State of Utah

SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of
Environmental Quality

Tim Davis
Commissioner

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-035-26

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

THROUGH: Jazmine Lopez, Rules Coordinator

FROM: Devin Mulrooney, Environmental Scientist

DATE: July 22, 2026

SUBJECT: PROPOSE FOR PUBLIC COMMENT: Amend Section R307-110-28. Regional Haze; Utah State Implementation Plan, Section XX.A.1; Amend Section R307-110-17. Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits.

Background

In 1977, the Clean Air Act (CAA) established a program to protect visibility in the nation's mandatory Class I areas (CIAs). Mandatory CIAs are national parks, wilderness areas, and national forests that meet size criteria established under the CAA. Utah contains five mandatory CIAs: Arches National Park, Bryce Canyon National Park, Canyonlands National Park, Capitol Reef National Park, and Zion National Park. The CAA established a national goal of "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."

To implement this goal, the CAA and the Regional Haze Rule require states to develop State Implementation Plans (SIPs) that describe the controls and long-term strategies necessary to achieve reasonable progress toward improving visibility in CIAs. The program is organized in ten year planning periods with an end goal of natural visibility in 2064. The first regional haze implementation period began with SIP submissions due in 2008 and covered the period through 2018. The second implementation period SIPs were due in 2021 after the Environmental Protection Agency (EPA) granted states an extension for submission. Utah submitted its Regional Haze Second Implementation Period SIP to EPA on August 2, 2022.

EPA partially approved and partially disapproved Utah's Second Implementation Period Regional Haze SIP in a final action published on January 2, 2025. EPA approved portions of the SIP related to baseline, current, and natural visibility conditions; assessment of progress to date; the uniform rate of progress (URP); reasonably attributable visibility impairment; progress report requirements; monitoring strategy; and other applicable implementation plan requirements. EPA disapproved portions of the SIP related to the long-term strategy, reasonable progress goals, and Federal Land Manager consultation requirements.

This SIP revision incorporates by reference Section XX.A.1 to address the deficiencies identified in EPA's partial disapproval and to update the SIP consistent with recent regional haze guidance and state legislative policy. Specifically, the revision updates the long-term strategy for the Intermountain Power Plant (IPP) and US Magnesium (USM).

Intermountain Power Plant

In Utah's initial Second Implementation Period Regional Haze SIP, IPP agreed to an enforceable shutdown date of December 31, 2027, for its two coal-fired generating units. This commitment was made because IPP had already begun permitting, planning, and constructing the IPP Renewed project, which consists of two combined-cycle combustion turbine (CCCT) units designed to operate on natural gas. IPP voluntarily pursued this transition due primarily to economic and market drivers. Approximately 98 percent of the electricity generated at IPP is sold to California customers. California legislation established greenhouse gas emissions performance standards requiring imported electricity to come from generation sources equivalent to natural gas-fired generation. As a result, IPP initiated construction of the CCCT units to maintain its ability to provide electricity to California customers.

Following the announcement of the planned coal unit retirement, the Utah Legislature considered and enacted legislation intended to preserve dispatchable electricity generation capacity within the state. In addition, more recent EPA regional haze guidance and federal executive policy directives have placed increased emphasis on consideration of electric grid reliability when evaluating potential generating unit retirements. As a result of these developments, Utah revised the SIP to remove the enforceable shutdown date for the coal-fired units at IPP.

The Second Implementation Period regional haze process consisted of three primary phases. The first phase involved a screening analysis to determine which sources contributed to visibility impairment at CIAs. IPP was identified as a source contributing to visibility impacts and therefore advanced to the next phase of review.

The second phase required selected sources to conduct a four-factor analysis. Under the CAA and Regional Haze Rule, a four-factor analysis evaluates:

1. The cost of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of the source.

Sources that advanced beyond the screening phase were required to evaluate visibility-impairing pollutants, including nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulate matter (PM). In the original SIP submission, IPP did not perform a four-factor analysis because the units were subject to the enforceable shutdown date. Removal of the shutdown date as part of this SIP revision necessitated completion of a four-factor analysis for IPP.

In the third phase, the Division of Air Quality (the division) considers the results of the four factor analysis and implements which controls and strategy it deems reasonable into the regional haze SIP. For SO_2 and PM, the analysis concluded that emissions are already effectively controlled through the facility's existing flue gas desulfurization systems and baghouse controls. Existing permitted emission limits for SO_2 and PM are below the thresholds identified in regional haze guidance where additional controls are generally considered for evaluation. Accordingly, the division determined that additional SO_2 and PM controls were not necessary to achieve reasonable progress.

For NO_x, the four-factor analysis concluded that additional reasonable progress controls were warranted and reasonable. As a result, the SIP revision establishes a new mass-based NO_x emission limit for the coal-fired units of 14,340 tons per year, along with a 1,813-ton 30-day rolling emission limit. These limits were derived based on a reasonable control efficiency achievable through selective non-catalytic reduction controls and were determined to be cost-effective if the units were to operate at higher utilization levels over a 20-year remaining useful life.

As part of this SIP revision, the division conducted updated regional haze visibility modeling performed by Ramboll. In the original regional haze modeling analysis, emissions from the coal-fired units at IPP were assumed to be zero due to the enforceable shutdown date. The updated modeling represents a conservative analysis because it assumes maximum potential emissions from both the coal-fired units and the CCCT units while not accounting for recent emissions reductions resulting from the closure of USM and the Kennecott Power Plant, emission reductions at CCI Paradox Midstream, or new emission limits at the Tesoro Refinery.

The regional haze modeling was conducted to predict visibility impacts in 2028 on the 20 percent most impaired days at CIAs within Utah and in neighboring states. Visibility impacts are measured in deciviews (dv), which is the standard metric used to quantify visibility impairment. The modeled visibility impacts are compared to the URP, which represents the rate of visibility improvement needed to achieve natural visibility conditions by 2064, consistent with EPA regional haze guidance.

Under the updated conservative modeling scenario, all of Utah's CIAs remained below the URP. Although removal of the enforceable shutdown date for IPP resulted in some modeled increase in visibility impairment, the impacts remained small. The projected visibility impacts attributable to IPP at Utah's CIAs are as follows:

- Bryce Canyon National Park: 0.118 dv
- Canyonlands National Park and Arches National Park (shared monitor): 0.046 dv
- Capitol Reef National Park: 0.113 dv
- Zion National Park: 0.013 dv

For reference, a dv is a logarithmic scale used to measure visibility impairment, and a change of approximately 1 dv is generally considered perceptible to the human eye. The modeled visibility impacts associated with IPP are substantially below that threshold.

The updated modeling also demonstrated impacts at CIAs outside Utah; however, those impacts were similarly minimal, with the largest modeled impact remaining below 0.04 dv. The division determined that the controls and limitations established to ensure reasonable progress for Utah's CIAs are also sufficient to address impacts at out-of-state CIAs.

Even under the conservative maximum-emissions modeling scenario, Utah's CIAs remain below the URP with only limited additional visibility impacts. Actual impacts are expected to be lower than those modeled because the revised SIP establishes a new mass-based NO_x emission limit for the coal-fired units at IPP.

The new mass-based NO_x emission limit and associated compliance and reporting requirements are incorporated into Section H.23 of the SIP revision.

US Magnesium

This SIP revision also addresses updates related to USM. In January 2026, the USM facility and associated property were acquired by Utah Division of Forestry, Fire and State Lands (FFSL). Under Utah's original Second Implementation Period Regional Haze SIP, USM was required to install flue gas recirculation (FGR) controls on the Riley Boiler by 2028 as a reasonable progress control measure. However, the facility has not operated since 2021.

FFSL acquired the property primarily to secure associated water rights that may assist ongoing efforts to support and restore the Great Salt Lake. As a result, operation of the facility in the near future is considered unlikely. Nevertheless, FFSL retains the authority to restart operations, sell the facility, or authorize a third party to operate the plant in the future.

The current SIP provision requires installation of FGR controls by 2028 regardless of whether the facility is operating. Because the facility is currently shut down, this SIP revision modifies the compliance schedule to require installation of FGR controls either prior to restart of operations or by 2028, whichever occurs later. This revision provides the current owner flexibility to determine the most appropriate long-term use and value of the facility while still ensuring that FGR controls will be installed before any future operations resume.

The division determined that this revision will not adversely impact visibility because the underlying control requirement remains unchanged. The amendment only revises the timing of compliance to reflect the facility's current non-operational status.

The timing provision and current ownership were both updated in Section H.23 to reflect this SIP revision.

Other Reasoning for Disapproval

As part of EPA's partial disapproval of Utah's Second Implementation Period Regional Haze SIP, EPA also identified issues related to PacifiCorp's Hunter Power Plant and Huntington Power Plant, the Sunnyside Cogeneration Station, and CCI Lisbon.

These facilities and issues are not addressed in this SIP revision because the affected parties filed petitions for reconsideration and judicial review challenging EPA's action before the United States Court of Appeals for the Tenth Circuit and were granted reconsideration of those issues, and the matters are currently under further review by the EPA.

Because EPA is reconsidering those portions of the partial disapproval, the division is not providing additional revisions related to those facilities as part of this amendment. The division will continue coordinating with EPA regarding the outcome of the reconsideration process and determine whether additional SIP revisions are necessary following EPA's review.

Recommendation: Staff recommend the Board approve the amendments to Section R307-110-28, Regional Haze; Utah State Implementation Plan, Section XX.A.1, and Section R307-110-17. Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits, for a 30-day public comment period.

State of Utah
Administrative Rule Analysis
Revised May 2026

NOTICE OF SUBSTANTIVE CHANGE	
TYPE OF FILING: Amendment	**Filing ID: OFFICE USE ONLY**
Rule or section number:	**R307-110**
Date of previous publication (only for CPRs):	

1. Agency Information

Title catchline:	Environmental Quality, Air Quality
Building:	Multi-Agency State Office Building
Street address:	195 N 1950 W
City, state:	Salt Lake City, UT
Mailing address:	PO Box 144820
City, state and zip:	Salt Lake City, UT 84114-4820

2. Contact Persons

Name:	Phone:	Email:
Devin Mulrooney	385-315-3368	dmulrooney@utah.gov
Jazmine Lopez	801-536-4050	jazminelopez@utah.gov

Please address questions regarding information on this notice to the persons listed above.

3. General Information

A. Rule or section catchline:

R307-110. General Requirements: State Implementation Plan

B. Purpose of the new rule or reason for the change:

The Clean Air Act and Regional Haze Rule requires states to submit a State Implementation Plan (SIP) demonstrating reasonable progress towards achieving natural visibility by 2064 in Utah's five Class I Areas (CIAs), which include all five of the national parks in the State. As part of this SIP, the state must conduct an emissions control determination to identify its long-term strategy (LTS) to achieve the 2064 natural conditions goal. This rule is being amended to incorporate by reference Utah SIP Section XX.A.1: Regional Haze Second Implementation Period and amendments to SIP Section IX.H.23: Regional Haze Emissions Limits and Operating Practices.

C. Summary of the new rule or change:

This amendment changes the "most recently amended" date in Sections R307-110-17 and R307-110-28 to November 4, 2026, incorporating by reference the requirements of Section XX.A.1: Regional Haze Second Implementation Period and Section IX: Control Measures for Area and Point Sources, Part H, Emission Limits, of the Utah SIP. The reasonable progress determinations in these sections revise Section XX.A with the following changes to measures supporting the State's LTS:

1. Establishes mass-based annual and 30-day rolling Nitrogen Oxides (NOx) emissions limits for the Intermountain Power Plant (IPP) based on a four-factor analysis and the achievable control efficiency of selective non-catalytic reduction;
2. Removes the enforceable closure date for the coal-fired boilers at the IPP due to changes in federal and state policy; and
3. Revises the compliance date for flue gas recirculation at the US Magnesium Riley boiler to 2028, or upon source startup, whichever occurs later, and updates the SIP to reflect the current operator.

4. Legislative Action Information

A. Are any changes in this filing because of state legislative action?	Changes are because of legislative action.
B. If yes, any bill number and session:	HB 425 (2023 General Session), SB 161 (2024 General Session), HB 3004 (2024 Special Session), HB 70 (2025 General Session)

5. Fiscal Information

Provide an estimate and written explanation of the aggregate anticipated cost or savings to:

A. State budget:

Removal of the IPP closure date from the SIP provides the opportunity for the facility to be sold and potentially returned to

operation in the future. If a purchaser were to acquire and restart the facility, the State could experience fiscal benefits from tax revenue associated with the sale, potential job creation, and economic activity related to energy production and sales. Because no sale or restart has occurred, these potential benefits cannot be reliably quantified at this time.

The previous NOx emissions limit of 21,234.7 tons per 12-month rolling total is being reduced to 14,340 tons per 12-month rolling total, and a new 30-day rolling limit of 1,813 tons is being established. These revised NOx emissions limits are not anticipated to impact the State budget. IPP is currently not operating, and the new limits are consistent with existing emissions limits for other pollutants at the facility. If the facility resumes operation, the revised limits are not expected to reduce productivity or utilization.

The revisions related to US Magnesium are not anticipated to impact the State budget because they only revise the timeline for installation of previously required controls. The control installation requirement was adopted in a prior rulemaking, and the associated fiscal impacts were evaluated at that time.

B. Local governments:

IPP is owned by the Intermountain Power Agency (IPA), a political subdivision of the State consisting of 23 municipalities that receive financial benefits associated with IPP operations. By removing the enforceable closure date, this revision allows for the continued operation of IPP and preserves the potential for sale of the facility. If the facility were sold or returned to operation, the participating municipalities could experience financial benefits associated with employment, energy production, and related economic activity. Because no sale or restart has occurred, these potential benefits cannot be reliably quantified at this time.
The revisions related to US Magnesium are not anticipated to impact local governments because they only revise the timeline for installation of previously required controls. The control installation requirement was adopted in a prior rulemaking, and associated fiscal impacts were evaluated at that time.

C. Small businesses ("small business" means a business employing 1-49 persons)**:**

This amendment is not anticipated to create costs for small businesses. Removal of the IPP closure date preserves the potential for future operation or sale of the facility, which could provide indirect economic benefits to small businesses through increased economic activity, employment, and demand for local goods and services. Because no sale or restart has occurred, these potential benefits cannot be reliably quantified at this time.

The newly established NOx emissions limits apply to IPP and are not anticipated to affect small businesses because the facility is currently not in operation and other limits already impact utilization and production. The revisions related to US Magnesium only revise the timeline for installation of previously required controls and do not create new requirements for small businesses.

D. Non-small businesses ("non-small business" means a business employing 50 or more persons)**:**

A potential purchaser and operator of the IPP could experience significant fiscal benefits associated with operation of the facility, including revenue from energy production and related economic activity. Removal of the enforceable closure date preserves the opportunity for future operation or sale of the facility. Because there is currently no purchaser and the facility is not operating, these potential impacts cannot be reliably quantified at this time.

The newly established NOx emissions limits apply only to IPP and are not anticipated to create significant additional costs because the limits are inline with other pollutants and are not expected to reduce facility productivity or utilization.

The revisions related to US Magnesium only revise the timeline for installation of previously required controls and do not create fiscal impact for non-small businesses.

E. Persons other than small businesses, non-small businesses, state, or local government entities ("person" means any individual, partnership, corporation, association, governmental entity, or public or private organization of any character other than an ***agency***)**:**

If IPP were purchased and returned to operation, the facility would require approximately 300 employees onsite. This would provide a significant economic benefit to the individuals employed by the facility and to the surrounding communities.
The revisions related to US Magnesium only modify the compliance timeline for installation of previously required emission controls and do not create any fiscal impact for persons.

F. Compliance costs for affected persons:

The impacted entities will incur no additional costs to comply with these revisions. For IPP, the new emission limit is not expected to restrict production or facility utilization. For US Magnesium, the revisions only modify the compliance timeline for previously required controls and do not impose any new control requirements or associated costs.

6. Regulatory Impact Summary Table

Enter the cost or savings in the relevant cell. If there is no cost or savings, enter, "$0." If a cost or savings is inestimable, enter, "inestimable."

Fiscal Cost	FY2027	FY2028	FY2029	FY2030	FY2031
State Budget	inestimable	inestimable	inestimable	inestimable	inestimable
Local Governments	inestimable	inestimable	inestimable	inestimable	inestimable
Small Businesses	inestimable	inestimable	inestimable	inestimable	inestimable
Non-Small Businesses	inestimable	inestimable	inestimable	inestimable	inestimable
Other Persons	inestimable	inestimable	inestimable	inestimable	inestimable
Total Fiscal Cost	**inestimable**	**inestimable**	**inestimable**	**inestimable**	**inestimable**
Fiscal Benefits	**FY2027**	**FY2028**	**FY2029**	**FY2030**	**FY2031**
State Budget	inestimable	inestimable	inestimable	inestimable	inestimable
Local Governments	inestimable	inestimable	inestimable	inestimable	inestimable
Small Businesses	inestimable	inestimable	inestimable	inestimable	inestimable
Non-Small Businesses	inestimable	inestimable	inestimable	inestimable	inestimable
Other Persons	inestimable	inestimable	inestimable	inestimable	inestimable
Total Fiscal Benefits	**inestimable**	**inestimable**	**inestimable**	**inestimable**	**inestimable**
Net Fiscal Benefits	**inestimable**	**inestimable**	**inestimable**	**inestimable**	**inestimable**

7. Regulatory Impact Analysis Approval

The Commissioner of the Department of Environmental Quality, Tim Davis, has reviewed and approved this regulatory impact analysis.

8. Family Impact Information

A. The agency has considered this rule's impact on family health, stability, and formation:	☒

B. Summary of reasonable alternatives or modifications:

9. Citation Information

Provide citations to the statutory authority for the rule. If there is also a federal requirement for the rule, provide a citation to that requirement:

Section 19-2-104	40 CFR 51 Subpart P	

10. Incorporation by Reference Information

Incorporation by Reference (if this rule incorporates more than two items by reference, please include additional tables)**:**

A. This rule adds or updates the following title of material incorporated by reference (a copy of the material incorporated by reference must be submitted to the Office of Administrative Rules. *If none, leave blank*)**:**

Official Title of Materials Incorporated (from title page)	Utah State Implementation Plan, Section XX, Regional Haze.
Publisher	Division of Air Quality, Utah Department of Environmental Quality
Issue Date	November 4, 2026
Issue or Version	

B. This rule adds or updates the following title of material incorporated by reference (a copy of the material incorporated by reference must be submitted to the Office of Administrative Rules. *If none, leave blank*)**:**

Official Title of Materials Incorporated (from title page)	Utah State Implementation Plan, Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits and Operating Practices.
Publisher	Division of Air Quality, Utah Department of Environmental Quality
Issue Date	November 4, 2026
Issue or Version	

11. Public Notice Information

The public may submit written or oral comments to the agency identified in box 1.	
A. Comments will be accepted until:	10/01/2026

B. A public hearing (optional) will be held (The public may request a hearing by submitting a written request to the agency, as outlined in Section 63G-3-302 and Rule R15-1.)**:**

Date:	**Time** (hh:mm AM/PM)**:**	**Place** (physical address or URL)**:**
09/24/2026	02:00 PM - 03:00 PM	A public hearing is set for September 24, 2026. Further details may be found below. The hearing will be cancelled should no request for one be made by September 22, 2026, at 10 AM MT. The final status of the public hearing will be posted on September 22, 2026, after 10 AM MT. The status of the public hearing may be checked at the following website location under the corresponding rule. https://deq.utah.gov/public-notices-archive/air-quality-rule-plan-changes-open-public-comment Interested Persons can participate in person or electronically, via the internet. In Person: MASOB 195 N. 1950 W. Salt Lake City, UT, 84116, First Floor, Air Quality Board Room Virtual Attendance: Time zone: America/Denver Google Meet joining info: Video call link: https://meet.google.com/qpx-feyv-vom Or dial:(US) +1 740-936-3821 PIN: 799 848 699#

To the agency: If more than one hearing is planned to take place, continue to add rows.

12. Effective Date Information

This rule change MAY become effective on: (NOTE: This is the date the agency anticipates making the filing effective. It is NOT the effective date)	11/04/2026

13. Agency Authorization Information

To the agency: Information requested on this form is required by Sections 63G-3-301, 63G-3-302, 63G-3-303, and 63G-3-402. The office may return incomplete forms to the agency, possibly delaying publication in the *Utah State Bulletin* and delaying the first possible effective date.

Agency head or designee and title:	Bryce C. Bird, Director, Division of Air Quality	**Date:**	07/20/2026

R307. Environmental Quality, Air Quality.
R307-110. General Requirements: State Implementation Plan.
R307-110-17. Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits.
The Utah State Implementation Plan, Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits and Operating Practices, as most recently amended by the Utah Air Quality Board on November 4, 2026 [~~July 1, 2026~~], pursuant to Section 19-2-104, is incorporated by reference and made a part of Rule R307-110.

R307-110-28. Regional Haze.
The Utah State Implementation Plan, Section XX, Regional Haze, as most recently amended by the Utah Air Quality Board on November 4, 2026 [~~July 6, 2022~~], pursuant to Section 19-2-104, is incorporated by reference and made a part of [~~these rules~~] Rule R307-110.

KEY: air pollution, PM10, PM2.5, ozone
Date of Last Change: [~~July 1, 2026~~] 2026
Notice of Continuation: December 1, 2021
Authorizing, and Implemented or Interpreted Law: 19-2-104

Utah State Implementation Plan Regional Haze Second Implementation Period: Section XX.A.1

Revision Summary

This State Implementation Plan (SIP) revision includes Utah's Regional Haze Second Implementation Period plan (XX.A.1)[1] to reflect changes in the planned operation of the Intermountain Power Plant (IPP) – Intermountain Generating Station and ownership changes to the U.S. Magnesium (USM) - Rowley Facility to ensure continued compliance with the federal enforceability requirements of the Regional Haze Rule (RHR).[2]

On December 2, 2024, the Environmental Protection Agency (EPA) partially approved and partially disapproved Utah's Second Implementation Period Regional Haze SIP.[3] The SIP included a state enforceable commitment to shut down the IPP coal-fired units by December 31, 2027 and requirements to install flue gas recirculation at the U.S. Magnesium Riley Boiler, both codified in SIP Subsection IX.H.23.[4]

The revisions discussed in the following chapters represent material modifications to the enforceable commitments underlying the SIP and therefore require revision. This revision evaluates each facility separately, with Chapter 1 addressing IPP and Chapter 2 addressing USM.

Ultimately, the updated analyses demonstrate that Utah's Class I Areas (CIAs) are projected to remain below their applicable Uniform Rate of Progress (URP) glidepaths for the 20 percent most impaired days (MIDs) in 2028. The revised SIP will not impede reasonable progress, will continue to satisfy the requirements of the RHR, and appropriately updates the long-term strategy (LTS).

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[1] See XX.A.

[2] See 40 CFR § 51.308(f).

[3] See Air Plan Partial Approval and Partial Disapproval; Utah; Regional Haze State Implementation Plan for the Second Implementation Period; Air Plan Disapproval; Utah; Prong 4 (Visibility) for the 2015 8-Hour Ozone National Ambient Air Quality Standard.

[4] See IX.H.23.

Chapter 1
Intermountain Power Plant – Intermountain Generating Station

Executive Summary

This SIP revision includes Utah's Regional Haze Second Implementation Period plan (XX.A.1)[5] to reflect changes in the planned operation of the Intermountain Power Plant – Intermountain Generating Station and to ensure continued compliance with the federal enforceability requirements of the RHR.[6]

On December 2, 2024, the EPA partially approved and partially disapproved Utah's Second Implementation Period Regional Haze SIP.[7] The SIP included a state enforceable commitment to shut down the IPP coal-fired units by December 31, 2027, codified in SIP Subsection IX.H.23.[8] Following legislative changes enacted in 2025 through House Bill (H.B.) 70 and a subsequent evaluation by the Utah Energy Council, the Intermountain Power Agency elected to keep the coal-fired units operational beyond 2027.[9] This decision constitutes a material change to the enforceable commitment relied upon in the SIP and necessitates a revision to avoid reliance on a shutdown date that is not federally enforceable.

Recent EPA actions and the February 19, 2026, Regional Haze Guidance[10], demonstrate the need for Utah to revise its SIP to maintain consistency with EPA guidance, the Clean Air Act (CAA), and RHR requirements. Accordingly, this SIP revision removes the IPP coal-unit shutdown date and updates the LTS and supporting analyses to reflect revised IPP operational assumptions.

To address the continued authorization of coal-unit operation at IPP, the Utah Division of Air Quality (the Division) updated the emissions quantity/distance (Q/d) screening

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[5] See XX.A.

[6] See 40 CFR § 51.308(f).

[7] See Air Plan Partial Approval and Partial Disapproval; Utah; Regional Haze State Implementation Plan for the Second Implementation Period; Air Plan Disapproval; Utah; Prong 4 (Visibility) for the 2015 8-Hour Ozone National Ambient Air Quality Standard.

[8] See IX.H.23.

[9] See Utah House Bill 70.

[10] See Memorandum: Update to Guidance on Regional Haze State Implementation Plans for the Second Implementation Period

analysis[11], conducted a four-factor reasonable progress evaluation for the coal-fired units[12], and revised regional visibility modeling[13] using conservative assumptions. These updates ensure that potential visibility impacts are not underestimated and confirm that the carefully considered reasonable progress determinations along with LTS amendments will continue to contribute toward natural visibility conditions.

The updated analyses demonstrate that Utah's CIAs are projected to remain below their applicable URP glidepaths for the 20 percent MIDs in 2028. This SIP revision removes the IPP shutdown date from the LTS[14], provides a new reasonable determination for control strategies while demonstrating that Utah's updated LTS strategy is sufficient to achieve reasonable progress toward natural visibility conditions.

1. Purpose of Chapter 1

This SIP revision addresses changes in the operational status of the Intermountain Power Plant – Intermountain Generating Station and the implications of those changes for Utah's Regional Haze Second Implementation Period plan. The revision updates the following elements to reflect revised assumptions regarding IPP operations:

- Emissions/Distance (Q/d) screening analysis;
- Four-factor reasonable progress analysis for the IPP coal-fired units;
- Regional visibility modeling;
- Reasonable progress determinations; and
- Applicable elements of the LTS.

This document supersedes all prior analyses related to IPP and reflects the most current information and determinations; accordingly, previous IPP-specific analyses are no longer relied upon for purposes of this SIP revision.

2. Background

2.1 Second Planning Period SIP and Recent Legislative Actions

In Utah's second planning period, the Division established an enforceable state shutdown date of December 31, 2027, for the two coal-fired units at IPP, codified in SIP Subsection IX.H.23. This commitment aligned with the *IPP Renewed* project initiated by the Intermountain Power Agency in 2019, which planned to replace the coal-fired units

[11] See 3. Updated Q/d Analysis.

[12] See 4. Revised Four Factor Analysis.

[13] See 5. Determination of Reasonable Progress.

[14] See 6. Long Term Strategy.

with new natural-gas combined-cycle units capable of hydrogen co-firing.[15] Construction of the replacement units began in 2022, and the new combined-cycle units entered commercial operation in July 2025.[16]

Prior to the closure of IPP's coal units, the Utah State Legislature passed several bills concerned with the future energy generation within Utah and potential decommission of energy generating facilities. The first bill passed H.B. 425[17] in 2023 which required 180-day advance notice before a project entity sells major energy assets or decommissions a coal-fired power plant. The bill directed the Office of Energy Development to study a project entity, IPP, and report findings to the legislature. It strengthened Utah's energy policy by promoting in-state energy production and evaluating energy sources based on full life-cycle emissions. The bill also requires utilities to alert the Attorney General about federal rules that could force early plant retirements and authorizes the state to take legal action in response.

In 2024, Senate Bill (S.B.) 161[18] was passed which allowed a project entity, IPP, to apply for an alternative air permit and established the process and conditions under which alternative or transition permits may take effect. It authorized the state to purchase power plants slated for decommissioning and created a Decommissioned Asset Disposition Authority within the Office of Energy Development to manage those assets and pursue permitting feasibility. It also required a study of SIP-related implications, determination of fair market value, and evaluation of options for selling state-acquired facilities.

A third bill, H.B. 3004[19] was passed in 2024 during the special session. The bill updated requirements for notifying the state about the decommissioning or disposal of project entity assets and removed oversight steps tied to that notice. It directed the Decommissioned Asset Disposition Authority to submit a complete alternative air permit application by the end of 2024 and required a timely evaluation response from the Division of Air Quality. The bill also refocused the required study on ensuring continued plant operations under an alternative permit will not interfere with federal air quality compliance.

During the 2025 General Legislative Session, the Utah Legislature enacted H.B. 70[20], later codified in Utah Code § 79-6-1101, establishing the Utah Energy Council and directing it to evaluate the feasibility of continued operation of decommissioned or soon-

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[15] See IPP Renewed.

[16] See IPP AO25 in Appendices I.

[17] See H.B. 425

[18] See S.B. 161

[19] See H.B. 3004

[20] See H.B. 70

to-be-decommissioned energy assets, including the IPP coal-fired units. H.B. 70 also prohibited a project entity, like IPP, from modifying critical infrastructure, like the station service power, interconnections, and switchyard equipment, in ways that would prevent continued or future operation of a power plant. Following the evaluation and several energy asset related bills passed in previous years, IPP elected not to decommission the coal-fired units by 2027 and leave them operational, constituting a material deviation from the enforceable shutdown commitment included in Utah's state approved SIP.

2.2 Factors Affecting Continued Coal Operations

Continued operation of the coal-fired units at IPP still will face several significant economic, operational, and regulatory challenges.

First, IPP's operational decisions are heavily influenced by regulatory and contractual constraints associated with California's Emissions Performance Standard (EPS). California S.B. 1368, approved on September 29, 2006, established an EPS prohibiting long-term financial commitments for baseload electricity generation with greenhouse gas emissions exceeding those of a combined-cycle natural gas facility. Because IPP's coal-fired units exceed the EPS threshold, electricity generated by those units cannot be used to support long-term California utility procurement.

Historically, approximately 98 percent of IPP's electricity output was sold to California utilities. However, the previous power purchase agreements associated with the coal-fired units expired in 2025 and were not renewed. As a result, there is limited economic incentive to continue operating the coal-fired units. IPP has indicated it is actively seeking a buyer for the units, which were placed into cold idle status on November 26, 2025, meaning the units are maintained but not currently operating.

Second, there is currently limited market demand for coal-based electricity generated by the facility. Most of the major transmission infrastructure associated with IPP delivers power directly to California, where utilities cannot purchase the energy generated from coal-fired units due to the previously mentioned state energy and emissions policies. As a result, substantial new transmission development would likely be necessary to deliver power from the coal units to alternative markets.

Third, IPP's workforce has significantly decreased as the facility has transitioned to combined-cycle combustion turbine (CCCT) units. During coal operations, approximately 300 employees were required to operate the plant. IPP has decreased their employee count to roughly 130 employees solely operating the CCCT units. Many former coal unit employees have retired or otherwise exited the workforce, meaning that any future operator seeking to continue coal operations would need to recruit and train a substantial number of new personnel. This challenge is compounded by IPP's remote

location near Delta, which has a population of fewer than 4,000 residents, limiting the immediately available labor pool.

Fourth, IPP has limited remaining on-site coal reserves and, absent significant long-term supply agreements with coal producers, may face increasing uncertainty regarding the availability, reliability, and cost of future coal supplies. Existing on-site reserves are finite and would only support continued operation for a limited duration. In addition, IPP does not intend to enter into new long-term coal supply agreements. As a result, any future operator seeking to continue coal-fired operations would likely need to independently negotiate and execute new coal supply contracts and potentially make additional investments associated with coal production, transportation, and related infrastructure.

Fifth, IPP historically operated an unlined Coal Combustion Residuals (CCR) surface impoundment. Under EPA's CCR Rule[21] and the Code of Federal Regulations (CFR) 40 CFR 257.103(f)(2)[22], IPP committed to permanently cease operation of the coal-fired units prior to the applicable compliance deadline rather than undertake major modifications or replacement of the CCR impoundment system. If a future owner or operator sought to continue coal operations beyond the applicable closure timeline of 2031, substantial capital investments would likely be required to bring the CCR management system into compliance with current federal requirements.

2.3 Basis for SIP Revision

While the factors listed above affect the likelihood of coal-unit operation, they are not legal limitations to operation of the coal units and do not limit potential to emit (PTE) emissions under the current Approval Order DAQE-AN103270031-25 (AO25).[23] In addition, with recent EPA actions regarding decommissioning coal units, the February 19, 2026 RH guidance, and state legislature actions highlighted the need for the Division to revise the SIP. Accordingly, the Division is removing the IPP coal-unit shutdown date from the SIP.

In light of these developments, the assumptions regarding IPP operations that were used in Utah's approved Second Implementation Period SIP (XX.A) are no longer valid. These changes necessitate a reevaluation of reasonable progress using assumptions that do not rely on a future shutdown date, and the following sections document the Division's updated technical analyses conducted to ensure consistency with the requirements of the RHR.

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[21] See Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Extension of an Alternative Closure Requirement Deadline

[22] See 40 CFR 257.103

[23] See IPP AO25 in Appendix I.

3. Updated Q/d analysis

The Division's standard Q/d screening methodology, as described in the initial SIP Narrative (XX.A), relies on representative annual emissions from the National Emissions Inventory (NEI). The original Second Implementation Period SIP (XX.A) includes Tables 29 and 30 providing the Q/d analysis for Utah sources. Section 7.A.2 specifically addressed IPP and concluded that a Q/d analysis was unnecessary as the plant was scheduled to shut down within the second implementation period, by December 31, 2027. This updated analysis reflects the removal of that shutdown assumption.

Because the facility has not yet operated for a full year under its revised configuration, and the most recent NEI data from 2020 does not reflect current operating scenarios, representative annual emissions are unavailable. Accordingly, the Division conducted an updated Q/d analysis using the PTE for the CCCT units and Coal Units.

The scenarios evaluated in Table 1 include:

- **Scenario 1:** PTE from AO25 for the CCCT units;
- **Scenario 2:** 2024 Actual Emissions; and
- **Scenario 3:** PTE from AO25 for the CCCT units plus the coal-fired units.

Although PTE is not consistent with the conventional Q/d approach, it provides a conservative, worst-case estimate and ensures that potential visibility impacts are not underestimated.

Consistent with 40 CFR § 51.308(f)(2)(i) and EPA's *2019 Guidance on Regional Haze State Implementation Plans (2019 Guidance)* for the Second Implementation Period,[24] the Division evaluates whether stationary sources warrant a four-factor reasonable progress analysis using the Q/d method, where:

- **Q** = combined annual emissions (tons per year) of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter less than 10 microns (PM_{10})
- **d** = distance (km) to the nearest CIA

The Western Regional Air Partnership (WRAP) recommends a Q/d screening threshold of ten; however, the Division opted for a more conservative threshold of six for the second planning period.

[24] See EPA's 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period.

Facility Name	Total Q/d (tpy/km)	Total Q (tpy)	Distance to Nearest Class I Area in km (d)	Class I Area	Q/d NO_x (tpy/km)	Q/d SO_2 (tpy/km)	Q/d PM_{10} (tpy/km)	Q NO_x tons per year (tpy)	Q SO_2 tons per year (tpy)	Q PM_{10} tons per year (tpy)	Data source
Intermountain Power Plant - Intermountain Generation Station	3.5	528.39	149.5	Capitol Reef	1.9	0.9	0.8	286.92	128.9	112.6	Scenario 1: PTE IPP Renewed
Intermountain Power Plant - Intermountain Generation Station	60.6	9,063	149.5	Capitol Reef	45	11	4.8	6,709	1,644	710	Scenario 2: 2024 Actual Emissions
Intermountain Power Plant - Intermountain Generation Station	175.6	26,255	149.5	Capitol Reef	144.0	20.4	11.3	21,521	3,046	1,688	Scenario 3: PTE IPP Renewed Plus Coal-Fired Units

Table 1: Q/d analysis for Intermountain Power Plant

3.1 Q/d Determination

A Q/d determination for IPP is challenging due to ongoing operational changes, uncertainty regarding future operations, and the absence of a full-year emissions inventory reflecting the revised plant configuration.

On December 5, 2022, IPP received AO DAQE-AN103270030-22 (AO22) authorizing construction of the CCCT turbines and decommissioning the coal units. This configuration substantially reduced emissions of visibility-impairing pollutants. The PTE values associated with AO22 result in a combined Q/d of 3.5, below Utah's threshold of six, indicating no four-factor analysis would be required.[25] Because the CCCT units are effectively controlled with Selective Catalytic Reduction (SCR) technology pursuant to AO22 and AO25, and PM and SO_2 emissions are inherently low due to the fuel type, the Division has determined that a four-factor analysis is not necessary for these units.[26]

[25] See IPP AO22 in Appendices I.

[26] See 3.2 Effective Controls.

Following legislative changes in 2025, IPP received AO25 on October 3, 2025, authorizing operation of the CCCT units in conjunction with both coal-fired units.[27] The PTE values associated with AO25 yields a combined Q/d of 175.6. This value significantly overestimates expected annual emissions because it assumes the units will be operated at their maximum permitted capacity. Regulatory and contractual constraints, specifically limits on the sale of coal-generated electricity to California, make sustained coal-unit operation unlikely. On November 26, 2025, the coal units were placed in cold idle, leaving the CCCT units as the sole source of power from the IPP plant to California customers. The Division does not have a representative full year of data for the current operating scenario, with the CCCT units running while the coal units remain on cold idle.

A review of recent actual emissions data provides additional context regarding the potential overestimation inherent in the AO25 PTE-based Q/d value. Using 2024 actual emissions, the Division calculated a Q/d value of 60.6. While this value remains above Utah's screening threshold of six, it is substantially lower than the PTE-based value of 175.6.

It is important to note that 2024 represents a transitional operating scenario in which the coal-fired units were operating, but the CCCT units had not yet been fully constructed. During this period, the plant operated at approximately 40% of its maximum capacity due to electrical demand. As such, the 2024 Q/d value does not reflect current or expected future operations.

Under the anticipated operating scenario, the CCCT units will serve as the primary generation source, while the coal units are expected to remain in cold idle or operate infrequently. The CCCT units are projected to produce less than 10% of the emissions observed in 2024 when the coal units were operating, indicating that future emissions of visibility impairing emissions are expected to be substantially lower.

Despite these constraints and IPP's stated intent to limit coal-unit operation, the Division determined that a four-factor analysis specific to the coal-fired units is warranted based on AO25, which allows the coal units to operate and emit visibility-impairing pollutants either under IPP ownership or if transferred to another entity. Use of PTE in this context is consistent with the Division's methodology for sources lacking representative annual emissions due to recent permitting or operational changes and ensures the screening analysis does not underestimate potential visibility impacts.[28]

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[27] See IPP AO25 in Appendix I.

[28] See Utah Second Implementation Period Supplement for GNG.

3.2 Effective Controls

AO25 for the IPP facility ensures that effective emissions control technology is in place for the newly constructed CCCT units. To comply with New Source Performance Standards (NSPS) and meet California EPS, IPP installed SCR technology on its two 487 MW combined-cycle turbines to control NO_x emissions. SCR is a post-combustion control technology that achieves substantial reductions in NO_x, representing a significant degree of emission reduction. The installation of the units and associated SCR systems was completed in 2025.

Given the recent installation of these post-combustion controls, the Division concludes that there is a low likelihood that additional control measures or current technological advancements would yield further reasonable emissions reductions from the CCCT units during Utah's current Regional Haze Second Implementation Period.

EPA's *2019 Guidance* acknowledges that it may be reasonable for a state not to select a source for further four-factor analysis where the source has recently installed effective emission controls to comply with other CAA requirements, such as NSPS or Prevention of Serious Deterioration (PSD) permitting, and where a full four-factor evaluation would likely not identify additional reasonable controls.[29] In this case, IPP has voluntarily made a significant investment resulting in substantial reductions of visibility-impairing pollutants, and the revised AO25 establishes enforceable emission limits reflecting those controls for the CCCT units.

Accordingly, in combination with the updated Q/d screening demonstrating that the CCCT units are not reasonably anticipated to contribute to visibility impairment at any CIA, the Division concludes that it is reasonable and appropriate not to conduct a four-factor analysis for the CCCT units at the IPP facility for the second implementation period.

3.3 Q/d determination summary

The Division evaluated IPP using an updated Q/d screening methodology to determine whether a four-factor reasonable progress analysis is warranted.

- **Coal-Fired Units:** Using conservative PTE values or 2024 actuals, the coal-fired units exceed Utah's Q/d threshold, indicating potential visibility impacts at CIAs. A full four-factor analysis is required for these units to assess the need for additional reasonable controls.

[29] See EPA's 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period

- **CCCT Units:** The new 487 MW turbines are equipped with SCR technology, effectively controlling NO_x emissions. Q/d screening shows these units are unlikely to impact visibility, and a four-factor analysis is not required.

This approach focuses additional analysis on sources with significant visibility-impairment potential while acknowledging the effectiveness of controls at the natural gas units.

4. Revised Four Factor analysis for IPP

Utah's Second Implementation Period Regional Haze SIP (XX.A) establishes the framework for evaluating additional emission controls under the four statutory reasonable progress factors. For a more detailed description see Sections 7.B and 7.C of XX.A.

The Division requested a report evaluating available control technologies for SO_2 and NO_x emission reductions and the applicability of those technologies from IPP for the coal fired units. The Division notes that IPP is not located within an area designated nonattainment for any National Ambient Air Quality Standards.

Consistent with RHR requirements, the four-factor analyses address the following statutory factors when determining potential emission reductions:

Factor 1 – Costs of Compliance;

Factor 2 – Time Necessary for Compliance;

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

Factor 4 – Remaining Useful Life of the Source.

Although not explicitly required by the RHR, the Division recommended that IPP evaluate potential controls using a stepwise, "top-down" approach similar to EPA's guidance for Best Available Retrofit Technology determinations (70 Fed. Reg. 39,104, 39,108–09; July 6, 2005). Under this approach, sources:

1. Identify all available retrofit control technologies;
2. Eliminate technically infeasible control options;
3. Evaluate the control effectiveness of the remaining technologies; and
4. Evaluate associated costs, implementation timelines, and energy and non-air quality environmental impacts, and document the results.

For IPP, the Division coordinated closely with the facility and requested a four-factor analysis specific to the coal-fired units, providing guidance on cost estimation consistent

with EPA's *Air Pollution Control Cost Manual*[30] and the use of facility-specific information reflecting current operations, projected emissions, and potential control scenarios. The Division reviewed the submitted analysis, provided written technical comments and requests for clarification, and evaluated IPP's responses and revisions. The subsections below present the IPP four-factor analysis, the Division's evaluation, the facility's responses, and the Division's final conclusions regarding reasonable progress for the IPP coal-fired units.

4.1 Intermountain Power Plant – Intermountain Generation Station Four Factor Analysis Summary and Evaluation[31]

Facility identification

Name: Intermountain Generation Station

Facility Address: 850 West Brush Wellman Road Delta, UT 84624-9546

Owner/Operator: Intermountain Power Agency, Intermountain Power Service Cooperation

UTM coordinates: 364,136 m Easting, 4,374,605 m Northing, UTM Zone 12

Facility process summary

The Intermountain Generation Station is located in Delta, Millard County, Utah. The nearest CIAs and their approximate distances from the facility are Arches National Park (160 miles), Canyonlands National Park (145 miles), Capitol Reef National Park (92 miles), Bryce Canyon National Park (126 miles), and Zion National Park (242 miles).

IPP is owned by Intermountain Power Agency and began operations in 1986. The electricity it produces is sold to customers predominantly in California. The facility operates two 9225 Million British Thermal units per hour (MMBtu/hr) coal-fired combustion boiler units equipped with low nitrogen oxide burners (LNB) over-fire-air (OFA) ports installed in 2000, a baghouse installed during initial construction in 1986, and a flue gas desulfurization (FGD) scrubber installed 1986. The coal units have been on cold idle since November 26, 2025, and are expected to remain in cold idle until a new owner begins operating them.

To comply with California laws requiring electricity purchased to come from low-carbon dioxide electricity generation, IPP installed a new two-train 840-MW natural gas combined cycle power plant ('IPP Renewed'). The two-train natural-gas combined cycle units are permitted under New Source Review (NSR) AO DAQE-AN103270031-25. The

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[30] See EPA Air Pollution Control Cost Manual

[31] See Appendices C which includes IPP's four factor analysis and the Division's more detailed analysis.

two coal boiler units are currently permitted under the Division's Title V air operating permit 2700010006, which was renewed November 21, 2023, with additional limits in the NSR AO Alternative Operation Scenario described in AO DAQE-AN103270031-25, approved October 3, 2025. The two coal-fired boiler units at the IPP are subject to the National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63, Subpart UUUUU Mercury and Air Toxics Standards (MATS). As a result, the coal units are required to comply with a SO_2 emission limit of 0.20 pounds per Million British Thermal Units (lb/MMBtu) and to comply with a PM emission limit of 0.03 lb/MMBtu.

Facility criteria air pollutant emissions sources

1. Combined Cycle Combustion Turbines: Two 487 MW natural gas and hydrogen-fired combined cycle combustion turbines equipped with SCR and oxidation catalyst for controlling NO_x and other emissions; these are the primary new generators of electricity under the "IPP Renewed" project.

2. Fuel Gas Heaters: Two natural gas-fired heaters each rated ~9.9 MMBtu/hr for process or auxiliary heating associated with the new combustion turbine plant; these heaters emit combustion pollutants when operating.

3. Auxiliary Boiler: One natural gas-fired auxiliary boiler rated ~136 MMBtu/hr with LNB serving plant auxiliary steam needs.

4. Emergency Generators: Three diesel-fired emergency generators (each ~2,500 kilowatt) installed for backup site power at the new plant; regulated under New Source Performance Standard Subpart IIII.

5. Firewater Pump Engine: One 425 brake horsepower diesel-fired firewater pump engine for emergency fire suppression systems; small stationary engine with criteria pollutant emissions during operation.

6. Coal-Fired Boiler Plant (Existing Equipment): Unit #1 and Unit #2 coal-fired boilers, two 9225 MMBtu/hr units. Controls include LNB, OFA, a baghouse for PM, and FGD for SO_2.

Facility Potential to emit

The current PTE values for IPP, as established by the most recent NSR permit issued to the source (AO25) are as follows:

Pollutant	Potential to Emit (total)	Potential to Emit (coal fired units)
Particulate Matter (PM_{10})	1,688	1,404
Sulfur Dioxide (SO_2)	3,046	2,917
Nitrogen Oxides (NO_x)	21,522	21,235

IPP Four Factor Analysis Conclusion

Visibility-impairing pollutants of $PM_{10}/PM_{2.5}$, SO_2, and NO_x from IPP Units 1 and 2 are controlled by existing baghouses, FGD systems, and LNB plus OFA combustion controls. Additional emission reductions have also been achieved through the continued use of these controls and reduced unit utilization in recent operating periods.

Recent visibility modeling indicates minimal impacts to Utah's CIAs, with maximum modeled impairment of approximately 0.118 deciviews (dv). All affected CIAs remain below the URP glidepath.

Accordingly, IPP concludes that no additional controls are necessary for the Division to meet reasonable progress for the second implementation period. The facility will maintain operation at a 57% capacity factor and continue operation of existing $PM_{10}/PM_{2.5}$, SO_2, and NO_x controls.

IPP's initial 4-factor analysis can be found in Appendix C.

Utah Division of Air Quality Four-Factor Analysis Evaluation

On February 25, 2026, the Division issued its response to IPP's Four-Factor Analysis through DAQP-010-26, "SIP Evaluation Report." This report summarized the Division's conclusions at that time and identified specific errors requiring revision. The evaluation also outlined the potential methodology supporting the development of a mass-based NO_x limit and the rationale for its consideration.

A summary of the evaluation is included in this document in the following sections "PM and SO_2 Evaluation", and "NO_x Identified Deficiencies Evaluation". The full response is provided in Appendix C.[32]

PM and SO_2 Evaluation

The Division reviewed the four-factor analyses submitted by the IPP for PM and SO_2 and determined that the analyses did not correctly evaluate whether additional control technologies could provide reasonable emissions reductions. The analyses did not fully assess potentially applicable control options or demonstrate why further controls would be unreasonable.

IPP relies on EPA's *2019 Guidance* to support its conclusion that the source is adequately controlled.[33] While the guidance states that a state may determine that no further analysis is necessary, IPP used the guidance as its sole rationale for not

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[32] See Appendix C Four Factor Analysis Documents

[33] See EPA's *2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*.

evaluating additional control options. Although emissions at the facility are currently well controlled, a more complete analysis could have identified additional reasonable emissions reductions that would contribute to achieving the national goal of eliminating anthropogenic visibility impairment by 2064.

The *2019 Guidance* identifies when an emissions unit may be considered effectively controlled. For SO_2, electricity generating units with add-on FGD meeting the MATS alternative SO_2 limits are unlikely to need additional controls. IPP meets this scenario, with wet FGD and an SO_2 limit of 0.138 lb/MMBtu, which is well below the MATS coal-fired limit of 0.2 lb/MMBtu.[34] The IPP wet FGD system achieves 90% emissions reduction or greater reduction as required in condition II.B.2.d of IPP's Title V permit.[35] The current wet FGD system control efficiency cannot be measured due to the cold idle, but the low emission rate and control efficiency required by the Title V permit indicates a high level of existing control and suggests that a full four-factor evaluation of additional SO_2 controls would be unlikely to identify measures necessary to achieve reasonable progress.

For PM, the *2019 Guidance* identifies units subject to recent National Emission Standards for Hazardous Air Pollutants requirements regulating filterable PM as already effectively controlled. The IPP coal-fired units are subject to 40 CFR Part 63, Subpart UUUUU, which establishes an emission limit of 0.03 lb/MMBtu. IPP's applicable PM emission limit is more stringent at 0.0184 lb/MMBtu.

IPP utilizes fabric filter baghouses for PM control, which were designed for 99.95 percent control efficiency.[36] Although the coal-fired units are currently not operating and therefore a current control efficiency measurement is unavailable, historical stack test results demonstrate consistent compliance with the 0.0184 lb/MMBtu limit. While PM control efficiency is not directly measured in routine operation, compliance with the emission limit serves as a reliable indicator that the required level of PM reduction is being achieved.

In addition, the baghouses are subject to opacity monitoring requirements, including regulatory reporting and corrective action obligations for opacity exceedances above 10 percent and 45 percent. SO_2 removal performance also provides a secondary indicator of overall air pollution control system performance, as SO_2 removal rates below 90 percent trigger inspection, corrective action, and reporting requirements that further support proper operation of the PM control systems.

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[34] Id

[35] See IPP's Title V Permit

[36] See DAQE-AN0327009-04 in Appendices I.

Taken together, these regulatory requirements, operational design features, and demonstrated compliance history indicate that the existing PM controls achieve a high level of performance. Accordingly, a full four-factor analysis of additional PM controls would be unlikely to identify further technically or economically reasonable measures necessary to support reasonable progress under the RHR.

Since IPP has top level controls installed for PM or SO_2, limits below national standards, and are operating at effective control levels, the Division has determined that no further analysis of PM or SO_2 control is necessary to meet Utah's regional haze goals.

NO_x Identified Deficiencies Evaluation

1. **Incorrect Selective Non-Catalytic Reduction (SNCR) Reagent Calculations**
   Ammonia was identified as the SNCR reagent, the density and concentration values used in the cost spreadsheet correspond to urea. IPP utilized the density (71 lb/ft^3) and the cost basis of Urea while identifying the reagent as Ammonia (56 lb/ft^3). This technical error inflates the storage tank sizing and logistics costs. As a result, reagent usage rates and associated costs are overstated, biasing the calculated cost-effectiveness values high. These inputs must be corrected to reflect the correct reagent to produce accurate cost estimates.

2. **Energy and Non-Air Quality Impacts Grid Reliability**

   Recent EPA guidance on February 19, 2026, clarifies that states may consider electric grid reliability as part of the "energy and non-air quality environmental impacts" factor under CAA §169A(g)(1).[37] This includes evaluating how installation of retrofit controls or requirements that could lead to curtailment or retirement may affect bulk electric system reliability, resource adequacy, or transmission stability.

   IPP's four-factor analysis does not evaluate potential grid reliability impacts associated with requiring installation and operation of SNCR, SCR controls, or unit retirement. The analysis discusses energy penalties and environmental trade-offs but does not assess how compliance obligations, capital expenditures, or operational constraints associated with add-on controls could affect dispatch capability or the facility's role in the regional transmission system.

   Because grid reliability considerations fall within Factor 3, and EPA has recently clarified that these impacts should be evaluated as part of the Regional Haze four-factor analysis, the Division requests that IPP supplement its analysis to address potential grid reliability implications associated with installation or

[37] See Memorandum: Update to Guidance on Regional Haze State Implementation Plans for the Second Implementation Period.

operation of additional control technologies. The Division recognizes that this clarification reflects recent guidance; however, inclusion of this evaluation is necessary to ensure a complete assessment of energy and non-air quality environmental impacts.

3. **Unsupported Assumptions Regarding SCR Control Lifetime**
   The analysis assumes an SCR control lifetime of 20 years, rather than the more typical 30-year control life and then states in the Remaining Useful Life discussion that a 30-year lifetime is not realistic due to the age of the facility. Absent an enforceable shutdown date, a shortened assumed control lifetime is generally not supported. The Division requests updating the modeling and associated tables to utilize a 30-year control life for SCR.

4. **Lack of Feasibility Determination**
   The analysis does not clearly conclude whether the evaluated NO_x control technologies are technically, monetarily, and operationally feasible for installation at IPP. Instead, the conclusion relies heavily on URP and visibility considerations to justify not requiring additional controls. While visibility impacts are an important component of the Regional Haze Program, EPA's *2019 Guidance* explains that visibility impacts cannot be the sole basis for determining the reasonableness of controls.[38] The absence of a clear feasibility determination, supported by facility-specific constraints or design considerations and balanced consideration of all four statutory factors, limits the usefulness and completeness of the analysis. The Division requests further clarification in the determination of whether the evaluated NO_x controls are feasible.

5. **Quantifiable Values**

   A general area for improvement is the use of quantifiable, facility-specific values when applying the four-factor analysis. For example, when evaluating energy impacts associated with installing SNCR or SCR, the analysis could describe impacts using numerical estimates such as cost ranges for additional energy to run the technology and potential amount of megawatts required rather than qualitative descriptors like "significant." Providing quantitative metrics will improve transparency and allow the Division to better evaluate the magnitude of impacts. While deficiencies identified in items 1 through 4 should be specifically addressed to complete the analysis, this fifth item is intended as a recommended enhancement rather than a required correction, though inclusion of such

[38] See EPA's 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period

information could help support the Division's evaluation and determination for the facility.

Additionally, based on the information as of February 25, 2026, the Division is currently finding it reasonable to implement a mass\-based NO_x limit for the coal units. Described below is the methodology to implement and calculate the limit.

Methodology to Set Mass-Based Limit

The Division derived the proposed a NO_x emissions limit annually of 5050 tons of NOx per unit using the following methodology:

- **Baseline Emission Rate**
  The Division calculated a five-year average NO_x emission rate for unit 1 and unit 2, resulting in a facility-wide average baseline rate of 0.25 lb/MMBtu.

- **Control Efficiency Assumption**
  A 50 percent reduction factor was applied to the baseline emission rate to represent the technically feasible performance of SNCR when operated without excessive ammonia slip. The 50 percent control efficiency assumption was selected based on the four-factor analysis submitted by IPP, which identified this level of reduction as achievable for the units.

  The Division does not believe it is appropriate to establish a federally enforceable NO_x limit that is set so low that the facility could not reasonably achieve compliance even with the installation and proper operation of SNCR technology, as such a limit would effectively preclude operation of the plant. If subsequent, more detailed vendor analysis, engineering design, or modeling demonstrates that a 50 percent reduction is not achievable under expected operating conditions, the Division will adjust the limit to reflect the maximum achievable level of control supported by the record.

- **Mass-Based Conversion**
  The reduced emission rate was multiplied by each unit's maximum heat input capacity to calculate an annual NO_x tonnage limit that would allow for operation at maximum output while ensuring reasonable progress.

By expressing the limit in tons per year rather than lb/MMBtu, the facility retains flexibility in how compliance is achieved. The operator may install SNCR to support full-capacity operation or operate at reduced utilization without additional controls; in either case, the total mass of NO_x emissions entering the airshed is capped at a level consistent with reasonable progress and prevention of emissions backsliding.

The Division requests that IPP address the identified deficiencies and provide a formal response to allow the Division to make its determination using the best available information.

IPP Evaluation Response

IPP submitted a revised Four-Factor Analysis on April 8, 2026, which addressed the deficiencies described above and a supplemental document with additional information, included in Appendix C.

IPP corrected prior errors by revising its calculations to reflect the appropriate reagent, with corresponding updates to cost estimates. The analysis was also updated to incorporate grid reliability considerations under Factor 3, concluding that both SNCR and SCR are economically infeasible and, if required, could result in permanent shutdown of the coal units, leading to a loss of approximately 10,000 gigawatt hours of generation annually.

IPP further revised its cost analysis to reflect a 30-year useful life for SCR; however, it emphasized that the units are already approximately 40 years old and are unlikely to remain in operation for an additional 30 years.

Throughout the updated Four-Factor Analysis, IPP included additional information supporting its conclusion that SCR and SNCR are not feasible, citing cost as well as other considerations such as grid reliability, energy consumption, and water usage. The analysis estimates that SCR would require approximately 56,000 MWh annually, while SNCR would require approximately 1,345 MWh annually. In addition, SNCR is estimated to require approximately 18 million gallons of water per year.

IPP also provided an updated cost analysis for SNCR based on a 25% NOx reduction assumption, asserting that this level of control is more realistic for a 40-year-old facility requiring retrofit installation. The analysis includes additional justification for the lower reduction efficiency, including poor temperature control, inadequate mixing, insufficient residence time, and limitations on urea/ammonia injection rates.

Based on this revised 25% reduction assumption, IPP proposed a facility-wide mass-based NOx limit of 15,593 tons per year, using a methodology consistent with Utah's initially proposed approach.

Utah Division of Air Quality Response Conclusion

After a comprehensive review of the four statutory factors required by CAA § 169A(g)(1), along with the additional fifth factor addressing visibility considerations, the Division determines that the mass-based NO_x emissions limits described below for IPP are necessary and reasonable to ensure the Regional Haze reasonable progress.

The Division agrees with IPP that a 50 percent reduction is likely overly optimistic given the age and configuration of the units. While a 25 percent reduction falls on the lower end of observed and reported performance for SNCR for coal fired boilers, a 35 percent reduction more reasonably reflects representative performance for retrofit SNCR applications under similar operating conditions. Without specific vendor quotes and analysis for IPP's facility, a 35 percent reduction represents a reasonable estimate of achievable control.[39] The Division is providing flexibility by establishing a mass-based limit rather than requiring installation of a specific control technology or compliance with a rate-based limit. Because installation of SNCR is not required, the selected reduction does not need to reflect the exact performance of a specific installation, but rather a level of reduction that SNCR could reasonably be expected to achieve and is deemed necessary for reasonable progress.

The Division has determined that implementation of a mass-based NO_x emissions limit for the IPP is necessary to ensure reasonable progress. Accordingly, the Division proposes to establish a combined NO_x emissions limit of 14,340 tons per year for the coal-fired units, along with a 1,813-ton 30-day rolling sum limit.

The previous PTE for the coal units was 21,521.62 tons per year. The proposed limit represents a reduction of 7,182 tons per year, or approximately a 33 percent decrease from the existing PTE. This reduction provides durable and enforceable emission reductions that will contribute to continued visibility improvement during the second planning period.

Consistent with the Division's approach for establishing mass-based limits in other approval orders, and in response to IPP's request, the Division updated the methodology used to calculate the limit to rely on the highest NO_x emission rates from the past five years for Unit 1 (0.26 lb/MMBtu) and Unit 2 (0.285 lb/MMBtu), and applied a 35 percent reduction. The resulting emission rates were then converted to mass-based limits using the maximum heat input capacity of the units, as shown in Table 2. The resulting limits were then summed, and the total was established as a facility-wide limit. A facility-wide mass-based limit provides operational flexibility and incentivizes dispatch of the lower-emitting unit, allowing it to operate longer and account for a greater share of generation prior to reaching the emissions cap. A 30-day rolling sum limit was derived using the maximum emissions rate per unit and maximum 30-day heat input to ensure the plant can operate at full capacity during peak operating conditions, as shown in Table 3, and to ensure that current NO_x controls remain in continuous operation and effective during normal and peak operating scenarios.

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[39] See EPA Control Cost Manual, Section 4 - NOx Controls Chapter 1 - Selective Noncatalytic Reduction Table 1.2, which reports a 20–66% NO_x reduction range for coal-fired boilers using urea-based SNCR.

Unit Number	Pollutant	Emission Rate (lb/MMBtu)	Reduction Factor	Maximum Heat Input (MMBtu)	New ton per year NO_x Limit
Unit 1	NO_x	0.26	0.35	80,811,000	6,829
Unit 2	NO_x	0.285	0.35	80,811,000	7,485
				Coal Unit Total Limit	14,340

Table 2: Mass based emission limit calculation

Unit Number	Pollutant	Emission Rate (lb/MMBtu)	Max Hourly Heat Input	Hours in a 30-day period (Hours/30-days)	New 30-day rolling sum NO_x Limit
Unit 1	NO_x	0.26	9,225	720	867
Unit 2	NO_x	0.285	9,225	720	946
				Coal Unit Total Limit 30 day	1,813

Table 3: 30 day rolling limit

This approach provides immediate and enforceable emissions reductions that are comparable to those that would be achieved through the installation of SNCR technology. Based on the Division's review, SNCR may be a cost-effective control strategy at sustained, high utilization rates; however, it is not cost-effective under current conditions, as the facility is not intended to operate and presently has no contracted purchaser for its power output. Establishing a rate-based NO_x limit under these circumstances would effectively require the immediate installation of SNCR technology regardless of actual utilization, which would be unreasonable given that the facility is not currently operating and has an unknown future.

A mass-based NO_x limit appropriately reflects this operational reality by ensuring emissions reductions occur if and when the facility operates, while also providing necessary operational flexibility given the plant's uncertain future utilization. Importantly, this framework ensures that any operator or potential future owner who elects to utilize

the facility will be responsible for the costs associated with additional emissions controls needed to comply with the established limits.

The Division's Consideration of the Four-Factors for SNCR

Factor 1: Cost of Compliance

The Division's analysis identifies SNCR as a cost-effective control technology for this facility on a dollar-per-ton basis with either a 50 or 25 percent control efficiency. The average cost-effectiveness is calculated to be less than $2,000 per ton of NO_x removed with a 50 percent control efficiency and less than $3600 with a 25% control efficiency.[40]

However, the Division must also weigh the total capital investment. Installing SNCR requires a capital expenditure exceeding $20 million per unit (reaching $40 million total), alongside the potential need for costly air pre-heater modifications. Crucially, the future utilization of IPP is uncertain. If the Division were to mandate the physical installation of SNCR hardware and the facility continue to remain at "cold idle", the operator would be forced to carry a significant "stranded asset", a major capital investment that provides no environmental benefit if the plant is not running.

By implementing a mass-based limit equivalent to SNCR performance, the Division places the decision on the current or future operator. They may incur the cost of controls to run at full capacity, or they may accept a production cap. The total pollution load is restricted, ensuring protection for CIAs without mandating potentially uneconomic expenditures.

Factor 2: Time Necessary for Compliance

A requirement to install physical SNCR technology would necessitate a compliance schedule of approximately three to four years to account for design, permitting, and construction. During this period, uncontrolled emissions could continue.

In contrast, a mass-based emissions limit can be made effective immediately. By decoupling compliance from a design and construction timeline, the Division ensures that the emissions cap is enforceable upon the effective date of this determination. This approach guarantees that reductions are realized within the current planning period rather than being deferred to 2028 or beyond. Given the delays that have already occurred in this planning cycle, establishing an immediate, binding cap is the most effective mechanism to secure guaranteed reductions without further lag.

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[40] See Appendix C - Four Factor Analysis Documents.

Factor 3: Energy and Non-Air Quality Environmental Impacts

Energy:

SNCR operation would require approximately 1,345 MWh of electricity annually. In addition, it would require an estimated 151,000 MMBtu of fuel, which could otherwise generate approximately 15,100 MWh of electricity if not consumed for SNCR operation. The added energy demand associated with SNCR further supports the use of a mass-based limit, which can be achieved through alternative compliance approaches while allowing that energy to remain available to serve customers and support grid reliability.

Grid Reliability:

The potential loss of approximately 10,000 gigawatt-hours resulting from the installation of a non-economical physical control could adversely impact grid reliability and must be considered. This risk supports the conclusion that a mass-based emissions limit is a more feasible and reasonable approach.

Environmental Impacts:

Operating SNCR would require approximately 1,629 gallons of water per hour for Unit 1 and 1,779 gallons per hour for Unit 2, resulting in an estimated annual consumption of about 18 million gallons. Given that Utah has been increasingly affected by drought and declining water availability, this level of water use is a significant consideration, as reduced moisture conditions can exacerbate dust emissions from exposed soils and increase the frequency and intensity of wildfires, both of which can contribute to decreased visibility. The additional demand could place further strain on both facility operations and the state's limited water resources. Utilizing a mass-based limit would achieve emissions reductions without requiring SNCR deployment, thereby avoiding the associated increase in water demand.

While SNCR is capable of higher theoretical reduction rates (e.g., up to 66%), pushing the technology to its maximum limits creates significant negative environmental trade-offs regarding "ammonia slip".[41] Ammonia slip contributes to the formation of secondary particulate matter, particularly fine $PM_{2.5}$, through atmospheric reactions that produce ammonium-based compounds, which can worsen regional haze and reduce visibility. It may also contribute to localized odor concerns and, when deposited to land or water systems, can disrupt natural nutrient cycling by adding excess nitrogen to sensitive ecosystems. Together, these impacts can offset some of the air quality benefits of NO_x control if ammonia emissions are not carefully managed.

[41] See EPA Control Cost Manual, Section 4 - NOx Controls Chapter 1 - Selective Noncatalytic Reduction

IPP currently utilizes LNB and OFA, achieving stable emission rates averaging 0.25 lb/MMBtu. While ammonia slip is a significant operational concern, SNCR has been successfully implemented at coal-fired boilers and other high-NO_x sources. When properly designed, tuned, and operated within an appropriate load range, SNCR systems can achieve meaningful NO_x reductions while maintaining ammonia slip at low levels, often below 10 parts per million.[42] Utilizing a mass-based limit would achieve emissions reductions without requiring SNCR deployment, thereby avoiding the associated negative trade-offs caused by a potential increase in ammonia slip.

Factor 4: Remaining Useful Life of the Source

The remaining useful life of the coal-fired units aligns with the standard amortization period for the control technology (20 years). This timeframe was utilized in the cost calculations presented in Factor 1.

Additional 5th Factor: Visibility

The Division evaluated the projected visibility impacts associated with emissions from IPP as part of its reasonable progress analysis. While visibility improvement cannot be the sole basis for declining to require additional controls, it remains a critical consideration in determining the appropriate level of emissions reductions.

Modeling conducted using conservative PTE assumptions indicates that Utah CIAs remain below the URP glidepath even without additional reductions from IPP.[43] However, emissions from IPP continue to contribute to anthropogenic visibility impairment at both in-state and out-of-state CIAs. As the EPA has made clear, the URP does not function as a "safe harbor"; sources may still be required to implement emissions controls where such measures are determined to be reasonable and necessary to achieve reasonable progress and the future goal of zero anthropogenic impairment by 2064.

The proposed mass-based NO_x emissions limits secure additional enforceable reductions that contribute to continued progress toward natural visibility conditions, while maintaining regulatory certainty and flexibility during the second planning period.

Combined analysis

Considering the four statutory factors and the additional visibility evaluation, the Division concludes that a mass-based NO_x limit is necessary because SNCR is cost-effective only at higher utilization levels, while costs increase substantially at low or uncertain operating levels. Establishing a mass-based limit allows for immediate, enforceable

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[42] See Id

[43] See 5. Determination of Reasonable Progress Goals

emission reductions without the multi-year delay associated with physical control installation. The analysis also indicates that energy and non-air quality impacts associated with SNCR are additional reasons a mass-based limit is favorable. Emissions from the source continue to contribute to regional CIAs impairment, and additional reductions support continued progress toward natural visibility conditions. Therefore, the mass-based limit provides a reasonable balance of cost, timing, operational flexibility, and environmental protection.

The Division's Consideration of the Four-Factors for SCR

Factor 1: Cost of Compliance SCR

The Division evaluated SCR as the most effective control for reducing NO_x emissions at IPP. However, the four-factor analysis shows SCR is not cost-effective, with costs ranging from $6,500 to over $7,300 per ton depending on the unit. While Utah does not have a specific cost threshold, $6,500 per ton is not cost effective. This consideration aligns with analyses from the original Second Implementation Period SIP revisions XX.A and several other state's Regional Haze State Implementation Plans.

In addition to high costs per ton removed, SCR would require substantial capital, about $400 million per unit, or $800 million for both. Such an investment is significant given the facility's unknown future operation.

Factor 2: Time Necessary for Compliance SCR

The Division agrees with IPP that installation of SCR would require approximately 3 to 4 years to design, procure, install, and commission. This time frame is reasonable and consistent with similar retrofit projects.

Factor 3: Energy and Non-Air Quality Environmental Impacts

Energy:

Installation of SCR at IPP Units 1 and 2 would result in increased auxiliary load and turbine backpressure, reducing overall net generation. Additionally, operating the SCR system would take 56,000 MWh annually for both units. While the four-factor analysis did not quantify these impacts of the turbine backpressure, such reductions in output and the energy required to operate SCR raise concerns when considered alongside EPA's February 19, 2026, Regional Haze Guidance[44] emphasizing grid reliability.

Grid Reliability:

The potential loss of approximately 10,000 gigawatt-hours resulting from the installation of a non-economical physical control could adversely impact grid reliability and must be

[44] See February 19 Regional Haze Guidance

considered. This risk supports the conclusion that a mass-based emissions limit is a more feasible and reasonable approach.

Environmental Impacts:

The Division also evaluated non-air quality environmental impacts. SCR operation would require periodic handling and disposal of spent catalyst, which is classified as hazardous waste. However, the facility has experience managing such materials through operation of SCR at the new CCCT units. Additionally, SCR can oxidize a portion of SO_2 to sulfur trioxide, leading to the formation of ammonium sulfate and related compounds that may increase PM_{10} emissions. The analysis did not quantify this potential increase, limiting the Division's ability to fully assess the magnitude of this impact.

Overall, while energy and environmental impacts are not fully quantified, the additional energy to operate SCR and grid reliability concerns introduce additional considerations that weigh against selection of SCR for this source.

Factor 4: Remaining Useful Life of the Source SCR

The Division notes that a standard useful life of approximately 30 years is typically assumed for SCR systems. In the updated four-factor analysis, IPP applied a 30-year useful life for SCR, consistent with *EPA's 2019 Guidance*, which recommends use of a full useful life absent an enforceable retirement date. This approach avoids artificially inflating annualized costs and provides a more representative evaluation of cost-effectiveness.

At the same time, the Division recognizes that both the remaining useful life and future utilization of the coal-fired units remain uncertain due to ongoing market and operational considerations. The units were placed in cold idle on November 26, 2025, further increasing uncertainty regarding future operations. This uncertainty in remaining useful life and utilization weighs against the installation of a capital-intensive physical control such as SCR.

Additional 5th Factor: Visibility SCR

The Division evaluated the visibility benefits of SCR versus SNCR at IPP units. The updated modeling did not isolate control-specific emission reductions; it assessed broader operational scenarios affecting multiple pollutants. Since SCR mainly reduces NO_x, these scenarios provide limited insight into its incremental visibility benefits relative to SNCR.

SCR is estimated to reduce NO_x by 4,319 (50% reduction efficiency for SNCR) or 7727 (25% reduction efficiency for SNCR) tons per year more than SNCR, but the visibility difference was not specifically modeled, so the corresponding visibility improvement

cannot be quantified. Conservative modeling indicates Utah CIAs remain below the URP glidepath even with IPP running at maximum constrained emissions. Given the minimal incremental benefit in the context of overall visibility, the Division finds it difficult to justify requiring SCR as the most stringent control for this source.

Combined analysis SCR

Considering the four statutory factors and the additional visibility evaluation, the Division concludes that installation of SCR at IPP Units 1 and 2 is not warranted as a reasonable progress control. While SCR would achieve greater NO_x reductions than SNCR, the associated costs are substantial, with cost-effectiveness estimates exceeding levels typically considered reasonable and total capital investments approaching $800 million. These costs are further compounded by reduced unit utilization and uncertainty regarding the remaining useful life of the facility.

The time required for SCR installation, estimated at 3 to 4 years, would delay emission reductions compared to other available approaches. In addition, SCR would introduce greater concerns with grid reliability because of increased auxiliary load than SNCR. Additional SCR has additional environmental considerations, potential impacts to PM formation, and management of spent catalyst, none of which were fully quantified in the analysis.

Importantly, the incremental visibility benefit of SCR compared to SNCR cannot be quantified, as the modeling did not isolate control-specific emission reductions.

Available modeling indicates that Utah CIAs are projected to remain below the URP glidepath without additional reductions from IPP, further limiting the justification for selecting the most stringent control option.

Based on the totality of these considerations, the Division finds that the significantly higher costs, uncertain future, and unquantified incremental visibility benefits when already below the URP of SCR do not support its selection as a reasonable progress control for IPP source.

5. Determination of Reasonable Progress Goals

5.1 Reasonable Progress Requirements

Under the RHR, Utah must submit an LTS that includes measures necessary to achieve the Reasonable Progress Goals (RPGs) for each CIA. This strategy must consider emissions from major and minor stationary sources, mobile sources, and area sources. Section 169A(a)(4) of the CAA calls for reasonable progress "toward meeting the national goal" of eliminating anthropogenic visibility impairment.

RPGs are interim targets representing incremental improvements in visibility over time toward natural background conditions, developed in consultation with Federal Land Managers and neighboring states. In establishing reasonable progress criteria, Utah evaluates the four statutory factors in Section 169A(g) of the CAA: cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and the remaining useful life of existing sources contributing to visibility impairment.

5.2 Updated Regional Modeling of the LTS to set RPG

WRAP modeling tracks progress using dv measurements from Interagency Monitoring of Protected Visual Environments (IMPROVE) sites representing CIAs.[45] This SIP revision updates 2018–2028 modeling to reflect the extended operation of the IPP coal-fired units using revised emissions in the WRAP "on-the-books" (OTB) 2028OTBa2 scenario.[46] The modeling was conducted by Ramboll and evaluated for multiple IPP operational scenarios. The most conservative scenario, "Scenario 4" utilized PSD constrained maximum emissions, which estimates maximum emissions allowed while operating both the two CCCT units and two coal-fired units at full output.[47] This conservative upper-bound scenario ensures that potential visibility impairment is not underestimated and demonstrates the robustness of the State's RPGs, which are not impeded even under maximum facility utilization.

2028OTBa2 scenario is a WRAP-developed modeled visibility projection expressed in dv. It is built off the "representative baseline" Rep2014v2 simulation, which uses 2014 NEI data and meteorology, and is updated to reflect expected 2028 operating conditions.[48] The most noticeable emissions changes from Rep2014v2 to 2028OTBa2 include source retirements, enforceable shutdowns, and emissions reductions from ongoing pollution control programs. The IPP shutdown date was one of the source retirements utilized in the initial round two SIP modeling. The model used in the initial planning for the second implementation period thus had IPP input emissions as zero for NO_x, PM, and SO_2. The Division, with technical support from Ramboll, updated the 2028 visibility projection in March 2025 to account for the revised IPP closure timeline and input representative emissions for NO_x, PM, and SO_2 for its continued operation. Like the initial SIP submittal, the updated analysis uses "2028OTBa2 w/o fire" to exclude fire contributions and incorporates revised IPP emissions.

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[45] See Improve Monitoring Network Data.

[46] See Regional Haze Modeling of the Intermountain Power Plant Conducted by Ramboll.

[47] The modeling was conducted prior to the issuance of AO25. As a result, it relied on anticipated PSD limits and projected maximum PTE values. The finalized limits in AO25 are lower than those used in the modeling.

[48] See National Emissions Inventory.

The updated 2028OTBa2 projection reflects the Division's revised LTS and reasonable progress determinations. However, several additional source changes from plant closures and limit changes were not incorporated, which makes the projection conservative (see Table 4). In addition, emission reductions associated with recent $PM_{2.5}$ and ozone SIP updates were not included in the updated 2028OTBa2 modeling.

Source	Pollutant	Original Modeled Emissions for 2022 SIP – 2028OTBa2 Scenario (tons)	Revised Modeled Emissions for 2026 SIP – 2028OTBa2 Scenario (tons)	2024 Actual Emissions (tons)	Difference between 2026 modeling and 2024 actuals	Reasoning
U.S. Magnesium Rowley Facility	NO_x	1,052	1,052	0	-1,052	Plant shutdown in 2021
	SO_2	18	18	0	-18	
	PM_{10}	1,054	1,054	0	-1,054	
Kennecott Power Plant	NO_x	1,152	1,152	0	-1,152	Plant shutdown in 2019
	SO_2	2,152	2,152	0	-2,152	
	PM_{10}	135	135	0	-135	
Tesoro Refinery	NO_x	358	358	242	-116	$PM_{2.5}$ SIP BACT limit reductions
	SO_2	140	140	20	-120	
	PM_{10}	708	708	135	-573	
CCI Paradox Midstream	NO_x	202	202	114.82[a]	-87.18	Ownership change and conversion to natural gas significantly reduced permitted PTE.
	SO_2	63	63	56.96[a]	-6.04	
	PM_{10}	535	535	30.05[a]	-504.95	
Intermountain Power Plant	NO_x	0	22,662	7,179[b]	-15,483	Modeled at maximum constrained levels not reflective of typical operations; proposed NO_x limit further reduces allowable emissions.
	SO_2	0	3,203	710[b]	-2,493	
	PM_{10}	0	1,755	1,642[b]	-113	

Table 4: Comparison of Updated 2028OTBa2 Modeled Emissions Inputs to 2024 Actual Emissions for Selected Utah Sources

[a] Emissions are reported as PTE, as reflected in the Notice of Intent. The new owner, Green Natural Gas Ventures has not yet completed a full year of continuous operations.

[b] Emissions are from annual submission to the Division which most recently occurred in 2024 prior to the coal units going on cold idle.

Collectively, these assumptions bias the projection toward worst-case visibility conditions, providing a conservative assessment of future visibility at Utah's CIAs. While not all of the emissions reductions shown in Table 4 are federally enforceable, the table

demonstrates that actual visibility-impairing emissions are lower than those assumed in the modeling. In combination with these reductions, the assumption that the plant operates at maximum constrained emissions, which is unlikely to occur, further contributes to the conservative nature of the modeling.

5.3 Uniform Rate of Progress with updated Modeling for Utah Class I Areas

The URP glidepath was developed and approved as part of Utah's Second Implementation Period SIP (XX.A) and is described in detail in that document.[49] The URP provides a benchmark for evaluating reasonable progress toward natural visibility conditions at Utah's CIAs.

This SIP revision does not revise the approved URP. Instead, it updates the 2018–2028 visibility modeling data points and compares the updated projections for the 20 percent MIDs to the existing URP glidepath. Based on this updated modeling, Utah's CIAs remain on track to achieve reasonable progress toward natural visibility conditions for 2028 and beyond.

Table 5 summarizes the 2028 modeled visibility projections for the 20 percent MIDs at each Utah CIA, comparing the original SIP modeling scenario to the updated scenario reflecting continued operation of the IPP coal-fired units. The table also presents the applicable 2028 URP glidepath value for each site and the margin by which the updated modeled visibility remains below the glidepath.

Site	2028 URP Glidepath (dv)	2028 Visibility – Original SIP Reasonable Progress Goal (dv)	2028 Visibility – Updated Reasonable Progress (Coal Units Operating) (dv)	Change in 2028 Visibility Between Scenarios (dv)	Margin Below 2028 URP Glidepath (dv)	Below Glidepath? (Y/N)
BRCA1	6.682	6.029	6.147	0.118	0.535	YES
CAPI1	6.869	6.634	6.747	0.113	0.122	YES
CANY1	6.924	6.195	6.241	0.046	0.684	YES
ZICA1	8.346	8.269	8.282	0.013	0.063	YES

Table 5: 2028 modeled visibility relative to the URP glidepath for the 20 percent most MIDs.

[49] See Air Plan Partial Approval and Partial Disapproval; Utah; Regional Haze State Implementation Plan for the Second Implementation Period; Air Plan Disapproval; Utah; Prong 4 (Visibility) for the 2015 8-Hour Ozone National Ambient Air Quality Standard.

As shown in Table 5, differences between the original and updated modeling scenarios are small across all Utah CIAs. Under the updated scenario, modeled 2028 visibility remains below the applicable URP glidepath at each site, demonstrating continued reasonable progress toward natural visibility conditions despite continued operation of the IPP coal units. Margins below the glidepath range from 0.064 to 0.677 dv, and the modeled changes attributable to revised IPP operations are minimal.

The updated modeling evaluates the MID only. Clearest-day visibility projections remain based on the previously approved modeling submitted in the Utah Regional Haze SIP (Revision XX.A, Chapter 8, Section C, URP Glidepath Checks).[50] These projections are not re-evaluated here because changes associated with revised IPP operations are expected to have minimal impacts. Observed clearest-day visibility at all Utah CIAs, even with IPP currently operating, remains well below the no-degradation baseline, making it unlikely that revised IPP emissions would result in visibility degradation or exceed natural conditions. Accordingly, clearest-day projections are not included in this evaluation and are documented in the previously approved SIP.

These results confirm that, even with continued operation of the IPP coal-fired units, Utah's CIAs remain on track to achieve reasonable progress toward natural visibility conditions in 2028, consistent with the URP glidepath.

5.4 Uniform Rate of Progress with updated Modeling for Class I Areas Outside of Utah

Under 40 CFR §51.308(f)(3)(iv), Utah is required to consider the impacts of its visibility-impairing sources on CIAs located outside the state. Consistent with this requirement, the updated modeling evaluated the visibility impacts associated with the continued operation of IPP on nearby out-of-state CIAs.

The results indicate that IPP has a very limited impact on visibility at out-of-state CIAs for the 20 percent MID. The largest modeled impacts occurred at Craters of the Moon Wilderness, Idaho (CRMO) with an increase of 0.038 dv, and Bridger Wilderness, Wyoming (BIRD), with an estimated increase of 0.026 dv. Even with this increase, modeled 2028 visibility at both sites remains below the URP glidepath, indicating continued reasonable progress toward natural visibility conditions.

IPPs emissions impact were also evaluated at CIAs where modeled visibility conditions remain above the glidepath. Twelve IMPROVE sites adjacent to Utah remain above the glidepath in the updated modeling; however, the maximum modeled visibility impact attributable to IPP was 0.008 dv at Sycamore Canyon, Arizona (SYCA) for the 20 percent MID. The Arizona Regional Haze Plan explains that the IMPROVE monitor

[50] See XX.A Chapter 8 Section C.

SYCA moved in 2015 and there was a large increase in soil and coarse mass extinction, which are typically locally derived and have limited transportability.[51] This change called to question the representativeness of the SYCA analysis. Given these questions, it is reasonable to conclude that IPP is not the driving cause of 2028 projected visibility to be above the glidepath for SYCA. The remaining 11 sites experienced impacts of less than 0.006 dv for the 20 percent MID. For sites above the glidepath, the IPP contribution represents a maximum of a 0.07% increase to total visibility impairment. Nine of the twelve sites are more than 0.5 dv above the glidepath, this demonstrates that emissions from IPP are not the primary cause of anthropogenic visibility impairment causing these locations to be above the glidepath.

Additionally, the modeling framework used in this analysis applies the URP glidepath without adjustments for international anthropogenic emissions or prescribed fire contributions. While states may elect to evaluate and incorporate such adjustments in their reasonable progress demonstrations, Utah has determined that applying these adjustments is not necessary for its CIAs analysis in this implementation plan. In contrast, some states have chosen to apply these adjustments in their regional haze SIPs, which can result in certain CIA being projected to fall below the URP glidepath even with IPP's additional emissions. The adjusted URP glidepath is not included in Table 6 or this analysis because it is outside the scope of Utah's regional haze SIP and is more appropriately addressed by each individual state level.

Table 6 summarizes the modeled 2028 visibility conditions at out-of-state CIAs, including the URP glidepath, modeled visibility under the original SIP scenario and the updated scenario with continued IPP coal unit operation, the change in visibility between scenarios, and the margin above the glidepath. The table also presents the percentage of total visibility impairment attributable to IPP, illustrating the relative contribution of IPP compared to the total anthropogenic impairment at each site.

Site	2028 URP Glidepath (dv)	2028 Visibility – Original SIP Scenario (dv)	2028 Visibility – Updated Scenario (Coal Units Operating) (dv)	Change in 2028 Visibility Between Scenarios (dv)	Margin Above 2028 URP Glidepath (dv)	Percentage of total dv caused by IPP (%)
BAND	7.657	7.918	7.922	0.004	0.265	0.05
BOAP	9.119	9.924	9.927	0.003	0.808	0.03
CHIR	8.273	8.900	8.901	0.002	0.628	0.01

[51] See Arizona State Implementation Plan Revision: Regional Haze Program (2018-2028)

Site	2028 URP Glidepath (dv)	2028 Visibility – Original SIP Scenario (dv)	2028 Visibility – Updated Scenario (Coal Units Operating) (dv)	Change in 2028 Visibility Between Scenarios (dv)	Margin Above 2028 URP Glidepath (dv)	Percentage of total dv caused by IPP (%)
GICL	7.055	7.195	7.197	0.002	0.142	0.03
GUMO	10.694	12.130	12.134	0.004	1.440	0.03
JARB	7.334	7.747	7.750	0.003	0.416	0.04
SACR	12.094	14.608	14.610	0.002	2.515	0.01
SAGU	9.310	10.363	10.366	0.003	1.056	0.03
SAWT	7.645	8.301	8.302	0.001	0.657	0.01
SYCA	9.168	10.731	10.739	0.008	1.571	0.07
TONT	9.045	9.676	9.680	0.004	0.635	0.04
WHIT	8.738	9.637	9.638	0.001	0.900	0.01

Table 6: Updated visibility modeling for CIAs above glidepath outside of Utah

EPA's recent West Virginia Regional Haze SIP approval explains that when a CIA's visibility is below the URP and the State has considered the four statutory factors, the State can presumptively demonstrate reasonable progress. However, this framework does not clearly indicate how states should assess emissions from an in-state source, like IPP, that contribute to visibility impairment at out-of-state CIAs above the glidepath, aside from requiring a "robust demonstration".

EPA's action on Michigan Regional Haze SIP Second Implementation Period included approval of Michigan's use of a 1% contribution threshold to identify CIAs impacted by the state's emissions.[52] The Division recognizes that this framework is not directly transferable to Utah due to several important distinctions, including Michigan's use of light extinction metrics rather than dv, differences in URP baselines across CIAs, the statewide scope of Michigan's analysis compared to the source-specific focus here, and differing statutory and regulatory contexts. Nonetheless, the comparison provides useful context for evaluating the relative contribution of IPP to visibility impairment.

[52] See Air Plan Approval; Michigan; Second Period Regional Haze Plan

Using a similar conceptual benchmark, IPP's contributions to visibility impairment at downwind CIAs are an order of magnitude below 1%, indicating that its impacts are minimal in comparison to overall visibility conditions.

Overall, analysis of out-of-state CIAs indicates that IPP's continued operation will not result in significant or perceptible visibility reductions. The largest conservatively modeled impact outside of Utah at a truly representative IMPROVE location, can be considered negligible and will not impede reasonable progress. No CIAs are projected to move from below to above the URP glidepath as a result of IPP, and for CIAs already above the glidepath, IPP contributes only minimal additional impairment. Nevertheless, despite the relatively small, modeled contribution, the Division is still requiring a new SNCR-equivalent emission limit to ensure reasonable progress and achieve incremental visibility improvements at affected CIAs both inside and outside Utah. This limit meets the requirements of the RHR for reasonable progress even with the policy change.

Additionally, other regional haze plans are being revised to remove or reconsider coal-fired electricity generating unit closure assumptions that were previously relied upon in emissions modeling. Because such modeling often assumes zero emissions for these units, the shift away from enforceable retirement assumptions underscores the importance of implementing additional, enforceable control measures, like the mass-based NO_x limit adopted here, to ensure that reasonable progress is achieved.

Because visibility impacts from IPP are greater at Utah's CIAs than at out-of-state CIAs, any determinations found necessary for reasonable progress for Utah's CIA will be sufficient for the CIAs outside of Utah. IPP's continued operation has minimal influence on visibility beyond Utah, and reasonable progress is expected to be driven primarily by controls on other regional sources.

5.5 Reasonable Progress Determination Intermountain Power Service Corporation – Intermountain Generation Station

Upon reviewing the IPP four-factor analysis and evaluation response, the Division is establishing an annual mass-based NO_x emission limit for the coal-fired units. The new NO_x emission limit will be 14,340 tons per year combined for the coal fired units, along with a 1,813-ton NO_x 30-day rolling sum. Although the analysis found SNCR to be a cost-effective control technology at high utilization, the Division has determined that requiring its installation is not reasonable given the facility's currently limited intended utilization, future operational uncertainty, and consideration of the remaining statutory factors, including visibility benefits. Establishing a mass-based NO_x limit provides operational flexibility for IPP or any potential buyer while simultaneously guaranteeing that emissions will not exceed the level achievable by requiring SNCR, regardless of the facility's operating capacity. This new plantwide NO_x limit is lower than the emissions

levels used in the conservative regional visibility modeling, further reinforcing the determination of limited visibility impact from IPP on all CIAs. These emission limits will be implemented and enforced through SIP Subsection IX.H.23. The complete analysis and the Division's final conclusions regarding reasonable progress for IPP are detailed in Section *4.1 Utah Division of Air Quality Conclusion*.[53]

5.6 Reasonable progress summary

Utah's CIAs are modeled to remain below the URP glidepath under a conservative scenario that does not account for significant emissions reductions from other Utah programs. Modeling of CIAs outside of Utah indicates that IPP has limited impact, with the largest predicted visibility change of 0.118 dv at any site. Continued operation of the IPP coal-fired units does not cause any out-of-state CIA to move from below the URP glidepath to above it, and for CIAs already above the glidepath, IPP contributes only minimal increased visibility impairment. Based on these analyses, the Division concludes that the LTS is summarized in Section 6.A.10 of XX.A, with the removal of the IPP shutdown date, and addition of a mass-based NO_x limit is necessary to achieve reasonable progress for both Utah CIAs and those in neighboring states. This enforceable mass-based limit acts as a necessary requirement, ensuring that even with the continued operation of the coal units, emissions will not exceed a level that would jeopardize the attainment of the RPGs. Moreover, the new mass-based limit is lower than the conservative emissions levels used in the regional visibility modeling, thereby guaranteeing visibility-impairing emissions stay below a conservative value and securing continued reasonable progress for all affected CIA inside and outside of Utah.

6. Long Term Strategy Summary and Revisions

Based on the results of the updated visibility modeling and reasonable progress determinations, the Division has determined that Utah's Long-Term Strategy (LTS) should be updated to remove the previously identified December 31, 2027, closure date for the Intermountain Power Plant (IPP) and include a mass-based NO_x emission limit for the facility. The LTS continues to rely on a combination of existing and new control measures previously identified in Section 6.A.10 of Utah's approved Regional Haze Second Implementation Period SIP (XX.A), which together ensure that all Utah Class I Areas (CIAs) remain on track to achieve reasonable progress toward natural visibility conditions. Additional details regarding existing and new measures not described in this SIP revision are provided in the original SIP submittal (XX.A).

[53] See Section Utah Division of Air Quality Response Conclusion

6.1 Long-Term Strategy Summary

This updated LTS reflects the revised IPP operational assumptions and associated enforceable measures necessary to achieve Utah's reasonable progress goals (RPGs) for its CIAs. The Division's LTS incorporates existing measures implemented under other Division programs that contribute to regional haze visibility improvement, including:

- Existing rate-based NO_x emission limits for the Hunter Power Plant;
- Existing rate-based NO_x emission limits for the Huntington Power Plant;
- Existing SO_2 emission limits for the Hunter Power Plant (Section 309 control added to the SIP during the second implementation period);
- Existing SO_2 emission limits for the Huntington Power Plant (Section 309 control added to the SIP during the second implementation period); and
- Closure and demolition of the Carbon Power Plant in 2016.

In addition, during the second implementation period, the Division incorporated enforceable controls and limits at the following facilities, which remain in place to ensure continued progress toward regional haze goals:

- Graymont;
- Ash Grove;
- Sunnyside;
- U.S. Magnesium; and
- Intermountain Power Plant.

New measures included in the updated LTS consist of:

- A plantwide enforceable mass-based NO_x emission limit for the Hunter Power Plant;
- A plantwide enforceable mass-based NO_x emission limit for the Huntington Power Plant;
- Installation of flue gas recirculation on the U.S. Magnesium Rowley Plant Riley Boiler; and
- An enforceable mass-based NO_x emission limit for the coal-fired units at the Intermountain Power Plant.

6.2 Other Long-Term Strategy Elements

The remainder of the long-term strategy elements in XX.A, including emissions reductions due to ongoing pollution control programs and basic smoke management

practices, remain unchanged, except for construction measures to mitigate the impacts of construction activities, which are being updated as described below.

One measure used to mitigate the impacts of construction activities is Utah's fugitive dust control program. Utah is working to strengthen its fugitive dust requirements to further reduce particulate matter emissions which impair visibility. These requirements extend beyond just construction activities to other sources of fugitive dust as well. Currently, any source 0.25 acre or greater in size in particulate matter nonattainment or maintenance areas are required to submit a Fugitive Dust Control Plan to UDAQ. The Fugitive Dust Control Plan identifies measures to minimize fugitive dust emissions through best management practices, such as watering disturbed areas for dust suppression, limiting vehicle speeds, and controlling material hauling.

The Division is drafting revisions to expand these requirements statewide, with rule proposal anticipated in September 2026. Once adopted through the appropriate regulatory process, these revisions are expected to further reduce particulate matter emissions and provide additional air quality and visibility benefits.

6.3 Long-Term Strategy Conclusion

The LTS described in this section will be codified in SIP Subsection IX.H.23, which will be updated to remove the IPP shutdown date and include the new mass-based NO_x emission limit for IPP. Supported by conservative visibility modeling and reasonable progress analyses, this revised LTS demonstrates that replacing the shutdown date with enforceable emissions limits at IPP will continue to achieve reasonable progress toward natural visibility conditions at Utah’s CIAs.

7. Federal Land Manager Consultation, Interstate Coordination, Tribe Consultation, and Public Comment

7.1 Federal Land Management Consultation Summary

The FLMs agencies with jurisdiction over mandatory CIAs in the West include the National Park Service (NPS), U.S. Forest Service (U.S. Department of Agriculture) (USFS), and the Fish and Wildlife Service (FWS). The Division met regularly with the FLMs during the initial second implementation period planning process. A full summary of the meetings during initial planning can be found on XX.A Table 69.

Additionally, during the planning process for this SIP revision, the Division consulted with the FLMs as well. On March 4th, the Division hosted a virtual pre-consultation check-in meeting to discuss the proposed revisions which included representatives from the NPS, USFS, and FWS. During this meeting, the FLMs had the opportunity to learn about the proposed revisions, ask questions, and provide input.

On May 20th, the Division provided the FLMs with a draft copy of XX.A.1 initiating the 60 day comment period concluding on July 20th. The Division requested comments by July 1st to expedite proposals to the Utah Air Quality Board.

7.1.1 NPS Feedback Summary and UDAQ Responses

Comment 1: NPS supports Utah's DEQ decision to require a four-factor analysis for the just the coal fired units.

Response 1: The Division appreciates the support on this determination.

Comment 2: The NPS agrees with Utah DEQ findings that the units are well controlled for SO_2 and PM emissions.

Response 2: The Division appreciates the support on this determination.

Comment 3: The NPS also agrees with the state that there are technically-feasible and cost-effective options to further reduce haze-causing NO_x emissions from these emission units should they resume operation. The NPS supports Utah DEQ's determination that a mass-based NO_x limit is a reasonable approach for ensuring reasonable progress from these units.

Response 3: The Division appreciates the NPS support for the Division's determination that technically feasible and cost-effective options exist to further reduce NO_x emissions from these emission units should they resume operation. The Division also appreciates the support that the determination that a mass-based NOx emissions limit is a reasonable approach to ensure reasonable progress and allow IPP to determine the best way to meet the new mass-based limit.

Comment 4: This [$7,500/ton] would be considered cost-effective for reasonable progress in many states for the second regional haze implementation period. For example, Colorado and Washington both used cost-effectiveness thresholds of $10,000/ton. The NPS generally recommends that states require the most rigorous cost-effective emission controls available as reasonable progress, in this case SCR level controls. At this time however, the NPS recommends revisiting reasonable progress evaluation in future implementation periods if IPP coal-fired units resume regular operation.

Response 4: The Division appreciates the NPS recommendation. The cost for SCR of $7,500/ton is higher than levels the Division has previously determined to be reasonable in prior analyses. At this time, the Division is not establishing a fixed cost-effectiveness threshold for reasonable progress determinations. As discussed in Chapter 8 of Section XX.A, each four-factor analysis is evaluated on a case-by-case basis with consideration for similar source types. Establishing a single cost-effectiveness threshold would diminish consideration of the other statutory factors, including time necessary for

compliance, energy and non-air quality environmental impacts, and the remaining useful life of the source. Additionally, a single cost-effectiveness threshold encourages sources to artificially inflate costs to be above the threshold.

While SCR was determined to be technically feasible, the Division concluded it was not a reasonable control measure under the circumstances. The high capital cost of SCR, combined with uncertainty regarding the remaining operational life of the units, resulted in a level of cost that was not reasonable for this source. The Division also considered potential impacts to grid reliability associated with requiring SCR which IPP has indicated that installation could lead to retirement of the units, potentially affecting up to 1,800 MW of generation capacity in Utah.

This SIP revision establishes a mass-based NO_x emissions limit rather than prescribing a specific control technology. This performance-based approach provides the facility flexibility to determine the most appropriate compliance strategy, whether through installation of SCR or SNCR, operational adjustments, reduced utilization, or other means of achieving the emissions limit.

The Division agrees that IPP should be reevaluated during development of the Regional Haze third implementation period SIP and future implementation periods if the coal-fired units continue regular operation or utilization materially differs from the assumptions used in this analysis. The Division concludes that the mass-based NO_x emissions limits adopted in this SIP are sufficient to ensure reasonable progress for the second implementation period and that no additional reevaluation is necessary before development of the third implementation period SIP.

7.1.2 US Forest Service Feedback Summary and UDAQ Responses

Comment 1: If the IPP coal-fired units cease cold-idle status and resume regular operation, or if utilization materially increases above the assumptions in the SIP record, the State will notify the Federal Land Managers, re-evaluate reasonable progress for these units using current operational data, and consult with the Federal Land Managers consistent with 40 C.F.R. § 51.308(i) prior to final action.

Response 1: The Division appreciates this comment. The IPP four-factor analysis was conducted assuming potential continued operation of the units, and the resulting determination found that there are technically-feasible and cost-effective options to further reduce haze-causing emissions which were reasonable to ensure reasonable progress for this implementation period.

The Division acknowledged the role of uncertainty regarding future operation and utilization, which informed the selection of a mass-based limit approach. However, the adopted emissions limits are designed to still ensure reasonable progress requirements regardless of changes in utilization and therefore remain sufficient even if operations

cease cold-idle status and resume regular operation, or if utilization materially increases.

For this reason, the Division does not agree that a commitment to re-evaluate reasonable progress during this implementation period is necessary. The analysis and resulting limits are adequate for this planning period. The Division will, however, alert the FLMs if IPP ceases cold-idle. Additionally, the Division will evaluate IPP as part of the third Regional Haze implementation period SIP, with planning anticipated to begin in 2028 and the SIP due in 2031, where updated operational conditions will be considered.

Comment 2: Modeled visibility projections below the URP glidepath do not constitute a safe harbor from evaluation of additional controls under the Regional Haze Rule. The State will continue to evaluate sources for reasonable progress using the four statutory factors, independent of a CIA's position relative to the glidepath.

Response 2: The Division agrees with this comment, and the actions taken in this SIP revision are consistent with this principle. Updated regional haze modeling conducted for this SIP revision demonstrated that Utah's CIAs remain below the URP, even assuming the IPP coal-fired units and new natural gas units operate at their maximum potential to emit. However, the Division did not rely on the CIA's position relative to the URP as a basis for its reasonable progress determination. Instead, the Division evaluated IPP using the four statutory factors and concluded that establishing a mass-based NO_x emissions limit is a necessary and reasonable measure to ensure continued reasonable progress toward the national visibility goal.

7.1.3 US Fish and Wildlife Service Feedback Summary and UDAQ Responses

US Fish and Wildlife Service did not provide comments.

7.2 Interstate Consultation

During development of the initial second implementation period Regional Haze SIP, the Division consulted with other states through joint participation in the WRAP regional haze planning process. This multi-year collaborative effort included numerous technical and policy meetings over approximately five years and informed development of Utah's second implementation period Regional Haze SIP submission to the EPA. A full summary of the meetings during initial planning can be found on XX.A Table 66.

More recently, the Division presented information related to this SIP revision during the annual Western States Air Resources Council Regional Haze Panel meeting on April 8, 2026.

Because this SIP revision is narrower in scope than the original second implementation period planning effort, interstate consultation associated with this action has been more limited. On May 20th, the Division provided nearby states, Arizona, Colorado, Idaho,

Nevada, New Mexico, and Wyoming, with a draft copy of the XX.A.1 to allow an opportunity for review, comment, and to provide input prior to final submission. The Division requested a response within a 60-day comment period concluding on July 20th.

7.2.1 Arizona

Comment: ADEQ confirms that the following are accurate for the June 2026 draft Utah Regional Haze SIP revision:

- ADEQ was consulted in the development of this regional haze SIP revision;
- ADEQ is not requesting a meeting to discuss the regional haze SIP revision at this time;
- ADEQ and UDEQ have not made any agreements related to emission reduction measures during state-to-state consultations or the regional planning process;
- There are currently no disagreements between ADEQ and UDEQ on the emission reduction measures necessary to make reasonable progress in Arizona or Utah mandatory class I Federal areas.

Response: The Division appreciates Arizona's review.

7.2.2 Colorado

Comment: Colorado reviewed this SIP revision and did not have any substantive comments.

Response: The Division appreciates Colorado's review.

7.2.3 Idaho

Comment: Idaho reviewed this SIP revision and did not have any substantive comments.

Response: The Division appreciates Idaho's review.

7.2.4 Nevada

Comment: Nevada reviewed this SIP revision and did not have any substantive comments but identified an irregularity and an incorrect calculation in Table 4.

Response: The Division appreciates Nevada's review and comments and has revised Table 4 to include the correct calculation.

7.2.5 New Mexico

New Mexico did not provide comments.

7.2.6 Wyoming

Comment: Wyoming reviewed this SIP revision and did not have any substantive comments.

Response: The Division appreciates Wyoming's review.

7.3 Tribe Consultation

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 federally recognized tribes in Utah include the Paiute Indian Tribe, the Skull Valley Band of Goshute Indiana, and the Ute Indian Tribe of the Uintah and Ouray Reservation. The sources located on tribal lands are considered federal jurisdiction. UDAQ shared its RH SIP revision draft with the tribes of Utah at the same time it was shared with the FLMs and EPA for a 60-day review on May 20th, 2026. The tribes did not provide comment prior to this SIP revision being submitted.

7.4 Public Comment

8. Conclusion

This SIP revision updates Utah's Regional Haze Second Implementation Period plan to reflect the continued operation of the IPP coal-fired units, a new mass-based emissions limit for NO_x, and removes the previously enforceable December 31, 2027, shutdown date. The Division has evaluated the potential visibility impacts of continued IPP operation using an updating Q/d analysis, four factor analysis, conservative modeling (WRAP 2028OTBa2), reasonable progress analysis, and LTS to reflect the new determinations.

The results indicate that all Utah CIAs will remain below their glidepaths for the MID. Modeled changes in visibility associated with continued IPP operation are less than 0.12 dv.

The LTS maintains reliance on existing and new enforceable control measures, including NO_x and SO_2 limits at major power plants, emissions controls at other significant regional sources, and additional measures such as plantwide mass-based NO_x limits and installation of flue gas recirculation at U.S. Magnesium. These measures, codified in SIP Subsection IX.H.23, ensure that Utah continues to make reasonable progress toward natural visibility conditions in all CIAs.

Based on this analysis, the Division concludes that the removal of the IPP shutdown date and new mass-based emission limit is necessary for Utah's ability to meet RPGs.

The SIP revision demonstrates that the state's LTS, as updated, is sufficient to achieve continued progress in improving and protecting visibility for the second implementation period.

Chapter 2

US Magnesium – Rowley Plant

Executive Summary

This SIP revision updates Section IX.H.23 for the U.S. Magnesium - Rowley Plant to reflect current non-operational conditions and a change in ownership. During development of Utah's second implementation period Regional Haze SIP, the Riley Boiler was required to install flue gas recirculation (FGR) as a control necessary for reasonable progress, with a compliance deadline of January 1, 2028.

The facility ceased operations in 2021 and has not resumed production. The facility was sold to a new owner, who does not intend to restart existing magnesium production processes, though future operation remains possible. To reflect this, the SIP is revised to require FGR installation no later than January 1, 2028, or prior to any future start-up, whichever occurs later.

This revision preserves the original four-factor determination and ensures controls are in place before any emissions occur if the unit resumes operation. It avoids unnecessary installation during non-operation while maintaining enforceable requirements and consistency with RPGs.

1. Facility and Second Implementation Period Summary:

USM operated a primary magnesium production facility at its Rowley Plant, located in Tooele County, Utah. USM produced magnesium metal from the waters of the Great Salt Lake. Some of the water is evaporated in a system of solar evaporation ponds and the resulting brine solution is purified and dried to a powder in spray dryers. The powder is then melted and further purified in the melt reactor before going through an electrolytic process to separate magnesium metal from chlorine. The metal is then refined and/or alloyed and cast into molds. The chlorine from the melt reactor is combusted with natural gas in the chlorine reduction burner and converted into hydrochloric acid. The HCl is removed from the gas stream through a scrubber train. The chlorine that is generated at the electrolytic cells is collected and piped to the chlorine plant where it is liquefied for reuse or sale. USM Rowley Plant is a PSD source for carbon monoxide, NO_X, PM_{10}, $PM_{2.5}$, and volatile organic compounds.

During development of the second implementation period for Regional Haze, USM was screened using Q/d, based on the emissions in Table 7, and subsequently selected to conduct a four-factor analysis to determine if additional controls were necessary for reasonable progress.[54]

Based on evaluation of the four factors, the Division determined that installation of FGR on the Riley Boiler was necessary to achieve reasonable progress. This requirement was incorporated into SIP under Section IX.H.23.[55] The FGR retrofit was projected to reduce NO_x emissions by 22.6 tons per year at a cost effectiveness of $2,708 per ton removed.[56]

Pollutant	Tons Per Year
PM_{10}	993.21
SO_2	10.08
NO_x	1060.79

Table 7: U.S. Magnesium emissions total from four factor analysis.

2. Change in Facility Operations and Ownership

Since the four-factor analysis determination and incorporation into H.23, the facility ceased operations in 2021 and has remained shut down. On January 28, 2026, the Utah Division of Forestry, Fire, and State Lands (FFSL) acquired USM with the stated intent of increasing water flows to the Great Salt Lake. FFSL does not intend to resume the facility's prior magnesium production operations using the existing equipment and process. In addition, the facility is located within the Northern Wasatch Front Ozone Moderate Nonattainment Area. Any future redevelopment involving a new process would be subject to applicable Moderate Nonattainment Area requirements and possibly New Source Review permitting.

Although the facility is not currently operating, FFSL remains subject to applicable compliance and SIP requirements, which includes the requirement to install FGR by January 1, 2028, the end of the second implementation period. The SIP needs to be revised to reflect the correct operator.

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[54] See XX.A for a more detailed description of the Q/d screening process and USM specific four-factor analysis considerations and determinations.

[55] See IX.H.23

[56] See USM Four-Factor Analysis

3. Proposed Revision to Section IX.H.23

The existing language in H.23 did not consider the possibility that the USM and the Rowley boiler may no longer be in operation by January 1, 2028. The current requirement mandates the owner of the plant to install the control device regardless of the boiler's operational status. Requiring the installation of an emission control device on a unit that is not operating and will not be operated again constitutes an inefficient use of time, resources, and funds, as it will not produce any reduced emissions and would be unnecessary for reasonable progress towards the visibility goal.

To address the facility's non-operational status and new ownership, the Division proposes to revise Section IX.H.23[57] to include the following:

> "i. The owner/operator shall install and operate a flue gas recirculation (FGR) system on the 60MMBtu/hr (Riley) boiler no later than January 1, 2028~~.~~ or upon source start-up, whichever comes later."

Under this revision, if the Riley Boiler resumes operation after January 1, 2028, FGR must be installed prior to startup. This revision preserves the original reasonable progress determination while aligning the compliance obligation with actual operation.

4. Reasonable Progress Goals and Long Term Strategy

This revision does not interfere with reasonable progress or the underlying four-factor analysis for the USM - Rowley facility. The facility is currently not operating, and the requirement to install FGR will remain fully enforceable by January 1, 2028, or prior to startup occurring after January 1, 2028.

The revision avoids requiring installation of controls on a unit not in operation while ensuring that required emission reductions will be achieved if operations resume. As a result, the change has no adverse impact on air quality and maintains the integrity of the Regional Haze SIP.

This revision updates the LTS in form only; the underlying control requirements, enforceability, and intended emission reductions remain unchanged.

[57] See IX.H.23

5. Federal Land Manager Consultation, Interstate Coordination, Tribe Consultation, and Public Comment

5.1 Federal Land Management Consultation Summary

For a full summary of the FLM consultation process see Chapter 1 7. Federal Land Manager Consultation, Interstate Coordination, Tribe Consultation, and Public Comment.

The FLMs did not provide any comments related to US Magnesium.

5.2 Interstate Consultation

For a full summary of the FLM consultation process see Chapter 1 7. Federal Land Manager Consultation, Interstate Coordination, Tribe Consultation, and Public Comment.

Other states did not provide any comments related to US Magnesium.

5.3 Tribe Consultation

For a full summary of the FLM consultation process see Chapter 1 7. Federal Land Manager Consultation, Interstate Coordination, Tribe Consultation, and Public Comment.

The Tribes did not provide any comments related to US Magnesium.

5.4 Public Comment

6. Conclusion

The proposed revision to Section IX.H.23 for the U.S. Magnesium facility ensures that the Regional Haze State Implementation Plan remains current, enforceable, and aligned with the CAA. The original four-factor analysis determination for the Riley Boiler's required control FGR is preserved. By shifting the compliance deadline to "no later than January 1, 2028, or upon source start-up, whichever comes later," the revision accounts for the facility’s change in ownership and its current non-operating status. This approach eliminates the unnecessary burden of installing controls on a unit that may never operate again, thereby avoiding an inefficient use of resources. Crucially, the revision maintains the SIP’s integrity by ensuring that FGR installation is a fully enforceable requirement prior to any restart of operations after January 1, 2028, such that NO_x emissions would not occur from resumed operation without the required control in place, thereby demonstrating non-interference with visibility goals or air quality improvements.

Utah State Implementation Plan

Emission Limits and Operating Practices

Section IX, Part H.23

H.23. Source Specific Emission Limitations: Regional Haze Requirements, Reasonable Progress Controls

a. Ash Grove Cement Company – Leamington Cement Plant

i. Emissions from the Kiln 1/Raw Mill Stack shall not exceed the following:

A. 0.07 lbs filterable PM per ton of clinker

B. 2.8 lbs NO_x per ton clinker based upon a 30-day rolling average, and 1,347.2 tons per rolling 12-month period.

ii. The PM emission rate from the Kiln 1/Raw Mill Stack shall be determined by stack test. Stack testing shall be performed at least once annually.

iii. Emissions of NO_x shall be determined by CEM as outlined in IX.H.21.g.A and B.

b. Graymont Western US Incorporated - Cricket Mountain Plant

i. Emissions of PM_{10} from the listed emission points shall not exceed the following limits:

A. Kiln #1 Baghouse Stack: 6.0 lb/hr

B. Kiln #2 Baghouse Stack: 6.58 lb/hr

C. Kiln #3 Baghouse Stack: 7.54 lb/hr

D. Kiln #4 Baghouse Stack: 13.7 lb/hr

E. Kiln #5 Baghouse Stack: 11.7 lb/hr

F. Briquetter and Crusher Baghouse (D-488) Stack: 0.15 lb PM10 (filterable)/hr

c. Intermountain Power Service Corporation – Intermountain Generation Station

i. Conditions on Units #1 and #2.

~~A. The owner/operator shall permanently close and cease operation of Intermountain Generation Station units #1 and #2 by December 31, 2027. The owner/operator shall notify the Director of the permanent closure of units #1 and #2 by no later than January 31, 2028.~~

~~B. Until such time as units #1 and #2 are shut down as outlined above, the following shall apply:]~~

A. [~~I.~~] Emissions of PM_{10} from either the unit #1 or unit #2 stack shall not exceed 0.0184 lb/MMBtu heat input.

[~~II. Emissions of NOx from either the unit #1 or unit #2 stack shall not exceed 0.461 lb/MMBtu heat input (based on a 30-day rolling average).~~]

B. [~~III~~] Emissions of SO_2 from either the unit #1 or unit #2 stack shall not exceed 0.138 lb/MMBtu heat input (based on a 30-day rolling average).

[~~IV. These limits apply at all times except for periods of startup, shutdown, malfunction (NOx or PM10 only), or emergency conditions (SO2 only).~~]

C. Emissions of NO_x from the unit #1 and unit #2 stack combined shall not exceed 1,813 tons based on a 30-day rolling period, and 14,340 tons based on a rolling 12-month period.

I. Emissions of NO_x shall be determined by CEM as outlined in IX.H.21.g.

II. To determine compliance with the 12-month rolling NO_x limit, the owner/operator shall calculate new 12-month total NO_x emissions by the 20th day of each month using data from the previous 12 months. Records of emissions shall be kept for all periods when the plant is in operation.

d. PacifiCorp – Hunter Plant

i. The annual NO_x emissions for the entire Hunter Plant from all point and fugitive sources shall not exceed 11,041 tons/year based on a 12-month rolling total.

ii. As of January 1, 2025, the annual NO_x emissions for the entire Hunter Plant from all point and fugitive sources shall not exceed 10,442 tons/year based on a 12-month rolling total.

iii. As of January 1, 2028, the annual NO_x emissions for the entire Hunter Plant from all point and fugitive sources shall not exceed 9,843 tons/year based on a 12-month rolling total.

iv. The above NO_x limits shall be monitored in accordance with the procedures outlined in 40 CFR Part 52.21(aa)(12) and at a minimum shall be done by summing up emissions as follows:

A. For Units #1, #2 and #3 main boiler stacks, PacifiCorp's reporting to EPA's Acid Rain Emissions data base for NO_x in pounds per hour obtained from the boilers' CEM data shall be used to calculate NO_x emission rates.

B. For Units #1, #2 and #3 emergency diesel-fired equipment, emissions shall be calculated by multiplying the NO_x emission factor from the latest edition of

EPA's emission factors compilation AP-42 and hours of operation. Records documenting equipment usage shall be kept in a log, and they shall show the date the equipment was used and the duration in hours of operation.

C. For the record keeping requirements of each limit, PacifiCorp shall comply with 40 CFR Subpart 52.21(aa)(13).

D. For record submittal, PacifiCorp shall comply with 40 CFR Subpart 52.21(aa)(14).

v. To determine compliance with the 12-month rolling NO_x limits, the owner/operator shall calculate new 12-month total NO_x emissions by the 20th day of each month using data from the previous 12 months. Records of emissions shall be kept for all periods when the plant is in operation.

vi. Emissions of SO_2 from Unit #1 and Unit #2 shall not exceed the following limits:

A. 1.2 lb/MMBtu heat input for any 3-hour period

B. 0.12 lb/MMBtu heat input based on a 30-day rolling average

vii. Emissions of SO_2 from Unit #3 shall not exceed 1.2 lb/MMBtu heat input for any 3-hour period

viii. The SO_2 emissions shall be determined by CEM as outlined in IX.H.21.g.

e. PacifiCorp – Huntington Plant

i. The annual NO_x emissions for the entire Huntington Plant from all point and fugitive sources shall not exceed 6,604 tons/year based on a 12-month rolling total.

ii. As of January 1, 2025, the annual NO_x emissions for the entire Huntington Plant from all point and fugitive sources shall not exceed 6,422 tons/year based on a 12-month rolling total

iii. As of January 1, 2028, the annual NO_x emissions for the entire Huntington Plant from all point and fugitive sources shall not exceed 6,240 tons/year based on a 12-month rolling total.

iv. The above NO_x limits shall be monitored in accordance with the procedures outlined in 40 CFR Part 52.21(aa)(12) and at a minimum shall be done by summing up emissions as follows:

A. For Units #1 and #2 main boiler stacks, PacifiCorp's reporting to EPA's Acid Rain Emissions data base for NO_x in pounds per hour obtained from the

boilers' CEM data shall be used to calculate NO_x emission rates.

B. For Units #1 and #2 emergency diesel-fired equipment, emissions shall be calculated by multiplying the NO_x emission factor from the latest edition of EPA's emission factors compilation AP-42 and hours of operation. Records documenting equipment usage shall be kept in a log, and they shall show the date the equipment was used and the duration in hours of operation.

C. For the record keeping requirements of each limit, PacifiCorp shall comply with 40 CFR Subpart 52.21(aa)(13).

D. For record submittal, PacifiCorp shall comply with 40 CFR Subpart 52.21(aa)(14).

v. To determine compliance with the 12-month rolling NO_x limits, the owner/operator shall calculate new 12-month total NO_x emissions by the 20th day of each month using data from the previous 12 months. Records of emissions shall be kept for all periods when the plant is in operation.

vi. Emissions of SO_2 from Unit #1 shall not exceed 0.12 lb/MMBtu heat input (595 lb/hr) on a 30-day rolling average.

vii. Emissions of SO_2 from Unit #2 shall not exceed 0.12 lb/MMBtu heat input for any 24-hour block average.

viii. The SO2 emissions shall be determined by CEM as outlined in IX.H.21.g.

f. Sunnyside Cogeneration Facility

i. Emissions of NO_x (during normal boiler operation not including startup, shutdown and malfunction) shall not exceed 0.25 lb per MMBtu heat input on a 30-day rolling average.

ii. Emissions of NO_x (including startup, shutdown and malfunction) shall not exceed 0.6 lb per 10^6 BTU heat input on a 30-day rolling average.

iii. Emissions of SO_2 (during normal boiler operation not including startup, shutdown and malfunction) shall not exceed 0.42 lb per MMBtu heat input on a 30-day rolling average and 462 lb per hour on a 3-hour block average.

iv. Emissions of SO_2 (including startup, shutdown and malfunction) shall not exceed 1.2 lb per 10^6 BTU heat input on a 30-day rolling average.

v. The NO_x and SO_2 emissions shall be determined by CEM as outlined in IX.H.21.g.

g. [~~US Magnesium LLC - Rowley Plant~~] (Site ID: 10716; Unit: 3685; Process: 1)[1]

i. The owner/operator shall install and operate a flue gas recirculation (FGR) system on the 60 MMBtu/hr (Riley) boiler no later than January 1, 2028, or upon source start-up, whichever comes later.

ii. Following installation of the FGR system, total annual NO_x emissions from the Riley boiler shall not exceed 22.6 tons per rolling 12-month period.

iii. The emission rate from the Riley boiler shall be determined by stack test. Stack testing shall be performed at least once annually.

iv. To determine compliance with the 12-month rolling NO_x limit, the owner/operator shall calculate new 12-month total NO_x emissions by the 20th day of each month using data from the previous 12 months. Records of emissions shall be kept for all periods when the plant is in operation. To calculate the monthly NO_x emissions, the owner/operator shall multiply the lb/hr NO_x emission rate from the most recent stack test by the hours of operation of the Riley boiler for each month.

v. Emissions of NO_x from the following Lithium Plant emission points shall not exceed the listed limits:

A. Boilers: 0.012 lb/MMBtu

B. Burners: 0.037lb/MMBtu

vi. Stack testing to demonstrate compliance with the Lithium Plant NO_x limits shall be performed at least once every five years.

[1] The land associated with the US Magnesium LLC – Rowley Plant (Site ID: 10716), Title V Permit No. 4500030003, and Approval Order: DAQE-AN107160050-20 was acquired by the Utah Division of Forestry, Fire, and State Lands through bankruptcy proceedings. Ongoing legal and regulatory discussions are occurring regarding ownership of the air permit and its associated obligations. Existing permits and regulatory references continue to identify US Magnesium LLC as the owner/operator. The H.23(g) requirement remains in place for the Unit: 3685 at Site ID: 10716 permitted under Title V Permit No. 4500030003 and Approval Order: DAQE-AN107160050-20.