana has determined that SNCR is cost prohibitive for the second planning period. Therefore, additional NOx control is not reasonable for the second planning period. Further, the Wellons boiler is relatively new with existing NOx controls permitted under BACT in 2012. Future planning periods may revisit the need for emission reductions.

6.2.19 Sidney Sugars Inc.[142]

Sidney Sugars Inc. (Sidney Sugars) submitted their four-factor analysis on October 6, 2019, in conjunction with Environmental Consulting Services. Sidney Sugars was not evaluated in the first planning period, so there are no previous analyses conducted for either BART or Reasonable Progress that could be used as a base case. Sidney Sugars is located in Sidney, Montana. in Richland County and consists of four boilers that are each evaluated in this analysis. The four emitting units are identified as CE Boiler #1, CE Boiler #2 Union Boiler #3 and Union Boiler #4.

The Sidney Sugars facility is a season system that processes sugar beets using lignite coal supplied by the Savage Mine, which also supplies coal to MDU-Lewis and Clark Station. Section 4.3.7 discusses the MDU-Lewis and Clark Station and coal use from the Savage mine, including plans for ceasing operation by 2028. Sidney Sugars is a small purchaser of Savage Mine coal and the continued availability of lignite coal may change after MDU-Lewis and Clark ceases coal use. If lignite coal is no longer available, a likely scenario would be a conversion to natural gas; however, this would likely require installation of new natural gas-fired boilers, thereby invalidating any new NOx control which may have been installed for controlling NOx while burning coal.

Sidney Sugars RepBase and 2028 OTB/OTW Scenarios

Sidney Sugars selected the two-year average of 2017-2018 emissions for their representative baseline. Montana concurred that this two-year period was reflective of recent normal operation. Sidney Sugars also selected a future year 2028 OTB/OTW scenario, that was used to calculate the cost per ton of emission reduction achieved from applying controls.

Sidney Sugars chose to use the 2017-2018 representative baseline for the 2028 OTB/OTW scenario. Sidney Sugars was not asked to conduct an analysis for SO_2 reductions as their baseline emissions for SO_2 were relatively low and Montana determined that pursuing NOx reductions represented a higher priority at this time.

Representative baseline and 2028 OTB/OTW emissions are as follows:

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[142]Sidney Sugars Incorporated, Response to the Regional Haze Source Screening letter from the Montana Department of Environmental Quality (MDEQ) dated March 14, 2019 to Sidney Sugars Incormporated (SSI), (24 Sept. 2019) Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/Planning/PDF/SSI_RegionalHaze_MDEQResponseLtr.pdf?ver=2020-02-04-144859-790

Table 6-40. Sidney Sugars RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2017-2018	224.0	61.7	224.0	61.7

Source Screening Background

Sidney Sugars commented in the four-factor analysis that the emission factors used for the facility should be corrected. However, if the corrected emission factors referenced by Sidney Sugars were used in the Q/d equation, the facility would have had a Q/d of 4.04 instead of the 5.18 Montana calculated in the original screening process. Because Montana chose a Q/d threshold greater than 4, Sidney Sugars would still have been asked to submit a detailed four-factor analysis.

Step 1 – Identify All Available Technologies

Sidney Sugars used a reference document titled Amec Foster Wheeler Environmental & Infrastructure, Inc.; Final Four-factor Analysis for Regional Haze in the Northern Midwest Class I Areas, dated October 27, 2015, to perform the analysis for the four boilers.[143] The available Potential NOx Control Options for Industrial, Commercial, and Institutional Boilers at Sugar Beet Manufacturing Facilities are summarized as follows. As this document specifically looked at Sugar Beet manufacturing facilities, Montana considers this a reasonable review of available technologies. The control performance efficiencies are also included.:

Table 6-41. Sidney Sugars Available Control Technologies

Technology	Description	Applicability	Performance
Boiler Tuning/Optimization	Adjust air to fuel ratio	Potential control measure of all boilers	5-15% reduction in NOx
LNB	Low NOx burners	Potential control measure for all boilers; dependent upon fuels burned, boiler use, and boiler configuration	40-50% reduction in NOx
ULNB	Ultra low NOx burners	Potential control measure for all boilers; dependent on fuels burned, boiler use, and boiler configuration	45-85% reduction in NOx

[143] LADCO, Four-Factor Analysis for Regional Haze in the Northern Midwest Class I Areas (27 Oct. 2015), Available at: https://www.ladco.org/wp-content/uploads/Documents/Reports/Regional_Haze/Round2/2015_LADCO-4-Factor-Analysis-Regional-Haze.pdf

Technology	Description	Applicability	Performance
LNB+FGR	Low NOx burners and flue gas recirculation	Potential control measure for all boilers; dependent on fuels burned, boiler use, and boiler configuration	50-70% reduction in NOx
LNB+OFA	Low NOx burners and over-fired air	Potential control measure for all boilers; dependent on fuels burned, boiler use, and boiler configuration	40-60% reduction in NOx
SCR	A reducing agent such as ammonia is introduced into the flue gas stream to form nitrogen gas in the presence of a catalyst	Potential control measure for all boilers; dependent on flue gas temperature and boiler configuration	70-90% reduction in NOx
SNCR	A reducing agent such as ammonia is introduced into the flue gas stream to form nitrogen gas	Potential control measure for all boilers; dependent on flue gas temperature and boiler configuration	10-70% reduction in NOx
RSCR	A reducing agent such as ammonia is introduced into the flue gas stream to form nitrogen gas in the presence of a catalyst and heat exchangers	Potential control measure for all boilers; dependent on boiler configuration	60-75% reduction in NOx

Step 2: Eliminate Technically Infeasible Options

Sidney Sugars provided the following table, eliminating those technologies as noted. Montana does not fully concur that each of the options as noted are technically eliminated. Where stack temperatures have been noted as too-low, add on reheat options allow options to making these technologies work. The costs may become excessive and may be result in those options being eliminated for not being cost effective but not because of they are technically infeasible.

Table 6-42. Sidney Sugars Control Options Cost Effectiveness

Control Option	Specific Design Parameters Identified	Cost Effectiveness (2015 $/ton)	Factors Affecting Cost	Potential Applicability to Specific Boilers
Boiler Tuning/Optimization	None	Low	Engineering and contractor costs	All Boilers
LNB	None	$450-$3,700	Equipment, installation, and engineering	All Boilers

Control Option	Specific Design Parameters Identified	Cost Effectiveness (2015 $/ton)	Factors Affecting Cost	Potential Applicability to Specific Boilers
ULNB	None	$650-$2,200	Equipment, installation, and engineering	All Boilers
LNB+FGR	None	$1,200-$4,300	Equipment, installation, construction, and engineering	Union Boilers only
LNB+OFA	None	$700-$3,700	Equipment, installation, construction, and engineering	All Boilers
LNB+SNCR	Urea injection system	$1,700-$4,500	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	Not Applicable-Infeasible, stack temps too low
ULNB+SCR	Ammonia injection system	$2,900-$5,100	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	Not Applicable-Infeasible, stack temps too low
SCR	Ammonia injection system	$2,600-$17,000	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	Not Applicable-Infeasible, stack temps too low
SNCR	Urea injection system	$1,500-$4,400	Equipment, installation, engineering, energy use, waste removal, and reduction agent	Not Applicable-Infeasible, stack temps too low
RSCR	Ammonia injection system	$1,800-$5,300	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	Not Applicable-Infeasible, stack temps too low

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Under Step 1, - Identify All Available Technologies, Sidney Sugars indicated the approximate control efficiencies possible with each alternative. All control technologies listed in Table 6-42 remain and are evaluated in this analysis.

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

Based on the above cost-range estimates, Sidney Sugars has indicated that the only cost-effective controls would be for combustion modifications. However, Montana has not arrived at the same conclusion. Each of the alternatives listed above may be feasible, given some additional reheating scenarios that could be implemented and were not evaluated by Sidney Sugars.

Factor 2: Time Necessary for Compliance

Sidney Sugars provided information that allows Montana to conclude that any required controls could be implemented by 2028.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

Non-air environmental impacts include solid, liquid, and/or hazardous waste generation and deposition of atmospheric pollutants on land or water. Combustion modifications would have significant negative impacts on energy use. Boiler tuning, LNB/ULNBs, OFA, and FGR would reduce the efficiency of a boiler as the air to fuel ratio increases and temperature decreases. This increases fuel usage and, as a result, costs. OFA and FGR systems increase energy use in the form of fans and compressors.

Factor 4: Remaining Useful Life

Life expectancy for the Sidney Sugars CE Boilers and Union Boilers is estimated at between 10 and 30 years or more. Since Sidney Sugars did not provide any specifics Montana assumed that all boilers have a remaining useful life of at least 20 years.

Step 5: Select Reasonable Progress Control

There remains a potential option to replace the CE Boilers (i.e., coal-fired boilers) with natural gas fired boilers. As it is unclear whether the CE Boilers will continue to have a supply of lignite coal from the Savage Mine, Montana has determined to not require controls on the CE Boilers given that the costs of those controls would likely be stranded. Additionally, any retrofit controls that might be required for combusting coal could also be stranded if Sidney Sugars were to move to natural gas-fired boilers. Therefore, no NOx controls are required for the second planning period. However, if the Savage Mine remains operational or if Sidney Sugars outsources to another coal mine, NOx controls may be required in a future planning periods.

6.2.20 Phillips 66 Co. – Billings Refinery[144]

Phillips 66 Co. (P66) submitted their four-factor analysis (in conjunction with Bison Engineering Inc.) and supporting information on October 2, 2019. P66 is an integrated petroleum refinery that includes crude oil distillation, delayed coking, fluid catalytic cracking, hydrotreating, alkylation, and other associated petroleum refining processing units and auxiliary operations. Associated with P66 are the adjacent Jupiter Sulphur LLC

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[144] Phillips 66 Billings Refinery, Regional Haze Four-Factor Analysis, (September 2019), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/Planning/PDF/2619_2019_10_02_REGHAZE_4-FACTOR.pdf?ver=2020-02-03-161930-317

sulfur recovery operations (Jupiter Plant), which recover sulfur from the sour-acid gas streams generated at P66.

P66 encompasses approximately 200 acres and the location of the main refinery gate is 401 South 23rd Street, Billings, Montana. The legal description of the site location is NW¼ of Section 2, Township 1 South, Range 26 East, in Yellowstone County, Montana. P66 is one of the four oil refineries in Montana, with three of the four being near Billings, MT, including P66.

As previously discussed in the Source Screening section, Montana screened on a facility basis to determine whether four-factor analyses would be required. However, refineries contain many small emitting units that, in aggregate, contribute to emissions of SO_2 and/or NOx at the facility. Because of this, Montana determined that it was impractical to perform a four-factor analysis on each individual emitting unit. Montana and P66 agreed on a ranking of the highest emitting units for both NOx and SO_2 that could be evaluated in the four-factor analysis. Doing so provided the information necessary to determine opportunities for emissions reductions at the facility. P66's NOx emissions are significantly larger than SO_2, so Montana agreed that the greatest effort should be put into identifying opportunities for NOx reductions at P66.

This analysis focuses on the Boiler #1 and Boiler #2. This analysis focuses on emissions originating from these two Boilers at the facility because these two units are responsible for approximately 22% of the NOx emissions from the plant (based on 2018 emissions). Future planning periods may evaluate other emitting units; however, evaluating the highest existing emitting units in this planning period provides a reasonable approach to identifying possible emission reduction opportunities.

P66 RepBase and 2028 OTB/OTW Scenarios

P66 selected the two-year average of 2017-2018 as representative of baseline emissions. Montana concurred that this two-year period was reflective of recent normal operation. P66 also selected a future year 2028 OTB/OTW scenario used to calculate the cost per ton of emission reduction achieved from applying controls. P66 chose to use the 2017-2018 representative baseline for the 2028 OTB/OTW scenario.

Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 6-43. P66 RepBase and 2028 OTB/OTW Emissions

Baseline Period	**Rep. Baseline NOx**	**Rep. Baseline SO_2**	**2028 OTB/OTW NOx**	**2028 OTB/OTW SO_2**
2017-2018	563.5	100.7	563.5	100.7

SO_2 Evaluation

As previously mentioned, SO_2 emissions from P66 are relatively low, with NOx emissions being five times higher than SO_2. Therefore, Montana requested that P66 look specifically at NOx controls for this planning period. However, a limited analysis on SO_2 reductions was conducted.

The most common SO_2 control practice that may be applied to typical refinery boilers and other combustion devices (heaters, flares, etc.), specifically those fired with refinery fuel gas, is compliance with the Standards of Performance for Petroleum Refineries (NSPS, 40 CFR 60, Subpart J and Ja). Subpart J and Ja includes a hydrogen sulfide content limit of 162 parts per million by volume (ppmv) or less in refinery fuel gas on a 3-hour rolling average basis. All combustion devices fired with refinery fuel gas at the P66 Refinery are subject to and comply with this standard. In addition, other standards apply from terminated EPA Consent Decree requirements (that have largely been incorporated in permit conditions), state SIP requirements, and other NSPS limits to further control SO_2 emissions from the fluidized catalytic cracking unit (FCCU), among other units.

For the 2017-2018 baseline summary, P66 averaged 100.7 tons per year of SO_2 emissions over 38 emissions sources/points that have the potential to emit SO_2. While those emissions are not evenly distributed over those sources, many of the SO_2 sources are small boilers or heaters subject to NSPS Subpart J/Ja or other requirements or are larger well-controlled SO_2 sources (the FCCU or sulfur recovery units, for example). Given the number of sources and relatively small emissions per source, continued compliance with the above-mentioned standards and permit limits, should continue to keep SO_2 emissions at or near the current levels.

NOx Evaluation

Step 1 – Identify All Available Technologies

As previously discussed with respect to SO_2, the terminated EPA Consent Decree included significant emissions reductions for units across the refinery. These reductions included a NOx Control Plan for heaters and boilers (implementing NOx controls on at least 30% of the heater and boiler capacity greater than 40 million British Thermal Units per hour, MMBtu/hr) as well as catalyst additive demonstrations at the FCCU (with an associated NOx emission limit). NOx reductions were evaluated and implemented on units where the investment would provide the most efficient emission reduction value. P66 has demonstrated successful efforts through the terminated Consent Decree and beyond, to reduce NOx emissions in the recent past.

The NOx analysis focused on Boilers #1 and #2 as these two units are responsible for approximately 23% of the NOx emissions from the plant (based on the 2017-2018 baseline emissions). Twenty-one other NOx sources (with greater than five tpy emissions) split the other 77% of the NOx emissions, with three of those sources being grouped sources (gasoline engines, for example, or units with multiple fuel types in the inventory). Many of those twenty-one sources already have seen recent emissions control upgrades under the terminated Consent Decree.

The identified applicable NOx control technologies are described below and include:

- Ultra Low NOx Burners with Flue Gas Recirculation
- Selective Non-Catalytic Reduction
- Selective Catalytic Reduction.

The NOx basis ("uncontrolled emissions") for Boilers #1 and #2 is the 2019 annual emission inventory factor of 0.27451 lb/MMBtu.

<u>SNCR</u>

For SNCR, it was noted that none of the refinery process units or industrial boilers listed in EPA's applicable information collection request used ammonia; all used urea based on the unique operational considerations. Therefore, urea was employed as the reagent in the P66 SNCR cost analysis.

The median reductions for urea based SNCR systems are believed to fall within a range from 25 to 60 percent Additional industry-specific unit information included in the SNCR White Paper[145] provided boiler size and associated NOx reductions. In the "Refinery Process Units and Industrial Boiler" section, for units less than 200 MMBtu/hr (the P66 Boilers #1 and #2 are both rated 120 MMBtu/hr). The 200 MMBtu/hr was used as a logical cut-off for smaller industrial boilers and the range estimated a 40 to 62.5% NOx reduction. An average reduction of 58.5% was used in the cost efficiency calculations.

For SNCR, the costs provided in the four-factor analysis were calculated using EPA's SNCR Cost Calculation Spreadsheet, using the "retro fit factor" of 1 - average retrofit. The Spreadsheet stated that its use is particularly for boilers (coal-, oil-, and natural gas-fired) with maximum heat capacities greater than or equal to 250 MMBtu/hr. Based on the boiler size, the less-common refinery-fuel gas, the potential for higher retrofit costs, and the economies of scale described above, P66 believed that the costs calculated are highly conservative.

<u>SCR</u>

The outlet concentration from SCR on a utility boiler is rarely less than 0.04 pounds per MMBtu (lb/MMBtu). Based on that limitation, which is particularly applicable to a retrofit unit, the proposed reduction associated with SCR for Boilers #1 and #2 is 85.4%. This is based on current engineering mass balance/emissions factor of 0.2745 lb/MMBtu in the annual emissions reporting to 0.04 lb/MMBtu.

Ammonia is the most commonly used reagent (and is the default for the EPA's SCR Cost Calculation Spreadsheet), so it was used in the reagent calculations for Boilers #1 and #2.

As previously discussed for SNCR, there is an efficiency of scale associated with pollution control equipment installation. Because the cost calculator is based on units with a heat capacity greater than 250 MMBtu/hr, those efficiencies are included in the EPA spreadsheet estimates. The costs provided for SCR in the four-factor analysis are calculated using EPA's SCR Cost Calculation Spreadsheet also use the "retrofit factor" of 1 - average retrofit. Based on the boiler size, the less-common refinery-fuel gas, the potential for higher retrofit costs, and the economies of scale described above, P66 believes that the costs calculated for SCR are also highly conservative.

Step 2: Eliminate Technically Infeasible Options

Because of the intrinsic nature of both controls (often used in conjunction), they are generally installed in new boilers. While retrofits have occurred (and did, in specific instances during the EPA Refinery Consent Decree NOx reductions), they generally occurred on smaller, newer, and a low number of burners. Based on corporate information, practices and similar unit Consent Decree-required retrofits, P66 believes this type of a retrofit for Boilers #1 and #2 would be a difficult and expensive effort that would likely result in complete demolition and replacement of both boilers, at an estimated cost of $40 million for both ($20 million per boiler).

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[145] Institute of Clean Air Companies (ICAC), Selective Non-Catalytic Reduction (SNCR) for controlling NOx Emissions; White Paper. Prepared by the SNCR Committee of ICAC. (February 2008), Available at: https://cdn .ymaws. com/icac. siteym . com/resource/resmgr/Standards WhitePapers/SNCR Whitepaper Final.pdf

To annualize that cost and provide a cost per ton value for new RFG-(Refinery Fuel Gas) fired boilers equipped with ULNB and FGR, a NOx limit of 0.03 lb/MMBtu was used. This assumes the new boilers are of the same general size/capacity as Boilers #1 and #2 and general utilization. The 0.03 lb/MMBtu NOx limit comes from the recent retrofit of Boiler-5 and Boiler-6 at the P66 Billings Refinery. The $40 million total cost includes capital expenditures and demolition for both boilers but does not include annual maintenance costs associated with UNLB/FGR.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Table 6-44. P66 Potential Control Options

Source	Potential Control Option	Estimated Control Efficiency (%)
Boiler #1 and Boiler #2 (120 MMBtu/hr, refinery fuel gas fired)	SNCR	58.5
	SCR	85.4
	Replacement with new boiler equipped with ULNB and FGR	89.0

Step 4: Evaluate Impacts and Document Results

<u>Factor 1: Cost of Compliance</u>

Table 6-45. Estimated Costs of NOx Control Options for P66, ranked by Control

Source	Potential Control Option	Potential Emission Reduction (tons/year)	Total Annual Cost (in 2018 dollars)	Cost Effectiveness ($/ton)
Boiler#1 (120 MMBtu/hr, refinery fuel gas fired)	SNCR	36	$233,041	$6,427
	SCR	56	$378,163	$6,791
	Replacement with new boiler equipped with ULNB and FGR	58	$1,673,587	$28,855
Boiler #2 (120 MMBtu/hr, refinery fuel gas fired)	SNCR	36	$232,805	$6,445
	SCR	55	$378,069	$6,816
	Replacement with new boiler equipped with	58	$1,673,587	$28,855

Source	Potential Control Option	Potential Emission Reduction (tons/year)	Total Annual Cost (in 2018 dollars)	Cost Effectiveness ($/ton)
	ULNB and FGR			

Factor 2: Time Necessary for Compliance

If any controls are identified, the Department has concluded based on the submitted four-factor analysis that those controls could be operational by 2028.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

In general, the use of combustion controls for reducing NOx formation can in turn cause an increase in CO emissions.

SCR and SNCR both present several adverse environmental impacts. Unreacted ammonia in the flue gas (ammonia slip) and the products of secondary reactions between ammonia and other species present in the flue gas will be emitted to the atmosphere. Ammonia slip causes the formation of additional condensable particulate matter such as ammonium sulfate, $(NH_4)_2S0_4$. The ammonium sulfate can corrode downstream exhaust handling equipment, as well as increase the opacity or visibility of the exhaust plume. In addition, SCR would require disposal or recycling of catalyst materials, which may require handling in a specific landfill for hazardous waste.

Factor 4: Remaining Useful Life

It is expected that Boiler #1 and Boiler #2 will have at least 20 years of remaining useful life.

Step 5: Select Reasonable Progress Control

Montana has determined that additional controls for NOx are not reasonable this planning period. Future planning periods may revisit the need for emission reductions.

6.2.21 Northern Border Pipeline – N. Border Pipeline Co. Station 3[146]

Northern Border Pipeline Company's Compressor Station No. 3 (Northern Border) is located in Roosevelt County, Montana. Northern Border submitted a four-factor analysis and supporting information on September 30, 2019. The four-factor analysis considered application of NOx control on the facility combustion turbine.

Northern Border includes a simple cycle natural gas-fired combustion turbine rated at 38,000 horsepower (hp) at ISO conditions. The turbine drives a natural gas compressor. The turbine includes a low NOx lean

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[146] Northern Border Compressor Station No. 3, Attachment 1: Four-Factor Analysis, (11 June 2019), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/Planning/PDF/MT%20Four%20Factors%20Analysis_NBPL%20Compressor%20Station%20No%203_090619%20redline.pdf?ver=2020-02-04-131921-270

premixed combustion burner, as designated by "DLE" (i.e., "dry low emissions") in model number for the unit. DLE is the nomenclature used for second generation combustor NOx controls that replaced water/steam injection (i.e., DLE replaced "wet" emission controls). The facility also includes a small emergency generator.

Northern Border RepBase and 2028 OTB/OTW Scenarios

Northern Border selected the two-year average of 2017-2018 as representative of baseline emissions. Montana concurred that this two-year period was reflective of recent normal operation. Northern Border also selected a future year 2028 OTB/OTW, used to calculate the cost per ton of emission reduction achieved from applying controls. Northern Border chose not to scale the representative baseline, so the 2028 OTB/OTW scenario is equivalent to the representative baseline. Additionally, the Department's request to Northern Border did not include a request to evaluate SO_2 at the facility as the SO_2 emissions are extremely low. The Northern Border four-factor analysis, therefore, did not include any discussion of SO_2.

Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 6-46. Northern Border RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2014-2017	56.0	2.6	56.0	2.6

Step 1 – Identify All Available Technologies

As noted above, the pollutant of concern for the natural gas-fired turbine is nitrogen oxides (NOx). The facility turbine already includes the low NOx burner technology available from the manufacturer, thus additional combustion-based controls are not available. Lean premixed combustion (i.e., "DLE") is a second-generation technology that replaced water / steam injection, so water/steam injection is not applicable for this unit. The remaining options are post-combustion control. As discussed briefly below, the only add-on control technology that can be reviewed for application to a combustion turbine is selective catalytic reduction (SCR). Consistent with the EPA guidance document, methodologies from the EPA Control Cost Manual are used to evaluate the NOx control cost effectiveness for SCR.

Step 2: Eliminate Technically Infeasible Options

Non Selective Catalytic Reduction: NSCR is a technology that only applies to reciprocating engines where the air-to-fuel ratio (AFR) is controlled so that there is no excess combustion air. At these conditions, species such as ammonia naturally occur in the combustion exhaust and those species participate in reactions to reduce NOx. This combustion configuration and AFR is not applicable to combustion turbines.

Selective Non Catalytic Reduction: SNCR employs similar "ammonia + NOx" chemistry, with ammonia injected at higher temperatures to reduce NOx without the use of a catalyst. In contrast, similar chemistry occurs with SCR technology, but a catalyst is required for reactions to occur because the exhaust temperature is cooler. SNCR has been applied in limited cases to large boilers (e.g., utility scale electric generating units), where the boiler configuration provides ample residence time at an exhaust temperature of about 1700 °F. A very specific temperature range and residence time within that range is required for SNCR to function. Neither the temperature or residence time is available in a combustion turbine, thus SNCR is not applicable to turbines. SCR is the only potential technology, and an SCR control cost analysis follows.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The cost analysis assumes a 75 percent NOx reduction would occur with SCR.

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

SCR has had limited application as a retrofit control option for natural gas-fired compressor drivers, and a case study for retrofit application showed significant problems, system re-engineering, and ultimately revisions to permit limits. However, rather than providing a detailed assessment of technical feasibility, the SCR cost analysis is presented to assess economic feasibility. The analysis primarily relies on Control Cost Manual methods and related EPA support documentation. A key input for the analysis is the capital cost, and a 2016 Control Cost Manual supplement that updated the SCR chapter of the Control Cost Manual was used to estimate the capital cost.

In addition to the SCR capital cost, an important assumption for the analysis is the estimate of actual NOx emissions. The current and anticipated ongoing operation of the turbine at Northern Border is lower than full load due to capacity requirements for the system. Based on operations for about 18 months through early 2019, average operation load was 24,000 hp. This is based on data from days the unit operated from June 2017 through mid-February 2019. The projection of actual emissions is used as the best estimate of ongoing operation and associated NOx emissions. Primary assumptions for the analysis include:

- A capital cost of $4,250,000 to achieve 75% reduction in NOx; based on Chapter 2 of the Control Cost Manual with the cost adjusted to 2018 using the consumer price index (CPI). The Control Cost Manual Table 2.1b information for SCR cost ($ per kilowatt) is interpolated as approximately $100 per kilowatt for a 28.3 MW unit. This cost basis is estimated because the three unit sizes included in the table (2, 12, and 80 MW) are not similar to the Northern Border unit size. The CPI adjustment is a factor of 1.5
- Anticipated average operating load for future operations of 24,000 hp (63% of ISO rated load). This is based on average operating load from June 2017 through mid-February 2019 (over 20 months). Operation during this period is anticipated to be consistent with future operations based on pipeline system demand. Load has been marginally higher in the past, but future operation is anticipated to be similar to or lower than recent operation.
- The permit indicates a guaranteed heat rate of 7,038 Btu/hp-hr (Low heating value based). For a high heating value basis (consistent with NOx emission factors), the heat rate would be approximately 7,750 Btu/hp-hr. With standard operation at less than full load, this is rounded up to 8,000 Btu/hp-hr for calculating the NOx emission rate in pounds per hour (lb.hr). Thus, the fuel rate is approximately 192 MMBtu/hr.
- Baseline (pre-SCR) NOx emissions are based on a best estimate of actual emissions. The NOx emission rate used is 0.117 lb/MMBtu. This value has been used for annual emission estimates based on a compliance test in 2003. In more recent years, the average value from 18 portable analyzer tests conducted at full load from May 2012 through September 2018 is 0.1156 lb/MMBtu. In more recent years and projecting forward, a lower load is anticipated, and that operation would

result in lower NOx emissions from the DLE-equipped unit. Thus, the assumed pre-SCR emission rate is a reasonable, conservatively high estimate.

- From the previous bullets, the NOx emission rate prior to SCR control is 22.5 lb/hr (i.e., 0.117 lb/MMBtu x 192 MMBtu/hr).
- Capital cost recovery is based on a twenty-year life and interest rate of 5.25% (consistent with the current prime rate). Longer life is not appropriate for catalytic systems which typically have a warranty of no longer than five years. It would be reasonable to assume a shorter life for capital recovery, and the twenty-year life is conservatively high.
- Annual operating hours have varied from year to year, but operation in the last year is anticipated to be representative of future operations. Annual operating hours were 6,835 in 2017 and 2,113 in 2018. For 2019, the turbine has operated only 181 hours through May. Relatively low operations similar to 2018 and 2019 are expected in the future, but for the cost evaluation, 4,500 annual operating hours was assumed based on the average of 2017 and 2018 operating hours (4,474 hours).
- Most other costs (direct and indirect installation costs, etc.) are based on the Control Cost Manual.
- Reagent cost is based on a conservatively low-cost estimate of $550 per ton for ammonia and a molar ratio (NOx / NH_3) of 1.1. The ammonia cost is based on information available on-line from the U.S. Department of Agriculture4 for the cost of ammonia.

The resulting NOx control cost is estimated to be $37,750 per ton.

Factor #2 – Time Necessary for Compliance

Retrofitting SCR would require a timeline of three years to five years. This time is required for engineering design, permitting, site preparation, installation, commissioning, and startup. Extended commissioning periods may be needed to address performance issues. The schedule would also need to consider the timing of facility outage to ensure that natural gas demand is not affected by the lost compression capacity. Based on the information provided, Montana has concluded that any required controls could be implemented by 2028.

Factor #3 – Energy and Non-Air Environmental Impacts

SCR for NOx results in a fuel penalty and requires use of electricity to drive reagent pumps. Performance loss and electrical usage would increase greenhouse gas (GHG) emissions from the facility. SCR would also introduce other air impacts such as ammonia emissions.

Factor #4 – Remaining Useful Life of the Source

The cost analysis assumes control technology life of twenty years for SCR. The turbine life is much longer and not limited if standard maintenance requirements are followed.

Step 5: Select Reasonable Progress Control/ Final State Recommendations

The four-factor analysis indicates a NOx cost effectiveness of $37,750 per ton for SCR. Several conservative assumptions tend to lower this cost. If alternatives were assumed that decreased parameters such as hours of operation, and average load, the cost per ton would increase. In addition, there are questions about technological feasibility for retrofitting SCR to an existing compressor driver turbine, especially when the unit will typically operate at a reduced load.

Montana has determined that SCR is cost prohibitive for the second planning period. Therefore, additional NOx control is not reasonable for the second planning period. Future planning periods may revisit the need for emission reductions.

7 LONG-TERM STRATEGY FOR SECOND PLANNING PERIOD

In this chapter, we describe Montana's long-term strategy (LTS) for visibility improvement, covering the 10-year period from 2018 to 2028. Section169A(b)(2)(B) of the CAA requires a RH SIP to include an LTS for making reasonable progress toward the national goal of remedying any existing visibility impairment in Class I areas resulting from human-caused air pollution and preventing future visibility impairment.

40 CFR 51.308(f)(2) contains the administrative rules EPA uses to execute the CAA's LTS requirements. Section 6.1.1 documented the required four-factor analyses (40 CFR 51.308(f)(2)(i)) and in this chapter, Montana addresses the additional requirements outlined in 40-CFR51.308(f)(2)(iv) – 5 Additional Factors and 40 CFR 51.308(f)(2)(ii) – Coordinated Emissions Management Strategies.

When developing the LTS, states must consider the effect of emission reductions due to ongoing pollution control programs; measures to mitigate the impacts of construction activities; Montana's smoke management plan; the effect of source retirements and replacement schedules; and the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions expected through 2028. This information is presented in Sections 7.1.1- 7.1.5.

Section 7.2 contains the coordinated emissions management strategies Montana and neighboring states followed to ensure reasonable progress occurs in Class I areas in the western region. The RHR requires that states with sources identified to "affect" another state's Class I area must consult with that state in order to develop coordinated emission management strategies containing the emission reductions necessary to make reasonable progress. Montana consulted with North Dakota, South Dakota, Wyoming, Utah, Idaho, Oregon and Washington, both during and independent from the WESTAR/WRAP-facilitated regional planning process. In this chapter, Montana demonstrates that we have included in our implementation plan all measures agreed to during state-to-state consultations or a regional planning process.

Montana reviewed the conclusions of the four-factor analyses in concert with the 5 additional factors, and considered out-of-state impacts, to build the content of the LTS. The LTS establishes the RPGs, which serve as benchmarks for measuring progress toward meeting the national visibility goal in 2064. Montana looked for improvements in visibility on the MIDs as a way to measure the success of our LTS and our progress towards the RPGs. Furthermore, emission reductions that affect the MIDs will also improve or maintain visibility on the clearest days. The RPGs, while not directly federally enforceable, must be met through measures contained in the state's long-term strategy through the year 2028. As required by 40 CFR 51.308(f)(2)(iii), Montana relied upon the technical analyses (including modeling, monitoring and emissions information) developed by WRAP and EPA to determine emission reduction measures necessary to make reasonable progress. These technical analyses and the resultant RPGs for each Class I area in Montana are documented in Chapter 8.

7.1 5 Required Steps in Establishing LTS 40 CFR 51.308(f)(2)(iv)

7.1.1 Emissions reductions due to ongoing pollution control programs

There are a number of federal and state control programs aimed at reducing emissions across various sectors that have the co-benefit of reducing haze. These programs are described in the following sections.

7.1.1.1 Montana Minor Source Permitting Program

EPA granted Montana authority to implement the state's minor source permitting program, located in the Administrative Rules of Montana Chapter 17.8, Subchapter 7 – Permit, Construction and Operation of Air Contaminant Sources. The primary purpose of the permitting program is to assure compliance with ambient air standards set to protect public health, assure that Best Available Control Technology (BACT) is utilized to reduce or eliminate air pollution emissions, and to prevent deterioration of clean air areas.

As part of Montana's SIP, all new emission sources that are required to obtain a Montana Air Quality Permit (MAQP) must use BACT. According to Administrative Rules of Montana (ARM) 17.8.752, the owner or operator of a new or modified emitting unit or emitting unit for which a Montana air quality permit is required shall install on the new or modified facility or emitting unit the maximum air pollution control capability that is technically practicable and economically feasible.[147] This provides that permitted emission rates are generally consistent across source categories and that emission rates are minimized.

New equipment that replaces older equipment is subject to a thorough emissions control review under Montana's permitting rules. Requiring BACT on all sources, including minor sources, ensures that emissions reductions occur on a continuing, long-term basis. While the Minor Source Permitting Program did not directly influence the 2028OTBa2 emissions scenario, use of BACT limits emissions increases from modifications as new permitted equipment (such as engines) will generally have lower emission rates than the older units being replaced.

7.1.1.2 Prevention of Significant Deterioration

In addition to serving other air quality priorities, Montana's Prevention of Significant Deterioration (PSD) program serves to limit visibility impairment from proposed major stationary sources or major modifications to existing facilities. Montana's PSD program has been successfully implemented since 1983 and is fully approved by EPA.[148] The PSD program requires sources (that meet the definition of new or major modifications) to model the emissions impacts on Class I Areas within 10 km of the source to determine if the change in emissions would exceed maximum allowable increases over the minor source baseline concentrations for $PM_{2.5}$, PM_{10}, SO_2 and NO_2. The PSD New Source Review (NSR) permitting program is described in ARM Chapter 17.8, Subchapter 8. The PSD program also did not directly influence

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[147] All Administrative Rules of Montana discussed in this report can be accessed through the Montana Secretary of State web portal at http://www.mtrules.org/gateway/ChapterHome.asp?Chapter=17%2E8

[148] EPA, Approval and Promulgation of State Implementation Plans – Revision to the Montana Prevention of Significant Deterioration Regulations, 48 Fed. Reg. 20231 (5 May 1983), Available at: http://www.heinonline.org/HOL/Page?handle=hein.fedreg/048088&size=2&collection=fedreg&id=23.

the projected 2028 emission inventory but serves to reduce the growth in new emissions by preventing large increases that could cause significant decline in the Class I Areas.

7.1.1.3 New Source Performance Standards – 40 CFR Part 60 and National Emission Standards for Hazardous Air Pollutants – 40 CFR Part 63

Montana administers a delegated Clean Air Act Part 70, or Title V Operating Permit Program, thereby providing Montana with a mechanism to receive automatic delegation to implement the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) programs in the State.[149] Annually, the State undergoes rulemaking to incorporate by reference the most recent versions of these standards. Within the NSPS and NESHAP programs are numerous measures that have reduced visibility-impairing emissions nationally over time. As new standards continue to be developed, additional emission decreases will be realized. Montana does not have many affected facilities in certain NSPS and NESHAP source categories. However, neighboring states that do have more industry and contribute to visibility impairment in Montana comply with these standards, thus providing a level of visibility protection in Montana Class I areas.

7.1.1.4 National Petroleum Refinery Initiative

EPA's national Petroleum Refinery Initiative is an enforcement and compliance strategy to address air emissions from the nation's petroleum refineries.[150] Since 2000, EPA has entered into 17 settlements with U.S. companies that refine over 75% of the nation's petroleum.

The initiative resulted in emission decreases in the first planning period at Montana refineries, including Calumet, Phillips 66, CHS, Inc., and ExxonMobil. Emission reductions are expected to continue into the second planning period.

7.1.1.5 Federal Mobile Source Regulations

The Federal Motor Vehicle Control Program has already realized large emissions reductions in NO_x, SO_2, VOCs, and PM. In 2014, EPA published the Tier 3 motor vehicle emission and fuel standards, effective 2017. By setting both new vehicle emissions standards and a new gasoline sulfur standard, the program aims to reduce both tailpipe and evaporative emissions from passenger cars, light-duty trucks, medium duty passenger vehicles, and some heavy-duty vehicles. Additional programs include the following:

Federal onroad measures

- National low-emission vehicle standards
- Heavy-duty diesel standards

Federal offroad measures

- Lawn and garden equipment

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[149] EPA, Clean Air Act Full Approval of Operating Permit Program; State of Montana, 65 Fed. Reg. 37049 (13 Jun. 2000), Available at: https://www.federalregister.gov/d/00-14768.
[150] EPA, Petroleum Refinery National Case Results, https://www.epa.gov/enforcement/petroleum-refinery-national-case-results. (accessed 6/8/2021)

- Locomotive engine standards
- Compression ignition standards for vehicles and equipment
- Recreational marine engine standards

7.1.1.6 Mercury and Air Toxics Rule

On February 16, 2012, EPA finalized national standards to reduce mercury and other toxic air pollution from coal and oil-fired power plants as part of 40 CFR 63, Subpart UUUUU – National Emissions Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units, also referred to as the Mercury and Air Toxics Standards (MATS).[151] The final rule established power plant emission standards for mercury, acid gases, and non-mercury metallic toxic pollutants. EPA projected 2015 emissions with the standards in place – emissions of mercury, $PM_{2.5}$, SO_2, and acid gas will be reduced by 75, 19, 41, and 88%, respectively, from coal-fired EGUs greater than 25 megawatts (MW).[152] Compliance with MATS was required by April 16, 2015. Emission reductions that occur as a result of MATS, both in the form of particles and gases that may form aerosols, will reduce the amount of light extinction and reduce anthropogenic causes of haze.

Montana had previously adopted rules to control mercury in response to the proposed federal rulemaking known as the Clean Air Mercury Rule (CAMR), under which states were originally required to adopt a set of federal market trading standards for mercury or develop their own "equivalent" standard. Montana adopted its own mercury standard referenced as the Montana Mercury Rule.[153] The Montana Mercury Rule (ARM 17.8.771) was adopted effective October 27, 2006, and required compliance with mercury emission limits by January 1, 2010.[154] Although CAMR was vacated by the District of Columbia Court of Appeals in 2008, the Montana Mercury Rule was already in place by the time MATS was finalized.

There were five affected coal-fired facilities under the Montana Mercury Rule and MATS. These included the Colstrip Steam Electric Station, J.E. Corette Steam Electric Station, Montana-Dakota Utilities (MDU) Lewis & Clark Plant, Colstrip Energy Limited Partnership, and Rocky Mountain - Hardin.

<u>Colstrip Steam Electric Station</u>

Colstrip's mercury limit under the Montana Mercury rule is Colstrip is 0.9 pounds per trillion British thermal units (lb/TBtu) on a 12-month rolling average. Colstrip is required to meet a MATS limit of 1.2 lbs/TBtu on a 30-day rolling average. The compliance date for Colstrip was April 16, 2015, but the facility was granted a one-year extension to April 16, 2016. The extension provided a full one-year grace period for all required MATS limits, and during that time, upgrades were completed for particulate on Colstrip scrubbers to improve particulate removal.

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[151] EPA, National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units, 77 FR 9304 (16 Feb. 2012), Available at: https://www.gpo.gov/fdsys/pkg/FR-2012-02-16/pdf/2012-806.pdf.
[152] Ibid. p. 9424.
[153] EPA, Clean Air Mercury Rule, https://www3.epa.gov/airtoxics/utility/utiltoxpg.html.(accessed 11/10/19)
[154] ARM 17.8.771 Mercury Emission Standards for Mercury-Emitting Generating Units, Available at: http://www.mtrules.org/gateway/RuleNo.asp?RN=17%2E8%2E771.

PM emissions may be used as a surrogate for actual heavy metal emissions to meet the heavy metal limits in the MATS rule. Reductions in PM emissions reflect a broad category of particulate and gaseous species that contribute to the PM category. The mercury control system installed at Colstrip to meet Montana's Mercury Rule also allowed Colstrip to meet the MATS requirements for mercury capture and removal. In addition, existing controls on the units adequately remove acid gases covered by the MATS rule (using SO_2 as a surrogate). Prior to shutdown, Units 1 & 2 scrubber upgrades (sieve trays installed) were made for additional PM control and resulted in the secondary benefit of significant SO_2 reduction. The additional controls on Units 1 & 2 reduced emissions in the first part of this planning period, with the shutdown of these units ultimately providing the largest emission reduction realized in in this demonstration.

J.E. Corette Steam Electric Station

The J.E. Corette facility was also subject to MATS, but opted not to install the required control equipment, resulting in its shutdown in April 2015.

MDU Lewis & Clark Plant

During its operation, the MDU Lewis & Clark Plant burned lignite coal, a different type of coal than the Colstrip Steam Electric Station, and therefore had different limits than Colstrip. For this facility, the Montana Mercury Rule required a limit of 1.5 lb/TBtu on a rolling 12-month average, and MATS required 4.0 lb/TBtu on a rolling 30-day average. MDU Lewis & Clark upgraded the existing scrubber and installed sieve trays to satisfy the non-mercury metals emission standard of 0.03 lbs/MMBtu for filterable PM in 2015. The system was fully operational in early 2016. Prior to shutdown, these additional controls resulted in further particulate reductions plus a co-benefit of significant SO_2 emission reductions.

Rocky Mountain Power – Hardin

Also known as the Hardin Generating Station, this facility consists of a single coal-fired boiler with single steam turbine rated at 116 gross megawatts. Hardin must achieve a 0.9 lb/TBu mercury limit on a 12-month rolling average to comply with the Montana Mercury Rule, and a limit of 1.2 lb/TBtu on a 30-day average to comply with MATS. Hardin installed carbon injection controls to meet the limit in the Montana Mercury Rule.

Colstrip Energy Limited Partnership (CELP)

This facility often is referred to as the Rosebud Power Plant and also uses coal from the same geographic area as the Colstrip Steam Electric Station but is able to utilize a lower grade coal sometimes referred to as "waste coal". The facility has a single coal-fired boiler rated for 39 gross megawatts. CELP began planning for their compliance with the Montana Mercury Rule as early as December 2008, when Montana DEQ received an application to modify their Montana Air Quality Permit. CELP is meeting the same limits as Hardin, 0.9 lb/TBtu mercury limit on a 12-month rolling average and a MATS limit of 1.2 lb/TBtu on a 30-day average.

7.1.1.7 Revised National Ambient Air Quality Standards

According to EPA, the primary NAAQS serve to protect public health, including "the health of 'sensitive' populations such as asthmatics, children, and the elderly." In addition, secondary NAAQS protect public welfare, "including protection against decreased visibility and damage to animals, crops, vegetation, and buildings."[155] As EPA continues to revise NAAQS, the standards put pressure on states to manage pollution sources, often resulting in emissions decreases, including of pollutants responsible for visibility impairment.

The following NAAQS revisions have occurred since the baseline period (2000-2004) for the Regional Haze program. Each of these standards must be taken into account when permitting new or modified major sources, including fossil fuel-fired power plants, boilers, and a variety of other operations. Any reductions in SO_2, NO_x, or $PM_{2.5}$ brought about by these revised standards will enhance protection of visibility in Montana Class I Areas.

2010 SO_2 NAAQS

On June 2, 2010, EPA strengthened the SO_2 NAAQS by revising the primary SO_2 standard to 75 parts per billion (ppb) 3-year average of the 99th percentile of the yearly distribution of 1-hour daily maximum SO_2 concentrations. This short-term standard is significantly more stringent than the revoked standards of 0.140 parts per million (ppm) averaged over 24-hours and 0.030 ppm averaged over a calendar year.

On August 21, 2015, EPA released the 2010 SO_2 Data Requirements Rule (DRR), which instructs states to evaluate areas surrounding facilities with 2000 tons/year or more SO_2 emissions.[156] In Montana, all units at the Colstrip Steam Electric Station were modeled under the DRR since the facility exceeds the 2000 ton/year threshold. As a result, Montana requested to designate Rosebud County as "attainment" for SO_2. Montana had one area in Yellowstone County that was designated as nonattainment. The area was redesignated to attainment under a maintenance plan effective on June 9, 2016.[157]

On February 25, 2019, EPA issued a decision to retain the existing primary NAAQS for SO_2.The decision to retain the existing secondary SO_2 NAAQS has held since 2012.

2010 NO_2 NAAQS

Effective on April 12, 2010, EPA established a new 1-hour primary standard to supplement the existing annual standard. This 1-hour standard was set at a level of 100 ppb**,** based on the 3-year average of the 98th percentile of the yearly distribution of 1-hour daily maximum concentrations.[158] Along with the new standard, EPA set new requirements to monitor NO_2 levels near major roadways. Montana does not have a

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155 EPA, "NAAQS Table" (last updated 20 Dec. 2016), Available at: https://www.epa.gov/criteria-air-pollutants/naaqs-table (accessed 4/14/2017).

156 EPA, Data Requirements Rule for the 2010 1-Hour Sulfur Dioxide (SO_2) Primary National Ambient Air Quality Standard (NAAQS); Final Rule, 80 FR 51052 (21 Aug. 2015), Available at: https://www.gpo.gov/fdsys/pkg/FR-2015-08-21/html/2015-20367.htm.

157 EPA, Designation of Areas for Air Quality Planning Purposes; Redesignation Request and Associated Maintenance Plan for Billings, MT 2010 SO2 Nonattainment Area, 81 FR 28718 (10 May 2016), Available at: https://www.gpo.gov/fdsys/pkg/FR-2016-05-10/html/2016-10451.htm.

158 EPA, Primary National Ambient Air Quality Standards for Nitrogen Dioxide; Final Rule, 75 FR 6474 (9 Feb. 2010), https://www.gpo.gov/fdsys/pkg/FR-2010-02-09/pdf/2010-1990.pdf. See also EPA, "Nitrogen Dioxide (NO_2) Pollution," last updated 5 April 2018, https://www.epa.gov/no2-pollution/2010-primary-national-ambient-air-quality-standards-naaqs-nitrogen-dioxide.

population center with a density high enough to warrant or trigger the near-roadway monitoring requirement. In 2012, EPA designated every county in Montana as Unclassifiable/Attainment for the 2010 NO_2 NAAQS.

On April 6, 2018, EPA issued a decision to retain the current NAAQS for oxides of nitrogen (NOx).

2012 PM2.5 NAAQS

On January 15, 2013, EPA published a final rule strengthening the annual NAAQS for fine particles ($PM_{2.5}$) from 15.0 micrograms per cubic meter (μg/m^3) to 12.0 μg/m^3.[159] According to EPA, "Emission reductions from EPA and states rules already on the books will help 99 percent of counties with monitors meet the revised $PM_{2.5}$ standards without additional emission reductions."[160] These rules include many of the regulations discussed above, such as clean diesel rules for vehicles and fuels, and rules to reduce pollution from power plants.

On December 7, 2020, EPA announced its decision to retain, without revision, the existing primary and secondary NAAQS) for particulate matter. On June 10, 2021, EPA subsequently announced it will reconsider the prior administration's December 2020 decision.[161]

State Implementation Plan

The State Implementation Plans (SIPs) for nonattainment and maintenance areas contain control measures that may also contribute to the reduction of visibility-impairing pollution. Table 7-1. Existing Montana Nonattainment Areas shows the status of all the existing nonattainment areas and maintenance areas in Montana. For each nonattainment area, Montana drafted a SIP with control measures to bring the area back into attainment with the associated NAAQS.

Since the 2017 Progress Report, Montana has prioritized work toward redesignating many of our non-attainment areas (Table 7-1). To date, all but one of Montana's nonattainment areas have been redesignated.

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159 EPA, National Ambient Air Quality Standards for Particulate Matter, 78 FR 3086 (15 Jan. 2013), Available at: https://www.gpo.gov/fdsys/pkg/FR-2013-01-15/pdf/2012-30946.pdf.

160 EPA, "Overview Of EPA's Revisions to the Air Quality Standards for Particle Pollution (Particulate Matter)," Available at: https://www.epa.gov/sites/production/files/2016-04/documents/overview_factsheet.pdf (accessed 24 Apr. 2017).

161 EPA, "EPA to Reexamine Health Standards for Harmful Soot that Previous Administration Left Unchanged," (10 June 2021), Available at: https://www.epa.gov/newsreleases/epa-reexamine-health-standards-harmful-soot-previous-administration-left-unchanged

Table 7-1. Existing Montana Nonattainment Areas

Pollutant	Standard Violated	Community	Violated Standard level	Current Standard	2020 Design Value (With EE)‖	2020 Design Value (Without EE)‖	Nonattainment Date	Attainment/ Maintenance
Sulfur Dioxide	1971 (24-hr)	Laurel	0.14 ppm	NA	0.011 ppm*	NA	3/3/1978	
		East Helena			0.071 ppm†	NA	11/15/1990	10/11/2019[162]
	2010 (1-hr)	Billings	75 ppb	75 ppb	20 ppb	NA	10/4/2013	6/9/2016[163]
Particulate (PM2.5)	1997 (Annual)	Libby	15 µg/m³	12 µg/m³	13.3 µg/m³	11.0 µg/m³	4/5/2005	6/24/2020**
Particulate (PM10)‡	1987 (24-hr)	Kalispell	150 µg/m³	150 µg/m³	131 µg/m³	90 ug/m³	11/15/1990	7/27/2020[164]
		Columbia Falls			107 µg/m³	77 µg/m³	11/15/1990	7/27/2020[164]
		Whitefish			139 µg/m³	95 µg/m³	10/19/1993	7/08/2022[165]
		Libby			131 µg/m³	85 µg/m³	11/15/1990	7/27/2020[164]
		Missoula			123 µg/m³	71 µg/m³	11/15/1990	6/24/2019[166]
		Thompson Falls			148 µg/m³	66 µg/m³	1/20/1994	7/08/2022[167]
		Butte			93 µg/m³	72 µg/m³	11/15/1990	7/26/2021[168]
Carbon Monoxide	1971 (8-hour)	Billings	9 ppm	9 ppm	NA	NA	3/3/1978	4/22/2002[169]
		Great Falls			NA	NA	3/3/1978	7/8/2002[170]
		Missoula			NA	NA	3/3/1978	9/17/2007[171]
Lead	1978 (Cal. Qtr.)	East Helena	1.5 µg/m³	0.15 µg/m³	1.02 µg/m³§	NA	1/6/1992	10/11/2019[172]

* 2014 2nd high 24-hour value (30-111-0016), monitoring ceased in June 2015.

** Submitted to EPA for approval on 6-24-2020.

† 2001 2nd high 24-hour value for monitored max value (30-043-0913), monitoring ceased in May 2001.

‡ PM_{10} Design Concentrations are the 2018-2020 concentrations using the table lookup method, only PM_{10} flagged events removed above 98. For $PM_{2.5}$, all data with exceptional event flags were removed.

§ 2001 maximum calendar quarter average (30-049-0727), monitoring ceased in December 2001.

‖ Exceptional Events (EE) – EE are natural or unusual events that can affect air quality but that are not reasonable controllable using the techniques that air agencies use to attain or maintain the NAAQS. Additional information on Montana nonattainment areas, including designation references and current EPA status of areas, can be found at https://www3.epa.gov/airquality/urbanair/sipstatus/reports/mt_areabypoll.html

162 https://www.federalregister.gov/d/2019-19576/
163 https://www.federalregister.gov/d/2016-10451/
164 https://www.federalregister.gov/d/2020-12077/
165 https://www.federalregister.gov/d/2022-11580/

7.1.2 Measures to mitigate the impacts of construction activities

In addition to accounting for specific emission reductions due to ongoing air pollution programs as required under 40 CFR 51.308(f)(2)(iv)(B), states are also required to consider the air quality benefits of measures to mitigate the impacts of construction activities (40 CFR 51.308(f)(2)(iv)(B)).

Relative to sulfate, nitrate and elemental carbon, fine soils and coarse mass particulates are very small contributors to haze in Montana's Class I areas. (Figure 6-1– Figure 6-11). Coarse mass tends to drop out of the atmosphere quickly, however, fine soils can be transported longer distances. A common source of fine soil is windblown dust from dust storms. These events are not considered anthropogenic in nature (categorized as extreme episodic events with respect to the 2017 RHR revised approach to tracking visibility progress), and are less prevalent in Montana.

Construction activities are a source of both fine and coarse particulate matter. Montana's ARM 17.8.308 - Airborne Particulate Matter rule addresses measures to be used to mitigate particulate matter emissions from:

- production, handling, transportation or storage of any material,
- the use of any street, road, or parking lot,
- operation of a construction site or demolition project.

In particular, the rule states that reasonable precautions be taken to prevent or eliminate emissions. Reasonable precautions, as defined in ARM 17.8.301(18) means "…any reasonable measures to control emissions of airborne particulate matter. Determination of what is reasonable will be accomplished on a case-by-case basis taking into account energy, environmental, economic, and other costs." These emissions standards apply to any source of air emissions regardless of permitted status.

Examples of reasonable precautions include: a stationary source shall not exhibit an opacity of 20% or greater averaged over six consecutive minutes, or a source of road dust must take reasonable precautions to ensure roads are sprayed with a dust suppressant. This rule also addresses particulate matter sources operating within a nonattainment area.

7.1.3 Source retirement and replacement schedules

When determining controls needed to meet reasonable progress goals for the second planning period, Montana considered reductions that recently occurred and those that will occur in the second planning period. Facility closures are the most significant emissions reductions in this planning period.

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[166] https://www.federalregister.gov/d/2019-10797/

[167] https://www.federalregister.gov/d/2022-11581/

[168] https://www.federalregister.gov/d/2021-13618/

[169] https://www.federalregister.gov/d/02-4062/

[170] https://www.federalregister.gov/d/02-11448/

[171] https://www.federalregister.gov/d/E7-15784/

[172] https://www.federalregister.gov/d/2019-19541/

Table 7.2 shows the emission changes between the RepBase2 and 2028OTBa2 inventories and used as inputs to regional haze modeling to set the 2028 RPGs. Only three facilities modeled a slight emissions decrease in 2028. The remaining facilities were modeled in 2028 with either the same emissions as were included in RepBase2 or a slight emissions increase.

Table 7-2. Facilities with Emissions Changes between RepBase2 & 2028 OTBa2 Scenarios

Facility Name	Baseline	RepBase2 NOx	RepBase2 SO_2	2028 OTBa2 NOx	2028 OTBa2 SO_2
2028OTBa2 = 0 (Unit closures during this planning period)					
J.E. Corette Steam Electric Station*	2014-2015	499.6	905.3	0.0	0.0
Colstrip Steam Electric Station #1	2014-2016	3619.8	2022.3	0.0	0.0
Colstrip Steam Electric Station #2	2014-2016	2523.2	2350.7	0.0	0.0
MDU – Lewis & Clark Station	2017-2018	579.4	22.6	579.4**	22.6**
RepBase2 > 2028OTBa2 (slight emissions decreases projected in 2028)					
Colstrip Steam Electric Station #3	2014-2016	4228.0	2359.0	3933.0	2350.0
Colstrip Steam Electric Station #4	2014-2016	4228.0	2359.0	3833.0	2350.0
CHS Inc – Laurel Refinery	2017-2018	408.6	251.2	393.0	215.0
RepBase2 < 2028OTBa2 (slight emissions increases projected in 2028)					
Ash Grove Cement	2017-2018	810.3	101.6	981.5	120.8
GCC Trident, LLC	2017-2018	1204.8	7.5	1338.0	7.5
RepBase2 = 2028OTBa2 (no change between scenarios)					
Weyerhaeuser-Columbia Falls	2014-2017	969.6	14.8	969.6	14.8
Yellowstone Power Plant	2014-2017	404.3	1732.0	404.3	1732.0
Roseburg Forest Products	2014-2017	299.3	3.3	299.3	3.3
Colstrip Energy Ltd Partnership	2014-2016	892.6	1232.6	892.3	1231.0
Montana Sulphur & Chemical	2017-2018	5.8	1014.0	5.8	1014.0
Graymont Western Us Inc.	2017-2018	367.8	238.4	367.8	238.4
Exxonmobil Billings Refinery	2015-2016	427.4	539.4	427.4	539.4
F.H. Stoltze Land And Lumber Co	2017-2018	73.9	7.1	73.9	7.1
Sidney Sugar Facility	2017-2018	224.0	61.7	224.0	61.7
Phillips 66 Billings Refinery	2017-2018	563.5	100.7	563.5	100.7
Weyerhaeuser-Evergreen	2014-2017	129.5	*--	129.5	*--
N. Border Pipeline Co. Station #3	2017-2018	56.0	2.6	56.0	2.6
	Total	**22,515.4**	**15,325.8**	**14,892.0**	**9,988.3**
			% Reduction between RepBase2 and 2028	**33.9**	**34.8**
	Total (w/o J.E. Corette)	**22,015.70**	**14,420.00**	**14,891.90**	**9,988.30**

Facility Name	Baseline	RepBase2 NOx	RepBase2 SO_2	2028 OTBa2 NOx	2028 OTBa2 SO_2
% Reduction between RepBase2 and 2028(w/o J.E. Corette)				**32.4**	**30.7**
*As an oversight, emissions from J.E. Corette were not included in the RepBase2 modeling. Because of this oversight, the 2028 RPGs for the affected Class I areas may be overestimated because it doesn't reflect the closure of J.E. Corette. The average 2014-2015 emissions of NO_x and SO_2 are listed in this table for informational purposes only. **These emissions were modeled in 2028OTBa2, but zeroed out in the PAC2 run, therefore, the RPGs based on the 2028OTBa2 are considered conservative.					

Combined NO_x and SO_2 emissions were reduced **36 percent** from RepBase2 to 2028OTBa2. However, the RepBase2 modeling scenario did not include NO_x and SO_2 emissions from J.E. Corette (the facility closed during the representative baseline period). Therefore, the RepBase2 emissions scenario underestimated emissions of NO_x by 500 tpy and SO_2 by 900 tpy. This means that for affected Class I areas (in the MT FIP, J.E. Corette was found to impact North Absorka WA, Yellowstone NP, U.L. Bend WA, Gates of the Mountains WA and Red Rocks Lakes WA[173]) the 2028 RPG does not take into account emissions reductions from J.E. Corette's closure.

The combined NOx and SO_2 RepBase2 emissions from the four units (J.E. Corette, Colstrip Units 1 & 2, and MDU – Lewis & Clark) is 12,522 tons per year. The combined NOx and SO_2 2028OTBa2 emissions from the remaining four factor sources is 24,880 tons per year. It can be seen that the closures/retirements represent a significant emissions reduction when compared to the future projected emissions for all sources represented in Table 7-2.

Montana proposes the source closures and retirements that have occurred in this planning period as the LTS measures that are necessary to make reasonable progress by 2028. Operating Permit #OP0513-14[174], for Talen Montana, LLC – Colstrip Steam Electric Station included the Unit 1 & 2 enforceable shutdown date of July 1, 2022. In early January 2020, Colstrip shutdown and ceased operation of Units #1 and #2 (see Appendix D for more information). Because the units have ceased operations and are no longer permitted, this meets the LTS requirement to be federally enforceable.

MDU – Lewis & Clark requested an administrative amendment to their Montana Air Quality Permit MAQP0691-06 to remove all permit references to Emitting Unit #1 (Boiler #1) as the source had been

[173] EPA, Approvals and Promulgations of Air Quality Implementation Plans: Montana; State Implementation Plan and Regional Haze Federal Implementation Plan Proposed Rule, 82 Fed. Reg. 2012-08367. Page 24000. (April 19, 2012), Available at: https://www.regulations.gov/document/EPA-R08-OAR-2011-0851-0001

[174] https://www.regulations.gov/document/EPA-R08-OAR-2019-0047-0022

permanently removed from service.[175] Montana believes this permit update meets the LTS requirement to be federally enforceable.

7.1.4 Basic smoke management practices

Montana implements an EPA-approved Smoke Management Plan (SMP) to regulate open burning and prescribed fire activities. The SMP consists of Montana's official open burning rules, as written in the Administrative Rules of Montana, Title 17, Chapter 8, Subchapter 6.[176] The SMP considers smoke management techniques and the visibility impacts of smoke when developing, issuing or conditioning permits, and when making dispersion forecast recommendations. The SMP incorporates BACT as the visibility control measure to meet the requirements of the RHR. The State works closely with the Montana/Idaho Airshed group[177] to coordinate burning activities conducted by the large, major open burners and federal land managers. Major burners in Montana are defined as "any person, agency, institution, business, or industry conducting any open burning that, on a statewide basis, will emit more than 500 tons per calendar year of carbon monoxide or 50 tons per calendar year of any other pollutant." Examples of major open burners in Montana include the U.S. Forest Service and the Bureau of Land Management.

During the fall and winter burn seasons, Montana's open burn coordinator and meteorologist are actively involved in day-to-day burn decisions, and evaluate burn type, size, and location using dispersion forecasts. Through this coordination and the required minor burn permitting included in the SMP, anthropogenic smoke emissions are closely monitored and regulated. In addition, as mentioned above, burners must follow BACT, which aims to limit smoke impacts due to burning. A full list of BACT requirements for burners can be found in ARM 17.8.601. During open burn season (March through August) Montana is not involved in the day-to-day decisions of burners, although all other aspects of the Montana open burning rules still apply, including BACT.

Additionally, Montana participates in the newly-formed WRAP Fire & Smoke Group[178]. The scope of this group includes smoke management planning and coordination between western states and work on analysis and planning activities related to tracking fire activity and emissions inventories for smoke emissions.

7.1.5 Anticipated net effect on visibility due to projected changes in point, area and mobile emissions in this planning period

The anticipated net effect on visibility due to the projected changes in emissions this planning period are shown in Table 8-2 -Table 8-4. These tables show the 2028 RPG compared to the 2000-2004 baseline for both the most impaired days and the clearest days.

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[175] Montana Air Quality Permit MAQP 0691-07, (8 Sept. 21), Available at: https://deq.mt.gov/files/Air/AirQuality/Documents/ARMpermits/0691-07.pdf

[176] ARM 17.8.6: Open Burning, Available at: https://rules.mt.gov/gateway/Subchapterhome.asp?scn=17%2E8.6

[177] Montana Idaho Airshed Management System. Available at: https://mi.airshedgroup.org/

[178] Fire & Smoke Work Group. https://www.wrapair2.org/fswg.aspx (accessed 4/5/2021).

7.2 COORDINATED EMISSION MANAGEMENT STRATEGIES

As required in 40 CFR 51.308(f)(2), Montana determined which Class I area(s) in other states may be affected by Montana's emissions. Likewise, Montana identified out-of-state sources that may be impacting Montana Class I areas. Montana consulted with surrounding states directly and through the WESTAR-WRAP regional planning process to pursue a coordinated course of action designed to assure reasonable progress in Class I areas, as described in the following sections.

7.2.1 Interstate impacts reasonably anticipated to contribute to visibility impairment in nearby Class I areas

40 CFR 51.308 (f)(2)(ii) outlines the requirement for states that are reasonably anticipated to contribute to visibility impairment in out-of-state Class I areas to consult with those affected states. 40 CFR 51.308(f)(2)(ii)(A) requires a state to demonstrate that it has included in its implementation plan all measures agreed to during state-to-state consultation. Lastly, 40 CFR 51.308(f)(2)(ii)(B) directs states to consider any emission reduction measures identified by other States for their sources as necessary to make reasonable progress in the Class I area. Put simply, this section documents that Montana has:

- consulted with neighboring states,
- included any agreed upon measures during the consultations,
- and considered any recommendations from other states to reduce emissions from Montana that impact neighboring Class I areas.

To begin, Montana used the WEP/AOI analyses to identify significant emission sources that are upwind from targeted Class I areas. This analysis looked at sources affecting Montana Class I areas first, then a second analysis looked for out-of-state Class I areas that may be impacted by Montana sources.

The sources are ordered based on their emission "rank", or the influence of those sources on each Class I area monitor. Table 7-3 and Table 7-4 identify the sources of nitrate and sulfate, both in Montana and out-of-state, that were identified by the WEP/AOI/Rank Point analysis as impacting at least one of Montana's Class I areas. Facilities on Tribal lands are also listed. The tables also indicate whether the listed sources were considered for additional controls through a four-factor analysis, and if not, lists the source as "screened out" from additional control analysis.

Table 7-3. Upwind NO_3 Sources affecting Montana Class I area

CIA Code	NO_3 Rank	Facility Name	State	WEP_NO_3	4-Factor by State?
CABI1	1	Clearwater Paper Corp - PPD & CPD	ID	27,749	Yes
CABI1	2	Weyerhaeuser-Columbia Falls	MT	23,733	Yes
CABI1	3	Plummer Forest Products, Inc. - Post Falls	ID	14,471	No
CABI1	4	Waste To Energy	WA	13,272	Screened Out
CABI1	5	Spokane Intl Aiport	WA	10,787	Screened Out
CABI1	6	Stimson Lumber Company - Plummer Operation	ID-Tribal	10,685	No

CABI1	7	Idaho Forest Group LLC - Chilco	ID	9,949	No
CABI1	8	Transcanada GTN System	WA	9,567	Screened Out
CABI1	9	Kaiser Trentwood	WA	9,057	Screened Out
CABI1	10	Potlatch Land and Lumber, LLC - St. Maries	ID-Tribal	8,543	No

CIA Code	NO_3 Rank	Facility Name	State	WEP_NO_3	4-Factor by State?
GAMO1	1	Ash Grove Cement	MT	195,243	Yes
GAMO1	2	Graymont Western Us Inc.	MT	46,086	Yes
GAMO1	3	Oldcastle - Trident Plant	MT	22,593	Yes
GAMO1	4	Roseburg Forest Products	MT	6,042	Yes
GAMO1	5	Calumet Montana Refining	MT	5,463	No
GAMO1	6	Clearwater Paper Corp - PPD & CPD	ID	4,039	Yes
GAMO1	7	Weyerhaeuser-Columbia Falls	MT	2,880	Yes
GAMO1	8	Weyerhaeuser N.R. Company	WA	2,485	Yes
GAMO1	9	Boise Paper	WA	2,156	Yes
GAMO1	10	Colstrip Steam Electric Station	MT	1,913	Yes

CIA Code	NO_3 Rank	Facility Name	State	WEP_NO_3	4-Factor by State?
GLAC1	1	Weyerhaeuser-Columbia Falls	MT	5,819,418	Yes
GLAC1	2	F.H. Stoltze Land And Lumber Co	MT	411,598	Yes
GLAC1	3	Weyerhaeuser-Evergreen	MT	401,715	Yes
GLAC1	4	Clearwater Paper Corp - PPD & CPD	ID	51,342	Yes
GLAC1	5	Roseburg Forest Products	MT	22,915	Yes
GLAC1	6	Flathead Electric Lfge Facility	MT	21,392	No
GLAC1	7	Ash Grove Cement Company	OR	18,166	No
GLAC1	8	Boise Paper	WA	13,303	Yes
GLAC1	9	Waste To Energy	WA	13,143	Screened Out
GLAC1	10	Portland Intl Airport	OR	10,894	No

CIA Code	NO_3 Rank	Facility Name	State	WEP_NO_3	4-Factor by State?
LOST1	1	Tioga Gas Plant	ND	1,206,796	Yes

LOST1	2	Coyote Station	ND	914,488	Yes
LOST1	3	Leland Olds Station	ND	663,400	Yes
LOST1	4	Coal Creek Station	ND	657,830	Yes
LOST1	5	Milton R. Young Station	ND	651,531	Yes
LOST1	6	Antelope Valley Station	ND	468,469	Yes
LOST1	7	Great Plains Synfuels Plant	ND	346,484	Yes
LOST1	8	MDU - Lewis & Clark Station	MT	78,450	Yes
LOST1	9	Colstrip Steam Electric Station	MT	74,013	Yes
LOST1	10	Clark's Creek Compressor Station	ND-Tribal	72,747	No

CIA Code	NO_3 Rank	Facility Name	State	WEP_NO_3	4-Factor by State?
MELA1	1	Coyote Station	ND	311,514	Yes
MELA1	2	Coal Creek Station	ND	204,960	Yes
MELA1	3	MDU - Lewis & Clark Station	MT	199,929	Yes
MELA1	4	Milton R. Young Station	ND	155,489	Yes
MELA1	5	Antelope Valley Station	ND	150,526	Yes
MELA1	6	Leland Olds Station	ND	149,274	Yes
MELA1	7	Tioga Gas Plant	ND	136,712	Yes
MELA1	8	Great Plains Synfuels Plant	ND	111,708	Yes
MELA1	9	Colstrip Steam Electric Station	MT	103,497	Yes
MELA1	10	N. Border Pipeline Co Sta. 3	MT	89,280	Yes

CIA Code	NO_3 Rank	Facility Name	State	WEP_NO_3	4-Factor by State?
MONT1	1	Roseburg Forest Products	MT	29,837	Yes
MONT1	2	Clearwater Paper Corp - PPD & CPD	ID	5,779	Yes
MONT1	3	Ash Grove Cement	MT	2,451	Yes
MONT1	4	Boise Paper	WA	2,080	Yes
MONT1	5	Weyerhaeuser-Columbia Falls	MT	1,639	Yes
MONT1	6	Portland Intl Airport	OR	1,312	No
MONT1	7	The Amalgamated Sugar Company LLC	ID	1,134	Yes
MONT1	8	Weyerhaeuser NR Company	WA	1,083	Yes
MONT1	9	Ash Grove Cement Company	OR	901	No

MONT1	10	Dillard	OR	887	Yes

CIA Code	NO_3 Rank	Facility Name	State	WEP_NO_3	4-Factor by State?
NOAB1	1	Elk Basin Gas Plant	WY	46,158	Yes
NOAB1	2	Colstrip Steam Electric Station	MT	15,630	Yes
NOAB1	3	P4 Production LLC (TV Facility)	ID	11,169	Yes
NOAB1	4	Oldcastle - Trident Plant	MT	10,905	Yes
NOAB1	5	Billings Refinery	MT	8,841	Yes
NOAB1	6	Frannie Lime Plant	WY	8,222	No
NOAB1	7	Exxonmobil Billings Refinery	MT	6,525	Yes
NOAB1	8	Yellowstone Power Plant	MT	6,182	Yes
NOAB1	9	CHS INC Refinery Laurel	MT	4,818	Yes
NOAB1	10	Western Sugar Cooperative	MT	3,890	No

CIA Code	NO_3 Rank	Facility Name	State	WEP_NO_3	4-Factor by State?
SULA1	1	Clearwater Paper Corp - PPD & CPD	ID	14,515	Yes
SULA1	2	Ash Grove Cement	MT	5,008	Yes
SULA1	3	Roseburg Forest Products	MT	4,155	Yes
SULA1	4	Oldcastle - Trident Plant	MT	3,134	Yes
SULA1	5	Portland Intl	OR	2,680	No
SULA1	6	Boise Paper	WA	2,613	Screened Out
SULA1	7	Weyerhaeuser NR Company	WA	2,330	Yes
SULA1	8	Weyerhaeuser-Columbia Falls	MT	2,099	Yes
SULA1	9	Graymont Western Us Inc.	MT	1,740	Yes
SULA1	10	Ash Grove Cement Company	OR	1,476	No

CIA Code	NO_3 Rank	Facility Name	State	WEP_NO_3	4-Factor by State?
THRO1	1	Coyote Station	ND	1,846,204	Yes
THRO1	2	Milton R. Young Station	ND	1,012,371	Yes
THRO1	3	Coal Creek Station	ND	940,799	Yes
THRO1	4	Antelope Valley Station	ND	826,318	Yes
THRO1	5	Leland Olds Station	ND	819,875	Yes

THRO1	6	Great Plains Synfuels Plant	ND	616,254	Yes
THRO1	7	Colstrip Steam Electric Station	MT	197,796	Yes
THRO1	8	MDU - Lewis & Clark Station	MT	156,265	Yes
THRO1	9	Dickinson	ND	104,740	No
THRO1	10	Richardton Ethanol Plant	ND	72,670	No

CIA Code	NO_3 Rank	Facility Name	State	WEP_NO_3	4-Factor by State?
ULBE1	1	BLAINE COUNTY #1	MT	56,937	Below screening
ULBE1	2	Colstrip Steam Electric Station	MT	35,274	Yes
ULBE1	3	Milton R. Young Station	ND	21,345	Yes
ULBE1	4	Coal Creek Station	ND	19,443	Yes
ULBE1	5	Leland Olds Station	ND	14,156	Yes
ULBE1	6	Coyote Station	ND	12,804	Yes
ULBE1	7	Clearwater Paper Corp - PPD & CPD	ID	9,832	Yes
ULBE1	8	Compressor Station #103	MT	9,778	Below screening
ULBE1	9	Wyodak Plant	WY	8,969	No
ULBE1	10	Weyerhaeuser-Columbia Falls	MT	8,773	Yes

CIA Code	NO_3 Rank	Facility Name	State	WEP_NO_3	4-Factor by State?
YELL2	1	P4 Production LLC (TV Facility)	ID	43,791	Yes
YELL2	2	Oldcastle - Trident Plant	MT	14,925	Yes
YELL2	3	Rexburg Facility Of Basic American Foods	ID	9,196	Yes
YELL2	4	Northwest Pipeline LLC - Soda Springs	ID	6,838	Yes
YELL2	5	Amalgamated Sugar - Paul	ID	6,750	Yes
YELL2	6	Amalgamated Sugar - Twin Falls	ID	6,664	Yes
YELL2	7	Pocatello Compressor Station	ID-Tribal	6,392	No
YELL2	8	Bonanza	ID-Tribal	4,283	No
YELL2	9	Kennecott Utah Copper LLC	UT	4,042	No
YELL2	10	Salt Lake City Intl Airport	UT	3,887	No

Table 7-4. Upwind SO_4 Sources affecting Montana Class I area

CIA Code	SO_4 Rank	Facility Name	State	WEP_SO_4	4-Factor by State?
CABI1	1	Boise Paper	WA	31,229	Yes
CABI1	2	Alcoa Primary Metals Wenatchee Works	WA	14,706	Yes
CABI1	3	Alcoa Primary Metals Intalco Works	WA	13,858	Yes
CABI1	4	Stimson Lumber Company - Plummer Operation	ID-Tribal	7,444	No
CABI1	5	WestRock Northwest, LLC	OR	4,259	Yes
CABI1	6	Idaho Forest Group LLC - Chilco	ID	3,805	Yes
CABI1	7	Potlatch Land and Lumber, ST-Maries Complex	ID-Tribal	3,604	No
CABI1	8	Kootenai Electric-Fighting Creek	ID	3,303	Yes
CABI1	9	Spokane Intl Airport	WA	3,292	Screened Out
CABI1	10	Wauna Mill	OR	2,939	Yes

CIA Code	SO_4 Rank	Facility Name	State	WEP_SO_4	4-Factor by State?
GAMO1	1	Graymont Western Us Inc.	MT	109,910	Yes
GAMO1	2	Ash Grove Cement	MT	88,414	Yes
GAMO1	3	Yellowstone Power Plant	MT	11,209	Yes
GAMO1	4	Boise Paper	WA	8,707	Yes
GAMO1	5	Montana Sulphur & Chemical	MT	7,979	Yes
GAMO1	6	Alcoa Primary Metals Intalco Works	WA	4,624	Yes
GAMO1	7	Calumet Montana Refining	MT	4,453	No
GAMO1	8	Exxonmobil Billings Refinery	MT	3,496	Yes
GAMO1	9	Jim Bridger Plant	WY	3,373	No
GAMO1	10	Alcoa Primary Metals Wenatchee Works	WA	3,345	Yes

CIA Code	SO_4 Rank	Facility Name	State	WEP_SO_4	4-Factor by State?
GLAC1	1	Weyerhaeuser-Columbia Falls	MT	70,836	Yes
GLAC1	2	F.H. Stoltze Land And Lumber Co.	MT	31,663	Yes
GLAC1	3	Boise Paper	WA	15,881	Yes
GLAC1	4	Flathead Electric Lfge Facility	MT	10,044	No
GLAC1	5	Weyerhaeuser-Evergreen	MT	8,651	Yes
GLAC1	6	Alcoa Primary Metals Intalco Works	WA	5,888	Yes
GLAC1	7	Alcoa Primary Metals Wenatchee Works	WA	4,137	Yes

GLAC1	8	Amalgamated Sugar- Nampa	ID	4,082	Yes
GLAC1	9	Amalgamated Sugar - Twin Falls	ID	1,955	Yes
GLAC1	10	Stimson Lumber Company - Plummer Operation	ID-Tribal	1,927	No

CIA Code	SO_4 Rank	Facility Name	State	WEP_SO_4	4-Factor by State?
LOST1	1	Antelope Valley Station	ND	1,553,101	Yes
LOST1	2	Coyote Station	ND	1,445,614	Yes
LOST1	3	Tioga Gas Plant	ND	701,393	Yes
LOST1	4	Coal Creek Station	ND	572,888	Yes
LOST1	5	Great Plains Synfuels Plant	ND	557,990	Yes
LOST1	6	Lignite Gas Plant	ND	223,937	No
LOST1	7	Milton R. Young Station	ND	221,209	Yes
LOST1	8	Leland Olds Station	ND	213,134	Yes
LOST1	9	Hawkeye Gas Facility	ND	28,038	No
LOST1	10	Colstrip Steam Electric Station	MT	24,304	Yes

CIA Code	SO_4 Rank	Facility Name	State	WEP_SO_4	4-Factor by State?
MELA1	1	Antelope Valley Station	ND	441,357	Yes
MELA1	2	Coyote Station	ND	435,525	Yes
MELA1	3	Coal Creek Station	ND	174,039	Yes
MELA1	4	Great Plains Synfuels Plant	ND	159,107	Yes
MELA1	5	Tioga Gas Plant	ND	91,005	Yes
MELA1	6	Leland Olds Station	ND	48,215	Yes
MELA1	7	Milton R. Young Station	ND	46,172	Yes
MELA1	8	Colstrip Steam Electric Station	MT	40,382	Yes
MELA1	9	Sidney Sugar Facility	MT	17,666	Yes
MELA1	10	Little Knife Gas Plant	ND	17,208	Yes

CIA Code	SO_4 Rank	Facility Name	State	WEP_SO_4	4-Factor by State?
MONT1	1	Boise Paper	WA	12,230	Yes
MONT1	2	The Amalgamated Sugar- Nampa	ID	6,194	Yes
MONT1	3	Alcoa Primary Metals Intalco Works	WA	5,348	Yes

MONT1	4	Alcoa Primary Metals Wenatchee Works	WA	2,980	Yes
MONT1	5	Graymont Western Us Inc.	MT	2,261	Yes
MONT1	6	Amalgamated Sugar - Twin Falls	ID	1,941	Yes
MONT1	7	WestRock Northwest, LLC	OR	1,558	No
MONT1	8	Ash Grove Cement	MT	1,479	Yes
MONT1	9	Wauna Mill	OR	1,235	Yes
MONT1	10	Clearwater Paper Corp - PPD & CPD	ID	1,205	Yes

CIA Code	SO_4 Rank	Facility Name	State	WEP_SO_4	4-Factor by State?
NOAB1	1	Elk Basin Gas Plant	WY	193,567	Yes
NOAB1	2	Yellowstone Power Plant	MT	94,901	Yes
NOAB1	3	Oregon Basin Gas Plant	WY	71,329	No
NOAB1	4	Montana Sulphur & Chemical	MT	67,418	Yes
NOAB1	5	Colstrip Steam Electric Station	MT	30,171	Yes
NOAB1	6	Exxonmobil Billings Refinery	MT	29,540	Yes
NOAB1	7	J R Simplot Company-Don Siding Pocatello	ID	17,984	Yes
NOAB1	8	Kennecott Utah Copper LLC	UT	15,792	No
NOAB1	9	Amalgamated Sugar - Twin Falls	ID	14,125	Yes
NOAB1	10	Jim Bridger Plant	WY	13,253	No

CIA Code	SO_4 Rank	Facility Name	State	WEP_SO_4	4-Factor by State?
SULA1	1	Boise Paper	WA	18,259	Yes
SULA1	2	The Amalgamated Sugar - Nampa	ID	7,747	Yes
SULA1	3	Graymont Western Us Inc.	MT	5,280	Yes
SULA1	4	Alcoa Primary Metals Wenatchee Works	WA	4,454	Yes
SULA1	5	Wauna Mill	OR	3,609	Yes
SULA1	6	Ash Grove Cement	MT	2,885	Yes
SULA1	7	Amalgamated Sugar - Twin Falls	ID	2,878	Yes
SULA1	8	J R Simplot Company-Don Siding Pocatello	ID	2,523	Yes
SULA1	9	Clearwater Paper Corp - PPD & CPD	ID	2,504	Yes
SULA1	10	Weyerhaeuser NR Company	WA	2,160	Yes

CIA Code	SO_4 Rank	Facility Name	State	WEP_SO_4	4-Factor by State?
THRO1	1	Coyote Station	ND	3,906,409	Yes
THRO1	2	Antelope Valley Station	ND	3,666,815	Yes
THRO1	3	Great Plains Synfuels Plant	ND	1,328,393	Yes
THRO1	4	Coal Creek Station	ND	765,931	Yes
THRO1	5	Leland Olds Station	ND	362,725	Yes
THRO1	6	Little Knife Gas Plant	ND	280,229	Yes
THRO1	7	Milton R. Young Station	ND	269,970	Yes
THRO1	8	Colstrip Steam Electric Station	MT	109,622	Yes
THRO1	9	Tioga Gas Plant	ND	48,388	Yes
THRO1	10	Richardton Ethanol Plant	ND	31,880	Yes

CIA Code	SO_4 Rank	Facility Name	State	WEP_SO_4	4-Factor by State?
ULBE1	1	Colstrip Steam Electric Station	MT	52,997	Yes
ULBE1	2	Coyote Station	ND	52,595	Yes
ULBE1	3	Antelope Valley Station	ND	51,310	Yes
ULBE1	4	Yellowstone Power Plant	MT	27,864	Yes
ULBE1	5	Montana Sulphur & Chemical	MT	19,855	Yes
ULBE1	6	Coal Creek Station	ND	18,999	Yes
ULBE1	7	Great Plains Synfuels Plant	ND	18,516	Yes
ULBE1	8	Colstrip Energy Ltd. Partnership	MT	14,482	Yes
ULBE1	9	Exxonmobil Billings Refinery	MT	8,693	Yes
ULBE1	10	Milton R. Young Station	ND	7,690	Yes

CIA Code	SO_4 Rank	Facility Name	State	WEP_SO_4	4-Factor by State?
YELL2	1	J R Simplot Company-Don Siding Pocatello	ID	38,189	Yes
YELL2	2	Kennecott Utah Copper LLC	UT	23,791	No
YELL2	3	Green River Works	WY	22,560	No
YELL2	4	P4 Production LLC (TV Facility)	ID	18,839	Yes
YELL2	5	Amalgamated Sugar - Twin Falls	ID	17,865	Yes
YELL2	6	Nu-West Industries, Inc.	ID	16,952	Yes
YELL2	7	Westvaco Facility	WY	15,453	No

YELL2	8	Tesoro Refining & Marketing Company LLC	UT	10,964	No
YELL2	9	Yellowstone Power Plant	MT	10,784	Yes
YELL2	10	Jim Bridger Plant	WY	10,418	No

In addition, Montana identified out-of-state Class I areas that are affected by emissions from the state. This is different than assessing which out-of-state Class I areas are affected by a particular in-state source. This assessment evaluates all anthropogenic sources of visibility-impairing pollutants in Montana and determines what Class I areas are impacted by contributions from Montana. Table 7-5 lists data from the 2028OTBa2 source apportionment modeling run, including the percent total anthropogenic contribution at nearby Class I areas and the 2028 reasonable progress goal in inverse megameters and deciviews for the area. Montana's contribution, in inverse megameters is listed and used to calculate the deciview value that Montana contributes to the site. The out-of-state site that Montana contributes to the most is Wind Cave in South Dakota, where Montana anthropogenic sources contribute 0.12 dv of light extinction. Montana anthropogenic sources contribute 0.11 dv to both Theodore Roosevelt and Lostwood, both in North Dakota.

Table 7-5. Amount of Anthropogenic Contributions from Montana on nearby Class I areas

SiteCode	Site	State	% Total Anthro Contribution ($AmmSO_4$ &$AmmNO_3$)	RPG2028 (Mm-1)	RPG2028 (dv)	Montana contribution (Mm-1)	RPG2028 w/o MT (Mm-1)	RPG2028 w/o MT (dv)	dv_diff
MELA1	Medicine Lake	MT	28.9%	46.39	15.35	1.26	45.14	15.07	0.27
GLAC1	Glacier NP	MT	51.8%	38.34	13.44	0.97	37.37	13.18	0.26
ULBE1	UL Bend	MT	50.7%	30.47	11.14	0.57	29.89	10.95	0.19
WICA1	Wind Cave	SD	11.1%	27.82	10.23	0.32	27.50	10.11	0.12
THRO1	Theodore Roosevelt	ND	12.6%	40.62	14.02	0.46	40.16	13.90	0.11
LOST1	Lostwood	ND	6.9%	50.37	16.17	0.56	49.81	16.06	0.11
GAMO1	Gates of the Mountains	MT	35.2%	20.93	7.39	0.21	20.72	7.28	0.10
CABI1	Cabinet Mountains	MT	16.7%	26.55	9.77	0.26	26.30	9.67	0.10
BADL1	Badlands NP	SD	6.3%	32.89	11.91	0.30	32.59	11.81	0.09
MONT1	Monture	MT	23.0%	27.28	10.04	0.19	27.09	9.97	0.07
NOAB1	North Absaroka	WY	25.7%	20.31	7.09	0.14	20.18	7.02	0.07
SULA1	Sula Peak	MT	16.1%	23.11	8.38	0.11	23.01	8.33	0.05

SiteCode	Site	State	% Total Anthro Contribution ($AmmSO_4$ &$AmmNO_3$)	RPG2028 (Mm-1)	RPG2028 (dv)	Montana contribution (Mm-1)	RPG2028 w/o MT (Mm-1)	RPG2028 w/o MT (dv)	dv_diff
YELL2	Yellowstone NP	WY	6.8%	20.61	7.23	0.06	20.54	7.20	0.03
CRMO1	Craters of the Moon NM	ID	4.5%	21.79	7.79		21.74	7.77	0.02
MOZI1	Mount Zirkel Wilderness	CO	1.9%	16.67	5.11	0.03	16.64	5.09	0.02
MOHO1	Mount Hood	OR	1.1%	24.00	8.76	0.04	23.96	8.74	0.02
STAR1	Starkey	OR	3.0%	29.48	10.81	0.04	29.44	10.80	0.01
JARB1	Jarbidge Wilderness	NV	5.5%	22.12	7.94	0.02	22.10	7.93	0.01
WHPE1	Wheeler Peak	NM	0.8%	17.73	5.73	0.02	17.71	5.72	0.01
BRID1	Bridger Wilderness	WY	1.7%	19.05	6.44	0.02	19.03	6.43	0.01
ROMO1	Rocky Mountain NP	CO	0.9%	22.00	7.89	0.02	21.98	7.88	0.01
GRSA1	Great Sand Dunes NM	CO	1.2%	21.54	7.67	0.02	21.52	7.66	0.01
HECA1	Hells Canyon	OR	1.9%	34.73	12.45	0.03	34.70	12.44	0.01
PASA1	Pasayten	WA	1.0%	25.65	9.42	0.02	25.63	9.41	0.01
SAWT1	Sawtooth NF	ID	3.4%	23.50	8.54	0.02	23.49	8.54	0.01
BRCA1	Bryce Canyon NP	UT	1.4%	18.62	6.22	0.01	18.61	6.21	0.01
CANY1	Canyonlands NP	UT	0.7%	18.89	6.36	0.01	18.88	6.36	0.00
WHRI1	White River NF	CO	0.9%	15.97	4.68	0.01	15.96	4.67	0.00
CAPI1	Capitol Reef NP	UT	1.5%	19.69	6.78	0.01	19.68	6.77	0.00
ZICA1	Zion Canyon	UT	0.7%	23.07	8.36	0.00	23.07	8.36	0.00

SiteCode	Site	State	% Total Anthro Contribution ($AmmSO_4$ &$AmmNO_3$)	RPG2028 (Mm-1)	RPG2028 (dv)	Montana contribution (Mm-1)	RPG2028 w/o MT (Mm-1)	RPG2028 w/o MT (dv)	dv_diff
SYCA_RHTS	Sycamore Canyon (RHTS)	AZ	0.5%	29.95	10.97	0.00	29.94	10.97	0.00
FLAT1	Flathead	MT	38.5%	NA	NA	0.61	NA	NA	NA
FOPE1	Fort Peck	MT	32.2%	NA	NA	0.94	NA	NA	NA
NOCH1	Northern Cheyenne	MT	53.6%	NA	NA	0.90	NA	NA	NA

Montana consulted the states with sources listed in the tables above and agreed that with facility shutdowns throughout the region, emissions reductions from ongoing pollution control programs, and the projected improvement in visibility in all Montana Class I areas, that Montana will not request the adoption of controls for any facilities outside of Montana that affect Montana Class I areas.

40 CFR 51.308 (f)(2)(ii)(A) requires that a State must demonstrate that it has included in its implementation plan all measures agreed to during state-to-state consultations or a regional planning process. Nearly every Montana facility found to be impacting an out-of-state Class I area was considered for additional controls through the four factor analysis. The remaining sources were considered as part of Montana's Q/d analysis, but were below the screening thresholds considered for this planning period (see Appendix D for full list of screened sources). For Montana sources that were found to impact out-of-state Class I areas, Montana confirmed with those affected states that no additional controls on Montana sources will be required at this time. The states' consulted did not disagree with Montana's LTS and did not provide any additional measures to be included in Montana's LTS.

40 CFR 51.308(f)(ii)(B) requires a state to consider the emission reductions measures identified by other states for their sources as being necessary to make reasonable progress in the Class I area. No affected state recommended emission reduction measures for Montana sources.

A summary of Montana's coordination efforts with neighboring states is presented below. Montana consulted individually with the seven states between September 2020 and July 2021 regarding emission control technologies on respective facilities. On June 4th, Montana sent email correspondence to surrounding states to document additional control decisions, a copy of which can be found in Appendix A.

<u>North Dakota</u>

North Dakota's contribution to visibility impairment is largest at Medicine Lake, where state source apportionment modeling results indicate that, for both ammonium nitrate and ammonium sulfate, North

Dakota oil and gas sources contribute 0.8 Mm-1 light extinction. [179] Although North Dakota oil and gas sources, relative to the other modeled sources, represent the largest source contributor to visibility impairment at Medicine Lake, the total extinction is very low. Montana contributes 0.46 and 0.56 Mm-1 light extinction at Theodore Roosevelt and Lostwood, respectively - the portion of anthropogenic contribution to light extinction from Montana sources at North Dakota Class I areas is calculated to be very low.

Since September 2020, Montana and North Dakota have maintained communication through biweekly RH SIP discussions. The discussions have been mutually-beneficial, offering the opportunity for our states to discuss key challenges with SIP development, review modeling data and create a consistent framework in which to present results in the SIP, and collaborate to make decisions that reflect shared objectives. Through this dialogue, North Dakota and Montana agreed that neither state would request the adoption of control technologies on the states' respective facilities for this second implementation period.

South Dakota

On July 7th, Montana received email correspondence from South Dakota, indicating the state was not planning to install additional controls on its sources for the second implementation period. While South Dakota did find that several Montana sources contribute to visibility impairment in South Dakota Class I areas, South Dakota will not recommend any additional controls for Montana sources for this second implementation period. The source apportionment modeling results presented in Table 7-5 indicate Montana's anthropogenic portion of light extinction at Wind Cave NP is 0.12 dv and 0.09 dv at Badlands NP.

Wyoming

Montana and Wyoming applied the same approach to project the 2028 reasonable progress goal Yellowstone NP, a Class I area that is shared between the states. Montana informed Wyoming via email on November 16, 2020 that the state did not find controls to be reasonable this planning period, due in part to the large emission reductions resulting from EGU shutdowns. Wyoming and Montana met again via phone conference on May 13, 2021 to further discuss each states' long term strategy. Both states agreed that the adoption of controls would not be necessary to make reasonable progress in either Montana or Wyoming Class I areas. This decision was relayed in writing, via email correspondence from Wyoming to Montana on June 6, 2021, stating again that Wyoming will not request the adoption of controls on Montana sources for this second implementation period and that Wyoming agrees that reductions from ongoing pollution control programs and facility closures in Montana will result in improvements in visibility in Wyoming Class

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[179] WRAP Technical Support System, Modeled Data Analysis – Express Tools, Available at: https://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx [views.cira.colostate.edu]. Specifically, the "WRAP State Source Group Contributions - U.S. Anthro" product

I areas. Anthropogenic sources in Montana contribute 0.07 dv at North Absaroka Wilderness and 0.03 dv at Yellowstone NP.

Utah

On June 14, 2021, Montana received email correspondence from Utah. The Utah sources that were found to potentially impact Montana Class I areas were mostly screened out of Utah's additional control analyses, either because they did not meet the Q/d >6 that Utah employed, or the sources had recently undergone a thorough BACT analysis as part of the Salt Lake Serious $PM_{2.5}$ Nonattainment Area demonstration and were not considered for additional controls, or the sources have ceased operation. Montana agreed with Utah's approach and will not ask for control measures to be installed on Utah sources. Utah reviewed the NO_2 and SO_4 WEP rankings for Montana sources in Utah Class I areas and evaluated WRAP source apportionment modeling results to conclude that Montana sources are not a significant contributor to visibility impairment in Utah Class I areas. Therefore, Utah does not anticipate requesting adoption of controls for Montana facilities. Anthropogenic sources in Montana contribute 0.01 dv at Bryce Canyon NP.

Oregon

On June 18th, 2021, Oregon responded to Montana's request for information. Oregon provided a summary of the five facilities that were on the NO_3 and/or SO_4 rank point list as potential contributors to visibility impairment in Montana Class I areas. These facilities included: Ash Grove Cement Plant, Portland International, Roseburg Forest Products/Dillard, Westrock Northwest LLC, and Georgia Pacific/Wauna Mill. The Roseburg Forest Products/Dillard facility underwent a four-factor evaluation for NO_x controls. The Georgia Pacific/Wauna Mill was evaluated for SO_2 controls. The facilities that did not go through a four-factor analysis were either screened out based on a Q/d screening threshold or were determined to have adequate controls. A follow-up phone conversation was also held with Oregon to describe that a high-level summary of Oregon's comments would be included as part of Montana's SIP documentation. Montana will not require additional controls on Oregon sources in this second planning period. Montana anthropogenic sources contribute 0.02 dv at Mount Hood Wilderness and 0.01 dv at Strawberry Mountain Wilderness and Eagle Cap Wilderness.

Washington

On July 28, 2021, Montana received email correspondence from Washington. The Washington sources that appeared on the rank point list as potentially impacting Montana Class I areas were mostly screened out through Washington's source selection process. The sources that did undergo a four-factor evaluation include Weyerhaeuser NR Company, Boise Paper, and Alcoa Primary Metals (Wenatchee Works and Intalco Works). Washington determined that both the Weyerhaeuser NR Company and Boise Paper facilities are well-controlled with not additional reductions considered for this second implementation period. The two Alcoa Primary Metals facilities are in curtailment. Washington entered into Agreed Orders with Alacoa Primary Metals to perform a four-factor analyses at least 6 months prior to restarting and implement any necessary controls within 3 years of restarting. Montana agreed with Washington's approach and will not ask for control measures to be installed on Washington sources. Anthropogenic sources in Montana contribute 0.01 dv at Pasayten Wilderness

Idaho

On June 11, 2021, Montana received email correspondence from Idaho. As of July, 2021, Idaho was reviewing four-factor conclusions and finalizing decisions with sources regarding potential additional controls. The Selway- Bitterroot WA spans both Idaho and Montana and is represented by the SULA1 monitor. Montana sources do rank among the top 10 sources; however, the SULA1 monitor is mostly impacted by PM and SO_2 from wildfire, prescribed fire, and international emissions. Similar to North Dakota, Montana has kept in close contact with Idaho regarding SIP development, including interpreting monitoring and modeling data for our shared Class I area. Montana and Idaho applied the same approach to project the 2028 reasonable progress goal for Selway – Bitterroot WA and acknowledged Idaho's responsibility to set the RPG for this site.

Idaho and Montana established a close working relationship and share a common understanding of the sources that impact our respective Class I areas. Because wildfire, prescribed fire and international emissions are large contributors to haze in our Class I areas, both Montana and Idaho agreed that neither state will request additional controls on our sources. Anthropogenic sources in Montana contribute 0.01 dv at Sawtooth NF.

7.3 LTS Conclusion

Montana has decided, by considering the four factors and the five required factors, that source retirements and closures should be implemented as part of our LTS and used to set the RPGs for 2028. Montana did not require additional controls on sources in the LTS. Chapter 8 examines the resultant RPGs and checks that visibility is improved on the most impaired days while not degrading the clearest days.

8 Determination of Reasonable Progress Goals

States are required by 40 CFR 51.308(d)(1) to establish reasonable progress goals (expressed in deciviews) that provide for reasonable progress towards achieving natural visibility conditions. The reasonable progress goals must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period.

The RPGs reflect the projected visibility conditions as a result of the implementation of the long-term strategy. Therefore, the RPGs provide a way for states to check the projected outcome of the long-term strategy against the goals for visibility improvement.

Typically, states use a photochemical air quality modeling run that uses emissions that reflect the measures in its own LTS. Montana relied on the CAMx regional photochemical grid modeling platform developed/coordinated by WRAP with the assistance of Ramboll. The modeling framework includes all participating western states' approved emission scenarios that are a result of each state's proposed long-term strategy. Therefore, states across the region can see the implications of all the long-term strategies throughout the West. Descriptions of the WRAP methodologies for projecting RPGs are presented in Sections 2.2.2 and 2.2.4.

The RHR requires that, after a state projects the 2028 visibility conditions for its Class I areas, the state compares the projected RPGs to the baseline period visibility conditions and to the URP glidepath. These comparisons are presented below in Section 8.1.

8.1 Uniform Rate of Progress Glidepath Checks

Montana confirmed that the RPGs modeled for each Montana Class I area provide for improvement in visibility for the most impaired days, do not degrade visibility on the clearest days, and establish a rate of progress that Montana believes is adequate for this planning period.

Table 8-1 provides a summary of the various Class I areas in Montana, and references relevant tables and sections which contain the numeric information used to fulfill the requirements of 40 CFR 51.308(f)(3).

Table 8-1. Reasonable Progress Goals summary table

Site ID	Improvement in 2028 from the baseline on most impaired days? (40 CFR 51.308(f)(3))	No degradation in 2028 on clearest days baseline?	Determine the (adjusted) URP that will reach natural conditions by 2064	Compare 2028 RPG for MID to the URP
CABI1	✓	✓	✓	✓
GAMO1	✓	✓	✓	✓
GLAC1	✓	✓	✓	✓
MELA1	✓	✓	✓	✓
MONT1	✓	✓	✓	✓
SULA1	✓	✓	✓	✓
ULBE1	✓	✓	✓	✓
YELL2	✓	✓	✓	✓
Reference:	Table 8-2	Table 8-3	Section 4.3	Table 8-4

Table 8-2 lists, by Class I area, the 2028 RPG on most impaired days, compared to the baseline (2000-2004) and current (2014-2018) period.

Table 8-2. 2028 RPGs compared to MID baseline

Site ID	Class I Area Name(s)	MID baseline (2000-2004) (dv)	MID current (2014-2018) (dv)	2028 RPG (dv)
CABI1	Cabinet Mountains Wilderness Area	10.73	9.87	9.41
GAMO1	Gates of the Mountains Wilderness Area	8.95	7.47	7.12
GLAC1	Glacier National Park	15.89	13.77	12.92
MELA1	Medicine Lake Wilderness Area	16.62	15.30	14.85
MONT1	Bob Marshall Wilderness Area, Mission Mountain Wilderness Area, Scapegoat Wilderness Area	11	10.06	9.51
SULA1	Anaconda-Pintler Wilderness Area, Selway-Bitterroot Wilderness Area	10.06	8.37	8.01
ULBE1	UL Bend Wilderness Area	12.76	10.93	10.62
YELL2	Red Rock Lakes National Wildlife Refuge, Yellowstone National Park	8.3	7.52	6.97

Table 8-3 lists, by Class I area, the 2028 RPG on clearest days compared to the baseline (2000-2004) and current (2014-2018) period, indicating no degradation from the baseline (2000-2004) period.

Table 8-3. 2028 RPGs compared to clearest days baseline

Site ID	Class I Area Name(s)	Clearest Days baseline (dv)	Clearest Days current (dv)	2028 Clearest Days RPG (dv)
CABI1	Cabinet Mountains Wilderness Area	3.62	2.46	2.21
GAMO1	Gates of the Mountains Wilderness Area	1.71	0.66	0.53
GLAC1	Glacier National Park	7.22	5.38	5.10
MELA1	Medicine Lake Wilderness Area	7.27	6.19	6.12
MONT1	Bob Marshall Wilderness Area, Mission Mountain Wilderness Area, Scapegoat Wilderness Area	3.86	2.56	2.33
SULA1	Anaconda-Pintler Wilderness Area, Selway-Bitterroot Wilderness Area	2.57	1.60	1.51
ULBE1	UL Bend Wilderness Area	4.75	3.71	3.58
YELL2	Red Rock Lakes National Wildlife Refuge, Yellowstone National Park	2.58	1.43	1.21

Table 8-4 identifies the 2028 RPG compared to the URP in 2028 for the Montana Class I areas. All sites show projections below the URP glidepaths, indicating that Montana's long-term strategy ensures a quicker rate of progress to reach natural conditions.

Table 8-4. 2028 RPGs compared to glidepaths on MIDs

Site ID	Class I Area Name(s)	2028 RPG (dv)	2028 URP (dv)	2064 adjusted endpoint (dv)
CABI1	Cabinet Mountains Wilderness Area	9.41	10.36	10.73
GAMO1	Gates of the Mountains Wilderness Area	7.12	8.31	8.95
GLAC1	Glacier National Park	12.92	13.78	15.89
MELA1	Medicine Lake Wilderness Area	14.85	14.92	16.62
MONT1	Bob Marshall Wilderness Area, Mission Mountain Wilderness Area, Scapegoat Wilderness Area	9.51	10.02	11.00
SULA1	Anaconda-Pintler Wilderness Area, Selway-Bitterroot Wilderness Area	8.01	9.12	10.06
ULBE1	UL Bend Wilderness Area	10.62	12.05	12.76
YELL2	Red Rock Lakes National Wildlife Refuge, Yellowstone National Park	6.97	7.26	8.30

Figures 8-1 – 8.8 illustrate the 2028 RPGs in relation to the URP for the most impaired days and clearest days for each Montana Class I area.

Figure 8-1. CABI1 IMPROVE site RPG – Cabinet Mountains W.A.

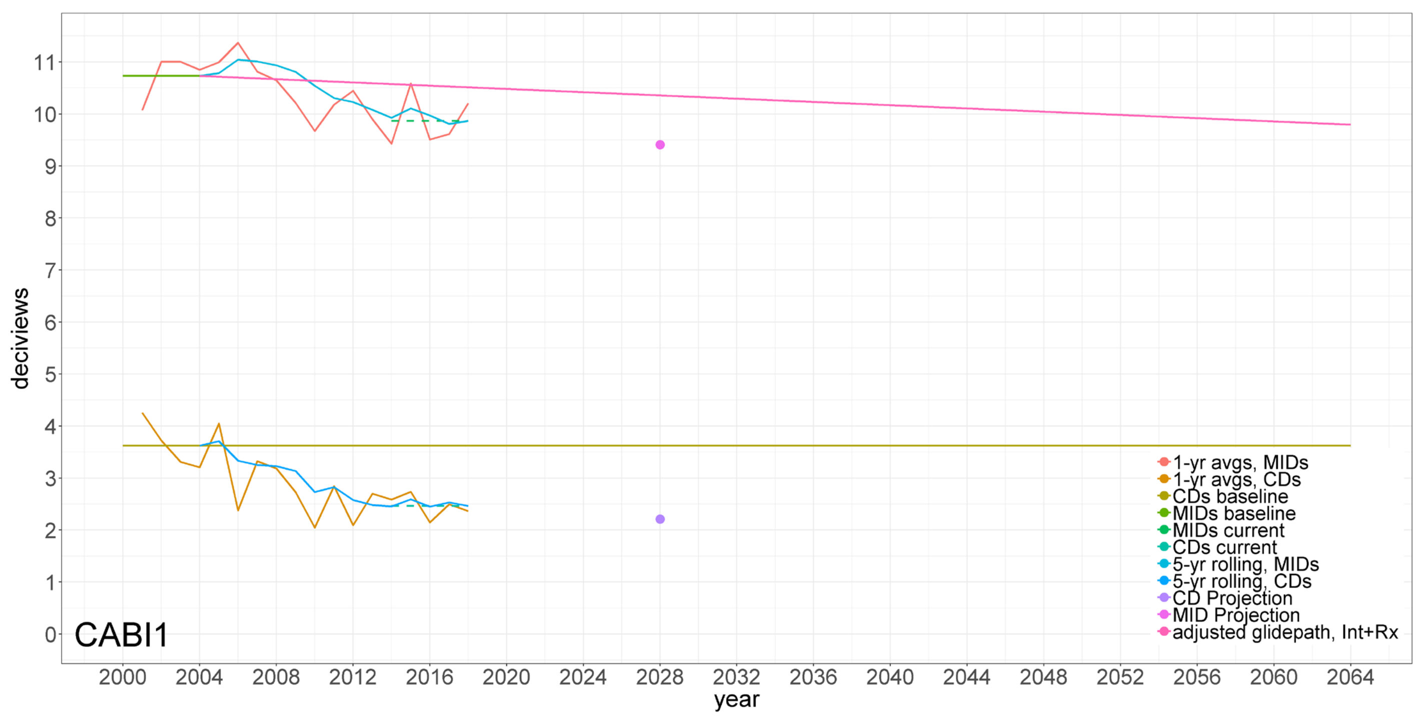


Figure 8-2. GAMO1 IMPROVE site RPG - Gates of the Mtns W.A.

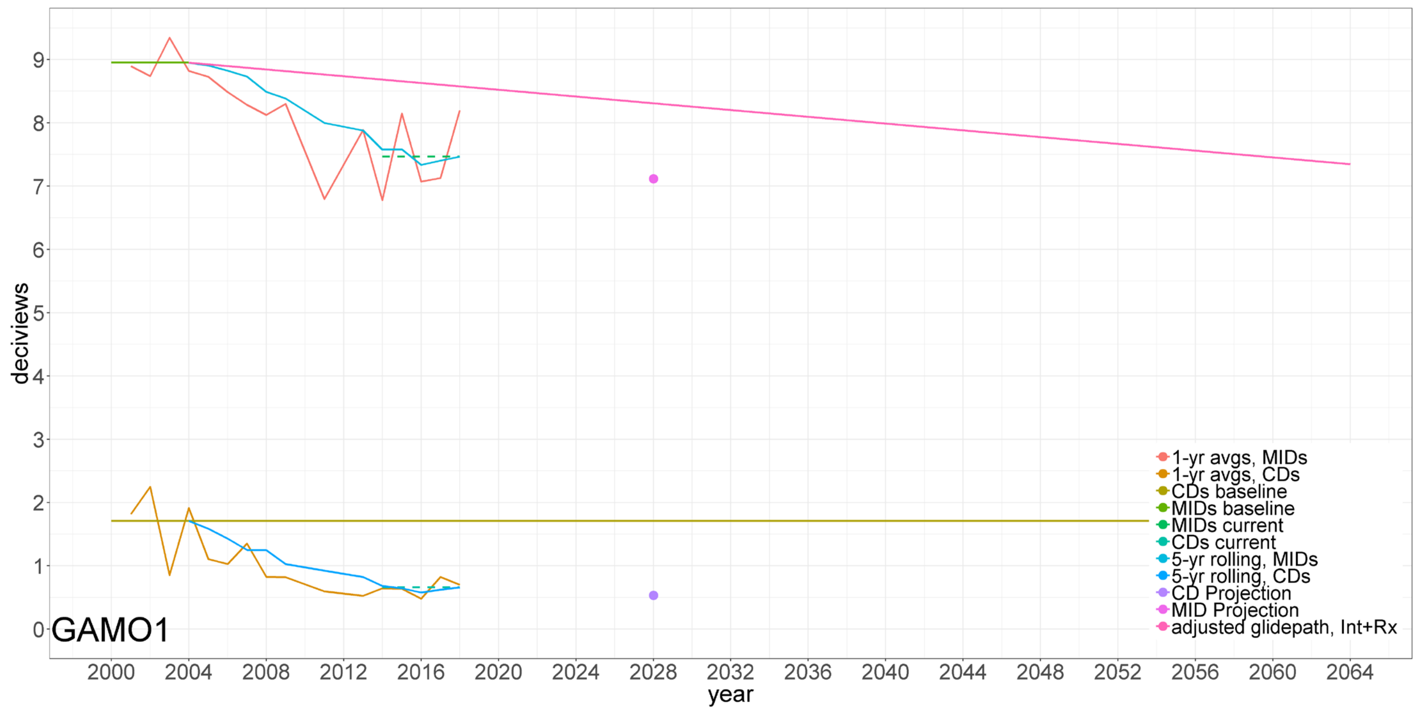


Figure 8-3. GLAC1 IMPROVE Site RPG - Glacier NP

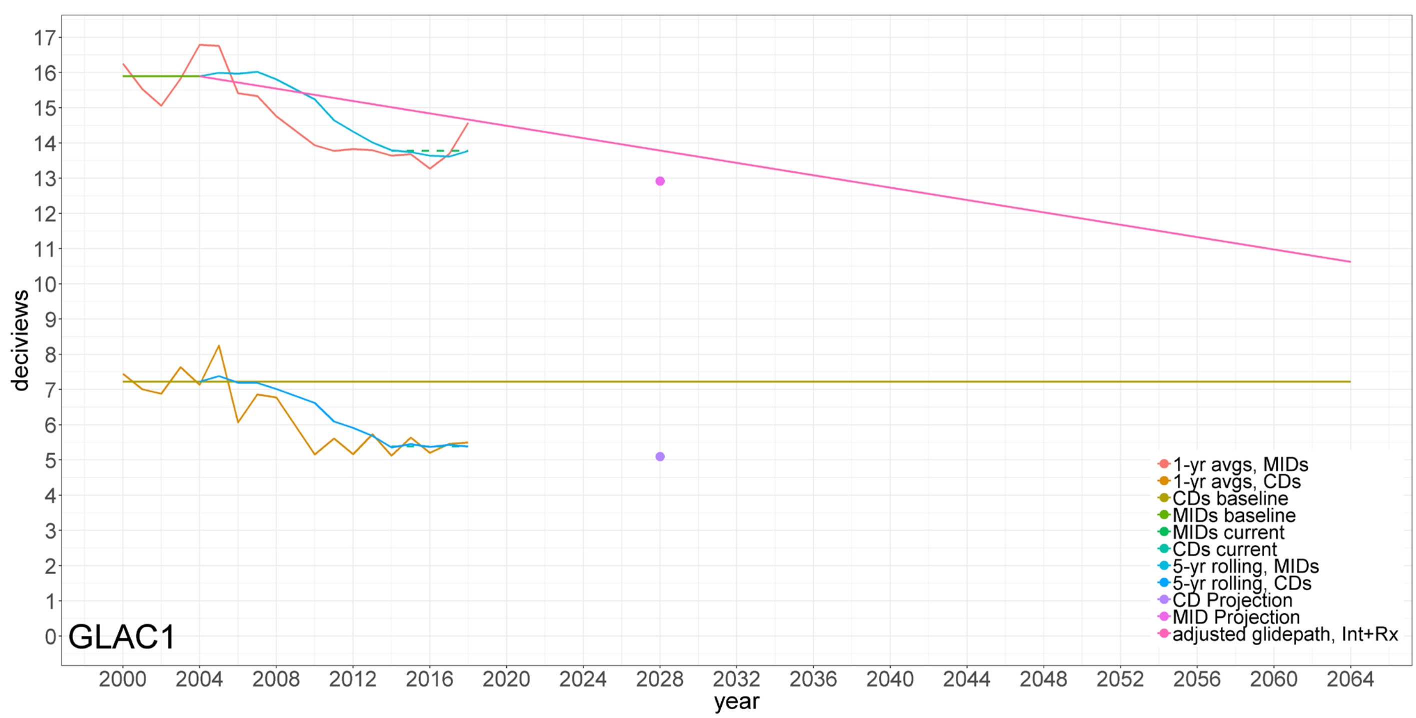


Figure 8-4. MELA1 IMPROVE Site RPG - Medicine Lake W.A.

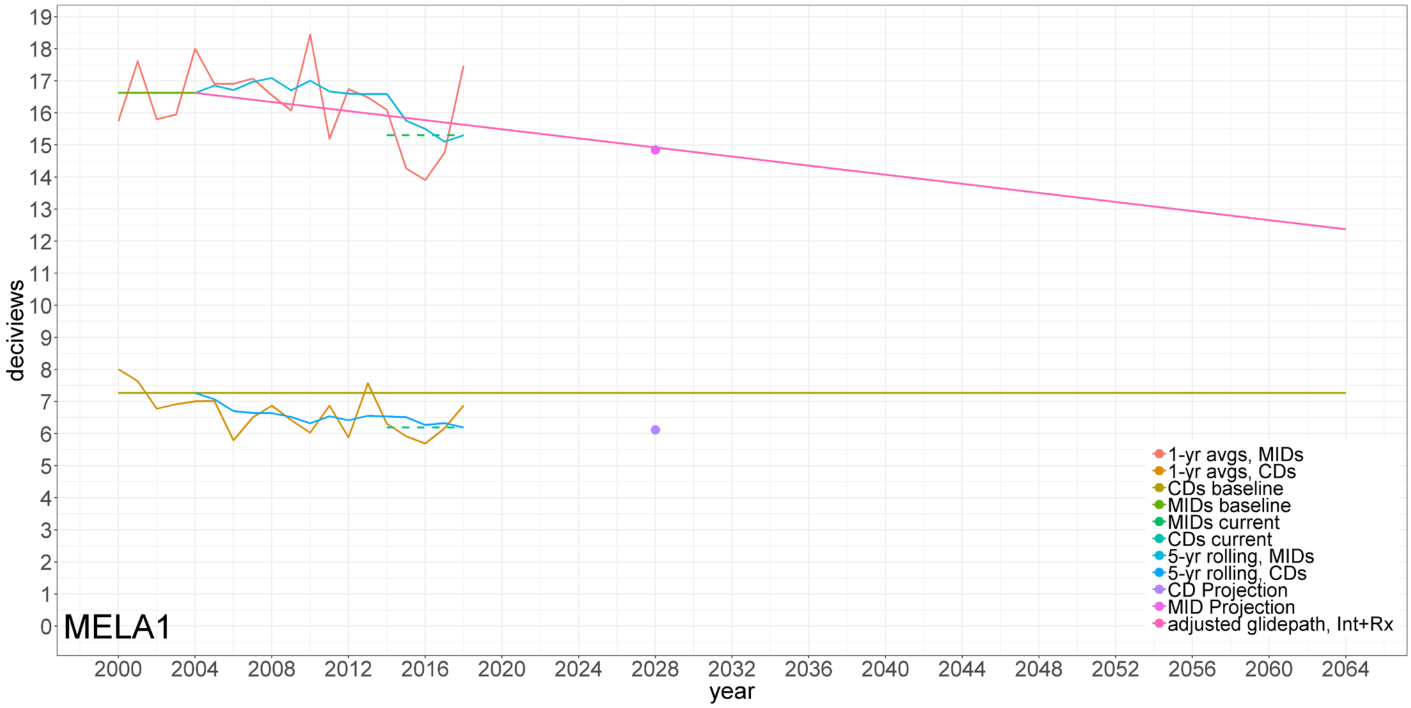


Figure 8-5. MONT1 IMPROVE Site RPG - Bob Marshall W.A., Mission Mtn W.A. & Scapegoat W.A.

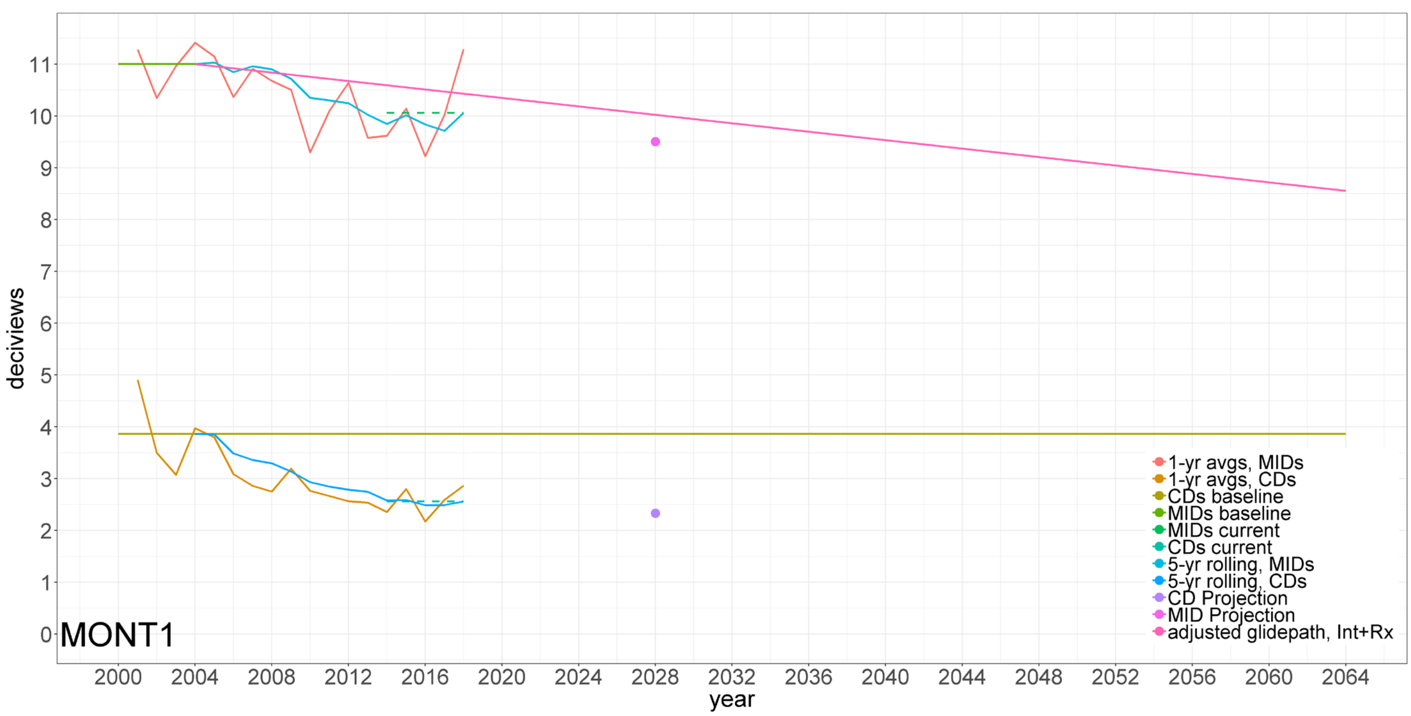


Figure 8-6. SULA1 IMPROVE Site RPG - Anaconda-Pintler W.A. & Selway Bitterroot W.A.

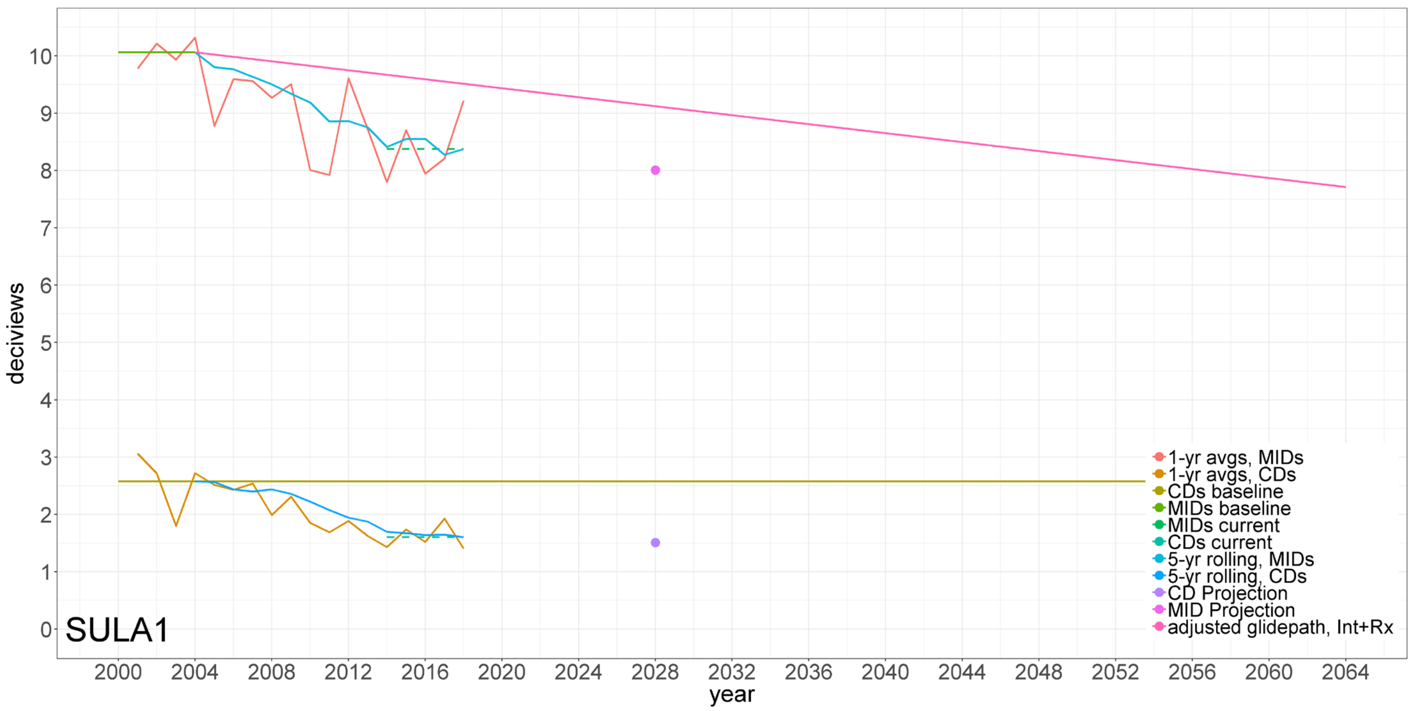


Figure 8-7. ULBE1 IMPROVE Site RPG - UL Bend W.A.

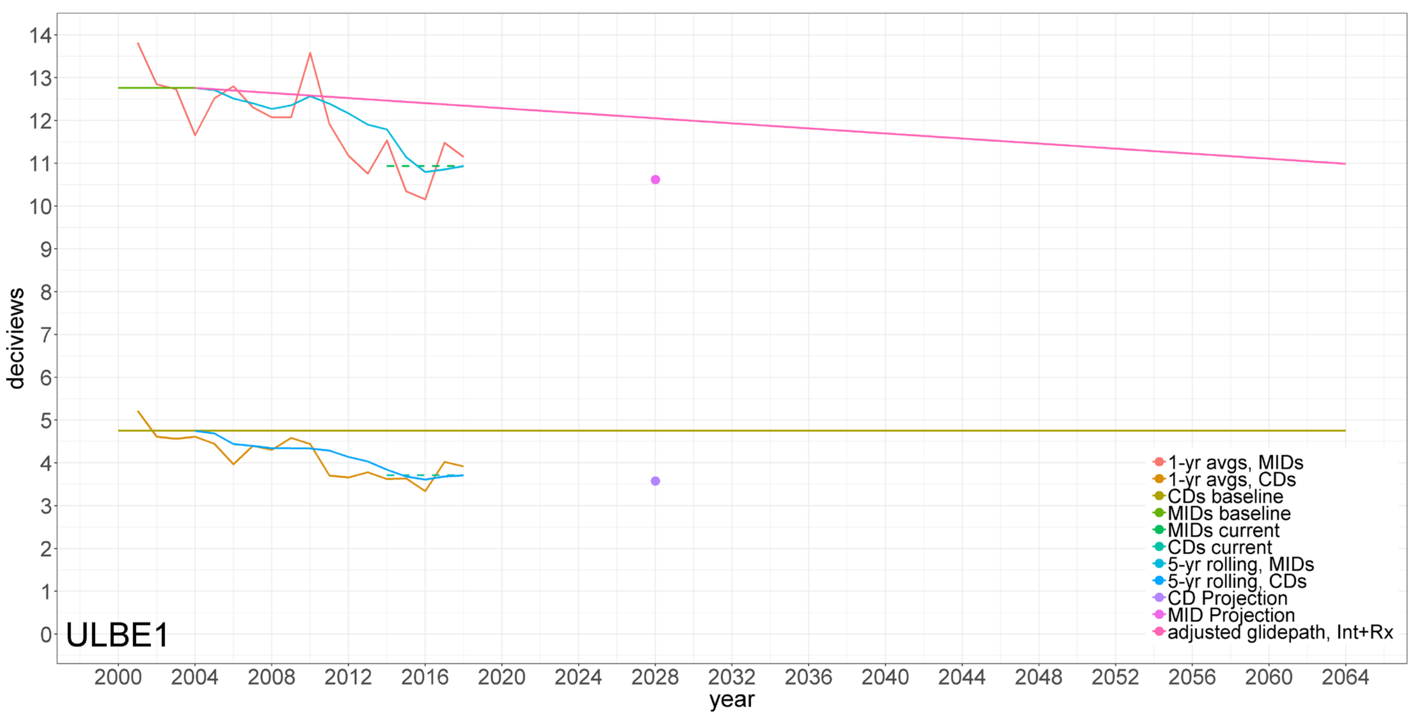
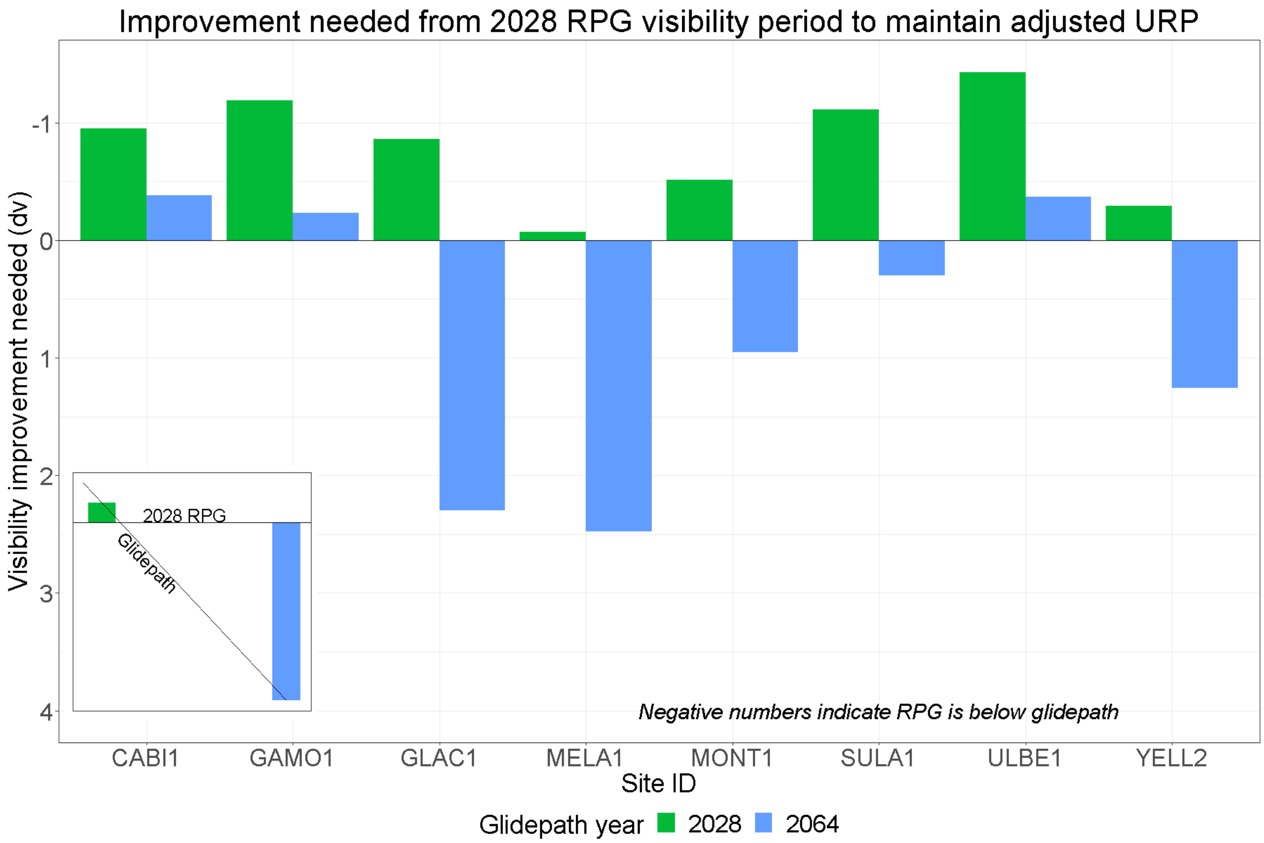


Figure 8-8. YELL2 IMPROVE Site RPG - Yellowstone NP

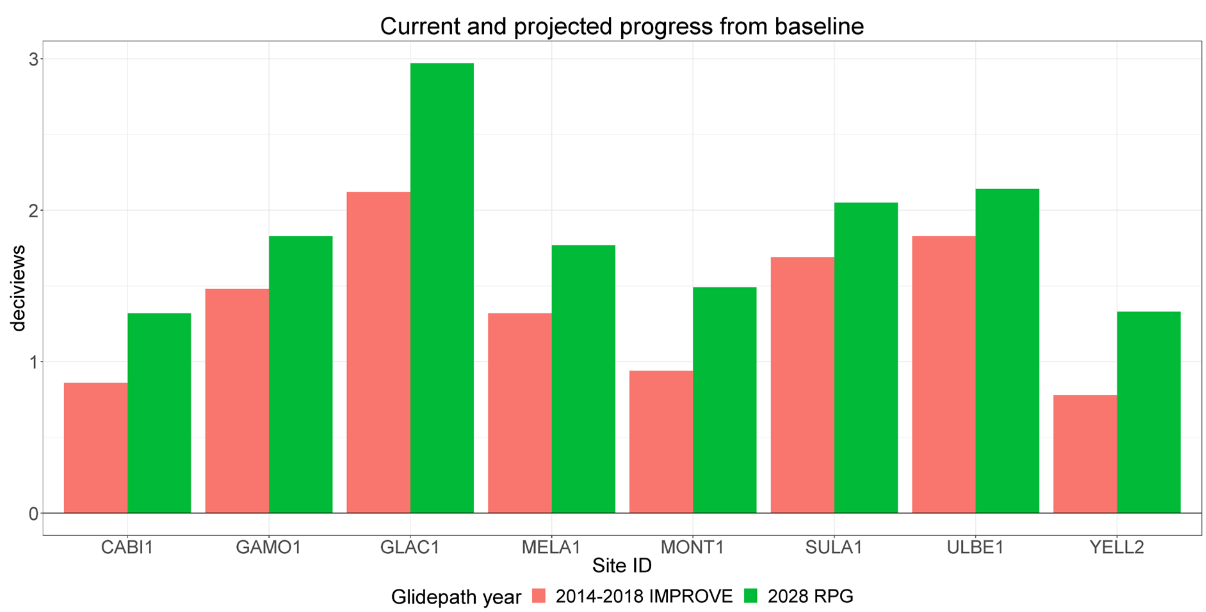
Figure 8-9 is meant to summarize where the 2028 projection is in relation to the glidepath in 2028 and in 2064. Each Class I area has a green and a blue bar. The green bar represents the position of the 2028 RPG with respect to the glidepath in 2028 – if the green bar is above the '0' line (the x axis) then the 2028 RPG is below the glidepath in 2028. The position of the blue bar indicates, based on the 2028 RPG, how much progress is needed to reach the 2064 end goal. For example, the 2028 RPG for GLAC1 is slightly less than one deciview below the glidepath in 2028 and there is a slightly more than two deciviews to improve in order to reach the end goal in 2064. In some cases, (CABI1, GAMO1 and ULBE1) the 2028 RPG is already below the 2064 end point (the blue bar is above the x-axis). Table 8-5 presents this information in tabular form.

Figure 8-9. 2028 RPGs position relative to URP in 2028 and 2064



The figure below is meant to summarize how much visibility improved from the baseline period. The improvement is shown for the current period (salmon colored bar) and the 2028 RPG (green bar).

Figure 8-10. Current and Projected Progress from Baseline



The table below represents the percent of progress needed, based on the 2028 RPG, to natural conditions.

Table 8-5. Progress needed to reach 2064 natural conditions

Site ID	Class I Area Name(s)	Baseline (2000-2004) (dv)	2028 RPG (dv)	2064 adjusted endpoint (dv)	Percent to natural
CABI1	Cabinet Mountains Wilderness Area	10.73	9.41	9.79	140%
GAMO1	Gates of the Mountains Wilderness Area	8.95	7.12	7.35	115%
GLAC1	Glacier National Park	15.89	12.92	10.62	56%
MELA1	Medicine Lake Wilderness Area	16.62	14.85	12.37	42%
MONT1	Bob Marshall Wilderness Area, Mission Mountain Wilderness Area, Scapegoat Wilderness Area	11.0	9.51	8.56	61%
SULA1	Anaconda-Pintler Wilderness Area, Selway-Bitterroot Wilderness Area	10.06	8.01	7.71	87%
ULBE1	UL Bend Wilderness Area	12.76	10.62	10.99	121%
YELL2	Red Rock Lakes National Wildlife Refuge, Yellowstone National Park	8.30	6.97	5.71	52%

9 Monitoring Strategy

A requirement of the RHR Rule, 40 CFR 51.308(f)(6), the state must submit a monitoring strategy for measuring, characterizing, and reporting regional haze visibility impairment that is representative of the Class I areas within the state. Montana's monitoring strategy relies on the work of the Interagency Monitoring of Protected Visual Environments (IMPROVE) program. A steering committee with representatives from federal, regional, and state organizations govern the program. Montana relies on the allocation of CAA air management grants to fund the program. Montana has sent a participant to the annual IMPROVE meetings (when virtual) to stay up to date with the program.

9.1 §51.308(f)(6)(i)

Montana will continue to participate in the IMPROVE monitoring network to measure, characterize and report aerosol monitoring data for long-term reasonable progress tracking.

Montana believes the existing IMPROVE monitors for the state's Class I areas are representative of conditions in the state's Class I areas and will rely on the IMPROVE steering committee to determine monitoring sites and equipment needs to address reasonable progress goals.

9.2 §51.308(f)(6)(ii)

The procedures and analyses discussed in Chapters 3-8 provide the basis for how the monitoring data and other information are used in determining the contribution of emissions to regional haze visibility impairment to Class I Areas within and outside of Montana.

9.3 §51.308(F)(6)(III)

This requirement does not apply to Montana since it does contain mandatory Class I Federal areas.

9.4 §51.308(F)(6)(IV)

The IMPROVE program's practice of providing data directly to EPA satisfies the requirement that all visibility monitoring data be reported annually to the Administrator.

9.5 §51.308(F)(6)(V)

Montana satisfies the requirement to provide a statewide emission inventory for the most recent year for which data are available and estimates of future projected emissions, which includes a commitment to update the inventory periodically by its compliance with the Air Emissions Reporting Requirements of 40 CFR Part 51 Subpart A. As discussed in Chapter 6, future emissions are projected in order to determine the RPGs for the Class I Areas.

9.6 §51.308(F)(6)(VI)

The IMPROVE program's practice of providing data directly to EPA satisfies the other reporting and recordkeeping requirements of the rule.

10 CONSULTATION & PUBLIC REVIEW AND COMMITMENT TO FURTHER PLANNING

Montana is committed to future planning for and participation in Regional Haze activities. Montana commits to submitting the 5-year progress report for this implementation period, due January 31, 2025.

10.1 DOCUMENTATION OF FLM CONSULTATION AND COMMITMENT TO CONTINUING CONSULTATION

As outlined in 40 CFR 51.308(i), in developing any implementation plan (or plan revision) or progress report, states must include a description of how comments provided by FLMs were addressed. For this SIP revision, Montana included the comments received during the FLM consultation period in Appendix F of this document. Montana addressed the FLM comments and suggested revisions along with the comments received during the public comment period. These responses are found in Appendix I.

The plan (or plan revision) must provide procedures for continuing consultation between the state and the FLMs on the implementation of the visibility protection program, including development and review of implementation plan revisions and progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in Class I areas. Montana will continue to consult with FLMs on the implementation of the visibility protection program and will provide the FLMs an opportunity to review and comment on SIP revisions, the five-year progress reports, and other developing programs that may contribute to Class I area visibility impairment.

10.2 Coordination with Indian Tribes

While there are no specific state-tribal consultation requirements set by federal legislation, Montana has and will continue to engage tribes in state visibility plans and progress reports. In addition, Montana intends to build on current consultation practices, such as hosting regular meetings and regularly soliciting evaluations from tribes on the consultation process. Documentation of the consultations and resultant recommendations will be maintained and used to strengthen effective communication.

10.3 Public Review Period

The public comment period on the RH SIP was held February 3, 2022 – March 21, 2022. The comments received during the public comment period are included in Appendix H of this document.

10.3.1 Public Hearing

The public hearing on this SIP revision was held March 18, 2022 in Room 40 of the Montana DEQ – Lee Metcalf Building (1520 E. 6th Avenue, Helena, MT 59601) from 10:00 a.m. to 11:30 a.m. Montana offered an online option for virtual participants. Information on the public hearing is found in Appendix G.