State of Utah

SPENCER J. COX
*Governor*

DEIDRE M. HENDERSON
*Lieutenant Governor*

Office of the Governor

July 26, 2022

Kathleen Becker, Regional Administrator
US EPA Region 8
1595 Wynkoop Street
Denver, Colorado 80202-1129

Dear Ms. Becker:

Enclosed for your review are revisions to the Utah State Implementation Plan (SIP) and associated administrative rules adopted by the Utah Air Quality Board on July 6, 2022.

*Section XX.A: Regional Haze Second Implementation Period.*

*Section IX.H.21: General Requirements: Control measures for Area and Point Sources, Emission Limits and Operating Practices, Regional Haze Requirements.*

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

*R307-110-17. General Requirements: State Implementation Plan, Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits.*

*R307-110-28. General Requirements: State Implementation Plan, Regional Haze.*

Supporting documentation is being submitted by the Utah Division of Air Quality. If you or your staff have questions regarding this request, please contact Bryce Bird, director of the Utah Division of Air Quality, at (801) 536-4064.

Sincerely,

Spencer J. Cox
Governor

# UTAH

## Administrative Documentation

## Utah State Implementation Plan

## Section XX.A, Regional Haze

## Section IX, Emission Limits and Operating Practices, Part H.21 and H.23

## R307-110-17: Section IX, Control Measures for Area and point Sources, Part H, Emission Limits

## R307-110-28: Regional Haze

**State of Utah**
**Department of Environmental Quality**
**Division of Air Quality**
**195 N. 1950 West**
**P.O. Box 144820**
**Salt Lake City, Utah 84114-4820**

**August 1, 2022**

# ADMINISTRATIVE DOCUMENTATION
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# Legal Authority (Codes)

# Chapter 2
# Air Conservation Act

## Part 1
## General Provisions

### 19-2-101 Short title -- Policy of state and purpose of chapter -- Support of local and regional programs -- Provision of coordinated statewide program.

(1) This chapter is known as the "Air Conservation Act."
(2) It is the policy of this state and the purpose of this chapter to achieve and maintain levels of air quality which will protect human health and safety, and to the greatest degree practicable, prevent injury to plant and animal life and property, foster the comfort and convenience of the people, promote the economic and social development of this state, and facilitate the enjoyment of the natural attractions of this state.
(3) Local and regional air pollution control programs shall be supported to the extent practicable as essential instruments to secure and maintain appropriate levels of air quality.
(4) The purpose of this chapter is to:
  (a) provide for a coordinated statewide program of air pollution prevention, abatement, and control;
  (b) provide for an appropriate distribution of responsibilities among the state and local units of government;
  (c) facilitate cooperation across jurisdictional lines in dealing with problems of air pollution not confined within single jurisdictions; and
  (d) provide a framework within which air quality may be protected and consideration given to the public interest at all levels of planning and development within the state.

Renumbered and Amended by Chapter 112, 1991 General Session

### 19-2-102 Definitions.

As used in this chapter:
(1) "Air pollutant" means a substance that qualifies as an air pollutant as defined in 42 U.S.C. Sec. 7602.
(2) "Air pollutant source" means private and public sources of emissions of air pollutants.
(3) "Air pollution" means the presence of an air pollutant in the ambient air in the quantities, for a duration, and under the conditions and circumstances that are injurious to human health or welfare, animal or plant life, or property, or would unreasonably interfere with the enjoyment of life or use of property, as determined by the rules adopted by the board.
(4) "Ambient air" means that portion of the atmosphere, external to buildings, to which the general public has access.
(5) "Asbestos" means the asbestiform varieties of serpentine (chrysotile), riebeckite (crocidolite), cummingtonite-grunerite, anthophyllite, actinolite-tremolite, and libby amphibole.
(6) "Asbestos-containing material" means a material containing more than 1% asbestos, as determined using the method adopted in 40 C.F.R. Part 61, Subpart M, National Emission Standard for Asbestos.
(7) "Asbestos inspection" means an activity undertaken to determine the presence or location, or to assess the condition of, asbestos-containing material or suspected asbestos-containing material, whether by visual or physical examination, or by taking samples of the material.

(8) "Board" means the Air Quality Board.
(9) "Clean school bus" means the same as that term is defined in 42 U.S.C. Sec. 16091.
(10) "Director" means the director of the Division of Air Quality.
(11) "Division" means the Division of Air Quality created in Section 19-1-105.
(12) "Friable asbestos-containing material" means a material containing more than 1% asbestos, as determined using the method adopted in 40 C.F.R. Part 61, Subpart M, National Emission Standard for Asbestos, that hand pressure can crumble, pulverize, or reduce to powder when dry.
(13) "Indirect source" means a facility, building, structure, or installation which attracts or may attract mobile source activity that results in emissions of a pollutant for which there is a national standard.

Amended by Chapter 154, 2015 General Session

**19-2-103 Members of board -- Appointment -- Terms -- Organization -- Per diem and expenses.**

(1) The board consists of the following nine members:
  (a) the following non-voting member, except that the member may vote to break a tie vote between the voting members:
    (i) the executive director; or
    (ii) an employee of the department designated by the executive director; and
  (b) the following eight voting members, who shall be appointed by the governor with the advice and consent of the Senate in accordance with Title 63G, Chapter 24, Part 2, Vacancies:
    (i) one representative who:
      (A) is not connected with industry;
      (B) is an expert in air quality matters; and
      (C) is a Utah-licensed physician, a Utah-licensed professional engineer, or a scientist with relevant training and experience;
    (ii) two government representatives who do not represent the federal government;
    (iii) one representative from the mining industry;
    (iv) one representative from the fuels industry;
    (v) one representative from the manufacturing industry;
    (vi) one representative from the public who represents:
      (A) an environmental nongovernmental organization; or
      (B) a nongovernmental organization that represents community interests and does not represent industry interests; and
    (vii) one representative from the public who is trained and experienced in public health.
(2) A member of the board shall:
  (a) be knowledgeable about air pollution matters, as evidenced by a professional degree, a professional accreditation, or documented experience;
  (b) be a resident of Utah;
  (c) attend board meetings in accordance with the attendance rules made by the department under Subsection 19-1-201(1)(d)(i)(A); and
  (d) comply with all applicable statutes, rules, and policies, including the conflict of interest provisions described in Title 63G, Chapter 24, Part 3, Conflicts of Interest, and the conflict of interest rules made by the department under Subsection 19-1-201(1)(d)(i)(B).
(3) No more than five of the appointed members of the board shall belong to the same political party.

(4) A majority of the members of the board may not derive any significant portion of their income from persons subject to permits or orders under this chapter.
(5)
(a) Members shall be appointed for a term of four years.
(b) Notwithstanding the requirements of Subsection (5)(a), the governor shall, at the time of appointment or reappointment, adjust the length of terms to ensure that the terms of board members are staggered so that half of the appointed board is appointed every two years.
(6) A member may serve more than one term.
(7) A member shall hold office until the expiration of the member's term and until the member's successor is appointed, but not more than 90 days after the expiration of the member's term.
(8) When a vacancy occurs in the membership for any reason, the replacement shall be appointed for the unexpired term.
(9) The board shall elect annually a chair and a vice chair from its members.
(10)
(a) The board shall meet at least quarterly.
(b) Special meetings may be called by the chair upon the chair's own initiative, upon the request of the director, or upon the request of three members of the board.
(c) Three days' notice shall be given to each member of the board before a meeting.
(11) Five members constitute a quorum at a meeting, and the action of a majority of members present is the action of the board.
(12) A member may not receive compensation or benefits for the member's service, but may receive per diem and travel expenses in accordance with:
(a) Section 63A-3-106;
(b) Section 63A-3-107; and
(c) rules made by the Division of Finance pursuant to Sections 63A-3-106 and 63A-3-107.

Amended by Chapter 352, 2020 General Session
Amended by Chapter 373, 2020 General Session

**19-2-104 Powers of board.**
(1) The board may make rules in accordance with Title 63G, Chapter 3, Utah Administrative Rulemaking Act:
(a) regarding the control, abatement, and prevention of air pollution from all sources and the establishment of the maximum quantity of air pollutants that may be emitted by an air pollutant source;
(b) establishing air quality standards;
(c) requiring persons engaged in operations that result in air pollution to:
(i) install, maintain, and use emission monitoring devices, as the board finds necessary;
(ii) file periodic reports containing information relating to the rate, period of emission, and composition of the air pollutant; and
(iii) provide access to records relating to emissions which cause or contribute to air pollution;
(d)
(i) implementing:
(A) Toxic Substances Control Act, Subchapter II, Asbestos Hazard Emergency Response, 15 U.S.C. 2601 et seq.;
(B) 40 C.F.R. Part 763, Asbestos; and
(C) 40 C.F.R. Part 61, National Emission Standards for Hazardous Air Pollutants, Subpart M, National Emission Standard for Asbestos; and

(ii) reviewing and approving asbestos management plans submitted by local education agencies under the Toxic Substances Control Act, Subchapter II, Asbestos Hazard Emergency Response, 15 U.S.C. 2601 et seq.;

(e) establishing a requirement for a diesel emission opacity inspection and maintenance program for diesel-powered motor vehicles;

(f) implementing an operating permit program as required by and in conformity with Titles IV and V of the federal Clean Air Act Amendments of 1990;

(g) establishing requirements for county emissions inspection and maintenance programs after obtaining agreement from the counties that would be affected by the requirements;

(h) with the approval of the governor, implementing in air quality nonattainment areas employer-based trip reduction programs applicable to businesses having more than 100 employees at a single location and applicable to federal, state, and local governments to the extent necessary to attain and maintain ambient air quality standards consistent with the state implementation plan and federal requirements under the standards set forth in Subsection (2);

(i) implementing lead-based paint training, certification, and performance requirements in accordance with 15 U.S.C. 2601 et seq., Toxic Substances Control Act, Subchapter IV -- Lead Exposure Reduction, Sections 402 and 406; and

(j) to implement the requirements of Section 19-2-107.5.

(2) When implementing Subsection (1)(h) the board shall take into consideration:

(a) the impact of the business on overall air quality; and

(b) the need of the business to use automobiles in order to carry out its business purposes.

(3)

(a) The board may:

(i) hold a hearing that is not an adjudicative proceeding relating to any aspect of, or matter in, the administration of this chapter;

(ii) recommend that the director:

(A) issue orders necessary to enforce the provisions of this chapter;

(B) enforce the orders by appropriate administrative and judicial proceedings;

(C) institute judicial proceedings to secure compliance with this chapter; or

(D) advise, consult, contract, and cooperate with other agencies of the state, local governments, industries, other states, interstate or interlocal agencies, the federal government, or interested persons or groups; and

(iii) establish certification requirements for asbestos project monitors, which shall provide for experience-based certification of a person who:

(A) receives relevant asbestos training, as defined by rule; and

(B) has acquired a minimum of 1,000 hours of asbestos project monitoring related work experience.

(b) The board shall:

(i) to ensure compliance with applicable statutes and regulations:

(A) review a settlement negotiated by the director in accordance with Subsection 19-2-107(2)(b)(viii) that requires a civil penalty of $25,000 or more; and

(B) approve or disapprove the settlement;

(ii) encourage voluntary cooperation by persons and affected groups to achieve the purposes of this chapter;

(iii) meet the requirements of federal air pollution laws;

(iv) by rule in accordance with Title 63G, Chapter 3, Utah Administrative Rulemaking Act, establish work practice and certification requirements for persons who:

(A) contract for hire to conduct demolition, renovation, salvage, encapsulation work involving friable asbestos-containing materials, or asbestos inspections if:

(I) the contract work is done on a site other than a residential property with four or fewer units; or

(II) the contract work is done on a residential property with four or fewer units where a tested sample contained greater than 1% of asbestos;

(B) conduct work described in Subsection (3)(b)(iv)(A) in areas to which the general public has unrestrained access or in school buildings that are subject to the federal Asbestos Hazard Emergency Response Act of 1986;

(C) conduct asbestos inspections in facilities subject to 15 U.S.C. 2601 et seq., Toxic Substances Control Act, Subchapter II - Asbestos Hazard Emergency Response; or

(D) conduct lead-based paint inspections in facilities subject to 15 U.S.C. 2601 et seq., Toxic Substances Control Act, Subchapter IV -- Lead Exposure Reduction;

(v) establish certification requirements for a person required under 15 U.S.C. 2601 et seq., Toxic Substances Control Act, Subchapter II - Asbestos Hazard Emergency Response, to be accredited as an inspector, management planner, abatement project designer, asbestos abatement contractor and supervisor, or an asbestos abatement worker;

(vi) establish certification requirements for a person required under 15 U.S.C. 2601 et seq., Toxic Control Act, Subchapter IV - Lead Exposure Reduction, to be accredited as an inspector, risk assessor, supervisor, project designer, abatement worker, renovator, or dust sampling technician; and

(vii) assist the State Board of Education in adopting school bus idling reduction standards and implementing an idling reduction program in accordance with Section 41-6a-1308.

(4) A rule adopted under this chapter shall be consistent with provisions of federal laws, if any, relating to control of motor vehicles or motor vehicle emissions.

(5) Nothing in this chapter authorizes the board to require installation of or payment for any monitoring equipment by the owner or operator of a source if the owner or operator has installed or is operating monitoring equipment that is equivalent to equipment which the board would require under this section.

(6)

(a) The board may not require testing for asbestos or related materials on a residential property with four or fewer units, unless:

(i) the property's construction was completed before January 1, 1981; or

(ii) the testing is for:

(A) a sprayed-on or painted on ceiling treatment that contained or may contain asbestos fiber;

(B) asbestos cement siding or roofing materials;

(C) resilient flooring products including vinyl asbestos tile, sheet vinyl products, resilient flooring backing material, whether attached or unattached, and mastic;

(D) thermal-system insulation or tape on a duct or furnace; or

(E) vermiculite type insulation materials.

(b) A residential property with four or fewer units is subject to an abatement rule made under Subsection (1) or (3)(b)(iv) if:

(i) a sample from the property is tested for asbestos; and

(ii) the sample contains asbestos measuring greater than 1%.

(7) The board may not issue, amend, renew, modify, revoke, or terminate any of the following that are subject to the authority granted to the director under Section 19-2-107 or 19-2-108:

(a) a permit;

(b) a license;

(c) a registration;
(d) a certification; or
(e) another administrative authorization made by the director.
(8) A board member may not speak or act for the board unless the board member is authorized by a majority of a quorum of the board in a vote taken at a meeting of the board.
(9) Notwithstanding Subsection (7), the board may exercise all authority granted to the board by a federally enforceable state implementation plan.

Amended by Chapter 354, 2020 General Session

**19-2-105 Duties of board.**

The board, in conjunction with the governing body of each county identified in Section 41-6a-1643 and other interested parties, shall order the director to perform an evaluation of the inspection and maintenance program developed under Section 41-6a-1643 including issues relating to:
(1) the implementation of a standardized inspection and maintenance program;
(2) out-of-state registration of vehicles used in Utah;
(3) out-of-county registration of vehicles used within the areas required to have an inspection and maintenance program;
(4) use of the farm truck exemption;
(5) mechanic training programs;
(6) emissions standards; and
(7) emissions waivers.

Amended by Chapter 360, 2012 General Session

**19-2-105.3 Clean fuel requirements for fleets.**

(1) As used in this section:
(a) "1990 Clean Air Act" means the federal Clean Air Act as amended in 1990.
(b) "Clean fuel" means:
(i) propane, compressed natural gas, or electricity;
(ii) other fuel the board determines annually on or before July 1 is at least as effective as fuels under Subsection (1)(b)(i) in reducing air pollution; and
(iii) other fuel that meets the clean fuel vehicle standards in the 1990 Clean Air Act.
(c) "Fleet" means 10 or more vehicles:
(i) owned or operated by a single entity as defined by board rule; and
(ii) capable of being fueled or that are fueled at a central location.
(d) "Fleet" does not include motor vehicles that are:
(i) held for lease or rental to the general public;
(ii) held for sale or used as demonstration vehicles by motor vehicle dealers;
(iii) used by motor vehicle manufacturers for product evaluations or tests;
(iv) authorized emergency vehicles as defined in Section 41-6a-102;
(v) registered under Title 41, Chapter 1a, Part 2, Registration, as farm vehicles;
(vi) special mobile equipment as defined in Section 41-1a-102;
(vii) heavy duty trucks with a gross vehicle weight rating of more than 26,000 pounds;
(viii) regularly used by employees to drive to and from work, parked at the employees' personal residences when they are not at their employment, and not practicably fueled at a central location;

(ix) owned, operated, or leased by public transit districts; or
(x) exempted by board rule.
(2)
(a) After evaluation of reasonably available pollution control strategies, and as part of the state implementation plan demonstrating attainment of the national ambient air quality standards, the board may by rule require fleets in specified geographical areas to use clean fuels if the board determines fleet use of clean fuels is:
(i) necessary to demonstrate attainment of the national ambient air quality standards in an area where they are required; and
(ii) reasonably cost effective when compared to other similarly beneficial control strategies for demonstrating attainment of the national ambient air quality standards.
(b) A vehicle retrofit to operate on compressed natural gas in accordance with Section 19-1-406 qualifies as a clean fuel vehicle under this section.
(3) After evaluation of reasonably available pollution control strategies, and as part of a state implementation plan demonstrating only maintenance of the national ambient air quality standards, the board may by rule require fleets in specified geographical areas to use clean fuels if the board determines fleet use of clean fuels is:
(a) necessary to demonstrate maintenance of the national ambient air quality standards in an area where they are required; and
(b) reasonably cost effective as compared with other similarly beneficial control strategies for demonstrating maintenance of the national ambient air quality standards.
(4) Rules the board makes under this section may include:
(a) dates by which fleets are required to convert to clean fuels under the provisions of this section;
(b) definitions of fleet owners or operators;
(c) definitions of vehicles exempted from this section by rule;
(d) certification requirements for persons who install clean fuel conversion equipment, including testing and certification standards regarding installers; and
(e) certification fees for installers, established under Section 63J-1-504.
(5) Implementation of this section and rules made under this section are subject to the reasonable availability of clean fuel in the local market as determined by the board.

Amended by Chapter 154, 2015 General Session

**19-2-106 Rulemaking authority and procedure.**
(1)
(a) In carrying out the duties of Section 19-2-104, the board may make rules for the purpose of administering a program under the federal Clean Air Act different than the corresponding federal regulations which address the same circumstances if:
(i) the board holds a public comment period, as described in Title 63G, Chapter 3, Utah Administrative Rulemaking Act, and a public hearing; and
(ii) the board finds that the different rule will provide reasonable added protections to public health or the environment of the state or a particular region of the state.
(b) The board shall consider the differences between an industry that continuously produces emissions and an industry that episodically produces emissions, and make rules that reflect those differences.
(2) The findings described in Subsection (1)(a)(ii) shall be:
(a) in writing; and

(b) based on evidence, studies, or other information contained in the record that relates to the state of Utah and type of source involved.

(3) In making rules, the board may incorporate by reference corresponding federal regulations.

Amended by Chapter 80, 2015 General Session

**19-2-107 Director -- Appointment -- Powers.**

(1) The executive director shall appoint the director. The director shall serve under the administrative direction of the executive director.

(2)

(a) The director shall:

(i) prepare and develop comprehensive plans for the prevention, abatement, and control of air pollution in Utah;

(ii) advise, consult, and cooperate with other agencies of the state, the federal government, other states and interstate agencies, and affected groups, political subdivisions, and industries in furtherance of the purposes of this chapter;

(iii) review plans, specifications, or other data relative to air pollution control equipment or any part of the air pollution control equipment;

(iv) under the direction of the executive director, represent the state in all matters relating to interstate air pollution, including interstate compacts and similar agreements;

(v) secure necessary scientific, technical, administrative, and operational services, including laboratory facilities, by contract or otherwise;

(vi) encourage voluntary cooperation by persons and affected groups to achieve the purposes of this chapter;

(vii) encourage local units of government to handle air pollution within their respective jurisdictions on a cooperative basis and provide technical and consulting assistance to them;

(viii) determine by means of field studies and sampling the degree of air contamination and air pollution in all parts of the state;

(ix) monitor the effects of the emission of air pollutants from motor vehicles on the quality of the outdoor atmosphere in all parts of Utah and take appropriate responsive action;

(x) collect and disseminate information relating to air contamination and air pollution and conduct educational and training programs relating to air contamination and air pollution;

(xi) assess and collect noncompliance penalties as required in Section 120 of the federal Clean Air Act, 42 U.S.C. Section 7420;

(xii) comply with the requirements of federal air pollution laws;

(xiii) subject to the provisions of this chapter, enforce rules through the issuance of orders, including:

(A) prohibiting or abating discharges of wastes affecting ambient air;

(B) requiring the construction of new control facilities or any parts of new control facilities or the modification, extension, or alteration of existing control facilities or any parts of new control facilities; or

(C) adopting other remedial measures to prevent, control, or abate air pollution; and

(xiv) as authorized by the board and subject to the provisions of this chapter, act as executive secretary of the board under the direction of the chairman of the board.

(b) The director may:

(i) employ full-time, temporary, part-time, and contract employees necessary to carry out this chapter;

(ii) subject to the provisions of this chapter, authorize an employee or representative of the department to enter at reasonable times and upon reasonable notice in or upon public or private property for the purposes of inspecting and investigating conditions and plant records concerning possible air pollution;
(iii) encourage, participate in, or conduct studies, investigations, research, and demonstrations relating to air pollution and its causes, effects, prevention, abatement, and control, as advisable and necessary for the discharge of duties assigned under this chapter, including the establishment of inventories of pollution sources;
(iv) collect and disseminate information relating to air pollution and the prevention, control, and abatement of it;
(v) cooperate with studies and research relating to air pollution and its control, abatement, and prevention;
(vi) subject to Subsection (3), upon request, consult concerning the following with a person proposing to construct, install, or otherwise acquire an air pollutant source in Utah:
(A) the efficacy of proposed air pollution control equipment for the source; or
(B) the air pollution problem that may be related to the source;
(vii) accept, receive, and administer grants or other funds or gifts from public and private agencies, including the federal government, for the purpose of carrying out any of the functions of this chapter;
(viii) subject to Subsection 19-2-104(3)(b)(i), settle or compromise a civil action initiated by the division to compel compliance with this chapter or the rules made under this chapter; or
(ix) subject to the provisions of this chapter, exercise all incidental powers necessary to carry out the purposes of this chapter, including certification to state or federal authorities for tax purposes that air pollution control equipment has been certified in conformity with Title 19, Chapter 12, Pollution Control Act.
(3) A consultation described in Subsection (2)(b)(vi) does not relieve a person from the requirements of this chapter, the rules adopted under this chapter, or any other provision of law.

Amended by Chapter 281, 2018 General Session

**19-2-107.5 Solid fuel burning.**
(1) The division shall create a public awareness campaign, in consultation with representatives of the solid fuel burning industry, the healthcare industry, and members of the clean air community, on best wood burning practices and the effects of wood burning on air quality, specifically targeting nonattainment areas.
(2)
(a) Subject to Subsection (2)(b), the division shall create a program to assist an individual to convert a dwelling to a natural gas, propane, or electric heating source, as funding allows, if the individual lives in a dwelling where wood burning is the sole or secondary source of heat.
(b) In creating the program described in Subsection (2)(a), the division shall give preference to applicants who:
(i) have an adjusted gross household income of 250% or less of the federal poverty level;
(ii) live in a house where wood is the sole or supplemental source of heating; or
(iii) live within six miles of the Great Salt Lake Base and Meridian.
(3)
(a) The division may not impose a burning ban prohibiting burning during a specified seasonal period of time.
(b) Notwithstanding Subsection (3)(a), the division shall:

(i) allow burning:
(A) during local emergencies and utility outages; or
(B) if the primary purpose of the burning is to cook food; and
(ii) provide for exemptions, through registration with the division, for:
(A) devices that are sole sources of heat; or
(B) locations where natural gas service is limited or unavailable.
(4) The division may seek private donations and federal sources of funding to supplement any funds appropriated by the Legislature to fulfill Subsection (2).

Amended by Chapter 470, 2019 General Session

**19-2-107.7 Water heater regulations.**

(1) As used in this section:
(a) "Natural gas-fired water heater" means a device that heats water by the combustion of natural gas to a thermostatically-controlled temperature not exceeding 210 degrees Fahrenheit for use external to the vessel at pressures not exceeding 160 pounds per square inch gauge.
(b) "Recreational vehicle" means a motor home, travel trailer, truck camper, or camping trailer, with or without motive power, designed for human habitation for recreational, emergency, or other occupancy.
(2) A person may not sell or purchase a natural gas-fired water heater that is manufactured after July 1, 2018 with the intent to install it in Utah if the natural gas-fired water heater exceeds the applicable nitrogen oxide emission rate limit set in Title 15A, State Construction and Fire Codes Act.
(3) A manufacturer in Utah shall display the model number and nitrogen oxide emission rate of a water heater complying with this section on:
(a) the shipping carton for the water heater; and
(b) the permanent rating plate of each water heater unit.
(4) This section does not apply to a water heater unit that:
(a) uses a fuel other than natural gas;
(b) is used in a recreational vehicle; or
(c) is manufactured in Utah for shipment and use outside of Utah.

Enacted by Chapter 247, 2016 General Session

**19-2-108 Notice of construction or modification of installations required -- Authority of director to prohibit construction -- Hearings -- Limitations on authority of director -- Inspections authorized.**

(1) Notice shall be given to the director by a person planning to:
(a) construct a new installation that will or might reasonably be expected to be a source or indirect source of air pollution;
(b) make modifications to an existing installation that will or might reasonably be expected to increase the amount of or change the character or effect of air pollutants discharged, so that the installation may be expected to be a source or indirect source of air pollution; or
(c) install an air cleaning device or other equipment intended to control emission of air pollutants.
(2) A person may not operate a source of air pollution required to have a permit by a rule adopted under Section 19-2-104 or 19-2-107 without having obtained a permit from the director under procedures the board establishes by rule.
(3)

(a) The director may require, as a condition precedent to the construction, modification, installation, or establishment of the air pollutant source or indirect source, the submission of plans, specifications, and other information as the director finds necessary to determine whether the proposed construction, modification, installation, or establishment will be in accord with applicable rules in force under this chapter, and the payment of a new source review fee established under Subsection 19-1-201(6)(i).

(b) If within 90 days after the receipt of plans, specifications, or other information required under this Subsection (3), the director determines that the proposed construction, installation, or establishment or any part of it will not be in accord with the requirements of this chapter or applicable rules or that further time, not exceeding three extensions of 30 days each, is required by the director to adequately review the plans, specifications, or other information, the director shall issue an order prohibiting the construction, installation, or establishment of the air pollutant source or sources in whole or in part.

(4) In addition to any other remedies but before invoking any other remedies, a person aggrieved by the issuance of an order either granting or denying a request for the construction of a new installation, upon request, in accordance with the rules of the department, is entitled to a special adjudicative proceeding conducted by an administrative law judge as provided by Section 19-1-301.5.

(5) A feature, machine, or device constituting a part of or called for by plans, specifications, or other information submitted under Subsection (1) shall be maintained in good working order.

(6) This section does not authorize the director to require the use of machinery, devices, or equipment from a particular supplier or produced by a particular manufacturer if the required performance standards may be met by machinery, devices, or equipment otherwise available.

(7)

(a) An authorized officer, employee, or representative of the director may enter and inspect a property, premise, or place on or at which an air pollutant source is located or is being constructed, modified, installed, or established at a reasonable time for the purpose of ascertaining the state of compliance with this chapter and the rules adopted under this chapter.

(b)

(i) A person may not refuse entry or access to an authorized representative of the director who requests entry for purposes of inspection and who presents appropriate credentials.

(ii) A person may not obstruct, hamper, or interfere with an inspection.

(c) If requested, the owner or operator of the premises shall receive a report setting forth the facts found that relate to compliance status.

Amended by Chapter 256, 2020 General Session

**19-2-109 Air quality standards -- Hearings on adoption -- Orders of director -- Adoption of emission control requirements.**

(1)

(a) The board, in adopting standards of quality for ambient air, shall conduct public hearings.

(b) Notice of any public hearing for the consideration, adoption, or amendment of air quality standards shall specify the locations to which the proposed standards apply and the time, date, and place of the hearing.

(c) The notice shall be:

(i)

(A) published at least twice in any newspaper of general circulation in the area affected; and

(B) published on the Utah Public Notice Website created in Section 63A-16-601, at least 20 days before the public hearing; and

(ii) mailed at least 20 days before the public hearing to the chief executive of each political subdivision of the area affected and to other persons the director has reason to believe will be affected by the standards.

(d) The adoption of air quality standards or any modification or changes to air quality standards shall be by order of the director following formal action of the board with respect to the standards.

(e) The order shall be published:

(i) in a newspaper of general circulation in the area affected; and

(ii) as required in Section 45-1-101.

(2)

(a) The board may establish emission control requirements by rule that in its judgment may be necessary to prevent, abate, or control air pollution that may be statewide or may vary from area to area, taking into account varying local conditions.

(b) In adopting these requirements, the board shall give notice and conduct public hearings in accordance with the requirements in Subsection (1).

Amended by Chapter 84, 2021 General Session
Amended by Chapter 345, 2021 General Session

**19-2-109.1 Operating permit required -- Fees -- Implementation.**

(1) As used in this section and Sections 19-2-109.2 and 19-2-109.3:

(a) "1990 Clean Air Act" means the federal Clean Air Act as amended in 1990.

(b) "EPA" means the federal Environmental Protection Agency.

(c) "Operating permit" means a permit issued by the director to sources of air pollution that meet the requirements of Titles IV and V of the 1990 Clean Air Act.

(d) "Program" means the air pollution operating permit program established under this section to comply with Title V of the 1990 Clean Air Act.

(e) "Regulated pollutant" means the same as that term is defined in Title V of the 1990 Clean Air Act and implementing federal regulations.

(2) A person may not operate a source of air pollution required to have a permit under Title V of the 1990 Clean Air Act without having obtained an operating permit from the director under procedures the board establishes by rule.

(3)

(a) Operating permits issued under this section shall be for a period of five years unless the director makes a written finding, after public comment and hearing, and based on substantial evidence in the record, that an operating permit term of less than five years is necessary to protect the public health and the environment of the state.

(b) The director may issue, modify, or renew an operating permit only after providing public notice, an opportunity for public comment, and an opportunity for a public hearing.

(c) The director shall, in conformity with the 1990 Clean Air Act and implementing federal regulations, revise the conditions of issued operating permits to incorporate applicable federal regulations in conformity with Section 502(b)(9) of the 1990 Clean Air Act, if the remaining period of the permit is three or more years.

(d) The director may terminate, modify, revoke, or reissue an operating permit for cause.

(4) If the owner or operator of a source subject to this section fails to timely pay a fee established under Subsection 19-1-201(1)(f), the director may:

(a) impose a penalty of not more than 50% of the fee, in addition to the fee, plus interest on the fee computed at 12% annually; or
(b) revoke the operating permit.
(5) The owner or operator of a source subject to this section may contest a fee assessment or associated penalty in an adjudicative hearing under the Title 63G, Chapter 4, Administrative Procedures Act, and Section 19-1-301, as provided in this Subsection (5).
(a) The owner or operator shall pay the fee under protest before being entitled to a hearing. Payment of a fee or penalty under protest is not a waiver of the right to contest the fee or penalty under this section.
(b) A request for a hearing under this Subsection (5) shall be made after payment of the fee and within six months after the fee was due.
(6) To reinstate an operating permit revoked under Subsection (4) the owner or operator shall pay the outstanding fees, a penalty of not more than 50% of outstanding fees, and interest on the outstanding fees computed at 12% annually.
(7) Failure of the director to act on an operating permit application or renewal is a final administrative action only for the purpose of obtaining judicial review by any of the following persons to require the director to take action on the permit or the permit's renewal without additional delay:
(a) the applicant;
(b) a person who participated in the public comment process; or
(c) a person who could obtain judicial review of that action under applicable law.

Amended by Chapter 256, 2020 General Session

**19-2-109.2 Small business assistance program.**
(1) The division shall establish a small business stationary source technical and environmental compliance assistance program that conforms with Title V of the 1990 Clean Air Act to assist small businesses to comply with state and federal air pollution laws.
(2) There is created the Compliance Advisory Panel to advise and monitor the program created in Subsection (1). The seven panel members are:
(a) two members who are not owners or representatives of owners of small business stationary air pollution sources, selected by the governor to represent the general public;
(b) four members who are owners or who represent owners of small business stationary sources selected by leadership of the Utah Legislature as follows:
(i) one member selected by the majority leader of the Senate;
(ii) one member selected by the minority leader of the Senate;
(iii) one member selected by the majority leader of the House of Representatives; and
(iv) one member selected by the minority leader of the House of Representatives; and
(c) one member selected by the executive director to represent the Division of Air Quality, Department of Environmental Quality.
(3)
(a) Except as required by Subsection (3)(b), as terms of current panel members expire, the department shall appoint each new member or reappointed member to a four-year term.
(b) Notwithstanding the requirements of Subsection (3)(a), the department shall, at the time of appointment or reappointment, adjust the length of terms to ensure that the terms of panel members are staggered so that approximately half of the panel is appointed every two years.
(4) Members may serve more than one term.

(5) Members shall hold office until the expiration of their terms and until their successors are appointed, but not more than 90 days after the expiration of their terms.
(6) When a vacancy occurs in the membership for any reason, the replacement shall be appointed for the unexpired term.
(7) Every two years, the panel shall elect a chair from its members.
(8)
 (a) The panel shall meet as necessary to carry out its duties. Meetings may be called by the chair, the director, or upon written request of three of the members of the panel.
 (b) Three days' notice shall be given to each member of the panel prior to a meeting.
(9) Four members constitute a quorum at a meeting, and the action of the majority of members present is the action of the panel.
(10) A member may not receive compensation or benefits for the member's service, but may receive per diem and travel expenses in accordance with:
 (a) Section 63A-3-106;
 (b) Section 63A-3-107; and
 (c) rules made by the Division of Finance pursuant to Sections 63A-3-106 and 63A-3-107.

Amended by Chapter 154, 2015 General Session

**19-2-109.3 Public access to information.**

A copy of each permit application, compliance plan, emissions or compliance monitoring report, certification, and each operating permit issued under this chapter shall be made available to the public in accordance with Title 63G, Chapter 2, Government Records Access and Management Act.

Amended by Chapter 382, 2008 General Session

**19-2-110 Violations -- Notice to violator -- Corrective action orders -- Conference, conciliation, and persuasion by director -- Hearings.**

(1) Whenever the director has reason to believe that a violation of any provision of this chapter or any rule issued under it has occurred, the director may serve written notice of the violation upon the alleged violator. The notice shall specify the provision of this chapter or rule alleged to be violated, the facts alleged to constitute the violation, and may include an order that necessary corrective action be taken within a reasonable time.
(2) Nothing in this chapter prevents the director from making efforts to obtain voluntary compliance through warning, conference, conciliation, persuasion, or other appropriate means.
(3) Hearings may be held before an administrative law judge as provided by Section 19-1-301.

Amended by Chapter 360, 2012 General Session

**19-2-112 Generalized condition of air pollution creating emergency -- Sources causing imminent danger to health -- Powers of executive director -- Declaration of emergency.**

(1)
 (a)Title 63G, Chapter 4, Administrative Procedures Act, and any other provision of law to the contrary notwithstanding, if the executive director finds that a generalized condition of air pollution exists and that it creates an emergency requiring immediate action to protect human health or safety, the executive director, with the concurrence of the governor, shall order

persons causing or contributing to the air pollution to reduce or discontinue immediately the emission of air pollutants.
(b) The order shall fix a place and time, not later than 24 hours after its issuance, for a hearing to be held before the governor.
(c) Not more than 24 hours after the commencement of this hearing, and without adjournment of it, the governor shall affirm, modify, or set aside the order of the executive director.
(2)
(a) In the absence of a generalized condition of air pollution referred to in Subsection (1), but if the executive director finds that emissions from the operation of one or more air pollutant sources is causing imminent danger to human health or safety, the executive director may commence adjudicative proceedings under Section 63G-4-502.
(b) Notwithstanding Section 19-1-301 or 19-1-301.5, the executive director may conduct the emergency adjudicative proceeding in place of an administrative law judge.
(3) Nothing in this section limits any power that the governor or any other officer has to declare an emergency and act on the basis of that declaration.

Amended by Chapter 154, 2015 General Session

**19-2-113 Variances -- Judicial review.**
(1)
(a) A person who owns or is in control of a plant, building, structure, establishment, process, or equipment may apply to the board for a variance from its rules.
(b) The board may grant the requested variance following an announced public meeting, if it finds, after considering the endangerment to human health and safety and other relevant factors, that compliance with the rules from which variance is sought would produce serious hardship without equal or greater benefits to the public.
(2) A variance may not be granted under this section until the board has considered the relative interests of the applicant, other owners of property likely to be affected by the discharges, and the general public.
(3) A variance or renewal of a variance shall be granted within the requirements of Subsection (1) and for time periods and under conditions consistent with the reasons for it, and within the following limitations:
(a) if the variance is granted on the grounds that there are no practicable means known or available for the adequate prevention, abatement, or control of the air pollution involved, it shall be only until the necessary means for prevention, abatement, or control become known and available, and subject to the taking of any substitute or alternate measures that the board may prescribe;
(b)
(i) if the variance is granted on the grounds that compliance with the requirements from which variance is sought will require that measures, because of their extent or cost, must be spread over a long period of time, the variance shall be granted for a reasonable time that, in the view of the board, is required for implementation of the necessary measures; and
(ii) a variance granted on this ground shall contain a timetable for the implementation of remedial measures in an expeditious manner and shall be conditioned on adherence to the timetable; or
(c) if the variance is granted on the ground that it is necessary to relieve or prevent hardship of a kind other than that provided for in Subsection (3)(a) or (b), it may not be granted for more than one year.

(4)
(a) A variance granted under this section may be renewed on terms and conditions and for periods that would be appropriate for initially granting a variance.
(b) If a complaint is made to the board because of the variance, a renewal may not be granted unless, following an announced public meeting, the board finds that renewal is justified.
(c) To receive a renewal, an applicant shall submit a request for agency action to the board requesting a renewal.
(d) Immediately upon receipt of an application for renewal, the board shall give public notice of the application as required by its rules.
(5)
(a) A variance or renewal is not a right of the applicant or holder but may be granted at the board's discretion.
(b) A person aggrieved by the board's decision may obtain judicial review.
(c) Venue for judicial review of informal adjudicative proceedings is in the district court in which the air pollutant source is situated.
(6)
(a) The board may review a variance during the term for which it was granted.
(b) The review procedure is the same as that for an original application.
(c) The variance may be revoked upon a finding that:
(i) the nature or amount of emission has changed or increased; or
(ii) if facts existing at the date of the review had existed at the time of the original application, the variance would not have been granted.
(7) Nothing in this section and no variance or renewal granted pursuant to it shall be construed to prevent or limit the application of the emergency provisions and procedures of Section 19-2-112 to a person or property.

Amended by Chapter 154, 2015 General Session

**19-2-114 Activities not in violation of chapter or rules.**

The following are not a violation of this chapter or of a rule made under it:
(1) burning incident to horticultural or agricultural operations of:
(a) prunings from trees, bushes, and plants; or
(b) dead or diseased trees, bushes, and plants, including stubble;
(2) burning of weed growth along ditch banks incident to clearing these ditches for irrigation purposes;
(3) controlled heating of orchards or other crops to lessen the chances of their being frozen so long as the emissions from this heating do not violate minimum standards set by the board; and
(4) the controlled burning of not more than two structures per year by an organized and operating fire department for the purpose of training fire service personnel when the United States Weather Service clearing index for the area where the burn is to occur is above 500.

Amended by Chapter 154, 2015 General Session

**19-2-115 Violations -- Penalties -- Reimbursement for expenses.**

(1) As used in this section, the terms "knowingly," "willfully," and "criminal negligence" shall mean as defined in Section 76-2-103.
(2)

(a) A person who violates this chapter, or any rule, order, or permit issued or made under this chapter is subject in a civil proceeding to a penalty not to exceed $10,000 per day for each violation.
(b) Subsection (2)(a) also applies to rules made under the authority of Section 19-2-104, for implementation of 15 U.S.C.A. 2601 et seq., Toxic Substances Control Act, Subchapter II - Asbestos Hazard Emergency Response.
(c) Penalties assessed for violations described in 15 U.S.C.A. 2647, Toxic Substances Control Act, Subchapter II - Asbestos Hazard Emergency Response, may not exceed the amounts specified in that section and shall be used in accordance with that section.
(3) A person is guilty of a class A misdemeanor and is subject to imprisonment under Section 76-3-204 and a fine of not more than $25,000 per day of violation if that person knowingly violates any of the following under this chapter:
(a) an applicable standard or limitation;
(b) a permit condition; or
(c) a fee or filing requirement.
(4) A person is guilty of a third degree felony and is subject to imprisonment under Section 76-3-203 and a fine of not more than $25,000 per day of violation who knowingly:
(a) makes any false material statement, representation, or certification, in any notice or report required by permit; or
(b) renders inaccurate any monitoring device or method required to be maintained by this chapter or applicable rules made under this chapter.
(5) Any fine or penalty assessed under Subsections (2) or (3) is in lieu of any penalty under Section 19-2-109.1.
(6) A person who willfully violates Section 19-2-120 is guilty of a class A misdemeanor.
(7) A person who knowingly violates any requirement of an applicable implementation plan adopted by the board, more than 30 days after having been notified in writing by the director that the person is violating the requirement, knowingly violates an order issued under Subsection 19-2-110(1), or knowingly handles or disposes of asbestos in violation of a rule made under this chapter is guilty of a third degree felony and subject to imprisonment under Section 76-3-203 and a fine of not more than $25,000 per day of violation in the case of the first offense, and not more than $50,000 per day of violation in the case of subsequent offenses.
(8)
(a) As used in this section:
(i) "Hazardous air pollutant" means any hazardous air pollutant listed under 42 U.S.C. Sec. 7412 or any extremely hazardous substance listed under 42 U.S.C. Sec. 11002(a)(2).
(ii) "Organization" means a legal entity, other than a government, established or organized for any purpose, and includes a corporation, company, association, firm, partnership, joint stock company, foundation, institution, trust, society, union, or any other association of persons.
(iii) "Serious bodily injury" means bodily injury which involves a substantial risk of death, unconsciousness, extreme physical pain, protracted and obvious disfigurement, or protracted loss or impairment of the function of a bodily member, organ, or mental faculty.
(b)
(i) A person is guilty of a class A misdemeanor and subject to imprisonment under Section 76-3-204 and a fine of not more than $25,000 per day of violation if that person with criminal negligence:
(A) releases into the ambient air any hazardous air pollutant; and
(B) places another person in imminent danger of death or serious bodily injury.

(ii) As used in this Subsection (8)(b), "person" does not include an employee who is carrying out the employee's normal activities and who is not a part of senior management personnel or a corporate officer.

(c) A person is guilty of a second degree felony and is subject to imprisonment under Section 76-3-203 and a fine of not more than $50,000 per day of violation if that person:

(i) knowingly releases into the ambient air any hazardous air pollutant; and

(ii) knows at the time that the person is placing another person in imminent danger of death or serious bodily injury.

(d) If a person is an organization, it shall, upon conviction of violating Subsection (8)(c), be subject to a fine of not more than $1,000,000.

(e)

(i) A defendant who is an individual is considered to have acted knowingly under Subsections (8)(c) and (d), if:

(A) the defendant's conduct placed another person in imminent danger of death or serious bodily injury; and

(B) the defendant was aware of or believed that there was an imminent danger of death or serious bodily injury to another person.

(ii) Knowledge possessed by a person other than the defendant may not be attributed to the defendant.

(iii) Circumstantial evidence may be used to prove that the defendant possessed actual knowledge, including evidence that the defendant took affirmative steps to be shielded from receiving relevant information.

(f)

(i) It is an affirmative defense to prosecution under this Subsection (8) that the conduct charged was freely consented to by the person endangered and that the danger and conduct charged were reasonably foreseeable hazards of:

(A) an occupation, a business, a profession; or

(B) medical treatment or medical or scientific experimentation conducted by professionally approved methods and the other person was aware of the risks involved prior to giving consent.

(ii) The defendant has the burden of proof to establish any affirmative defense under this Subsection (8)(f) and shall prove that defense by a preponderance of the evidence.

(9)

(a) Except as provided in Subsection (9)(b), and unless prohibited by federal law, all penalties assessed and collected under the authority of this section shall be deposited in the General Fund.

(b) The department may reimburse itself and local governments from money collected from civil penalties for extraordinary expenses incurred in environmental enforcement activities.

(c) The department shall regulate reimbursements by making rules in accordance with Title 63G, Chapter 3, Utah Administrative Rulemaking Act, that:

(i) define qualifying environmental enforcement activities; and

(ii) define qualifying extraordinary expenses.

Amended by Chapter 360, 2012 General Session

**19-2-116 Injunction or other remedies to prevent violations -- Civil actions not abridged.**

(1) Action under Section 19-2-115 does not bar enforcement of this chapter, or any of the rules adopted under it or any orders made under it by injunction or other appropriate remedy.

The director has the power to institute and maintain in the name of the state any and all enforcement proceedings.
(2) This chapter does not abridge, limit, impair, create, enlarge, or otherwise affect substantively or procedurally the right of any person to damages or other relief on account of injury to persons or property and to maintain any action or other appropriate proceeding for this purpose.
(3)
(a) In addition to any other remedy created in this chapter, the director may initiate an action for appropriate injunctive relief:
(i) upon failure of any person to comply with:
(A) any provision of this chapter;
(B) any rule adopted under this chapter; or
(C) any final order made by the board, the director, or the executive director; and
(ii) when it appears necessary for the protection of health and welfare.
(b) The attorney general shall bring injunctive relief actions on request.
(c) A bond is not required.

Amended by Chapter 360, 2012 General Session

**19-2-117 Attorney general as legal advisor to board -- Duties of attorney general and county attorneys.**
(1) Except as provided in Section 63G-7-902, the attorney general is the legal advisor to the board and the director and shall defend them or any of them in all actions or proceedings brought against them or any of them.
(2) The county attorney in the county in which a cause of action arises may, upon request of the board or the director, bring an action, civil or criminal, to abate a condition which exists in violation of, or to prosecute for the violation of or to enforce, this chapter or the standards, orders, or rules of the board or the director issued under this chapter.
(3) The director may bring an action and be represented by the attorney general.
(4) In the event a person fails to comply with a cease and desist order of the board or the director that is not subject to a stay pending administrative or judicial review, the director may initiate an action for, and is entitled to, injunctive relief to prevent any further or continued violation of the order.

Amended by Chapter 154, 2015 General Session

**19-2-118 Violation of injunction evidence of contempt.**
Failure to comply with the terms of any injunction issued under this chapter is prima facie evidence of contempt which is punishable as for other civil contempts.

Renumbered and Amended by Chapter 112, 1991 General Session

**19-2-119 Civil or criminal remedies not excluded -- Actionable rights under chapter -- No liability for acts of God or other catastrophes.**
(1) Existing civil or criminal remedies for a wrongful action that is a violation of the law are not excluded by this chapter.
(2) Except as provided in Sections 19-1-301 and 19-1-301.5, and rules implementing those provisions, persons other than the state or the board do not acquire actionable rights by virtue of this chapter.

(3) The liabilities imposed for violation of this chapter are not imposed for a violation caused by an act of God, war, strike, riot, or other catastrophe.

Amended by Chapter 154, 2015 General Session

**19-2-120 Information required of owners or operators of air pollutant sources.**

The owner or operator of a stationary air pollutant source in the state shall furnish to the director the reports required by rules made in accordance with Section 19-2-104 and any other information the director finds necessary to determine whether the source is in compliance with state and federal regulations and standards. The information shall be correlated with applicable emission standards or limitations and shall be available to the public during normal business hours at the office of the division.

Amended by Chapter 154, 2015 General Session

**19-2-121 Ordinances of political subdivisions authorized.**

Any political subdivision of the state may enact and enforce ordinances to control air pollution that are consistent with this chapter.

Renumbered and Amended by Chapter 112, 1991 General Session

**19-2-122 Cooperative agreements between political subdivisions and department.**

(1) A political subdivision of the state may enter into and perform, with other political subdivisions of the state or with the department, contracts and agreements as they find proper for establishing, planning, operating, and financing air pollution programs.
(2) The agreements may provide for an agency to:
  (a) supervise and operate an air pollution program;
  (b) prescribe the agency's powers and duties; and
  (c) fix the compensation of the agency's members and employees.

Amended by Chapter 154, 2015 General Session

## Part 2
## Clean Air Retrofit, Replacement, and Off-road Technology Program

**19-2-201 Title.**

This part is known as the "Clean Air Retrofit, Replacement, and Off-road Technology Program."

Enacted by Chapter 295, 2014 General Session

**19-2-202 Definitions.**

As used in this part:
(1) "Board" means the Air Quality Board.
(2) "Certified" means certified by the United States Environmental Protection Agency or the California Air Resources Board to meet appropriate emission standards.

(3) "Cost" means the total reasonable cost of a project eligible for a grant under the fund, including the cost of labor.
(4) "Director" means the director of the Division of Air Quality.
(5) "Division" means the Division of Air Quality, created in Subsection 19-1-105(1)(a).
(6) "Eligible equipment" means equipment with engines, including stationary generators and pumps, operated and, if applicable, permitted in Utah.
(7) "Eligible vehicle" means a vehicle operated and, if applicable, registered in Utah that is:
(a) a medium-duty or heavy-duty transit bus;
(b) a school bus as defined in Section 53-3-102;
(c) a medium-duty or heavy-duty truck with a gross vehicle weight rating of at least 16,001 GVWR;
(d) a locomotive; or
(e) another type of vehicle identified by the board in rule as being a significant potential source of air pollution, as defined in Section 19-2-102.
(8) "Verified" means verified by the United States Environmental Protection Agency or the California Air Resources Board to reduce air emissions and meet durability requirements.

Amended by Chapter 321, 2016 General Session

**19-2-203 Grants and programs -- Conditions.**
(1) The director may make grants for implementing:
(a) verified technologies for eligible vehicles or equipment; and
(b) certified vehicles, engines, or equipment.
(2)
(a) The division may develop programs, including exchange, rebate, or low-cost purchase programs, to encourage replacement of:
(i) landscaping and maintenance equipment with equipment that is lower in emissions; and
(ii) other equipment or products identified by the board in rule as being a significant potential source of air pollution, as defined in Subsection 19-2-102(3).
(b) The division may enter into agreements with local health departments to administer the programs described in Subsection (2)(a).
(3) As a condition for receiving the grant, a person receiving a grant under Subsection (1) or receiving a grant under this Subsection (3) shall agree to:
(a) provide information to the division about the vehicles, equipment, or technology acquired with the grant proceeds;
(b) allow inspections by the division to ensure compliance with the terms of the grant;
(c) permanently disable replaced vehicles, engines, and equipment from use; and
(d) comply with the conditions for the grant.
(4) Grants and programs under Subsections (1) and (2) may be administered using a rebate program.
(5) Grants issued under this section may not exceed the actual cost of the project.

Enacted by Chapter 295, 2014 General Session

**19-2-204 Duties and authorities -- Rulemaking.**
(1) The board may, by following the procedures and requirements of Title 63G, Chapter 3, Utah Administrative Rulemaking Act, make rules:
(a) specifying the amount of money to be dedicated annually for grants;

(b) specifying criteria the director shall consider in prioritizing and awarding grants, including:
(i) a preference for awarding a grant to an individual who has already secured some other source of funding; and
(ii) a limitation on the types of vehicles that are eligible for funds;
(c) specifying the terms of a grant or exchange under Subsections 19-2-203(2), (3), and (4);
(d) specifying the procedures to be used in the grant and exchange programs authorized in Subsections 19-2-203(2), (3), and (5); and
(e) requiring all grant applicants to apply on forms provided by the division.
(2) The division shall:
(a) administer funds to encourage vehicle and equipment owners and operators to reduce emissions from vehicles and equipment;
(b) provide forms for application for a grant or exchange under Subsection 19-2-203(2) or (3); and
(c) provide information about which vehicles, engines, or equipment are certified and which technology is verified as provided in this part.
(3) The division may inspect vehicles, equipment, or technology for which a grant was made to ensure compliance with the terms of the grant.

Enacted by Chapter 295, 2014 General Session

## Part 3
## Conversion to Alternative Fuel Grant Program

**19-2-301 Title.**
This part is known as the "Conversion to Alternative Fuel Grant Program."

Enacted by Chapter 381, 2015 General Session

**19-2-302 Definitions.**
As used in this part:
(1) "Air quality standards" means vehicle emission standards equal to or greater than the standards established in bin 4 in Table S04-1 of 40 C.F.R. 86.1811-04(c)(6).
(2) "Alternative fuel" means:
(a) propane, natural gas, or electricity; or
(b) other fuel that the board determines, by rule, to be:
(i) at least as effective in reducing air pollution as the fuels listed in Subsection (2)(a); or
(ii) substantially more effective in reducing air pollution as the fuel for which the engine was originally designed.
(3) "Board" means the Air Quality Board.
(4) "Clean fuel grant" means a grant awarded under this part from the Conversion to Alternative Fuel Grant Program Fund created in Section 19-1-403.3 for reimbursement for a portion of the incremental cost of an OEM vehicle or the cost of conversion equipment.
(5) "Conversion equipment" means equipment designed to:
(a) allow an eligible vehicle to operate on an alternative fuel; and
(b) reduce an eligible vehicle's emissions of regulated pollutants, as demonstrated by:

(i) certification of the conversion equipment by the Environmental Protection Agency or by a state or country that has certification standards that are recognized, by rule, by the board;
(ii) testing the eligible vehicle, before and after the installation of the equipment, in accordance with 40 C.F.R. Part 86, Control of Emissions from New and In-Use Highway Vehicles and Engines, using all fuel the motor vehicle is capable of using;
(iii) for a retrofit natural gas vehicle that is retrofit in accordance with Section 19-1-406, satisfying the emission standards described in Section 19-1-406; or
(iv) any other test or standard recognized by board rule, made in accordance with Title 63G, Chapter 3, Utah Administrative Rulemaking Act.
(6) "Cost" means the total reasonable cost of a conversion kit and the paid labor, if any, required to install it.
(7) "Director" means the director of the Division of Air Quality.
(8) "Division" means the Division of Air Quality, created in Subsection 19-1-105(1)(a).
(9) "Eligible vehicle" means a:
(a) commercial vehicle, as defined in Section 41-1a-102;
(b) farm tractor, as defined in Section 41-1a-102; or
(c) motor vehicle, as defined in Section 41-1a-102.

Amended by Chapter 369, 2016 General Session

**19-2-303 Grants and programs -- Conditions.**
(1) The director may make grants from the Conversion to Alternative Fuel Grant Program Fund created in Section 19-1-403.3 to a person who installs conversion equipment on an eligible vehicle as described in this part.
(2) A person who installs conversion equipment on an eligible vehicle:
(a) may apply to the division for a grant to offset the cost of installation; and
(b) shall pass along any savings on the cost of conversion equipment to the owner of the eligible vehicle being converted in the amount of grant money received.
(3) As a condition for receiving the grant, a person who installs conversion equipment shall agree to:
(a) provide information to the division about the eligible vehicle to be converted with the grant proceeds;
(b) allow inspections by the division to ensure compliance with the terms of the grant; and
(c) comply with the conditions for the grant.
(4) A grant issued under this section may not exceed the lesser of 50% of the cost of the conversion system and associated labor, or $2,500, per converted eligible vehicle.

Amended by Chapter 369, 2016 General Session

**19-2-304 Duties and authorities -- Rulemaking.**
(1) The board may, by following the procedures and requirements of Title 63G, Chapter 3, Utah Administrative Rulemaking Act, make rules:
(a) specifying the amount of money to be dedicated annually for grants under this part;
(b) specifying criteria the director shall consider in prioritizing and awarding grants, including a limitation on the types of vehicles that are eligible for funds;
(c) specifying the minimum qualifications of a person who:
(i) installs conversion equipment on an eligible vehicle; and
(ii) receives a grant from the division;

(d) specifying the terms of a grant; and
(e) requiring all grant applicants to apply on forms provided by the division.
(2) The division shall:
(a) administer the Conversion to Alternative Fuel Grant Program Fund to encourage eligible vehicle owners to reduce emissions from eligible vehicles; and
(b) provide information about which conversion technology meets the requirements of this part.
(3) The division may inspect vehicles for which a grant was made to ensure compliance with the terms of the grant.

Amended by Chapter 369, 2016 General Session

# Chapter 3
# Utah Administrative Rulemaking Act

## Part 1
## General Provisions

**63G-3-101 Title.**

This chapter is known as the "Utah Administrative Rulemaking Act."

Renumbered and Amended by Chapter 382, 2008 General Session

**63G-3-102 Definitions.**

As used in this chapter:

(1) "Administrative record" means information an agency relies upon when making a rule under this chapter including:

(a) the proposed rule, change in the proposed rule, and the rule analysis form;

(b) the public comment received and recorded by the agency during the public comment period;

(c) the agency's response to the public comment;

(d) the agency's analysis of the public comment; and

(e) the agency's report of its decision-making process.

(2) "Agency" means each state board, authority, commission, institution, department, division, officer, or other state government entity other than the Legislature, its committees, the political subdivisions of the state, or the courts, which is authorized or required by law to make rules, adjudicate, grant or withhold licenses, grant or withhold relief from legal obligations, or perform other similar actions or duties delegated by law.

(3) "Bulletin" means the Utah State Bulletin.

(4) "Catchline" means a short summary of each section, part, rule, or title of the code that follows the section, part, rule, or title reference placed before the text of the rule and serves the same function as boldface in legislation as described in Section 68-3-13.

(5) "Code" means the body of all effective rules as compiled and organized by the office and entitled "Utah Administrative Code."

(6) "Department" means the Department of Government Operations created in Section 63A-1-104.

(7) "Director" means the director of the office.

(8) "Effective" means operative and enforceable.

(9) "Executive director" means the executive director of the department.

(10) "File" means to submit a document to the office as prescribed by the office.

(11) "Filing date" means the day and time the document is recorded as received by the office.

(12) "Interested person" means any person affected by or interested in a proposed rule, amendment to an existing rule, or a nonsubstantive change made under Section 63G-3-402.

(13) "Office" means the Office of Administrative Rules created in Section 63G-3-401.

(14) "Order" means an agency action that determines the legal rights, duties, privileges, immunities, or other interests of one or more specific persons, but not a class of persons.

(15) "Person" means any individual, partnership, corporation, association, governmental entity, or public or private organization of any character other than an agency.

(16) "Publication" or "publish" means making a rule available to the public by including the rule or a summary of the rule in the bulletin.

(17) "Publication date" means the inscribed date of the bulletin.

(18) "Register" may include an electronic database.
(19)
(a) "Rule" means an agency's written statement that:
(i) is explicitly or implicitly required by state or federal statute or other applicable law;
(ii) implements or interprets a state or federal legal mandate; and
(iii) applies to a class of persons or another agency.
(b) "Rule" includes the amendment or repeal of an existing rule.
(c) "Rule" does not mean:
(i) orders;
(ii) an agency's written statement that applies only to internal management and that does not restrict the legal rights of a public class of persons or another agency;
(iii) the governor's executive orders or proclamations;
(iv) opinions issued by the attorney general's office;
(v) declaratory rulings issued by the agency according to Section 63G-4-503 except as required by Section 63G-3-201;
(vi) rulings by an agency in adjudicative proceedings, except as required by Subsection 63G-3-201(6); or
(vii) an agency written statement that is in violation of any state or federal law.
(20) "Rule analysis" means the format prescribed by the office to summarize and analyze rules.
(21) "Small business" means a business employing fewer than 50 persons.
(22) "Substantive change" means a change in a rule that affects the application or results of agency actions.

Amended by Chapter 344, 2021 General Session

## Part 2
## Circumstances Requiring Rulemaking - Status of Administrative Rules

### 63G-3-201 When rulemaking is required.

(1) Each agency shall:
(a) maintain a current version of its rules; and
(b) make it available to the public for inspection during its regular business hours.
(2) In addition to other rulemaking required by law, each agency shall make rules when agency action:
(a) authorizes, requires, or prohibits an action;
(b) provides or prohibits a material benefit;
(c) applies to a class of persons or another agency; and
(d) is explicitly or implicitly authorized by statute.
(3) Rulemaking is also required when an agency issues a written interpretation of a state or federal legal mandate.
(4) Rulemaking is not required when:
(a) agency action applies only to internal agency management, inmates or residents of a state correctional, diagnostic, or detention facility, persons under state legal custody, patients admitted to a state hospital, members of the state retirement system, or , except as provided in Title 53B, Chapter 27, Part 3, Student Civil Liberties Protection Act,  students enrolled in a state education institution;

(b) a standardized agency manual applies only to internal fiscal or administrative details of governmental entities supervised under statute;
(c) an agency issues policy or other statements that are advisory, informative, or descriptive, and do not conform to the requirements of Subsections (2) and (3); or
(d) an agency makes nonsubstantive changes in a rule, except that the agency shall file all nonsubstantive changes in a rule with the office.

(5)
(a) A rule shall enumerate any penalty authorized by statute that may result from its violation, subject to Subsections (5)(b) and (c).
(b) A violation of a rule may not be subject to the criminal penalty of a class C misdemeanor or greater offense, except as provided under Subsection (5)(c).
(c) A violation of a rule may be subject to a class C misdemeanor or greater criminal penalty under Subsection (5)(a) when:
(i) authorized by a specific state statute;
(ii) a state law and programs under that law are established in order for the state to obtain or maintain primacy over a federal program; or
(iii) state civil or criminal penalties established by state statute regarding the program are equivalent to or less than corresponding federal civil or criminal penalties.

(6) Each agency shall enact rules incorporating the principles of law not already in its rules that are established by final adjudicative decisions within 120 days after the decision is announced in its cases.

(7)
(a) Each agency may enact a rule that incorporates by reference:
(i) all or any part of another code, rule, or regulation that has been adopted by a federal agency, an agency or political subdivision of this state, an agency of another state, or by a nationally recognized organization or association;
(ii) state agency implementation plans mandated by the federal government for participation in the federal program;
(iii) lists, tables, illustrations, or similar materials that are subject to frequent change, fully described in the rule, and are available for public inspection; or
(iv) lists, tables, illustrations, or similar materials that the director determines are too expensive to reproduce in the administrative code.
(b) Rules incorporating materials by reference shall:
(i) be enacted according to the procedures outlined in this chapter;
(ii) state that the referenced material is incorporated by reference;
(iii) state the date, issue, or version of the material being incorporated; and
(iv) define specifically what material is incorporated by reference and identify any agency deviations from it.
(c) The agency shall identify any substantive changes in the material incorporated by reference by following the rulemaking procedures of this chapter.
(d) The agency shall maintain a complete and current copy of the referenced material available for public review at the agency and at the office.

(8)
(a) This chapter is not intended to inhibit the exercise of agency discretion within the limits prescribed by statute or agency rule.
(b) An agency may enact a rule creating a justified exception to a rule.

(9) An agency may obtain assistance from the attorney general to ensure that its rules meet legal and constitutional requirements.

Amended by Chapter 408, 2020 General Session

**63G-3-202 Rules having the effect of law.**

(1) An agency's written statement is a rule if it conforms to the definition of a rule under Section 63G-3-102, but the written statement is not enforceable unless it is made as a rule in accordance with the requirements of this chapter.
(2) An agency's written statement that is made as a rule in accordance with the requirements of this chapter is enforceable and has the effect of law.

Renumbered and Amended by Chapter 382, 2008 General Session

## Part 3
## Rulemaking Procedures

**63G-3-301 Rulemaking procedure.**

(1) An agency authorized to make rules is also authorized to amend or repeal those rules.
(2) Except as provided in Sections 63G-3-303 and 63G-3-304, when making, amending, or repealing a rule agencies shall comply with:
  (a) the requirements of this section;
  (b) consistent procedures required by other statutes;
  (c) applicable federal mandates; and
  (d) rules made by the office to implement this chapter.
(3) Subject to the requirements of this chapter, each agency shall develop and use flexible approaches in drafting rules that meet the needs of the agency and that involve persons affected by the agency's rules.
(4)
  (a) Each agency shall file the agency's proposed rule and rule analysis with the office.
  (b) Rule amendments shall be marked with new language underlined and deleted language struck out.
  (c)
    (i) The office shall publish the information required under Subsection (8) on the rule analysis and the text of the proposed rule in the next issue of the bulletin.
    (ii) For rule amendments, only the section or subsection of the rule being amended need be printed.
    (iii) If the director determines that the rule is too long to publish, the office shall publish the rule analysis and shall publish the rule by reference to a copy on file with the office.
(5) Before filing a rule with the office, the agency shall conduct a thorough analysis, consistent with the criteria established by the Governor's Office of Planning and Budget, of the fiscal impact a rule may have on businesses, which criteria may include:
  (a) the type of industries that will be impacted by the rule, and for each identified industry, an estimate of the total number of businesses within the industry, and an estimate of the number of those businesses that are small businesses;
  (b) the individual fiscal impact that would incur to a typical business for a one-year period;
  (c) the aggregated total fiscal impact that would incur to all businesses within the state for a one-year period;

(d) the total cost that would incur to all impacted entities over a five-year period; and
(e) the department head's comments on the analysis.

(6) If the agency reasonably expects that a proposed rule will have a measurable negative fiscal impact on small businesses, the agency shall consider, as allowed by federal law, each of the following methods of reducing the impact of the rule on small businesses:
(a) establishing less stringent compliance or reporting requirements for small businesses;
(b) establishing less stringent schedules or deadlines for compliance or reporting requirements for small businesses;
(c) consolidating or simplifying compliance or reporting requirements for small businesses;
(d) establishing performance standards for small businesses to replace design or operational standards required in the proposed rule; and
(e) exempting small businesses from all or any part of the requirements contained in the proposed rule.

(7) If during the public comment period an agency receives comment that the proposed rule will cost small business more than one day's annual average gross receipts, and the agency had not previously performed the analysis in Subsection (6), the agency shall perform the analysis described in Subsection (6).

(8) The rule analysis shall contain:
(a) a summary of the rule or change;
(b) the purpose of the rule or reason for the change;
(c) the statutory authority or federal requirement for the rule;
(d) the anticipated cost or savings to:
(i) the state budget;
(ii) local governments;
(iii) small businesses; and
(iv) persons other than small businesses, businesses, or local governmental entities;
(e) the compliance cost for affected persons;
(f) how interested persons may review the full text of the rule;
(g) how interested persons may present their views on the rule;
(h) the time and place of any scheduled public hearing;
(i) the name and telephone number of an agency employee who may be contacted about the rule;
(j) the name of the agency head or designee who authorized the rule;
(k) the date on which the rule may become effective following the public comment period;
(l) the agency's analysis on the fiscal impact of the rule as required under Subsection (5);
(m) any additional comments the department head may choose to submit regarding the fiscal impact the rule may have on businesses; and
(n) if applicable, a summary of the agency's efforts to comply with the requirements of Subsection (6).

(9)
(a) For a rule being repealed and reenacted, the rule analysis shall contain a summary that generally includes the following:
(i) a summary of substantive provisions in the repealed rule which are eliminated from the enacted rule; and
(ii) a summary of new substantive provisions appearing only in the enacted rule.
(b) The summary required under this Subsection (9) is to aid in review and may not be used to contest any rule on the ground of noncompliance with the procedural requirements of this chapter.

(10) A copy of the rule analysis shall be mailed to all persons who have made timely request of the agency for advance notice of the agency's rulemaking proceedings and to any other person who, by statutory or federal mandate or in the judgment of the agency, should also receive notice.

(11)

(a) Following the publication date, the agency shall allow at least 30 days for public comment on the rule.

(b) The agency shall review and evaluate all public comments submitted in writing within the time period under Subsection (11)(a) or presented at public hearings conducted by the agency within the time period under Subsection (11)(a).

(12)

(a) Except as provided in Sections 63G-3-303 and 63G-3-304, a proposed rule becomes effective on any date specified by the agency that is:

(i) no fewer than seven calendar days after the day on which the public comment period closes under Subsection (11); and

(ii) no more than 120 days after the day on which the rule is published.

(b) The agency shall provide notice of the rule's effective date to the office in the form required by the office.

(c) The notice of effective date may not provide for an effective date before the day on which the office receives the notice.

(d) The office shall publish notice of the effective date of the rule in the next issue of the bulletin.

(e) A proposed rule lapses if a notice of effective date or a change to a proposed rule is not filed with the office within 120 days after the day on which the rule is published.

(13)

(a) Except as provided in Subsection (13)(d), before an agency enacts a rule, the agency shall submit to the appropriations subcommittee and interim committee with jurisdiction over the agency the agency's proposed rule for review, if the proposed rule, over a three-year period, has a fiscal impact of more than:

(i) $250,000 to a single person; or

(ii) $7,500,000 to a group of persons.

(b) An appropriations subcommittee or interim committee that reviews a rule submitted under Subsection (13)(a) shall:

(i) before the review, directly inform the chairs of the Administrative Rules Review and General Oversight Committee of the coming review, including the date, time, and place of the review; and

(ii) after the review, directly inform the chairs of the Administrative Rules Review and General Oversight Committee of the outcome of the review, including any recommendation.

(c) An appropriations subcommittee or interim committee that reviews a rule submitted under Subsection (13)(a) may recommend to the Administrative Rules Review and General Oversight Committee that the Administrative Rules Review and General Oversight Committee not recommend reauthorization of the rule in the omnibus legislation described in Section 63G-3-502.

(d) The requirement described in Subsection (13)(a) does not apply to:

(i) the State Tax Commission; or

(ii) the State Board of Education.

(14)

(a) As used in this Subsection (14), "initiate rulemaking proceedings" means the filing, for the purposes of publication in accordance with Subsection (4), of an agency's proposed rule that is required by state statute.
(b) A state agency shall initiate rulemaking proceedings no later than 180 days after the day on which the statutory provision that specifically requires the rulemaking takes effect, except under Subsection (14)(c).
(c) When a statute is enacted that requires agency rulemaking and the affected agency already has rules in place that meet the statutory requirement, the agency shall submit the rules to the Administrative Rules Review and General Oversight Committee for review within 60 days after the day on which the statute requiring the rulemaking takes effect.
(d) If a state agency does not initiate rulemaking proceedings in accordance with the time requirements in Subsection (14)(b), the state agency shall appear before the legislative Administrative Rules Review and General Oversight Committee and provide the reasons for the delay.

Amended by Chapter 443, 2022 General Session

**63G-3-302 Public hearings.**
(1) Each agency may hold a public hearing on a proposed rule, amendment to a rule, or repeal of a rule during the public comment period.
(2) Each agency shall hold a public hearing on a proposed rule, amendment to a rule, or repeal of a rule if:
(a) a public hearing is required by state or federal mandate;
(b)
(i) another state agency, 10 interested persons, or an interested association having not fewer than 10 members request a public hearing; and
(ii) the agency receives the request in writing not more than 15 days after the publication date of the proposed rule.
(3) The agency shall hold the hearing:
(a) before the rule becomes effective; and
(b) no less than seven days nor more than 30 days after receipt of the request for hearing.

Renumbered and Amended by Chapter 382, 2008 General Session

**63G-3-303 Changes in rules.**
(1)
(a) To change a proposed rule already published in the bulletin, an agency shall file with the office:
(i) the text of the changed rule; and
(ii) a rule analysis containing a description of the change and the information required by Section 63G-3-301.
(b) A change to a proposed rule may not be filed more than 120 days after publication of the rule being changed.
(c) The office shall publish the rule analysis for the changed rule in the bulletin.
(d) The changed proposed rule and its associated proposed rule will become effective on a date specified by the agency, not less than 30 days or more than 120 days after publication of the last change in proposed rule.

(e) A changed proposed rule and its associated proposed rule lapse if a notice of effective date or another change to a proposed rule is not filed with the office within 120 days of publication of the last change in proposed rule.
(2) If the rule change is nonsubstantive:
(a) the agency need not comply with the requirements of Subsection (1); and
(b) the agency shall notify the office of the change in writing.
(3) If the rule is effective, the agency shall amend the rule according to the procedures specified in Section 63G-3-301.

Amended by Chapter 193, 2016 General Session

**63G-3-304 Emergency rulemaking procedure.**
(1) All agencies shall comply with the rulemaking procedures of Section 63G-3-301 unless an agency finds that these procedures would:
(a) cause an imminent peril to the public health, safety, or welfare;
(b) cause an imminent budget reduction because of budget restraints or federal requirements; or
(c) place the agency in violation of federal or state law.
(2)
(a) When finding that its rule is excepted from regular rulemaking procedures by this section, the agency shall file with the office and the members of the Administrative Rules Review and General Oversight Committee:
(i) the text of the rule; and
(ii) a rule analysis that includes the specific reasons and justifications for its findings.
(b) The office shall publish the rule in the bulletin as provided in Subsection 63G-3-301(4).
(c) The agency shall notify interested persons as provided in Subsection 63G-3-301(10).
(d) Subject to Subsection 63G-3-502(4), the rule becomes effective for a period not exceeding 120 days on the date of filing or any later date designated in the rule.
(3) If the agency intends the rule to be effective beyond 120 days, the agency shall also comply with the procedures of Section 63G-3-301.

Amended by Chapter 443, 2022 General Session

**63G-3-305 Agency review of rules -- Schedule of filings -- Limited exemption for certain rules.**
(1) Each agency shall review each of its rules within five years after the rule's original effective date or within five years after the filing of the last five-year review, whichever is later.
(2) An agency may consider any substantial review of a rule to be a five-year review if the agency also meets the requirements described in Subsection (3).
(3) At the conclusion of its review, and no later than the deadline described in Subsection (1), the agency shall decide whether to continue, repeal, or amend and continue the rule and comply with Subsections (3)(a) through (c), as applicable.
(a) If the agency continues the rule, the agency shall file with the office a five-year notice of review and statement of continuation that includes:
(i) a concise explanation of the particular statutory provisions under which the rule is enacted and how these provisions authorize or require the rule;
(ii) a summary of written comments received during and since the last five-year review of the rule from interested persons supporting or opposing the rule; and

(iii) a reasoned justification for continuation of the rule, including reasons why the agency disagrees with comments in opposition to the rule, if any.
(b) If the agency repeals the rule, the agency shall:
(i) comply with Section 63G-3-301; and
(ii) in the rule analysis described in Section 63G-3-301, state that the repeal is the result of the agency's five-year review under this section.
(c) If the agency amends and continues the rule, the agency shall comply with the requirements described in Section 63G-3-301 and file with the office the five-year notice of review and statement of continuation required in Subsection (3)(a).
(4) The office shall publish a five-year notice of review and statement of continuation in the bulletin no later than one year after the deadline described in Subsection (1).
(5)
(a) The office shall make a reasonable effort to notify an agency that a rule is due for review at least 180 days before the deadline described in Subsection (1).
(b) The office's failure to comply with the requirement described in Subsection (5)(a) does not exempt an agency from complying with any provision of this section.
(6) If an agency finds that it will not meet the deadline established in Subsection (1):
(a) before the deadline described in Subsection (1), the agency may file one extension with the office indicating the reason for the extension; and
(b) the office shall publish notice of the extension in the bulletin in accordance with the office's publication schedule established by rule under Section 63G-3-402.
(7) An extension permits the agency to comply with the requirements described in Subsections (1) and (3) up to 120 days after the deadline described in Subsection (1).
(8)
(a) If an agency does not comply with the requirements described in Subsection (3), and does not file an extension under Subsection (6), the rule expires automatically on the day immediately after the date of the missed deadline.
(b) If an agency files an extension under Subsection (6) and does not comply with the requirements described in Subsection (3) within 120 days after the day on which the deadline described in Subsection (1) expires, the rule expires automatically on the day immediately after the date of the missed deadline.
(9) After a rule expires under Subsection (8), the office shall:
(a) publish a notice in the next issue of the bulletin that the rule has expired and is no longer enforceable;
(b) remove the rule from the code; and
(c) notify the agency that the rule has expired.
(10) After a rule expires, an agency must comply with the requirements of Section 63G-3-301 to reenact the rule.

Amended by Chapter 193, 2016 General Session

## Part 4
## Office of Administrative Rules

### 63G-3-401 Office of Administrative Rules created -- Director.

(1) There is created within the Department of Government Operations the Office of Administrative Rules, to be administered by a director.
(2)
(a) The executive director shall appoint the director.
(b) The director shall hire, train, and supervise staff necessary for the office to carry out the provisions of this chapter.

Amended by Chapter 344, 2021 General Session

**63G-3-402 Office of Administrative Rules -- Duties generally.**
(1) The office shall:
(a) record in a register the receipt of all agency rules, rule analysis forms, and notices of effective dates;
(b) make the register, copies of all proposed rules, and rulemaking documents available for public inspection;
(c) publish all proposed rules, rule analyses, notices of effective dates, and review notices in the bulletin at least monthly, except that the office may publish the complete text of any proposed rule that the director determines is too long to print or too expensive to publish by reference to the text maintained by the office;
(d) compile, format, number, and index all effective rules in an administrative code, and periodically publish that code and supplements or revisions to it;
(e) publish a digest of all rules and notices contained in the most recent bulletin;
(f) publish at least annually an index of all changes to the administrative code and the effective date of each change;
(g) print, or contract to print, all rulemaking publications the director determines necessary to implement this chapter;
(h) distribute without charge the bulletin and administrative code to state-designated repositories, the Administrative Rules Review and General Oversight Committee, the Office of Legislative Research and General Counsel, and the two houses of the Legislature;
(i) distribute without charge the digest and index to state legislators, agencies, political subdivisions on request, and the Office of Legislative Research and General Counsel;
(j) distribute, at prices covering publication costs, all paper rulemaking publications to all other requesting persons and agencies;
(k) provide agencies assistance in rulemaking;
(l) if the department operates the office as an internal service fund agency in accordance with Section 63A-1-109.5, submit to the Rate Committee established in Section 63A-1-114:
(i) the proposed rate and fee schedule as required by Section 63A-1-114; and
(ii) other information or analysis requested by the Rate Committee;
(m) administer this chapter and require state agencies to comply with filing, publication, and hearing procedures; and
(n) make technological improvements to the rulemaking process, including improvements to automation and digital accessibility.
(2) The office shall establish by rule in accordance with Title 63G, Chapter 3, Utah Administrative Rulemaking Act, all filing, publication, and hearing procedures necessary to make rules under this chapter.
(3) The office may after notifying the agency make nonsubstantive changes to rules filed with the office or published in the bulletin or code by:

(a) implementing a uniform system of formatting, punctuation, capitalization, organization, numbering, and wording;
(b) correcting obvious errors and inconsistencies in punctuation, capitalization, numbering, referencing, and wording;
(c) changing a catchline to more accurately reflect the substance of each section, part, rule, or title;
(d) updating or correcting annotations associated with a section, part, rule, or title; and
(e) merging or determining priority of any amendment, enactment, or repeal to the same rule or section made effective by an agency.

(4) In addition, the office may make the following nonsubstantive changes with the concurrence of the agency:
(a) eliminate duplication within rules;
(b) eliminate obsolete and redundant words; and
(c) correct defective or inconsistent section and paragraph structure in arrangement of the subject matter of rules.

(5) For nonsubstantive changes made in accordance with Subsection (3) or (4) after publication of the rule in the bulletin, the office shall publish a list of nonsubstantive changes in the bulletin. For each nonsubstantive change, the list shall include:
(a) the affected code citation;
(b) a brief description of the change; and
(c) the date the change was made.

(6) All funds appropriated or collected for publishing the office's publications shall be nonlapsing.

Amended by Chapter 443, 2022 General Session

**63G-3-403 Repeal and reenactment of Utah Administrative Code.**

(1) When the director determines that the Utah Administrative Code requires extensive revision and reorganization, the office may repeal the code and reenact a new code according to the requirements of this section.

(2) The office may:
(a) reorganize, reformat, and renumber the code;
(b) require each agency to review its rules and make any organizational or substantive changes according to the requirements of Section 63G-3-303; and
(c) require each agency to prepare a brief summary of all substantive changes made by the agency.

(3) The office may make nonsubstantive changes in the code by:
(a) adopting a uniform system of punctuation, capitalization, numbering, and wording;
(b) eliminating duplication;
(c) correcting defective or inconsistent section and paragraph structure in arrangement of the subject matter of rules;
(d) eliminating all obsolete or redundant words;
(e) correcting obvious errors and inconsistencies in punctuation, capitalization, numbering, referencing, and wording;
(f) changing a catchline to more accurately reflect the substance of each section, part, rule, or title;
(g) updating or correcting annotations associated with a section, part, rule, or title; and
(h) merging or determining priority of any amendment, enactment, or repeal to the same rule or section made effective by an agency.

(4)
(a) To inform the public about the proposed code reenactment, the office shall publish in the bulletin:
(i) notice of the code reenactment;
(ii) the date, time, and place of a public hearing where members of the public may comment on the proposed reenactment of the code;
(iii) locations where the proposed reenactment of the code may be reviewed; and
(iv) agency summaries of substantive changes in the reenacted code.
(b) To inform the public about substantive changes in agency rules contained in the proposed reenactment, each agency shall:
(i) make the text of their reenacted rules available:
(A) for public review during regular business hours; and
(B) in an electronic version; and
(ii) comply with the requirements of Subsection 63G-3-301(10).
(5) The office shall hold a public hearing on the proposed code reenactment no fewer than 30 days nor more than 45 days after the publication required by Subsection (4)(a).
(6) The office shall distribute complete text of the proposed code reenactment without charge to:
(a) state-designated repositories in Utah;
(b) the Administrative Rules Review and General Oversight Committee; and
(c) the Office of Legislative Research and General Counsel.
(7) The former code is repealed and the reenacted code is effective at noon on a date designated by the office that is not fewer than 45 days nor more than 90 days after the publication date required by this section.
(8) Repeal and reenactment of the code meets the requirements of Section 63G-3-305 for a review of all agency rules.

Amended by Chapter 443, 2022 General Session

## Part 5
## Legislative Oversight

### 63G-3-501 Administrative Rules Review and General Oversight Committee.

(1)
(a) There is created an Administrative Rules Review and General Oversight Committee of the following 10 permanent members:
(i) five members of the Senate appointed by the president of the Senate, no more than three of whom may be from the same political party; and
(ii) five members of the House of Representatives appointed by the speaker of the House of Representatives, no more than three of whom may be from the same political party.
(b) Each permanent member shall serve:
(i) for a two-year term; or
(ii) until the permanent member's successor is appointed.
(c)
(i) A vacancy exists when a permanent member ceases to be a member of the Legislature, or when a permanent member resigns from the committee.
(ii) When a vacancy exists:

(A) if the departing member is a member of the Senate, the president of the Senate shall appoint a member of the Senate to fill the vacancy; or

(B) if the departing member is a member of the House of Representatives, the speaker of the House of Representatives shall appoint a member of the House of Representatives to fill the vacancy.

(iii) The newly appointed member shall serve the remainder of the departing member's unexpired term.

(d)

(i) The president of the Senate shall designate a member of the Senate appointed under Subsection (1)(a)(i) as a cochair of the committee.

(ii) The speaker of the House of Representatives shall designate a member of the House of Representatives appointed under Subsection (1)(a)(ii) as a cochair of the committee.

(e) Three representatives and three senators from the permanent members are a quorum for the transaction of business at any meeting.

(f)

(i) Subject to Subsection (1)(f)(ii), the committee shall meet at least once each month to review new agency rules, amendments to existing agency rules, and repeals of existing agency rules.

(ii) The committee chairs may suspend the meeting requirement described in Subsection (1)(f)(i) at the committee chairs' discretion.

(2) The office shall submit a copy of each issue of the bulletin to the committee.

(3)

(a) The committee shall exercise continuous oversight of the rulemaking process.

(b) The committee shall examine each rule, including any rule made according to the emergency rulemaking procedure described in Section 63G-3-304, submitted by an agency to determine:

(i) whether the rule is authorized by statute;

(ii) whether the rule complies with legislative intent;

(iii) the rule's impact on the economy and the government operations of the state and local political subdivisions;

(iv) the rule's impact on affected persons;

(v) the rule's total cost to entities regulated by the state;

(vi) the rule's benefit to the citizens of the state; and

(vii) whether adoption of the rule requires legislative review or approval.

(c) The committee may examine and review:

(i) any executive order issued pursuant to Title 53, Chapter 2a, Part 2, Disaster Response and Recovery Act;

(ii) any public health order issued during a public health emergency declared in accordance with Title 26, Utah Health Code, or Title 26A, Local Health Authorities; or

(iii) an agency's policies that:

(A) affect a class of persons other than the agency; or

(B) are contrary to legislative intent.

(d)

(i) To carry out these duties, the committee may examine any other issues that the committee considers necessary.

(ii) Notwithstanding anything to the contrary in this section, the committee may not examine an agency's internal policies, procedures, or practices.

(iii) The committee may also notify and refer rules to the chairs of the interim committee that has jurisdiction over a particular agency when the committee determines that an issue involved in an agency's rules may be more appropriately addressed by that committee.

(e) An agency shall respond to a request from the committee for:

(i) an agency's policy described in Subsection (3)(c)(iii); or

(ii) information related to an agency's policy described in Subsection (3)(c)(iii).

(f) In reviewing a rule, the committee shall follow generally accepted principles of statutory construction.

(4) When the committee reviews an existing rule, the committee chairs shall invite the Senate and House chairs of the standing committee and of the appropriation subcommittee that have jurisdiction over the agency whose existing rule is being reviewed to participate as nonvoting, ex officio members with the committee.

(5) The committee may request that the Office of the Legislative Fiscal Analyst prepare a fiscal note on any rule.

(6) In order to accomplish the committee's functions described in this chapter, the committee has all the powers granted to legislative interim committees under Section 36-12-11.

(7)

(a) The committee may prepare written findings of the committee's review of a rule, policy, practice, or procedure and may include any recommendation, including:

(i) legislative action; or

(ii) action by a standing committee or interim committee.

(b) When the committee reviews a rule, the committee shall provide to the agency that enacted the rule:

(i) the committee's findings, if any; and

(ii) a request that the agency notify the committee of any changes the agency makes to the rule.

(c) The committee shall provide a copy of the committee's findings described in Subsection (7)(a), if any, to:

(i) any member of the Legislature, upon request;

(ii) any person affected by the rule, upon request;

(iii) the president of the Senate;

(iv) the speaker of the House of Representatives;

(v) the Senate and House chairs of the standing committee that has jurisdiction over the agency whose rule, policy, practice, or procedure is the subject of the finding; and

(vi) the Senate and House chairs of the appropriation subcommittee that has jurisdiction over the agency that made the rule.

(8)

(a)

(i) The committee may submit a report on the committee's review under this section to each member of the Legislature at each regular session.

(ii) The report shall include:

(A) any finding or recommendation the committee made under Subsection (7);

(B) any action an agency took in response to a committee recommendation; and

(C) any recommendation by the committee for legislation.

(b) If the committee receives a recommendation not to reauthorize a rule, as described in Subsection 63G-3-301(13)(b), and the committee recommends to the Legislature reauthorization of the rule, the committee shall submit a report to each member of the Legislature detailing the committee's decision.

(c) If the committee recommends legislation, the committee may prepare legislation for consideration by the Legislature at the next general session.

Amended by Chapter 443, 2022 General Session

**63G-3-502 Legislative reauthorization of agency rules -- Extension of rules by governor.**

(1) All grants of rulemaking power from the Legislature to a state agency in any statute are made subject to the provisions of this section.

(2)

(a) Except as provided in Subsection (2)(b), every agency rule that is in effect on February 28 of any calendar year expires on May 1 of that year unless it has been reauthorized by the Legislature.

(b) Notwithstanding the provisions of Subsection (2)(a), an agency's rules do not expire if:

(i) the rule is explicitly mandated by a federal law or regulation; or

(ii) a provision of Utah's constitution vests the agency with specific constitutional authority to regulate.

(3)

(a) The Administrative Rules Review and General Oversight Committee shall have omnibus legislation prepared for consideration by the Legislature during its annual general session.

(b) The omnibus legislation shall be substantially in the following form: "All rules of Utah state agencies are reauthorized except for the following:".

(c) Before sending the legislation to the governor for the governor's action, the Administrative Rules Review and General Oversight Committee may send a letter to the governor and to the agency explaining specifically why the committee believes any rule should not be reauthorized.

(d) For the purpose of this section, the entire rule, a single section, or any complete paragraph of a rule may be excepted for reauthorization in the omnibus legislation considered by the Legislature.

(4) The Administrative Rules Review and General Oversight Committee may have legislation prepared for consideration by the Legislature in the annual general session or a special session regarding any rule made according to emergency rulemaking procedures described in Section 63G-3-304.

(5) The Legislature's reauthorization of a rule by legislation does not constitute legislative approval of the rule, nor is it admissible in any proceeding as evidence of legislative intent.

(6)

(a) If an agency believes that a rule that has not been reauthorized by the Legislature or that will be allowed to expire should continue in full force and effect and is a rule within their authorized rulemaking power, the agency may seek the governor's declaration extending the rule beyond the expiration date.

(b) In seeking the extension, the agency shall submit a petition to the governor that affirmatively states:

(i) that the rule is necessary; and

(ii) a citation to the source of its authority to make the rule.

(c)

(i) If the governor finds that the necessity does exist, and that the agency has the authority to make the rule, the governor may declare the rule to be extended by publishing that declaration in the Administrative Rules Bulletin on or before April 15 of that year.

(ii) The declaration shall set forth the rule to be extended, the reasons the extension is necessary, and a citation to the source of the agency's authority to make the rule.

(d) If the omnibus bill required by Subsection (3) fails to pass both houses of the Legislature or is found to have a technical legal defect preventing reauthorization of administrative rules intended to be reauthorized by the Legislature, the governor may declare all rules to be extended by publishing a single declaration in the Administrative Rules Bulletin on or before June 15 without meeting requirements of Subsections (6)(b) and (c).

Amended by Chapter 443, 2022 General Session

## Part 6
## Judicial Review

**63G-3-601 Interested parties -- Petition for agency action.**

(1) As used in this section, "initiate rulemaking proceedings" means the filing, for the purposes of publication in accordance with Subsection 63G-3-301(4), of an agency's proposed rule to implement a petition for the making, amendment, or repeal of a rule as provided in this section.

(2) An interested person may petition an agency to request the making, amendment, or repeal of a rule.

(3) The office shall prescribe by rule the form for petitions and the procedure for their submission, consideration, and disposition.

(4) A statement shall accompany the proposed rule, or proposed amendment or repeal of a rule, demonstrating that the proposed action is within the jurisdiction of the agency and appropriate to the powers of the agency.

(5) Within 60 days after submission of a petition, the agency shall either deny the petition in writing, stating its reasons for the denial, or initiate rulemaking proceedings.

(6)

(a) If the petition is submitted to a board that has been granted rulemaking authority by the Legislature, the board shall, within 45 days of the submission of the petition, place the petition on its agenda for review.

(b) Within 80 days of the submission of the petition, the board shall either:

(i) deny the petition in writing stating its reasons for denial; or

(ii) initiate rulemaking proceedings.

(7) If the agency or board has not provided the petitioner written notice that the agency has denied the petition or initiated rulemaking proceedings within the time limitations specified in Subsection (5) or (6) respectively, the petitioner may seek a writ of mandamus in state district court.

Amended by Chapter 408, 2020 General Session

**63G-3-602 Judicial challenge to administrative rules.**

(1)

(a) Any person aggrieved by a rule may obtain judicial review of the rule by filing a complaint with the county clerk in the district court where the person resides or in the district court in Salt Lake County.

(b) Any person aggrieved by an agency's failure to comply with Section 63G-3-201 may obtain judicial review of the agency's failure to comply by filing a complaint with the clerk of the district court where the person resides or in the district court in Salt Lake County.

(2)

(a) Except as provided in Subsection (2)(b), a person seeking judicial review under this section shall exhaust that person's administrative remedies by complying with the requirements of Section 63G-3-601 before filing the complaint.

(b) When seeking judicial review of a rule, the person need not exhaust that person's administrative remedies if:

(i) less than six months has passed since the date that the rule became effective and the person had submitted verbal or written comments on the rule to the agency during the public comment period;

(ii) a statute granting rulemaking authority expressly exempts rules made under authority of that statute from compliance with Section 63G-3-601; or

(iii) compliance with Section 63G-3-601 would cause the person irreparable harm.

(3)

(a) In addition to the information required by the Utah Rules of Civil Procedure, a complaint filed under this section shall contain:

(i) the name and mailing address of the plaintiff;

(ii) the name and mailing address of the defendant agency;

(iii) the name and mailing address of any other party joined in the action as a defendant;

(iv) the text of the rule or proposed rule, if any;

(v) an allegation that the person filing the complaint has either exhausted the administrative remedies by complying with Section 63G-3-601 or met the requirements for waiver of exhaustion of administrative remedies established by Subsection (2)(b);

(vi) the relief sought; and

(vii) factual and legal allegations supporting the relief sought.

(b)

(i) The plaintiff shall serve a summons and a copy of the complaint as required by the Utah Rules of Civil Procedure.

(ii) The defendants shall file a responsive pleading as required by the Utah Rules of Civil Procedures.

(iii) The agency shall file the administrative record of the rule, if any, with its responsive pleading.

(4) The district court may grant relief to the petitioner by:

(a) declaring the rule invalid, if the court finds that:

(i) the rule violates constitutional or statutory law or the agency does not have legal authority to make the rule;

(ii) the rule is not supported by substantial evidence when viewed in light of the whole administrative record; or

(iii) the agency did not follow proper rulemaking procedure;

(b) declaring the rule nonapplicable to the petitioner;

(c) remanding the matter to the agency for compliance with proper rulemaking procedures or further fact-finding;

(d) ordering the agency to comply with Section 63G-3-201;

(e) issuing a judicial stay or injunction to enjoin the agency from illegal action or action that would cause irreparable harm to the petitioner; or

(f) any combination of Subsections (4)(a) through (e).

(5) If the plaintiff meets the requirements of Subsection (2)(b), the district court may review and act on a complaint under this section whether or not the plaintiff has requested the agency review under Section 63G-3-601.

Renumbered and Amended by Chapter 382, 2008 General Session

**63G-3-603 Time for contesting a rule -- Statute of limitations.**

(1) A proceeding to contest any rule on the ground of noncompliance with the procedural requirements of this chapter shall commence within two years of the effective date of the rule.
(2) A proceeding to contest any rule on the ground of not being supported by substantial evidence when viewed in light of the whole administrative record shall commence within four years of the effective date of the challenged action.
(3) A proceeding to contest any rule on the basis that a change to the rule made under Subsection 63G-3-402(2) or (3) substantively changed the rule shall be commenced within two years of the date the change was made.

Renumbered and Amended by Chapter 382, 2008 General Session

## Part 7
## Official Compilation of Administrative Rules

**63G-3-701 Utah Administrative Code as official compilation of rules -- Judicial notice.**

The code shall be received by all the judges, public officers, commissions, and departments of the state government as evidence of the administrative law of the state of Utah and as an authorized compilation of the administrative law of Utah. All courts shall take judicial notice of the code and its provisions.

Renumbered and Amended by Chapter 382, 2008 General Session

**63G-3-702 Utah Administrative Code -- Organization -- Official compilation.**

(1) The Utah Administrative Code shall be divided into three parts:
  (a) titles, whose number shall begin with "R";
  (b) rules; and
  (c) sections.
(2) All sections contained in the code are referenced by a three-part number indicating its location in the code.
(3) The office shall maintain the official compilation of the code and is the state-designated repository for administrative rules. If a dispute arises in which there is more than one version of a rule, the latest effective version on file with the office is considered the correct, current version.

Amended by Chapter 193, 2016 General Session

**R15. Government Operations, Administrative Rules (Office of).**
**R15-1. Administrative Rule Hearings.**
**R15-1-1. Authority.**

(1) This rule establishes procedures and standards for administrative rule hearings as required by Subsection 63G-3-402(1)(a).

(2) The procedures of this rule constitute the minimum requirements for mandatory administrative rule hearings. Additional procedures may be required to comply with any other governing statute, federal law, or federal regulation.

**R15-1-2. Definitions.**

(1) Terms used in this rule are defined in Section 63G-3-102.

(2) In addition:

(a) "director" means the director of the Office of Administrative Rules;

(b) "hearing" means an administrative rule hearing; and

(c) "officer" means an administrative rule hearing officer.

**R15-1-3. Purpose.**

(1) The purpose of this rule is to provide:

(a) procedures for agency hearings on proposed administrative rules or rules changes, or on the need for a rule or change;

(b) opportunity for public comment on rules; and

(c) opportunity for agency response to public concerns about rules.

**R15-1-4. When Agencies Hold Hearings.**

(1) Agencies shall hold hearings as required by Subsection 63G-3-302(2).

(2) Agencies may hold hearings:

(a) during the public comment period on a proposed rule, after its publication in the bulletin and prior to its effective date;

(b) before initiating rulemaking procedures under Title 63G, Chapter 3, to promote public input prior to a rule's publication;

(c) during a regular or extraordinary meeting of a state board, council, or commission, in order to avoid separate and additional meetings; or

(d) to hear any public petition for a rule change as provided by Section 63G-3-601.

(3) Voluntary hearings, as described in this section, follow the procedures prescribed by this rule or any other procedures the agency may provide by rule.

(4) Mandatory hearings, as described in this section, follow the procedures prescribed by this rule and any additional requirements of state or federal law.

(5) If an agency holds a mandatory hearing under the procedures of this rule during the public comment period described in Subsection 63G-3-301(6), no second hearing is required for the purpose of comment on the same rule or change considered at the first hearing.

**R15-1-5. Hearing Procedures.**

(1) Notice.

(a) An agency shall provide notice of a hearing by:

(i) publishing the hearing date, time, place, and subject in the bulletin;

(ii) mailing copies of the notice directly to persons who have petitioned for a hearing or rule changes under Section 63G-3-302 or 63G-3-601, respectively; and

(iii) posting for at least 24 hours in a place in the agency's offices which is frequented by the public.

(b) If a hearing becomes mandatory after the agency has published the proposed rule in the bulletin, the agency shall notify in writing persons requesting the hearing of the time and place.

(c) An agency may provide additional notice of a hearing, and shall give further notice as may otherwise be required by law.

(2) Hearing Officer.

(a) The agency head shall appoint as hearing officer a person qualified to conduct fairly the hearing.

(b) No restrictions apply to this appointment except the officer shall know rulemaking procedure.

(c) If a state board, council, or commission is responsible for agency rulemaking, and holds a hearing, a member or the body's designee may be the hearing officer.

(3) Time. The officer shall open the hearing at the announced time and place and permit comment for a minimum of one hour. The hearing may be extended or continued to another day as necessary in the judgment of the officer.

(4) Comment.

(a) At the opening of the hearing, the officer shall explain the subject and purpose of the hearing and invite orderly, germane comment from all persons in attendance. The officer may set time limits for speakers and shall ensure equitable use of time.

(b) The agency shall have a representative at the hearing, other than the officer, who is familiar with the rule at issue and who can respond to requests for information by those in attendance.

(c) The officer shall invite written comment to be submitted at the hearing or after the hearing, within a reasonable time. Written comment shall be attached to the hearing minutes.

(d) The officer shall conduct the hearing as an open, informal, orderly, and informative meeting. Oaths, cross-examination, and rules of evidence are not required.

(5) The Hearing Record.

(a) The officer shall cause to be recorded the name, address, and relevant affiliation of all persons speaking at the hearing, and cause an electronic or mechanical verbatim recording of the hearing to be made, or make a brief summary, of their remarks.

(b) The hearing record consists of a copy of the proposed rule or rule change, submitted written comment, the hearing recording or summary, the list of persons speaking at the hearing, and other pertinent documents as determined by the agency.

(c) The hearing officer shall, as soon as practicable, assemble the hearing record and transmit it to the agency for consideration.

(d) The hearing record shall be kept with and as part of the rule's administrative record in a file available at the agency offices for public inspection.

**R15-1-8. Decision on an Issue Regarding Rulemaking Procedure.**

(1) When a hearing issue requires a decision regarding rulemaking procedure, the officer shall submit a written request for a decision to the director as soon as practicable after, or after recessing, the hearing, as provided in Section R15-5-6. The director shall reply to the agency head as provided in Subsection R15-5-6(2). The director's decision shall be included in the hearing record.

**R15-1-9. Appeal and Judicial Review.**

(1) Persons may appeal the decision of the agency head or the director by petitioning the district court for judicial review as provided by law.

**KEY: administrative law, government hearings**
**Date of Enactment or Last Substantive Amendment: June 1, 1996**
**Notice of Continuation: June 1, 2020**
**Authorizing, and Implemented or Interpreted Law: 63G-3-402**

**R15. Government Operations, Administrative Rules (Office of).**

**R15-2. Public Petitioning for Rulemaking.**

**R15-2-1. Authority.**

As required by Subsection 63G-3-601(3), this rule prescribes the form and procedures for submission, consideration, and disposition of petitions requesting the making, amendment, or repeal of an administrative rule.

**R15-2-2. Definitions.**

(1) Terms used in this rule are defined in Section 63G-3-102.

(2) Other terms are defined as follows:

(a) "rule change" means:

(i) making a new rule;

(ii) amending, repealing, or repealing and reenacting an existing rule;

(iii) amending a proposed rule further by filing a change in proposed rule under the provisions of Section 63G-3-303;

(iv) allowing a proposed (new, amended, repealed, or repealed and reenacted) rule or change in proposed rule to lapse; or

(v) any combination of the above.

(b) "petitioner" means an interested person who submits a petition to an agency pursuant to Section 63G-3-601 and this rule.

**R15-2-3. Petition Procedure.**

(1) The petitioner shall send the petition to the head of the agency authorized by law to make the rule change requested.

(2) The agency receiving the petition shall record the date it received the petition.

**R15-2-4. Petition Form.**

The petition shall:

(a) be clearly designated "petition for a rule change";

(b) state the petitioner's name;

(c) state the petitioner's interest in the rule, including relevant affiliation, if any;

(d) include a statement as required by Subsection 63G-3-601(4) regarding the requested rule change;

(e) state the approximate wording of the requested rule change;

(f) describe the reason for the rule change;

(g) include an address, an e-mail address when available, and telephone where the petitioner can be reached during regular business hours; and

(h) be signed by the petitioner.

**R15-2-5. Petition Consideration and Disposition.**

(1) The agency head or designee shall:

(a) review and consider the petition;

(b) write a response to the petition stating:

(i) that the petition is denied and reasons for denial; or

(ii) the date when the agency is initiating a rule change consistent with the intent of the petition; and

(c) send the response to the petitioner within the time frame provided by Section 63G-3-601.

(2) The petitioned agency may, within the time frame provided by Section 63G-3-601, interview the petitioner, hold a public hearing on the petition, or take any action the agency, in its judgment, deems necessary to provide the petition due consideration.

(3) The agency shall retain the petition and a copy of the agency's response as part of the administrative record.

(4) The agency shall mail copies of its decision to all persons who petitioned for a rule change.

**KEY: administrative law, open government, transparency**
**Date of Enactment or Last Substantive Amendment: December 25, 2006**
**Notice of Continuation: September 8, 2020**
**Authorizing, and Implemented or Interpreted Law: 63G-3-601**

**R15. Government Operations, Administrative Rules (Office of).**
**R15-3. Administrative Rules: Scope, Content, and When Required.**
**R15-3-1. Authority, Purpose, and Definitions.**

(1) This rule is authorized under Subsection 63G-3-402(1) and (2).

(2) This rule clarifies when rulemaking is required, and requirements for incorporation by reference within rules.

(3) Terms used in this rule are defined in Section 63G-3-102.

**R15-3-2. Agency Discretion.**

(1) A rule may restrict agency discretion to prevent agency personnel from exceeding their scope of employment, or committing arbitrary action or application of standards, or to provide due process for persons affected by agency actions.

(2) A rule may authorize agency discretion that sets limits, standards, and scope of employment within which a range of actions may be applied by agency personnel. A rule may also establish criteria for granting exceptions to the standards or procedures of the rule when, in the judgment of authorized personnel, documented circumstances warrant.

(3) An agency may have written policies which broadly prescribe goals and guidelines. Policies are not rules unless they meet the criteria for rules set forth under Section 63G-3-201(2).

(4) Within the limits prescribed by Sections 63G-3-201 and 63G-3-602, an agency has full discretion regarding the substantive content of its rules. The office has authority over nonsubstantive content under Subsections 63G-3-402(3) and (4), and 63G-3-403(2) and (3), rulemaking procedures, and the physical format of rules for compilation in the Utah Administrative Code.

**R15-3-3. Use of Incorporation by Reference in Rules.**

(1) An agency incorporating materials by reference as permitted under Subsection 63G-3-201(7) shall comply with the following standards:

(a) The rule shall state specifically that the cited material is "incorporated by reference."

(b) If the material contains options, or is modified in its application, the options selected and modifications made shall be stated in the rule.

(c) If the incorporated material is substantively changed at a later time, and the agency intends to enforce the revised material, the agency shall amend its rule through rulemaking procedures to incorporate by reference any applicable changes as soon as practicable.

(d) In accordance with Subsection 63G-3-201(7)(c), an agency shall describe substantive changes that appear in the materials incorporated by reference as part of the "summary of rule or change" in the rule analysis.

(2) An agency shall comply with copyright requirements when providing the office a copy of material incorporated by reference.

**R15-3-4. Computer-Prohibited Material.**

(1) All rules shall be in a format that permits their compatibility with the office's computer system and compilation into the Utah Administrative Code.

(2) Rules may not contain maps, charts, graphs, diagrams, illustrations, forms, or similar material.

(3) The office shall issue and provide to agencies instructions and standards for formatting rules.

**R15-3-5. Statutory Provisions that Require Rulemaking Pursuant to Subsection 63G-3-301(13).**

For the purposes of Subsection 63G-3-301(13), the phrase "statutory provision that requires the rulemaking" means a state statutory provision that explicitly mandates rulemaking.

**KEY: administrative law**
**Date of Enactment or Last Substantive Amendment: April 30, 2007**
**Notice of Continuation: September 10, 2020**
**Authorizing, and Implemented or Interpreted Law: 63G-3-201; 63G-3-301; 63G-3-402**

**R15. Government Operations, Administrative Rules (Office of).**
**R15-4. Administrative Rulemaking Procedures.**
**R15-4-1. Authority and Purpose.**

(1) This rule establishes procedures for filing and publication of agency rules under Sections 63G-3-301, 63G-3-303, and 63G-3-304, as authorized under Subsection 63G-3-402(2).

(2) The procedures of this rule constitute minimum requirements for rule filing and publication. Other governing statutes, federal laws, or federal regulations may require additional rule filing and publication procedures.

**R15-4-2. Definitions.**

(1) Terms used in this rule are defined in Section 63G-3-102.

(2) Other terms are defined as follows:

(a) "Anniversary date" means the date that is five years from the original effective date of the rule, or the date that is five years from the date the agency filed with the office the most recent five-year review required under Subsection 63G-3-305(3), whichever is sooner.

(b) "Digest" means the Utah State Digest that summarizes the content of the bulletin as required by Subsection 63G-3-402(1)(e);

(c) "Codify" means the process of collecting and arranging administrative rules systematically in the Utah Administrative Code, and includes the process of verifying that each amendment was marked as required under Subsection 63G-3-301(4)(b);

(d) "Compliance cost" means expenditures a regulated person will incur if a rule or change is made effective;

(f) "director" means the director of the Office of Administrative Rules;

(e) "Cost" means the aggregated expenses persons as a class affected by a rule will incur if a rule or change is made effective;

(g) "eRules" means the administrative rule filing application that agencies use to file rules and notices;

(h) "Savings" means:

(i) an aggregated monetary amount that will no longer be incurred by persons as a class if a rule or change is made effective;

(ii) an aggregated monetary amount that will be refunded or rebated if a rule or change is made effective;

(iii) an aggregated monetary amount of anticipated revenues to be generated for state budgets, local governments, or both if a rule or change is made effective; or

(iv) any combination of these aggregated monetary amounts.

(i) "Unmarked change" means a change made to rule text that was not marked as required by Subsection 63G-3-301(4)(b).

**R15-4-3. Publication Dates and Deadlines.**

(1) For the purposes of Subsections 63G-3-301(4) and 63G-3-303(1), an agency shall file its rule and rule analysis by 11:59:59 p.m. on the fifteenth day of the month for publication in the bulletin and digest issued on the first of the next month, and by 11:59:59 p.m. on the first day of the month for publication on the fifteenth of the same month.

(a) If the first or fifteenth day is a Saturday, or a Tuesday, Wednesday, Thursday, or Friday holiday, the agency shall file the rule and rule analysis by 11:59:59 p.m. on the previous regular business day.

(b) If the first or fifteenth day is a Sunday or Monday holiday, the agency shall file the rule and rule analysis by 11:59:59 p.m. on the next regular business day.

(2) For all purposes, the official date of publication for the bulletin and digest shall be the first and fifteenth days of each month.

**R15-4-4. Thirty-Day Comment Period for a Proposed Rule and a Change in Proposed Rule.**

(1) For the purposes of Sections 63G-3-301 and 63G-3-303, "30 days" shall be computed by:

(a) counting the day after publication of the rule as the first day; and

(b) counting the thirtieth consecutive day after the day of publication as the thirtieth day, unless

(c) the thirtieth consecutive day is a Saturday, Sunday, or holiday, in which event the thirtieth day is the next regular business day.

**R15-4-5a. Notice of the Effective Date for a Proposed Rule.**

(1)(a) Pursuant to Subsection 63G-3-301(12), upon expiration of the comment period designated on the rule analysis and filed with the rule, and before expiration of 120 days after publication of a proposed rule, the agency proposing the rule shall notify the office of the date the rule is to become effective and enforceable.

(b) The agency shall notify the office after determining that the proposed rule, in the form published, shall be the final form of the rule, and after informing the office of any nonsubstantive changes in the rule as provided for in Section R15-4-6.

(2)(a) The agency shall notify the office by filing with the office a Notice of Effective Date form using eRules.

(b) If the eRules Notice of Effective Date form is unavailable to the agency, the agency may notify the office by any other form of written communication clearly identifying the proposed rule, stating the date the rule was filed with the office or published in the bulletin, and stating its effective date.

(3) The date designated as the effective date shall be:

(a) at least seven days after the comment period specified on the rule analysis; or

(b) if the agency formally extends the comment period for a proposed rule by publishing a subsequent notice in an issue of the bulletin, at least seven days after the extended comment period.

(4) The office shall publish notice of the effective date in the next issue of the bulletin. There is no publication deadline for a notice of effective date for a proposed rule, nor requirement that it be published prior to the effective date.

**R15-4-5b. Notice of the Effective Date for a Change in Proposed Rule.**

(1)(a) Upon expiration of the 30-day period required by Section 63G-3-303, and before expiration of the 120th day after publication of a change in proposed rule, the agency promulgating the rule shall notify the office of the date the rule is to become effective and enforceable.

(b) The agency shall notify the office after determining that the rule text as published is the final form of the rule, and after informing the office of any nonsubstantive changes in the rule as provided for in Section R15-4-6.

(2)(a) The agency shall notify the office by filing with the office a Notice of Effective Date form using eRules.

(b) If the eRules Notice of Effective Date form is unavailable to the agency, the agency may notify the office by any other form of written communication clearly identifying the change in proposed rule and any rules upon which the change in proposed rule is dependent, stating the date the rules were filed with the office or published in the bulletin, and stating the effective date.

(3) The date designated as the effective date shall be:

(a) at least 30 days after the publication date of the rule in the bulletin, or

(b) if the agency designated a comment period, at least seven days after a comment period designated by the agency on the rule analysis or formally extended by publication of a subsequent notice in the bulletin.

(4) The office shall publish notice of the effective date in the next issue of the bulletin. There is no publication deadline for the notice of effective date for a change in proposed rule, nor requirement that it be published prior to the effective date.

**R15-4-6. Nonsubstantive Changes in Rules.**

(1) Pursuant to Subsections 63G-3-201(4)(d) and 63G-3-303(2), for the purpose of making rule changes that are grammatical or do not materially affect the application or outcome of agency procedures and standards, agencies shall comply with the procedures of this section.

(2) The agency proposing a change shall determine if the change is substantive or nonsubstantive according to the criteria cited in Subsection R15-4-6(1).

(a) The agency may seek the advice of the attorney general or the office, but the agency is responsible for compliance with the cited criteria.

(3) Without complying with regular rulemaking procedures, an agency may make nonsubstantive changes in:

(a) proposed rules already published in the bulletin and digest but not made effective; or

(b) rules already effective.

(4) To make a nonsubstantive change in a rule, the agency shall:

(a) notify the office by filing with the office the form designated for nonsubstantive changes;

(b) include with the notice the rule text to be changed, with changes marked as required by Section R15-4-9; and

(c) include with the notice the name of the agency head or designee authorizing the change.

(5) A nonsubstantive change becomes effective on the date the office makes the change in the Utah Administrative Code.

(6) The office shall record the nonsubstantive change and its effective date in the administrative rules register.

**R15-4-7. Substantive Changes in Proposed Rules.**

(1) Pursuant to Section 63G-3-303, agencies shall comply with the procedures of this section when making a substantive change in a proposed rule.

(a) The procedures of this section apply if:

(i) the agency determines a change in the rule is necessary;

(ii) the change is substantive under the criteria of Subsection 63G-3-102(20);

(iii) the rule was published as a proposal in the bulletin and digest; and

(iv) the rule has not been made effective under the procedures of Subsection 63G-3-301(12) and Section R15-4-5a.

(b) If the rule is already effective, the agency shall comply with regular rulemaking procedures.

(2) To make a substantive change in a proposed rule, the agency shall file with the office:

(a) a rule analysis, marked to indicate the agency intends to change a rule already published, and describing the change and reasons for it; and

(b) a copy of the proposed rule previously published in the bulletin marked to show only those changes made since the proposed rule was previously published.

(3) The office shall publish the rule analysis in the next issue of the bulletin, subject to the publication deadlines of Section R15-4-3. The office may also publish the changed text of the rule.

(4) The agency may make a change in proposed rule effective by following the requirements of Section R15-4-5b, or may further amend the rule by following the procedures of Sections R15-4-6 or R15-4-7.

**R15-4-8. Temporary 120-Day Rules.**

(1) Pursuant to Section 63G-3-304, for the purpose of filing a temporary rule, an agency shall comply with the procedures of this section.

(2) The agency proposing a temporary rule shall determine if the need for the rule complies with the criteria of Subsection 63G-3-304(1).

(a) The office interprets the criteria of Subsection 63G-3-304(1) to include under "welfare" any substantial material loss to the classes of persons or agencies the agency is mandated to regulate, serve, or protect.

(3) The agency shall use the same procedures for filing and publishing a temporary rule as for a permanent rule, except:

(a) the rule shall become effective and enforceable on the day and hour it is recorded by the office unless the agency designates a later effective date on the rule analysis;

(b) no comment period is necessary;

(c) no public hearing is necessary; and

(d) the rule shall expire 120 days after the rule's effective date unless the filing agency notifies the office, on the form or by memorandum, of an earlier expiration date.

(4) A temporary rule is separate and distinct from a rule filed under regular rulemaking procedures, though the language of the two rules may be identical. To make a temporary rule permanent, the agency shall propose a separate rule for regular rulemaking.

(5) When a temporary rule and a similar regular rule are in effect at the same time, any conflict between the provisions of the two are resolved in favor of the rule with the most recent effective date, unless the agency designates otherwise as part of the rule analysis.

(6) A temporary rule has the full force and effect of a permanent rule while in effect, but a temporary rule is not codified in the Utah Administrative Code.

**R15-4-9. Underscoring and Striking Out.**

(1) (a) Pursuant to Subsection 63G-3-301(4)(b), an agency shall underscore language to be added and strike out language to be deleted in proposed rules.

(b) Consistent with Subsection 63G-3-301(4)(b), an agency shall underscore language to be added and strike out language to be deleted in changes in proposed rules, 120-day rules, and nonsubstantive changes.

(c) The struck out language shall be surrounded by brackets.

(2) When an agency proposes to make a new rule or section, the entire proposed text shall be underscored.

(3)(a) When an agency proposes to repeal a complete rule it shall include as part of the information provided in the rule analysis a brief summary of the deleted language and a brief explanation of why the rule is being repealed.

(b) The agency shall include with the rule analysis a copy of the text to be deleted in one of the following formats:

(i) each page annotated "repealed in its entirety" or

(ii) the entire text struck out in its entirety and surrounded by one set of brackets.

(c) The office shall not publish repealed rules unless space is available within the page limits of the bulletin.

(4) When an agency fails to mark a change as described in this section, the director may refuse to codify the change. When determining whether or not to codify an unmarked change, the director shall consider:

(a) whether the unmarked change is substantive or nonsubstantive; and

(b) if the purpose of public notification has been adequately served.

(5) The director's refusal to codify an unmarked change means that the change is not operative for the purposes of Section 63G-3-701 and that the agency must comply with regular rulemaking procedures to make the change.

**R15-4-10. Estimates of Anticipated Cost or Savings, and Compliance Cost.**

(1) Pursuant to Subsections 63G-3-301(8)(d), 63G-3-303(1)(a), 63G-3-304(2), and 53C-1-201(3), when an agency files a proposed rule, change in proposed rule, 120-day (emergency) rule, or expedited rule and provides anticipated cost or savings, and compliance cost information in the rule analysis, the agency shall:

(a) estimate the incremental cost or savings and incremental compliance cost associated with the changes proposed by the rule or change;

(b) estimate the incremental cost or savings and incremental compliance cost in dollars, except as otherwise provided in Subsections R15-4-10(4) and (5);

(c) indicate that the amount is either a cost or a savings; and

(d) estimate the incremental cost or savings expected to accrue to "state budgets," "local governments," "small businesses," and "persons other than small businesses, businesses, or local governmental entities" as aggregated cost or savings;

(2) In addition, an agency may:

(a) provide a narrative description of anticipated cost or savings, and compliance cost;

(b) compare anticipated cost or savings, and compliance cost figures, for the rule or change to:

(i) current budgeted costs associated with the existing rule,

(ii) figures reported on a fiscal note attached to a related legislative bill, or

(iii) both (i) and (ii).

(3) If an agency chooses to provide comparison figures, it shall clearly distinguish comparison figures from the anticipated cost or savings, and compliance cost figures.

(4) If dollar estimates are unknown or not available, or the obtaining thereof would impose a substantial unbudgeted hardship on the agency, the agency may substitute a reasoned narrative description of cost-related actions required by the rule or change, and explain the reason or reasons for the substitution.

(5) If no cost, savings, or compliance cost is associated with the rule or change, an agency may enter "none," "no impact," or similar words in the rule analysis followed by a written explanation of how the agency estimated that there would be no impact, or how the proposed rule, or changes made to an existing rule does not apply to "state budgets," "local government," "small businesses," "persons other than small businesses, businesses, or local governmental entities," or any combination of these.

(6) If an agency does not provide an estimate of cost, savings, compliance cost, or a reasoned narrative description of cost information; or a written explanation as part of the rule analysis in compliance with this section, the office may, after making an attempt to obtain the required information, refuse to register and publish the rule or change. If the office refuses to register and publish a rule or change, it shall:

(a) return the rule or change to the agency with a notice indicating that the office has refused to register and publish the rule or change;

(b) identify the reason or reasons why the office refused to register and publish the rule or change; and

(c) indicate the filing deadlines for the next issue of the bulletin.

**KEY: administrative law**
**Date of Enactment or Last Substantive Amendment: August 24, 2007**
**Notice of Continuation: September 10, 2020**
**Authorizing, and Implemented or Interpreted Law: 63G-3-301; 63G-3-303; 63G-3-304; 63G-3-402**

**R15. Government Operations, Administrative Rules (Office of).**
**R15-5. Administrative Rules Adjudicative Proceedings.**
**R15-5-1. Purpose.**

(1) This rule provides the procedures for informal adjudicative proceedings governing:

(a) appeal and review of a decision by the office not to publish an agency's proposed rule or rule change or not to register an agency's notice of effective date; and

(b) a determination by the office whether an agency rule meets the procedural requirements of Title 63G, Chapter 3, the Utah Administrative Rulemaking Act.

(2) The informal procedures of this rule apply to all other division actions for which an adjudicative proceeding may be required.

**R15-5-2. Authority.**

This rule is required by Sections 63G-4-202 and 63G-4-203, and is enacted under the authority of Subsection 63G-3-402(1)(m) and Sections 63G-4-202, 63G-4-203, and 63G-4-503.

**R15-5-3. Definitions.**

(1) The terms used in this rule are defined in Section 63G-4-103.

(2) In addition:

(a) "director" means the director of the Office of Administrative Rules; and

(b) "digest" means the Utah State Digest which summarizes the content of the bulletin as required under Subsection 63G-3-402(1)(f).

**R15-5-4. Refusal to Publish or Register a Rule or Rule Change.**

(1) The office shall not publish a proposed rule or rule change when the office determines the agency has not met the requirements of Title 63G, Chapter 3, or of Rules R15-3 or R15-4.

(2) The office shall not register an agency's notice of effective date, nor codify the rule or rule change in the Utah Administrative Code, if the agency exceeds the 120-day limit required by Subsection 63G-3-301(6)(a) as interpreted in Section R15-4-5.

(3) The office shall notify the agency of a refusal to publish or register a rule or rule change, and shall advise and assist the agency in correcting any error or omission, and in re-filing to meet statutory and regulatory criteria.

**R15-5-5. Appeal of a Refusal to Publish or Register a Rule or Rule Change.**

(1) An agency may request a review of an office refusal to publish or register a rule or rule change by filing a written petition for review with the director.

(2) The director shall grant or deny the petition within 20 days, and respond in writing giving the reasons for any denial.

(3) The agency may appeal the decision of the director by filing a written appeal to the executive director of the Department of Government Operations within 20 days of receipt of the director's decision. The executive director shall respond within 20 days affirming or reversing the director's decision.

**R15-5-6. Determining the Procedural Validity of a Rule.**

(1) A person may contest the procedural validity, or request a determination of whether a rule meets the requirements of Title 63G, Chapter 3, by filing a written petition with the office.

(a) The rule at issue may be a proposed rule or an effective rule.

(b) The petition must be received by the office within the two-year limit set by Section 63G-3-603.

(c) The petition may emanate from a rulemaking hearing as in Section R15-1-8.

(d) The petition shall specify the rule or rule change at issue and reasons why the petitioner deems it procedurally flawed or invalid.

(e) The petition shall be accompanied by any documents the office should consider in reaching its decision.

(f) The petition shall be signed and designate a telephone number where the petitioner can be contacted during regular business hours.

(2) The office shall respond to the petition in writing within 20 days of its receipt.

(a) The office shall research all records pertaining to the rule or rule change at issue.

(b) The response of the office shall state whether the rule is procedurally valid or invalid and how the agency may remedy any defect.

(c) The office shall send a copy of the petition and its response to the pertinent agency.

(3) The petitioner may request reconsideration of the office's findings by filing a written request for reconsideration with the director.

(a) The director may respond to the request in writing.

(b) If the petitioner receives no response within 20 days, the request is denied.

**R15-5-7. Remedies Resulting from an Adjudicative Proceeding.**

(1) A rule the office determines is procedurally invalid shall be stricken from the Utah Administrative Code and notice of its deletion published in the next issues of the bulletin and digest.

(2) The office shall notify the pertinent agency and assist the agency in re-filing or otherwise remedying the procedural omission or error in the rule.

(3) A rule the office determines is procedurally valid shall be published and registered promptly.

**KEY: administrative procedures, administrative law**
**Date of Enactment or Last Substantive Amendment: June 1, 1996**
**Notice of Continuation: September 10, 2020**
**Authorizing, and Implemented or Interpreted Law: 63G-3-402; 63G-4-202; 63G-4-203; 63G-4-503**

# Proposed for Public Comment

State of Utah
SPENCER J. COX
*Governor*

DEIDRE HENDERSON
*Lieutenant Governor*

Department of
Environmental Quality

Kimberly D. Shelley
*Executive Director*

DIVISION OF AIR QUALITY
Bryce C. Bird
*Director*

DAQ-032-22

**M E M O R A N D U M**

**TO:** Air Quality Board

**THROUGH:** Bryce C. Bird, Executive Secretary

**FROM:** Chelsea Cancino, Environmental Scientist

**DATE:** March 24, 2022

**SUBJECT:** PROPOSE FOR PUBLIC COMMENT: Utah State Implementation Plan. Section XX.A: Regional Haze Second Implementation Period; Utah State Implementation Plan. Emission Limits and Operating Practices: Section IX, Part H.21 and Part H.23; R307-110-17. Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits; and R307-110-28. Regional Haze.

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The Regional Haze State Implementation Plan (SIP) for the second planning period addresses requirements for periodic comprehensive revisions of implementation plans for regional haze (RH). The Regional Haze Rule (RHR) requires Utah to address RH in each mandatory Class I Area (CIA) located in Utah and in each mandatory CIA located outside of Utah that may be affected by pollutants emitted from sources within Utah. Utah is required to submit a SIP revision to the EPA addressing the specific elements required by the rule.

The objectives of the RHR are: 1) to improve existing visibility in 156 national parks, wilderness areas, and monuments 2) to prevent future visibility impairment by manmade sources, and 3) to meet the national goal of natural visibility conditions in all mandatory CIAs by 2064. Utah's CIAs are Arches National Park, Bryce Canyon National Park, Canyonlands National Park, Capitol Reef National Park, and Zion National Park.

The RHR establishes several planning periods extending from 2005 to 2064. The State of Utah is required to develop an RH SIP for each period. The first implementation period spanned from 2008 to 2018. This SIP revision consists of the second implementation period spanning from 2018 to 2028. This SIP was originally due to the EPA on July 31, 2018. However, the deadline was extended to July 31, 2021. In this revision, UDAQ demonstrates the visibility progress to date in each of Utah's CIAs and analyzes Utah's emissions trends and sources of visibility impairment. Utah is required to set reasonable progress goals which:

1) must provide for an improvement in visibility for the most impaired days throughout the implementation plan, and

2) ensure no degradation in visibility for the least impaired days over the same period.

For this purpose, Utah has outlined its Long-Term Strategy (LTS) in this document as well as the determination of reasonable progress goals (RPGs) for CIAs in Utah.

The RH SIP must also address mandatory CIAs outside of the state that are reasonably anticipated to be affected by emissions from Utah as well as out-of-state sources impacting Utah CIAs. For this requirement, UDAQ analyzed Western Regional Air Partnership (WRAP) photochemical modeling and found that Utah does not significantly impact visibility at out-of-state CIAs. Utah has also determined that Utah's CIAs are not significantly impacted by out-of-state sources. Upon consultation with Utah's surrounding states, Utah will not require any actions from other states for impacts on Utah's CIAs and Utah has received no requests for actions regarding Utah sources' impacts on out-of-state CIAs.

Throughout this second implementation period, UDAQ has participated in the WRAP, which has conducted modeling and technical analysis to support state RH planning. UDAQ has also consulted with federal land managers (FLMs), Tribes, Utah's surrounding states, as well as environmental advocates, industry stakeholders, and the public.

This SIP revision also examines the need to implement additional emission reduction measures on sources that are reasonably anticipated to contribute to visibility impairment. The examination required to determine actions for this period is known as a four-factor analysis and consists of four criteria each selected source must consider when analyzing the possible installation of controls: 1) cost of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts, and 4) remaining useful life.

To determine which sources must submit a four-factor analysis to the State, UDAQ performed a Q/d (emissions/distance) analysis to determine which of Utah's sources have the highest potential visibility impact on Utah's CIAs. These facilities include the Ash Grove Cement Company Leamington Cement Plant, the Graymont Western US Inc. Cricket Mountain Plant, PacifiCorp, the Sunnyside Cogeneration Associated Sunnyside Cogeneration Facility, and the US Magnesium LLC Rowley Plant. UDAQ requested each facility to submit a four-factor analysis for this second implementation period. UDAQ has received each facility's four-factor analysis, provided each with an evaluation of their analysis, and received evaluation responses from each. After consideration of the information provided, as well as the modeling results provided by the WRAP, UDAQ has made reasonable progress determinations for each facility.

The actions deemed necessary for reasonable progress to be made in Utah's CIAs for this implementation period consist of establishing a firm closure date for units 1 and 2 of the Intermountain Generation Station, setting mass-based emissions limits for PacifiCorp's Hunter and Huntington Power Plants, and requiring the installation of a Flue Gas Recirculation (FGR) unit on the Riley Boiler at US Magnesium's Rowley Plant. The emissions limits proposed for PacifiCorp ensure their emissions do not exceed their modeled or recent actual emissions levels to maintain Utah's 2028 "on-the-books" projections as modeled by WRAP to ensure reasonable visibility progress at Utah's CIAs by the end of this implementation period.

Recommendation: Staff recommends that the Board propose the Utah SIP, Section XX.A: Regional Haze Second Implementation Period; Utah SIP, Emission Limits and Operating Practices: Section IX, Part H.21 and Part H.23; R307-110-17, Section IX, Control Measures for Area and point Sources, Part H, Emission Limits; and R307-110-28, Regional Haze, for a 30-day public comment period.

~~(5) The Board may approve an eminence authorization if the LEA can find no other qualified individual to fill the position, then:~~

~~(a) the LEA shall submit the following documented information to the Superintendent annually:~~

~~(i) description;~~

~~(ii) recruitment efforts;~~

~~(iii) the qualifications of all applicants; and~~

~~(iv) the LEA's rationale for hiring the individual;~~

~~(b) the Superintendent shall review the information within 15 days of receipt;~~

~~(c) the Superintendent shall notify the individual and the LEA if the Superintendent approves the documented information;~~

~~(d) the LEA shall submit a request for a Letter of Authorization to the Board for the individual through normal administrative procedures; or~~

~~(6) An individual has exceptional skills, expertise, and experience that make the individual the primary candidate for the position, then:~~

~~(a) the LEA shall submit the following documented information to the Superintendent annually:~~

~~(i) information about the position;~~

~~(ii) the individual's expertise, and experience; and~~

~~(iii) the LEA's rationale for hiring the individual.~~

~~(b) the Superintendent shall review the information within 15 days of receipt.~~

~~(c) the Superintendent shall notify the individual and the LEA if the Superintendent approves the documented information.~~

~~(d) the LEA shall submit a request for a Letter of Authorization to the Board for the individual through normal administrative procedures.~~

~~(7) An LEA shall require an individual teaching with an eminence authorization to have a criminal background check consistent with Section 53E-6-401 prior to employment by the LEA.~~

~~(8) An LEA that employs the teacher with an eminence authorization shall determine the amount and type of professional development required of the teacher.~~

~~(9) An LEA that employs a teacher with an eminence authorization shall apply for renewal of the authorization annually.~~

~~(10) An eminence authorization may apply to:~~

~~(a) an individual without a teaching license; or~~

~~(b) an unusual and infrequent teacher situation where a license holder is needed to teach in a subject area for which the license holder is not endorsed, but in which the license holder may be eminently qualified.~~

**~~R277-520-6. Routes to Appropriate Endorsements for Teachers.~~**

~~(1) An educator may add an endorsement to an existing license area of concentration by completing the endorsement requirements established by the Board.~~

~~(2) An endorsement requirement in a core academic subject area shall include passage of a Board-approved content knowledge assessment.~~

~~(3) A teacher may demonstrate competency in subject areas of the teacher's teaching assignment as approved by the Superintendent to meet specific endorsement requirements except the Board approved content knowledge assessment.~~

~~(4) An educator shall be properly endorsed consistent with Section R277-520-3 or have a Board approved SAEP. Otherwise, the Board may withhold professional staff cost program funds pursuant to the Board's authority under Subsection 53E-3-401(4).~~

**~~R277-520-7. Board-Approved Endorsement Program (SAEP).~~**

~~(1) An educator assigned to teach in a subject for which the educator does not hold the appropriate endorsement and who has successfully completed at least 9 semester credit hours of the endorsement requirements shall be placed on an SAEP as determined by the Superintendent.~~

~~(2) An individuals participating in an SAEP shall demonstrate progress toward completion of the required endorsements annually, as determined jointly by the LEA and the Superintendent.~~

~~(3) An SAEP may be granted for one two-year period and may be extended by the Superintendent for up to 2 additional years if the individual has made progress towards completing the SAEP.~~

~~(4) An individual currently participating in an SAEP is considered to hold the endorsement for the purposes of meeting the requirements of Section R277-520-4.~~

**~~R277-520-8. Background Check Requirement and Withholding of State Funds for Non-Compliance.~~**

~~(1) An educators qualified under any provision of this R277-520 shall also satisfy the criminal background requirement of Section 53E-6-401 prior to unsupervised access to students.~~

~~(2) If an LEA does not appropriately employ and assign teachers consistent with this R277-520, the LEA may have state appropriated professional staff cost program funds withheld pursuant to R277-486, Professional Staff Cost Formula, pursuant to the Board's authority under Section 53E-3-401.~~

**~~KEY: educators, licenses, assignments~~**
**~~Date of Last Change: August 7, 2017~~**
**~~Notice of Continuation: June 6, 2017~~**
**~~Authorizing, and Implemented or Interpreted Law: Art X Sec 3; 53E-3-401(4); 53E-6-201(2)(a)]~~**

| NOTICE OF PROPOSED RULE | | |
|---|---|---|
| **TYPE OF RULE:** Amendment | | |
| **Utah Admin. Code Ref (R no.):** | **R307-110** | **Filing ID 54498** |

**Agency Information**

| | | |
|---|---|---|
| **1. Department:** | Environmental Quality | |
| **Agency:** | Air Quality | |
| **Building:** | MASOB | |
| **Street address:** | 195 N 1950 W | |
| **City, state and zip:** | Salt Lake City, UT 84116 | |
| **Mailing address:** | PO Box 144820 | |
| **City, state and zip:** | Salt Lake City, UT 84114-4820 | |
| **Contact person(s):** | | |
| **Name:** | **Phone:** | **Email:** |
| Bo Wood | 385-499-3416 | rwood@utah.gov |

| | | |
|---|---|---|
| Chelsea Cancino | 801-536-4015 | ccancino@utah.gov |
| Glade Sowards | 801-536-4020 | gladesowards@utah.gov |
| Please address questions regarding information on this notice to the agency. | | |

**General Information**

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|---|
| **2. Rule or section catchline:** |
| R307-110. General Requirements: State Implementation Plan |
| **3. Purpose of the new rule or reason for the change** (Why is the agency submitting this filing?)**:** |
| EPA's Regional Haze Rule (RHR) requires states to submit a Utah 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 controls determination to identify its long-term strategy (LTS) to achieving the 2064 natural conditions goal. This rule is being amended incorporate by reference Section XX.A: Regional Haze Second Implementation Period and amendments to Amend SIP Section IX Control Measures for Area and Point Sources, Part H, Emission Limits into the SIP. |
| **4. Summary of the new rule or change** (What does this filing do? If this is a repeal and reenact, explain the substantive differences between the repealed rule and the reenacted rule)**:** |
| This amendment changes the "most recently amended" date in Sections R307-110-17 and R307-110-28 to July 6, 2022, incorporating by reference the requirements of Section XX.A: Regional Haze Second Implementation Period and Section IX: Control Measures for Area and Point Sources, Part H, Emissions Limits of the Utah State Implementation Plan.<br><br>The reasonable progress determination of these Sections requires the following measures to meet the state's LTS:<br>(1) Establishing mass-based annual NOx and SO2 emissions limits for Hunter Power Plant based upon recent actual emissions and plant utilization levels,<br><br>(2) Establishing mass-based annual NOx and SO2 emissions limits for the Huntington Power Plant based upon recent actual emissions and plant utilization levels,<br><br>(3) Establishing a federally enforceable closure date for the coal-fired boilers at the Intermountain Generation Station (IGS) based on the Intermountain Power Agency's (IPA's) 2021 notice of intent (NOI) to replace the coal-fired boilers with combined cycle natural gas turbines, and<br><br>(4) Requiring the retrofit of U.S. Magnesium's Rowley Plant's Riley boiler with flue gas recirculation (FGR). |

**Fiscal Information**

| |
|---|
| **5. Provide an estimate and written explanation of the aggregate anticipated cost or savings to:** |
| **A) State budget:** |
| Because the Hunter and Huntington Power Plants are already operating at approximately at the emissions and utilization levels required by the proposed SIP limits, the Division of Air Quality (DAQ) anticipates no fiscal impact to the state budget associated with these facilities. Because IPA has submitted an NOI to replace the coal-fired boilers at the IGS, the proposed closure date for the IGS coal-fired boilers does not, in itself, result in the closure of the facility, but rather establishes federal enforceability of the already planned boiler closures as required by the RHR and the Clean Air Act. As a result, DAQ anticipates no fiscal impacts to the state budget associated with the IGS. The requirement to install FGR at the Riley Boiler of U.S. Magnesium's Rowley Plant may result in small fiscal impact to the state budget resulting from economic activity associated with FGR installation. The direction of such impacts could be positive or negative depending on the extent to which installation of FGR could increase economic activity within the state, with a potential increase in state revenue, and/or decrease economic activity while the unit is down for installation. While it is difficult to estimate the net effect of such impacts, DAQ anticipates that it is likely small due to the relative cost of FGR installation relative to overall economic activity in Utah. |
| **B) Local governments:** |
| Because the Hunter and Huntington Power Plants are already operating at approximately at the emissions and utilization levels required by the proposed SIP limits, DAQ anticipates no fiscal impact to local governments associated with these facilities. Because IPA has submitted an NOI to replace the coal-fired boilers at the IGS, the proposed closure date for the IGS coal-fired boilers does not, in itself, result in the closure of the facility, but rather establishes federal enforceability of the already planned boiler closures as required by the RHR and the Clean Air Act. As a result, DAQ anticipates no fiscal impact to local governments associated with the IGS (e.g., City of Delta, Millard County, etc.). The requirement to install FGR at the Riley Boiler of U.S. Magnesium's Rowley Plant may result in small fiscal impacts to local governments resulting from economic activity associated with FGR installation. The direction of such impacts could be positive or negative depending on the extent to which installation of FGR could increase economic activity in local government jurisdictions, with a potential increase local government revenue, and/or decrease economic activity while the unit is down for installation. While it is difficult to estimate the net effect of such impacts, DAQ anticipates that it is likely small. |

| **C) Small businesses** ("small business" means a business employing 1-49 persons)**:** |
|---|
| Some small businesses may see small increases or decreases in economic activity associated with the installation of FGR on the Riley Boiler at the U.S. Magnesium Rowley Plant. For example, the service industry near the Rowley plant may see increased patronage during the period of FGR installation, or may see small decreases in patronage if the installation process leads to traffic impacts or short-term changes to labor patterns while the boiler is being retrofitted. It is difficult to estimate the net impact to small businesses, but DAQ anticipates that it is likely small unless those businesses are directly involved with the FGR installation. |
| **D) Non-small businesses** ("non-small business" means a business employing 50 or more persons)**:** |
| The installation of FGR on the Riley Boiler at the U.S. Magnesium Rowley Plant is anticipated to require a one-time cost of $615,300 and approximately $3,100 per year thereafter. However, since the installation of these controls is not mandatory until January 2028, the fiscal impact in FY22, FY23, and FY24 is unknown. Companies that provide the equipment and installation of FGR at the facility will likely see an increase in revenue. |
| **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***)**:** |
| Some individuals working for U.S. Magnesium or for firms providing FGR installation equipment and services could see positive or negative impacts associated with the retrofit of the Riley Boiler. Such impacts are likely to affect a relatively small number of individuals and are likely to be short in duration. |
| **F) Compliance costs for affected persons** (How much will it cost an impacted entity to adhere to this rule or its changes?)**:** |
| The installation of FGR on the Riley Boiler at the U.S. Magnesium Rowley Plant is anticipated to cost the company $615,300 for initial installation and an additional $3,100 per year in ongoing maintenance over the life of the boiler. |
| **G) Comments by the department head on the fiscal impact this rule may have on businesses** (Include the name and title of the department head): |
| After a thorough analysis and engagement with impacted parties, DAQ has determined that the amendments to Regional Haze Second Implementation Period and Emission Limits of the Utah SIP will have fiscal impacts on businesses. The analysis shows that some small businesses and at least one non-small businesses will be impacted by the proposed changes. However, the proposed amendments are appropriate and necessary to comply with the requirements of EPA's Regional Haze Rule. Kimberly D. Shelley, Executive Director |

| **6. A) Regulatory Impact Summary Table** (This table only includes fiscal impacts that could be measured. If there are inestimable fiscal impacts, they will not be included in this table. Inestimable impacts will be included in narratives above.) | | | |
|---|---|---|---|
| **Regulatory Impact Table** | | | |
| **Fiscal Cost** | **FY2022** | **FY2023** | **FY2024** |
| State Government | $0 | $0 | $0 |
| Local Governments | $0 | $0 | $0 |
| Small Businesses | $0 | $0 | $0 |
| Non-Small Businesses | $0 | $0 | $0 |
| Other Persons | $0 | $0 | $0 |
| **Total Fiscal Cost** | **$0** | **$0** | **$0** |
| **Fiscal Benefits** | | | |
| State Government | $0 | $0 | $0 |
| Local Governments | $0 | $0 | $0 |
| Small Businesses | $0 | $0 | $0 |
| Non-Small Businesses | $0 | $0 | $0 |
| Other Persons | $0 | $0 | $0 |
| **Total Fiscal Benefits** | **$0** | **$0** | **$0** |
| **Net Fiscal Benefits** | **$0** | **$0** | **$0** |
| **B) Department head approval of regulatory impact analysis:** | | | |
| The Executive Director of the Department of Environmental Quality, Kim Shelley, has reviewed and approved this fiscal analysis. | | | |

**Citation Information**

| **7. 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 51.308(f) | |

**Incorporations by Reference Information**

| **8. A) This rule adds, updates, or removes the following title of materials incorporated by references:** | |
|---|---|
| | **First Incorporation** |
| **Official Title of Materials Incorporated (from title page)** | Utah Regional Haze State Implementation Plan |
| **Publisher** | Division of Air Quality, Utah Department of Environmental Quality |
| **Date Issued** | April 2022 |
| **Issue, or version** | Second Implementation Period |

**Public Notice Information**

| **9. The public may submit written or oral comments to the agency identified in box 1.** (The public may also request a hearing by submitting a written request to the agency. See Section 63G-3-302 and Rule R15-1 for more information.) | | |
|---|---|---|
| **A) Comments will be accepted until:** | | 5/31/2022 |
| **B) A public hearing (optional) will be held:** | | |
| **On:** | **At:** | **At:** |
| 05/26/2022 | 10:30AM | https://meet.google.com/thd-ffia-etr?hs=122&authuser=0 |

| **10. This rule change MAY become effective on:** | 07/07/2022 |
|---|---|
| NOTE: The date above is the date the agency anticipates making the rule or its changes effective. It is NOT the effective date. To make this rule effective, the agency must submit a Notice of Effective Date to the Office of Administrative Rules on or before the date designated in Box 10. | |

**Agency Authorization Information**

| **Agency head or designee, and title:** | Bryce C. Bird, Director | **Date:** | 04/06/2022 |
|---|---|---|---|

**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 [~~December 2, 2020~~]July 6, 2022, pursuant to Section 19-2-104, is [~~hereby~~ ]incorporated by reference and made a part of these rules.

**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 [~~June 24, 2019~~]July 6, 2022, pursuant to Section 19-2-104, is [~~hereby~~ ]incorporated by reference and made a part of these rules.

**KEY: air pollution, PM10, PM2.5, ozone**
**Date of Last Change: 2022[~~December 3, 2020~~]**
**Notice of Continuation: December 1, 2021**
**Authorizing, and Implemented or Interpreted Law: 19-2-104**

| **NOTICE OF PROPOSED RULE** | | |
|---|---|---|
| **TYPE OF RULE:** Amendment | | |
| **Utah Admin. Code Ref (R no.):** | **R307-506** | **Filing ID 54499** |

**Agency Information**

| **1. Department:** | Environmental Quality | |
|---|---|---|
| **Agency:** | Air Quality | |
| **Building:** | MASOB | |
| **Street address:** | 195 N 1950 W | |
| **City, state and zip:** | Salt Lake City, UT 84116 | |
| **Mailing address:** | PO Box 144820 | |
| **City, state and zip:** | Salt Lake City, UT 84114-4820 | |
| **Contact person(s):** | | |
| **Name:** | **Phone:** | **Email:** |
| Bo Wood | 385-499-3416 | rwood@utah.gov |
| Sheila Vance | 801-518-3132 | svance@utah.gov |
| Please address questions regarding information on this notice to the agency. | | |

**General Information**

| **2. Rule or section catchline:** |
|---|
| R307-506. Oil and Gas Industry: Storage Vessel |
| **3. Purpose of the new rule or reason for the change** (Why is the agency submitting this filing?)**:** |
| These amendments are necessary to align current oil and gas rules with new data from studies and compliance inspections. These changes reflect more accurate emission calculations that indicate a previous underestimation of Volatile Organic Compound (VOC) emissions from tanks and other components. The proposed changes will ensure the protection of air quality standards and improve compliance with required emission controls. |

PO BOX 271693
SALT LAKE CITY UTAH 84127
FED. TAX I.D.# 87-0128317
801-204-6910

**DeseretNews**

# PROOF OF PUBLICATION

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Salt Lake City, UT 84114-4820

ACCOUNT NUMBER

53839

ACCOUNT NAME

Utah Division of Air Quality

TELEPHONE

385-226-4019

ORDER #

DN0016211

CUSTOMER REFERENCE NUMBER

DAQP-038-22

CAPTION

NOTICE OF PUBLIC COMMENT PERIOD 2022 State Implementation Plan: Regional Haze Second Implementation Period On April 6, 2022, the Utah Air Quality Board proposed for public comment amendments to Utah State Implementation Plan, Section XX.A: Regional Haze and Section IX Parts H.21 and H.23.

TOTAL COST

$116.76

**NOTICE OF PUBLIC COMMENT PERIOD**

**2022 State Implementation Plan:
Regional Haze Second Implementation Period**

On April 6, 2022, the Utah Air Quality Board proposed for public comment amendments to Utah State Implementation Plan, Section XX.A: Regional Haze and Section IX Parts H.21 and H.23. Prior to action by the Air Quality Board, the National Parks Service (NPS) and US Forest Service (USFS) reviewed the documents and provided comments on the drafts. Federal Land Manager (FLM) comments are summarized with DAQ responses in Section 9.C.1 of the draft SIP, and their full reviews are available in a separate Appendix file. Each of these documents can be viewed and downloaded from: https://deq.utah.gov/air-quality/air-quality-rule-plan-changes-open-public-comment

The public comment period will begin on May 1, 2022, and end on May 31, 2022. A public hearing will be held at 10:30 AM on Thursday, May 26, 2022. Interested parties may participate in person at the anchor location in the Four Corners room on the 4th floor of the Multi-Agency State Office Building (MASOB), located at 195 N. 1950 W. Salt Lake City, UT., or electronically via Google Meet at the following address: https://meet.google.com/thd-ffia-etr. Comments may be submitted by electronic mail to rwood@utah.gov or may be mailed to:

ATTN: Regional Haze
Bryce Bird, Director
Utah Division of Air Quality
P.O. Box 144820
Salt Lake City, UT 84114-4820

Comments postmarked on or before May 31, 2022 will be accepted. The Air Quality Board welcomes comments on all aspects of the proposed SIP, but specifically requests public input on the following topics:

- The need for a cost threshold.
- Whether a mass-based limit or a rate-based limit would be more appropriate.
- Whether the closure date for the Intermountain Generation Station should be from a range of January 1, 2026, to December 31, 2027.
- Whether other controls explored in the draft SIP are both technically feasible and cost appropriate for US Magnesium at an appropriate date.
- Whether dry sorbent injection is considered cost-effective at Sunnyside.

**DN0016211**

AFFIDAVIT OF PUBLICATION

AS THE DESERET NEWS, INC. LEGAL BOOKER, I CERTIFY THAT THE ATTACHED ADVERTISEMENT OF **LEGAL NOTICE FOR UTAH DIVISION OF AIR QUALITY** WAS PUBLISHED BY DESERET NEWS, INC., WEEKLY NEWSPAPER PRINTED IN THE ENGLISH LANGUAGE WITH GENERAL CIRCULATION IN UTAH, AND PUBLISHED IN SALT LAKE CITY, SALT LAKE COUNTY IN THE STATE OF UTAH. NOTICE IS ALSO POSTED ON UTAHLEGALS.COM ON THE SAME DAY AS THE FIRST NEWSPAPER PUBLICATION DATE AND REMAINS ON UTAHLEGALS.COM INDEFINITELY. COMPLIES WITH UTAH DIGITAL SIGNATURE ACT UTAH CODE 46-2-101; 46-3-104.

PUBLISHED ON 04/27/2022

DATE 04/28/2022

SIGNATURE Karyn Vigil

STATE OF UTAH
COUNTY OF Salt Lake

SUBSCRIBED AND SWORN TO BEFORE ME ON THIS 28th DAY OF APRIL IN THE YEAR 2022

BY KARYN VIGIL

LENEA TAPUSOA
NOTARY PUBLIC - STATE OF UTAH
COMMISSION# 712892
COMM. EXP. 07-06-2024

Ltapusoa

NOTARY PUBLIC SIGNATURE

# NOTICE OF PUBLIC COMMENT PERIOD

## 2022 State Implementation Plan: Regional Haze Second Implementation Period

On April 6, 2022, the Utah Air Quality Board proposed for public comment amendments to Utah State Implementation Plan, Section XX.A: Regional Haze and Section IX Parts H.21 and H.23. Prior to action by the Air Quality Board, the National Parks Service (NPS) and US Forest Service (USFS) reviewed the documents and provided comments on the drafts. Federal Land Manager (FLM) comments are summarized with DAQ responses in Section 9.C.1 of the draft SIP, and their full reviews are available in a separate Appendix file. Each of these documents can be viewed and downloaded from:

https://deq.utah.gov/air-quality/air-quality-rule-plan-changes-open-public-comment

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ATTN: Regional Haze
Bryce Bird, Director
Utah Division of Air Quality
P.O. Box 144820
Salt Lake City, UT 84114-4820

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- The need for a cost threshold.
- Whether a mass-based limit or a rate-based limit would be more appropriate.
- Whether the closure date for the Intermountain Generation Station should be from a range of January 1, 2026, to December 31, 2027.
- Whether other controls explored in the draft SIP are both technically feasible and cost appropriate for US Magnesium at an appropriate date.
- Whether dry sorbent injection is considered cost-effective at Sunnyside.

Jared Fry <jfry@utah.gov>

# 5235059 - Legal Notice to Publish - Utah Division of Air Quality

1 message

**Gannett Legals Public Notices 3** <ganlegpubnotices3@gannett.com> Tue, Apr 26, 2022 at 4:53 PM
To: Jared Fry <jfry@utah.gov>

Jared,

The notice has been released for publication for Sunday.

**Liz Mui**
**Public Notice Representative**

USA TODAY NETWORK | LOCALiQ

Office: 866-301-5578

---

**From:** Jared Fry <jfry@utah.gov>
**Sent:** Tuesday, April 26, 2022 4:45 PM
**To:** Gannett Legals Public Notices 3 <ganlegpubnotices3@gannett.com>
**Subject:** Re: NO SAT PUBS - QUOTE 5235059 - Legal Notice to Publish - Utah Division of Air Quality

Thank you for letting me know.

Please go ahead and publish for this Sunday.

Thank you so much!

Jared

On Tue, Apr 26, 2022 at 1:06 PM Gannett Legals Public Notices 3 <ganlegpubnotices3@gannett.com> wrote:

> Jared,
>
> We no longer publish legal notices on Saturdays. Would Sunday work for you?
>
> Please find your quote and a proof of the ad attached. **Please note that the notice will not publish without your approval.**
>
> Your ad is set to run in: **The Spectrum on May 1, 2022 for $67.51**
>
> Please approve the quote by **3:00 pm on THURSDAY, April 28th** for the ad to run.
>
> **Liz Mui**
> **Public Notice Representative**

USA TODAY NETWORK | LOCALiQ

Office: 866-301-5578

---

**From:** Jared Fry <jfry@utah.gov>
**Sent:** Monday, April 25, 2022 8:21 PM
**To:** Legal Notices <stg-legal@smgpo.gannett.com>
**Subject:** NO SAT PUBS - QUOTE 5235059 - Legal Notice to Publish - Utah Division of Air Quality

Legal Notices Department,

Please publish the attached legal NOTICE in The Daily Spectrum on Saturday, April 30, 2022. The document contains a signed letter authorizing for publication and invoicing instructions.

Please provide a proof when it is ready.

Thank you so much and let me know if you have any questions.

Thanks,

Jared

--

**Jared Fry | Planning Branch Secretary | Utah Division of Air Quality**

(801) 536-4213 (Phone) | | **(801) 536-4099** (fax)

195 North 1950 West, Salt Lake City, UT 84116

--

**Jared Fry | Planning Branch Secretary | Utah Division of Air Quality**

(801) 536-4213 (Phone) | | **(801) 536-4099** (fax)

195 North 1950 West, Salt Lake City, UT 84116

# Utah State Implementation Plan

# Regional Haze Second Implementation Period

## Section XX.A

*[Date]*

# List of tables

# List of figures

# List of acronyms

| | |
|---|---|
| **BACT** | Best Available Control Technology |
| **CIA** | Class 1 Area |
| **CAA** | Clean Air Act |
| **CAMx** | Comprehensive Air Quality Model with Extensions |
| **CCR** | Consumer Confidence Report |
| **CF** | Code of Federal Regulations |
| **CIRA** | Cooperative Institute for Research in the Atmosphere |
| **CO** | Carbon Monoxide |
| **CSU** | Colorado State University |
| **DAQ** | Division of Air Quality |
| **DEQ** | Department of Environmental Quality |
| **EPA** | Environmental Protection Agency |
| **FLM** | Federal Land Manager |
| **FWS** | US Fish and Wildlife Service |
| **GCVTC** | Grand Canyon Visibility Transportation Commission |
| **IMPROVE** | Interagency Monitoring of Protected Visibility Elements |
| **LTS** | Long Term Strategy |
| **NAAQS** | National Ambient Air Quality Standards |
| **NOI** | Notice of Intent |
| **NO2** | Nitrogen Dioxide |
| **$NO_x$** | Nitrogen Oxides |
| **NPS** | National Parks Service |
| **O3** | Ozone |
| **PAL** | Plantwide Applicability Limit |
| **PB** | Lead |
| **PM** | Particulate Matter |
| **$PM_{10}$** | Particulate Matter Smaller Than 10 Microns in Diameter |
| **$PM_{2.5}$** | Particulate Matter Smaller Than 2.5 Microns in Diameter |
| **RH** | Regional Haze |
| **RHR** | Regional Haze Rule |
| **RHPWG** | Regional Haze Planning Work Group (WRAP) |
| **RPEL** | Reasonable Progress Emissions Limit |
| **RPG** | Reasonable Progress Goals |
| **SCR** | Selective Catalytic Reduction |
| **SIP** | State Implementation Plan |
| **SNCR** | Selective Non-Catalytic Reduction |
| **$SO_2$** | Sulfur Dioxide |
| **SOx** | Sulfur Oxides |
| **TSS** | Technical Support System |
| **UDOGM** | Utah Division of Oil, Gas, and Mining |
| **URP** | Uniform Rate of Progress |
| **UAC** | Utah Administrative Code |
| **USFS** | US Forest Service |
| **VOCs** | Volatile Organic Compounds |
| **WESTAR** | Western States Air Resources |
| **WRAP** | Western Regional Air Partnership |

# EXECUTIVE SUMMARY

This document comprises the State of Utah's State Implementation Plan (SIP) submittal to the U.S. Environmental Protection Agency (EPA) under the Regional Haze Rule.[1] The purpose of this SIP revision is to comply with the requirements of the Regional Haze Rule (RHR).[2] Specifically, this SIP addresses requirements for periodic comprehensive revisions of implementation plans for regional haze.[3] The RHR requires Utah to address regional haze in each mandatory Class I Area (CIA) located within Utah and in each mandatory CIA located outside Utah that may be affected by pollutants emitted from sources within Utah. Utah is required to submit a SIP addressing the specific elements required by the rule.

The objectives of the RHR are to improve existing visibility in 156 national parks, wilderness areas, and monuments (termed Mandatory Class I Areas or CIAs), prevent future impairment of visibility by manmade sources, and meet the national goal of natural visibility conditions in all mandatory CIAs by 2064. Utah's CIAs consist of: Arches National Park, Bryce Canyon National Park, Canyonlands National Park, Capitol Reef National Park, and Zion National Park.[4]

The RHR establishes several planning periods extending from 2005 to 2064. The State of Utah is required to develop a Regional Haze (RH) SIP for each period. The first implementation period spanned from 2008 to 2018. This SIP revision consists of the second implementation period spanning from 2018 to 2028. This SIP was originally due for submittal to the EPA on July 31st, 2018. However, the deadline was extended to July 31st, 2021. In this revision, UDAQ demonstrates the visibility progress to date[5] in each of Utah's CIAs and analyzes Utah's emissions trends and sources of visibility impairment[6]. Utah is required to set reasonable progress goals which 1) must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and 2) ensure no degradation in visibility for the least impaired days over the same period.[7] For this purpose, Utah has outlined its Long-Term Strategy (LTS) in this document[8] as well as determination of reasonable progress goals (RPGs) for CIAs in Utah.

The RH SIP must also address mandatory CIAs outside of the state that are reasonably anticipated to be affected by emissions from Utah as well as out-of-state sources impacting Utah CIAs. For this requirement, UDAQ analyzed Western Regional Air Partnership (WRAP) photochemical modeling and found that Utah does not significantly impact visibility at out-of-

---

[1] 40 CFR 51.308(f) and (g)

[2] 40 CFR 51
[3] 40 CFR 51.308(f)
[4] See chapter 1 for more information on the RHR and Utah's regional haze history
[5] See chapter 3 to view Utah's progress to date
[6] See chapter 5 for Utah's sources of visibility impairment
[7] See chapter 8 for more information on Utah's reasonable progress goals
[8] See chapter 6 for Utah's Long-Term Strategy

state CIAs.[9] Utah has also determined that Utah's CIAs are not significantly impacted by out-of-state sources. Upon consultation with Utah's surrounding states, Utah will not require any actions from other states for impacts on Utah's CIAs and Utah has received no requests for actions regarding Utah sources' impacts on out-of-state CIAs.[10]

Throughout this second implementation period, UDAQ has participated in the WRAP, which has conducted modeling and technical analysis for the purposes of supporting state RH planning. UDAQ has also consulted with Federal Land Managers (FLMs), Tribes, Utah's surrounding states, as well as environmental advocates, industry stakeholders, and the public.[11]

This SIP revision also examines the need to implement additional emission reduction measures on sources which are reasonably anticipated to contribute to visibility impairment. The examination required to determine actions for this period is known as a four-factor analysis[12] and consists of four criteria: 1) cost of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts, and 4) remaining useful life. In order to determine which sources must submit a four-factor analysis to the State, UDAQ performed a Q/d (emissions/distance) analysis to determine which of Utah's sources have the highest potential visibility impact on Utah's CIAs. These facilities include the Ash Grove Cement Company Leamington Cement Plant, the Graymont Western US Inc. Cricket Mountain Plant, PacifiCorp, the Sunnyside Cogeneration Associated Sunnyside Cogeneration Facility, and the US Magnesium LLC Rowley Plant. UDAQ requested each facility to submit a four-factor analysis for the purpose of this second implementation period. UDAQ has received each facility's four-factor analysis, provided each with an evaluation of their analysis, and received evaluation responses from each. After consideration of the information provided, as well as the modeling results provided by the WRAP, UDAQ has made reasonable progress determinations[13] for each facility. The actions deemed necessary for reasonable progress to be made in Utah's CIAs for the purposes of this implementation period consist of establishing a firm closure date for units 1 and 2 of the Intermountain Generation Station, setting mass-based emissions limits for PacifiCorp's Hunter and Huntington Power Plants, and requiring the installation of a Flue Gas Recirculation (FGR) unit on the Riley Boiler at US Magnesium's Rowley Plant. The emissions limits proposed for PacifiCorp ensure their emissions do not exceed their modeled or recent actual emissions levels for the purposes of maintaining Utah's 2028 "on-the-books" projections as modeled by WRAP in order to ensure reasonable visibility progress at Utah's CIAs by the end of this implementation period.

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[9] See chapter 3 for Utah's impacts on out of state CIAs and other state's impacts on Utah's CIAs
[10] See Appendix B for interstate consultation agreement documentation
[11] See chapter 9 for details on Utah's consultation efforts
[12] See chapter 7 for Utah's source selection and the four-factor analyses, evaluations, responses, and conclusions for each source
[13] See chapter 9 for Utah's reasonable progress determinations

# **Chapter 1:** Background and Overview of the Federal Regional Haze Rule

## 1.A Regional Haze Planning Periods and Due Dates

Utah took part in early regional haze planning through participation in the Grand Canyon Visibility Transport Commission (GCVTC), which originally consisted of nine states and 211 tribal lands. In 1996, the GCVTC submitted a report containing recommendations for improving western vistas.[14] In 2000, Utah established Sulfur Dioxide ($SO_2$) milestones with an Annex[15] to the original GCVTC report through the Western Regional Air Partnership. Based on the recommendations of the GCVTC and the Annex, in 2003 Utah's Air Quality Board adopted section XX[16] of the State Implementation Plan (SIP) to address regional haze and the many source categories and pollutants contributing to the regional haze in Utah. The first state plans were due in 2007 and the last date for states to submit initial regional haze control plans for all Mandatory Federal CIAs was in 2008. Utah submitted its evaluation of the Best Available Retrofit Technology (BART) in 2015[17] along with a revision in 2019[18]. Progress reports are due every five years and full plan revisions are required every 10 years. The first revision was originally due in 2018, but in 2017 EPA extended the deadline to July 31, 2021 with the latest revision of the Regional Haze Rule (RHR)[19]. As part of the RH SIP process, Utah must work towards the overarching goal of achieving natural visibility in its CIAs by 2064. This timeline is summarized in the figure below.

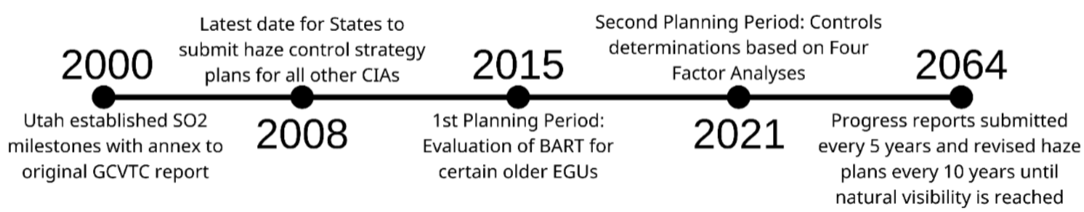


**Figure 1: Regional Haze Timeline option for GCVTC areas**

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[14] The original 1996 report of The Grand Canyon Visibility Transport Commission can be found at https://www.phoenixvis.net/PDF/GCVTCFinal.pdf

[15] The EPA Notice of Availability of the Annex to the Report of The Grand Canyon Visibility Transport Commission can be found at https://www.federalregister.gov/documents/2000/11/15/00-29226/notice-of-availability-of-annex-to-the-report-of-the-grand-canyon-visibility-transport-commission

[16] Section XX of Utah's Regional Haze SIP can be found at https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008934.pdf

[17] Utah's 2015 RH SIP can be found at https://documents.deq.utah.gov/legacy/laws-and-rules/air-quality/sip/docs/2015/07Jul/SecXXRegHaze201Final.pdf

[18] Utah's 2019 RH SIP revision can be found at https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2019-012208.pdf

[19] 40 C.F.R. § 51.308(f). For the purposes of this SIP submittal, the RHR acronym refers to the most current 2017 Regional Haze Rule revisions.

## 1.B Class I Areas in Utah

In the 1977 Clean Air Act, Congress established requirements for the prevention of significant deterioration of air quality in areas within the United States and for the review of pollution controls on new sources. Coupled with this, Congress established a visibility protection program for those larger national parks and wilderness areas designated as mandatory Federal CIAs. This program establishes a national goal of “the prevention of any future, and remedying of any existing, impairment of visibility in mandatory CIAs which impairment results from manmade air pollution”[20] and requires states to develop long-term strategies to assure reasonable progress toward this national goal. 40 CFR 81.400 Scope: Subpart D, §§ 81.401 through 81.437, lists Mandatory Federal CIAs, where the Administrator, in consultation with the Secretary of the Interior, has determined visibility to be an important value.

As shown in figure 2, there are five Mandatory Federal CIAs in Utah, all of which are National Parks: Arches National Park, Bryce National Park, Canyonlands National Park, Capitol Reef National Park and Zion National Park. The following sections include data from the National Parks Service (NPS) Stats website.[21]

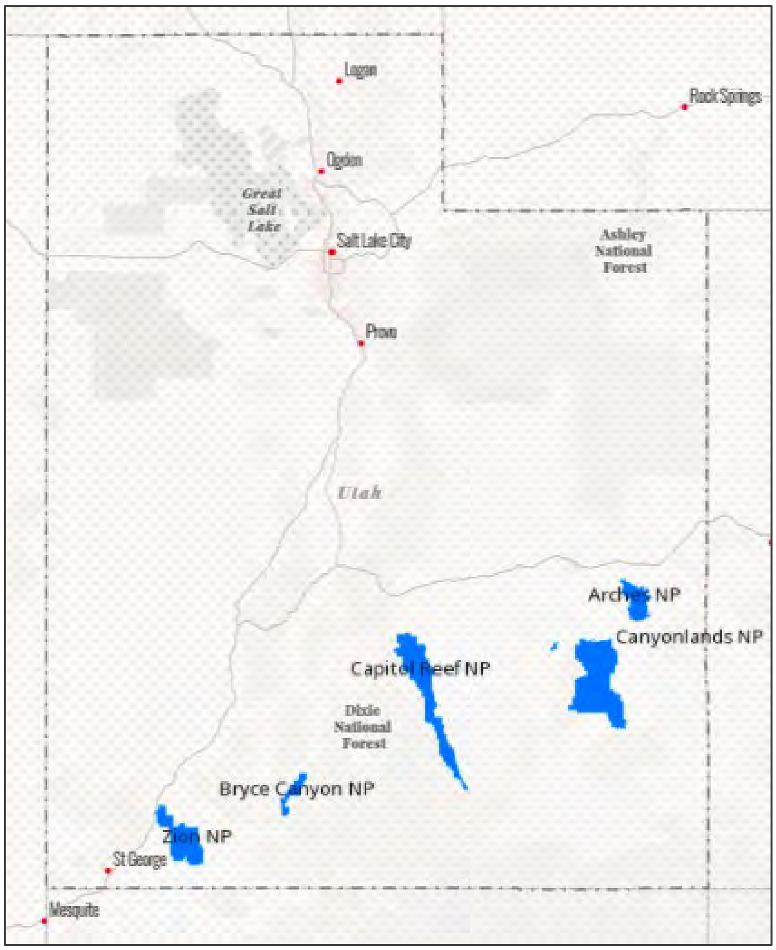


**Figure 2: Map of Utah CIAs**

[20] 42 U.S.C.A. § 7491(a)(1) (West).
[21] Statistics for all the National Parks discussed in this section come from the NPS Stats website at: https://irma.nps.gov/STATS/

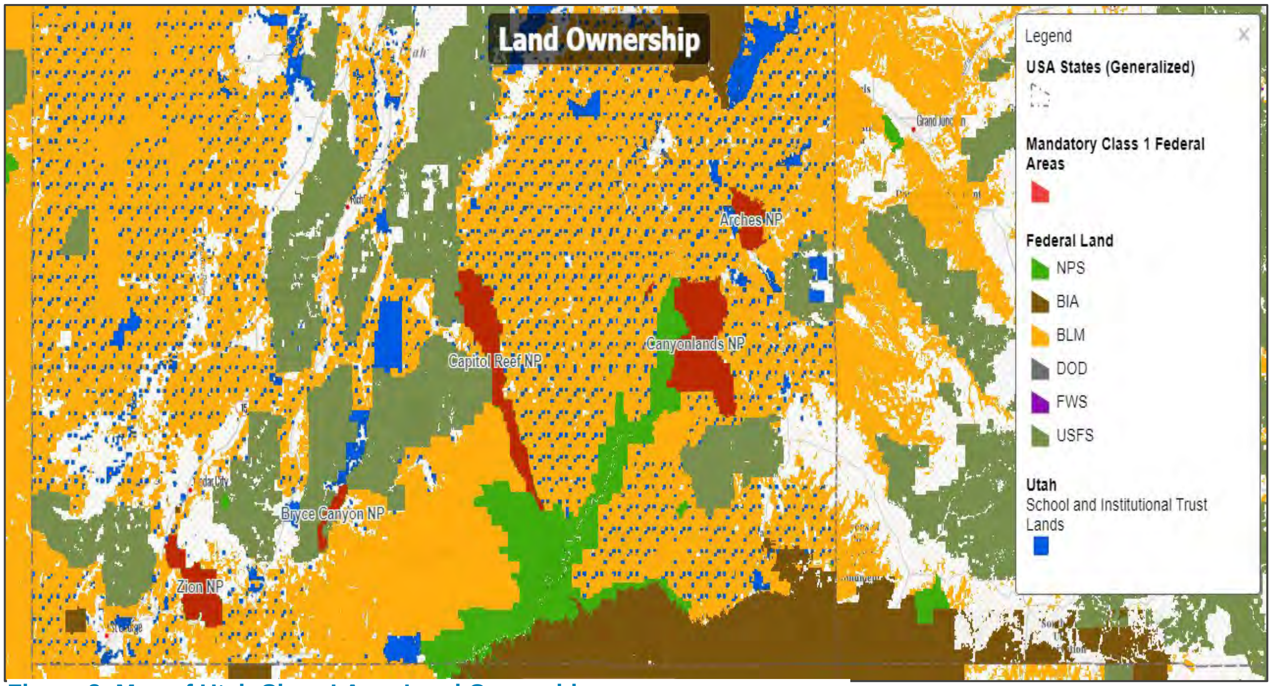


**Figure 3: Map of Utah Class I Area Land Ownership**

## 1.B.1 Arches National Park

**Figure 4: Arches National Park**

Arches National Park was originally designated as a National Monument in 1929 and became a national park in 1978. Congress established the park "to protect extraordinary examples of geologic features including arches, natural bridges, windows, spires, balanced rocks, as well as other features of geologic, historic, and scientific interest, and to provide opportunities to experience these resources and their associated values in their majestic natural settings."[22] Located in southwest Utah, Arches National Park is home to over 2,000 cataloged, naturally formed, sandstone arches. These 76,679 acres of red sandstone are surrounded by thousands of acres of additional natural lands, administered mainly by the Bureau of Land Management and Utah's School and Institutional Trust Lands Administration (See Figure 3). Over 1.6 million people visited Arches in 2019.[23] Over the past 10 years, park visitation has increased, on average, five% each year.[24] The largest population center near Arches National Park is Moab. This town of over 5,300 residents[25] is about five miles south of the Park. It is the major hub for recreation in Arches, Canyonlands National Park, and the surrounding areas.

### 1.B.2 Bryce Canyon National Park

Bryce Canyon was originally established as a National Monument in June 1923. One year later it was designated a national park. According to its foundation document, the purpose of the park was to "protect and conserve resources integral to a landscape of unusual scenic beauty exemplified by highly colored and fantastically eroded geological features, including rock fins and spires, for the benefit and enjoyment of the people."[26] Bryce Canyon contains the highest concentration of irregular rock columns (Hoodoos) on Earth. Located in southern Utah near the city of Bryce, the national park sits along the edge of a high plateau on top of the Grand Staircase. At 35,835 acres, Bryce Canyon is Utah's smallest National Park. However, nearly 2.6 million people visited Bryce Canyon in 2019.[27]

**Figure 5: Bryce Canyon National Park**

[22] Arches National Park Foundation Document, website: https://www.nps.gov/arch/learn/management/foundation-document.htm#CP_JUMP_5740028
[23] Data source: Stats Report Viewer (nps.gov).
[24] *See id*.
[25] United States Census Bureau, website: https://www.census.gov/quickfacts/moabcityutah (data for July 1, 2019).
[26] Bryce Canyon National Park Foundation Document, website: https://www.nps.gov/brca/learn/management/upload/BRCA_FD_SP.pdf
[27] Data source: Stats Report Viewer (nps.gov).

### 1.B.3 Canyonlands National Park

Canyonlands National Park was originally established on September 12, 1964 with the help of Bates Wilson, the superintendent of Arches National Park. Located near Moab, Utah with 337,598 acres of land and water, Canyonlands is Utah's largest national park. The Green and Colorado rivers split this section of the Colorado Plateau into three main districts: "Island in the Sky," "The Needles," and "The Maze." Since 2007, over 400,000 people visit Canyonlands each year with a record of 776,218 in 2016 alone.[28] Canyonlands features deep canyons, mesas, pinnacles, cliffs, and spires and contains one of the most photographed landforms in the west—the Mesa Arch.

**Figure 6: Canyonlands National Park**

### 1.B.4 Capitol Reef National Park

Capitol Reef National Park was originally designated a national monument in August 1937 but then turned into a national park in 1971. Spanning 241,904 acres, Capitol Reef is made of a geologic monocline almost 100 miles long. This monocline is called the Waterpocket Fold and is considered a geologic warp in the

**Figure 7: Capitol Reef National Park**

[28] Data source: Stats Report Viewer (nps.gov).

Earth's crust spanning from Thousand Lake Mountain to Lake Powell. The tall, seemingly impassible ridges made by the Waterpocket Fold were called "reefs" by early settlers. The white Navajo sandstone dome formations appear like those placed on capitol buildings, giving the park its name. Capitol Reef had 1,226,519 visitors in 2019[29] and offers many hiking and backpacking opportunities, including 71 campsites.

### 1.B.5 Zion National Park

Established on July 31, 1909, Zion National Park was the first national park in Utah. It is also the fourth most visited National Park in the United States with 4.48 million visitors in 2019.[30] The park's 147,243 acres contain the Zion Canyon which is 15 miles long and 2,640 feet tall.[31] The purpose of Zion National Park is to "preserve the dramatic geology including Zion Canyon and a labyrinth of deep and brilliantly colored Navajo sandstone canyons formed by extraordinary processes of erosion at the margin of the Colorado Plateau."[32] Located in southwestern Utah near St. George, Zion is home to famous hikes including Angel's Landing, The narrows, Observation Point, and the Emerald Pools.

**Figure 8: Zion National Park**

## 1.C Haze Characteristics and Effects

Unimpaired visibility is important to fully enjoy the experience of visiting Utah's national parks and wilderness areas. Visibility is defined as the greatest distance at which an observer can see a black object viewed against the horizon sky. Visibility is impaired by light scattering and absorption caused by PM and gases in the atmosphere that occur from both natural and

[29] Data source: [Stats Report Viewer (nps.gov)](nps.gov).
[30] Data source: [Stats Report Viewer (nps.gov)](nps.gov).
[31] Data Source: https://www.nps.gov/subjects/lwcf/upload/NPS-Acreage-12-31-2012.pdf

[32] Zion National Park Foundation Document, website: https://www.nps.gov/zion/learn/management/upload/ZION_Foundation_Document_SP-2.pdf

anthropogenic activities. This diminished clarity is called haze. Haze obscures the color, texture, and form of objects that can be seen at a distance.

Visibility can be impaired by natural sources such as rain, wildland fires, volcanic activity, sea mists, and wind-blown dust from undisturbed desert areas. Visibility also can be impaired by anthropogenic sources of air pollution such as industrial processes, (utilities, smelters, refineries, etc.), mobile sources (cars, trucks, trains, etc.), and area sources (residential wood burning, prescribed burning on wild and agricultural lands, wind-blown dust from disturbed soils, etc.). These sources emit pollutants that, in higher concentrations, can also affect public health.

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

**Figure 9: Monitoring station for Capitol Reef National Park**

There are different metrics to measure impact on visibility. Visual range is the most intuitive and is defined as the distance at which a given standard object can be seen with the unaided eye. It is measured in miles or kilometers. A deciview is a unit of visibility proportional to the logarithm of the atmospheric light extinction. This unit will be used in many figures and tables within this report. Deciviews measure visibility derived from light extinction so that incremental changes in the haze index correspond to uniform incremental changes in visual perception ranging from pristine to highly impaired conditions.

## 1.D Monitoring Strategy[33]

Interagency Monitoring of Protected Visual Environments (IMPROVE) was designated as the visibility monitoring network representative of the 156 visibility-protected federal CIAs. IMPROVE was developed in 1985 to establish current visibility conditions, track changes in

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[33] 40 CFR 51.308(f)(6) (IMPROVE PROGRAM)

visibility, and help determine the causes and sources of visibility impairment in CIAs. The network is comprised of 110 monitoring sites across the nation[34], four of which are in Utah. IMPROVE monitoring sites in Utah's CIAs include those at Canyonlands National Park (monitoring site for both Arches and Canyonlands national parks), Capitol Reef National Park, Bryce Canyon National Park, and Zion National Park. Figures 10 through 12 show three of Utah's monitoring stations.

The IMPROVE monitoring sites contain equipment programmed to automatically collect samples of haze-forming particles from the air continually. Local operators at each field site—in many cases a park ranger, firefighter, or rancher—inspect the samples and exchange filters weekly, shipping all exposed filters back to the Air Quality Research Center (AQRC) at the University of California (UC) Davis every three weeks. Each month, the program's 110 field sites generate about 7,000 filters, which are processed in AQRC's laboratories by staff members and UC Davis students working part-time.[35] The analyses conducted at the AQRC test samples for various pollutants and trace metals and estimate the light scattering effect of each species This estimation results in a light extinction value. For purposes of the RHR, light extinction is estimated for sulfate, nitrate, organic mass by carbon (OMC), light absorbing carbon (LAC), fine soil (FS), sea salt, and coarse material (CM)—all components of particulate emissions. Figure 12 shows the four separate modules used for sampling the different species.

**Figure 10: Monitoring station for Bryce Canyon National Park**

**Figure 11: Monitoring station for Canyonlands and Arches National Park**

[34] Shown in ta 13

[35] For more information see: https://aqrc.ucdavis.edu/improve

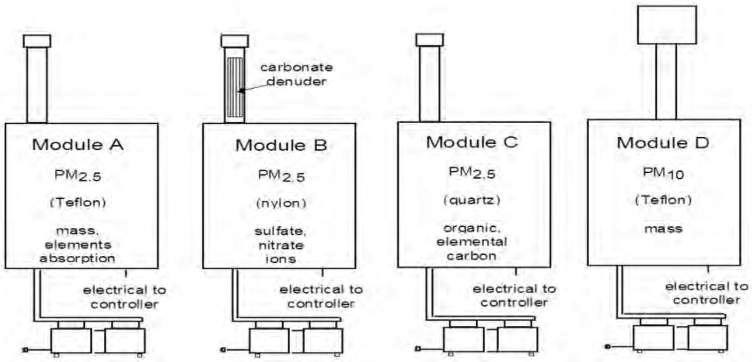


**Figure 12: Monitoring station layout**

## 1.D.1 Participation in the IMPROVE Network

In 1985, the IMPROVE program was established to coordinate the monitoring of air quality in national parks and wilderness areas and to ensure sound and consistent scientific methods were being used. The IMPROVE Steering Committee established monitoring protocols for visibility measurement, PM measurement, and scientific photography of the CIAs. IMPROVE monitoring is designed to establish reference information on visibility conditions and trends to aid in the development of visibility protection programs. Monitoring from the IMPROVE network, shown in Figure 13, demonstrated that visibility in all the CIAs is impaired to some degree by regional haze.

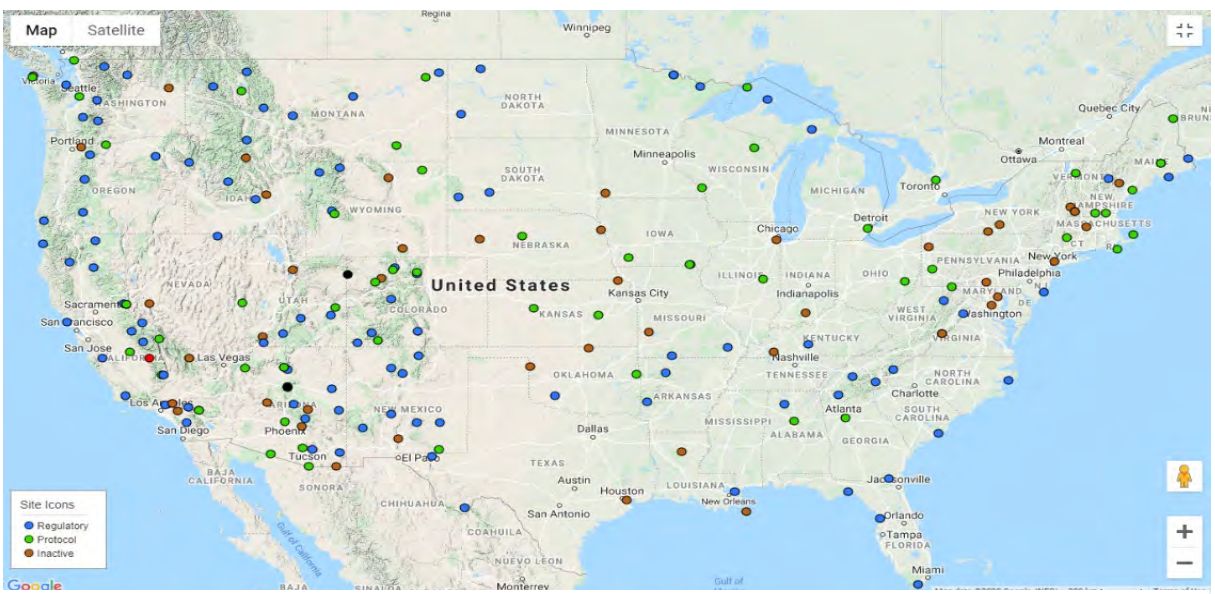


**Figure 13: IMPROVE monitoring sites**

## 1.E History of Regional Haze in Utah

Utah has been at the forefront of haze improvement and prevention since 1991 when the GCVTC was formed. The GCVTC recognized haze as a regional issue prior to the creation of the RHR in 1999 and was the first multi-state collaborative effort to address visual air quality issues. In recognition of the GCVTC, Section 309 of the RHR provided an early regional haze planning opportunity for states within the Colorado Plateau region. Utah is one of the five states to submit a complete Section 309 regional haze plan in 2003.

In amendments to the Clean Air Act (CAA) in 1977, Congress added Section 169A setting the national visibility goal of restoring pristine conditions in national parks and wilderness areas: "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory CIAs which impairment results from man-made air pollution."[36]

When the CAA was amended in 1990, Congress added Section 169B,[37] authorizing further research and regular assessments of the progress to improve visibility in the mandatory CIAs.[38]

The RHR specifies that these CIAs should attain "natural conditions" by 2064 and that states should make progress in controlling air pollution to meet this goal. The timeline is broken into


**Figure 14: United States map of mandatory CIAs**

[36] 42 U.S.C.A. § 7491.
[37] *See id*. § 7492.
[38] Figure 14: Map of 156 Mandatory Federal CIAs shows the location of the CIAs of concern and the Federal Land Managers (FLMs) responsible for each area around the nation.

10-year planning periods, and in each period, states must show reductions in emissions of haze-causing pollutants along a linear path, or glidepath, toward the 2064 end goal.

To meet the RHR planning requirements, states conduct analyses of visibility in each Class I area, identify the available reasonable measures to reduce haze, and implement those measures. The implemented measures establish the required Reasonable Progress Goals (RPG) for each Class I area. The RPGs are the visibility improvement benchmarks on the glidepath toward the long-term goal of natural visibility conditions by 2064.[39] The analysis, measures, and RPGs are the basis of the long-term strategy for the states, and this strategy must be included in the states' SIPs. States are also required to assess progress halfway through the 10-year implementation period - a process that is intended to keep the states on target to meet the 10-year goals established for each Class I area.

### 1.E.1 Grand Canyon Visibility Transport Commission

The GCVTC was established by EPA in November of 1991, consisting of seven western governors (or their designees), five tribes, and five ex-officio members representing federal land management agencies and EPA. When establishing the GCVTC, EPA designated a transport region including seven western states: California, Oregon, Nevada, Idaho, Utah, Arizona, Colorado, and New Mexico. Although a part of the Transport Region, the State of Idaho declined the invitation to participate in the GCVTC.

Although Congress required a commission to be established for Grand Canyon National Park, the member states agreed to expand the scope of the GCVTC to address all 16 of the CIAs on


**Figure 15: Regional haze glidepath for Bryce Canyon National Park tracking progress towards natural conditions in 2064**

[39] See Figure 15 for an RPG glidepath example of Bryce Canyon National Park, provided by the Western Regional Air Partnership (WRAP) Technical Support System.

the Colorado Plateau. The GCVTC elected to use a stakeholder-driven process to accomplish its objectives. Ultimately, the organization included 200+ political, policy and technical stakeholders who staffed a variety of committees and subcommittees to perform policy analysis and technical studies, and to participate in the public debate. The GCVTC was funded by EPA grants and contributions from stakeholders, including substantial in-kind labor. During its four-and-one-half year development, the GCVTC was expanded to include the State of Wyoming and tribal leaders as members. The GCVTC appointed a Public Advisory Committee (PAC) representing broad stakeholder interests to provide input and feedback to the GCVTC. Many Utahns were members of the PAC, with two serving on the PAC Steering Committee, and one serving on the Executive Committee as Vice-Chair of the PAC. The 80+ member Public Advisory Committee developed a consensus report of recommendations for the GCVTC that was ultimately adopted by the GCVTC and submitted to EPA in June 1996.[40]

Recommendations of the GCVTC included the following:

- Policies based on energy conservation, increased energy efficiency, and promotion of the use of renewable resources for energy production;
- Careful tracking of emissions growth that may affect air quality in clean air corridors;
- Regional targets for $SO_2$ emissions with a backstop program, probably including a regional cap and possibly a market-based trading program;
- Cooperatively developed strategies, expanded data collection and improved modeling for reducing or preventing visibility impairment in areas within and adjacent to CIAs, pending further studies of sources adjacent to CIAs;
- Emissions cap for mobile sources at the lowest level (expected to occur in 2005) and establishment of a regional emissions budget, as well as the implementation of national strategies aimed at reducing tailpipe emissions;
- Further study to resolve issues regarding the modeled contribution to visibility impairment of dust from paved and unpaved roads;
- Continued bi-national cooperation to resolve data gaps and jurisdictional issues around emissions from Mexico;
- Programs to minimize emissions and visibility impacts and to educate the public about impacts from prescribed fire and wildfire, because emissions are projected to increase significantly through 2040; and
- Creation of an entity like the GCVTC to promote, support, and oversee the implementation of many of the recommendations in this report.

EPA initially proposed regional haze regulations in 1997.[41] The proposed regulations described a generic program to apply nationally and did not include provisions to address the recommendations of the GCVTC. The Western Governors' Association (WGA) engaged key stakeholders to develop a recommendation on how to transform the GCVTC recommendations

[40] The Grand Canyon Visibility Transport Commission. Recommendations for Improving Western Vistas (June 10, 1996) available at https://www.phoenixvis.net/PDF/GCVTCFinal.pdf
[41] Regional Haze Regulations, 62 Fed. Reg. 41138 (July 31, 1997) (proposed rule).

into the regional haze regulations. WGA approved the stakeholders' recommendation and transmitted it to EPA in June 1998.[42] Based on this and other public input, EPA issued the final Regional Haze Rule in July 1999 with a national program (Section 308) that could apply to any state or tribe and an optional program (Section 309) relying on the work of the GCVTC that is available to the states and tribes in the nine-state GCVTC transport region.[43]

### 1.E.2 Western Regional Air Partnership

The GCVTC recognized the need for a long-term organization to address the policy and technical studies needed to address regional haze. The Western Regional Air Partnership (WRAP) was formed in September 1997 to fulfill this need. The WRAP's charter allows it to address any air quality issue of interest to WRAP members, though most current work is focused on developing the policy and technical work products needed by states and tribes in writing their regional haze SIPs and tribal implementation plans (TIPs). The WRAP has been co-chaired by the governor of Utah and the governor of the Acoma Pueblo. The WRAP Board is currently composed of representatives from 13 states, 13 tribes, the U.S. Department of Agriculture, the U.S. Department of the Interior, and the EPA. The WRAP operates on a consensus basis and receives financial support from EPA. The WRAP established stakeholder-based technical and policy oversight committees to assist in managing the development process of regional haze work products. Stakeholder-based working groups and forums were established to focus on the policy and technical work products the states and tribes need to develop their implementation plans.

The WRAP developed and submitted an Annex to the GCVTC recommendations to define a voluntary program of $SO_2$ emission reduction milestones coupled with a backstop market-trading program to assure emission reductions. EPA proposed changes to the Regional Haze Rule to incorporate the GCVTC Annex, and the final revised rule was published on June 5, 2003.[44] The WRAP has completed a suite of products to support states and tribes developing GCVTC-based regional haze implementation plans.[45]

### 1.E.3 2003 Regional Haze SIP

On June 5, 2003, EPA approved the Annex and incorporated the stationary source provisions into the RHR In December 2003 the Utah Air Quality Board adopted Section XX of the SIP to address regional haze. This plan was based on the GCVTC recommendations and the Annex and contained a broad-based strategy to address the many source categories and pollutants

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42 Leavitt, M. O., Governor of Utah, Letter to EPA Administrator Browner on behalf of the Western Governors' Association, June 29, 1998.

43 Regional Haze Regulations, 64 Fed. Reg. 35714 (July 1, 1999), codified at 40 C.F.R. pt. 51.

44 Revisions to Regional Haze Rule to Incorporate $SO_2$ Milestones and Backstop Emissions Trading Program for Nine Western States and Eligible Indian Tribes Within That Geographic Area, 68 Fed. Reg. 33764 (June 5, 2003), codified at 40 C.F.R. pt. 51.

45 Additional information about the WRAP can be found on the WRAP website at https://www.wrapair2.org/

that contributed to regional haze in Utah, including clean air corridors, fire, mobile sources, paved and unpaved road dust, pollution prevention and renewable energy programs, and stationary sources.

EPA's approval of the Annex was challenged in court, and on February 18, 2005, the DC Circuit Court of Appeals vacated EPA's 2003 rules.[46] The Court determined that EPA had required a BART demonstration in the Annex that was based on a methodology that had been vacated by the Court in 2002 in *American Corn Growers Association v. E.P.A.*, 291 F.3d 1 (D.C. Cir. 2002), decision. On October 13, 2006, EPA revised the RHR to establish the methodology for states to develop an alternative to BART that was consistent with the DC Circuit's 2005 decision.[47]

### 1.E.4 2008 Regional Haze SIP Revision

While most of the 2003 SIP remained unchanged, in 2008 the Utah Air Quality Board adopted revisions to the stationary source provisions of the SIP to meet the requirements of the revised RHR and to reflect changes in the number of states participating in the program. In addition to these changes, the rule required an update to the SIP in 2008 to address the BART requirement for $NO_x$ and PM as well as an analysis of the impact of sources in Utah on CIAs outside of the Colorado Plateau.

### 1.E.5 2011 Regional Haze SIP Revision

The $SO_2$ milestones were updated in 2011 to reflect a reduced number of states participating in the program (Arizona elected to pursue a SIP under Section 308 of the RHR). In addition, the growth estimates for coal-fired utilities and the estimates for emission reductions due to BART were revised.

### 1.E.6 2015 Regional Haze SIP Revision

On June 4, 2015, Utah resubmitted its SIP for PM BART and submitted an alternative to BART for $NO_x$ for PacifiCorp's Electrical Generating Units (EGUs). On January 14, 2016, EPA issued a proposed rule containing a proposal to approve the PM BART and a co-proposal to either approve or disapprove the BART Alternative for $NO_x$ and to impose a Federal Implementation Plan (FIP) requiring BART for $NO_x$ in the event of the disapproval.[48] On July 5, 2016, EPA issued the final rule disapproving the BART alternative for $NO_x$ and approving the BART for the PM portion of the June 4, 2015 SIP.[49] To replace the disapproved BART alternative, EPA

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[46] *See Ctr. for Energy & Econ. Dev. v. E.P.A.*, 398 F.3d 653 (D.C. Cir. 2005)

[47] *See* Regional Haze Regulations, 71 Fed. Reg. 60,612, 60,631 (Oct. 13, 2006), codified at 40 C.F.R. pt. 51.

[48] *See* Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plans and Federal Implementation Plan; Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze, 81 Fed. Reg. 2004 (Jan. 14, 2016) (proposed rule).

[49] *See* Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plans and Federal Implementation Plan; Utah;

promulgated a FIP, requiring installation of Selective Catalytic Reduction (SCR) controls on the subject EGUs by August of 2021.[50]

Utah filed a lawsuit against EPA challenging the July 5, 2016 disapproval of BART Alternative for $NO_x$ in the Tenth Circuit on September 1, 2016.[51] The parties engaged in settlement discussions to resolve the case administratively. As a result of the settlement negotiations, Utah conducted an additional technical analysis using the state-of-the-science model and methodologies to perform air quality model simulations.[52] Utah used the photochemical grid model Comprehensive Air Quality Model with Extensions (CAMx) to estimate and compare the potential visibility impacts at selected CIAs for different emissions scenarios considered for PacifiCorp's EGUs. The CAMx was used because it accounts for complex processes such as the chemistry, transport, and deposition of pollutants responsible for regional haze.

Utah came to the same conclusion employing the CAMx modeling: that its $NO_x$ BART Alternative would provide greater reasonable progress toward natural visibility conditions than BART.[53] Utah revised the disapproved SIP to include this additional technical analysis and, after public notice and comment, submitted the revised $NO_x$ BART Alternative to EPA on July 3, 2019. Utah submitted a supplement to the July 2019 submission on December 3, 2019 on the issue unrelated to the initial disapproval—the requirement to report all deviations from compliance with the applicable requirements under BART and BART Alternative, including emission limits for PacifiCorp's EGUs. On January 22, 2020, EPA published a proposed rule to approve the July 2019 SIP submittal with December 2019 supplement.[54]

After EPA's public notice and comment, on November 27, 2020, EPA issued a final rule approving Utah's July 2019 SIP submittal and December 2019 supplement.[55] This concluded and resolved the litigation that Utah initiated on September 1, 2016. The Tenth Circuit dismissed the case and issued a mandate on January 11, 2021.[56] EPA's November 27, 2020 final rule is currently challenged in the Tenth Circuit by the conservation organizations (HEAL Utah,

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Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze, 81 Fed. Reg. 43894 (July 5, 2016), codified at 40 C.F.R. pt. 52.

[50] *See id*., 81 Fed. Reg. at 43907.

[51] *See Utah v. E.P.A. et al.*, No. 16-9541 (10th Cir. Sept. 1, 2016).

[52] *See* Section 1.E.7 below for additional details.

[53] Staff Review Recommended Alternative to BART for $NO_x$ at 5-2 (Jan. 14, 2019) ("The model results... indicate that the emissions modeled under the Utah SIP will not degrade visibility conditions relative to the Baseline scenario at any of the analyzed CIAs during either the 20% best or 20% worst visibility days. The modeling results also show that, on average, visibility improvement at the analyzed CIAs is greater under the Utah SIP than the USEPA FIP scenarios during both the 20% best and 20% worst visibility days.").

[54] *See* Approval and Promulgation of Air Quality Implementation Plans; Utah; Regional Haze State and Federal Implementation Plans, 85 Fed. Reg. 3558 (Jan. 22, 2020) (proposed rule).

[55] Approval and Promulgation of Air Quality Implementation Plans; Utah; Regional Haze State and Federal Implementation Plans, 85 Fed. Reg. 75860 (Nov. 27, 2020), codified at 40 C.F.R. pt. 52.

[56] *See* Order, *Utah v. E.P.A. et al.*, No. 16-9541 (10th Cir. Jan. 11, 2021).

National Parks Conservation Association, Sierra Club, and Utah Physicians for a Healthy Environment).[57] The lawsuit was filed on January 19, 2021.[58]

### 1.E.7 2019 Regional Haze SIP Revision

In the 2019 SIP revision, Utah used dispersion modeling and the two-prong test prescribed by the RHR[59] to demonstrate that the proposed alternative to BART does show greater progress than the most stringent $NO_x$ controls (installation of SCR). The two prongs that Utah had to satisfy are (1) that visibility does not decline in any Class I area; and (2) that there is an overall improvement in visibility determined by comparing the average differences between BART and the BART Alternative over all affected CIAs.

The two-prong test was an objective pass-fail test which Utah's BART Alternative met. EPA proposed approval of this latest SIP on January 22, 2020.[60]EPA issued final approval of the 2019 SIP revision on November 27, 2020 with effective date of December 28, 2020.[61] In the final rule EPA concluded "that Utah's $NO_X$ BART Alternative achieves greater reasonable progress under 40 CFR 51.308(e)(2) and (3)."[62] With the final approval, EPA also found that "Utah's SIP fully satisfies the requirements of section 309 of the Regional Haze Rule and therefore the State has fully complied with the requirements for reasonable progress, including BART, for the first implementation period."[63]

## 1.F General Planning Provisions

### 1.F.1 Regional Haze Program Requirements

The program requirements of the RHR[64] are identified in Subsection 51.308(f) which lists the requirements for haze SIP updates, including a reference to the requirements in Subsection 51.308(d). In addition to re-evaluating all elements required in subsection (d), the states must also do the following:

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

[57] *See HEAL Utah et al. v. E.P.A. et al.*, No. 21-9509 (10th Cir. Jan 19, 2021).
[58] *See* Petition for Review, *HEAL Utah et al.*, No. 21-9509 (10th Cir. Jan. 19, 2021).
[59] 40 CFR 51.308€ (3)
[60] *See* 85 Fed. Reg. 3558.
[61] *See* 85 Fed. Reg. 75860.
[62] *Id.*, 85 Fed. Reg. at 75861.
[63] *Id.*
[64] 40 CFR 51.308

As noted above, the section addressing the requirements for the SIP revisions references the requirements of subsection (d). The subsection (d) requirements are as follows: requirements:

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

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

### 1.F.2 SIP Submission and Planning Commitments

This SIP revision meets the requirements of the EPA's RHR and the CAA. Elements of this SIP address the core elements required by 40 CFR Section 51.308(f)(3)—the establishment of RPGs and measures that Utah will take to meet the RPGs. This SIP revision also addresses 40 CFR 51.308(f)(2) (long-term strategy for regional haze) and 40 CFR 51.308(i)(2) (state coordination with the FLMs) and commits to develop future plan revisions and adequacy determinations as necessary.

The State of Utah commits to participate in a regional planning process, as a member state through the Western States Air Resource Council (WESTAR) and as a partner in WRAP. WESTAR is a partnership of 15 western states formed to promote the exchange of information, serve as a forum to discuss western regional air quality issues, and share resources for the common benefit of the member states. WRAP is a voluntary partnership of state, tribes, FLMs, local air agencies, and the EPA whose purpose is to understand current and evolving regional air quality issues in the West. The regional planning process describes the process, goals, objectives, management and decision-making structure, and deadlines for completing significant technical analyses of the regional group. To assist in making sound planning decisions, Utah has assisted the regional planning organization to complete regional analyses that include certain methods, inputs, and resources. Utah commits to continue regional participation through future SIPs.

Pursuant to the Tribal Authority Rule[65], any Tribe whose lands are within the boundaries of the State of Utah have the option to develop a regional haze Tribal Implementation Plan (TIP) for their lands to assure reasonable progress in the twelve CIAs in Utah. As such, no provisions of this Implementation Plan shall be construed as being applicable to tribal lands.

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Indian Tribes: Air Quality Planning and Management, 63 Fed. Reg. 7254 (Feb. 12, 1998).

### 1.F.3 Utah Statutory Authority

The Utah Air Conservation Act[66] gives the Utah Air Quality Board authority to make rules pertaining to air quality activities.[67]

An administrative rule serves two purposes:

- A properly enacted administrative rule has the binding effect of law. Therefore, a rule affects the regulated entities and citizens as much as a statute passed by the Legislature.
- An administrative rule informs citizens of actions a state government agency will take or how a state agency will conduct its business.

This SIP is a compilation of analyses under Utah's statutory authority that satisfies the requirements of Sections 110 and 169 of the CAA.

[66] Utah Code Ann. §§ 19-2-101 through 19-2-304 (West 2021).
[67] *See id*. § 19-2-104.

# **Chapter 2:** Utah Regional Haze SIP Development Process

This SIP addresses regulatory requirements of the second planning period by screening facilities with the most impact on Utah's CIAs, conducting and evaluating the four-factor analysis,[68] and making controls determinations based on this analysis. The current visibility conditions in relation to our Uniform Rate of Progress (URP) goals were also analyzed with the modeled data analysis tools provided by the WRAP Technical Support System (TSS).

Utah's SIP development process included consultation with industry stakeholders, environmental advocate stakeholders, regional states, WESTAR, WRAP, FLMs from the National Parks Service and the US Forest Service, and EPA's Region 8 office. Utah also consulted members of other state agencies including the Department of Energy Development and Office of Public Utilities. This chapter outlines Utah's consultation and communications with these entities. For additional details regarding individual consultation, see Chapter 9 Consultation, Public Review, Commitment to further Planning.

After initial consultation, Utah submitted the second planning period RH SIP to the FLMs, EPA, and Tribes of Utah on December, 8, 2021 for their mandatory 60-day comment period. After the comment period, the SIP was submitted to Utah Air Quality Board for the April 6th, 2022 Utah Air Quality Board meeting. The Board then proposed the SIP for public comment on May 1st, 2022 for the required 30 days. Utah then submitted the final SIP to the EPA on X, X, 2022.

## 2.A WRAP Engagement

During this second planning period, the WRAP Regional Haze Planning Work Group (RHPWG)[69] has helped create a framework for regional haze planning for all 15 participating states as well as the City of Albuquerque within the WESTAR and WRAP region. This initiative included regular meetings to discuss regional haze planning, encourage coordination among states, and offer training opportunities. WRAP has also been responsible for the WRAP TSS which is an online portal to the technical and analytical results created from technology development from Colorado State University (CSU) and the Cooperative Institute for Research in the Atmosphere (CIRA). TSS is the source of the key summary analytical results and methods for the required technical elements of the RHR contained within this SIP including:

- Inventories: current and future (growth projections methodologies by source categories)
- Development of a transparent and complete monitoring data metric for planning and model projection purposes
- Database management (including the TSS database)

[68] For purposes of this document, the Four-Factor Analysis is defined as the analysis required by 40 C.F.R. § 51.308(d)(1)(i)(A).
[69] More information on the Regional Haze Planning Work Group can be found at https://www.wrapair2.org/RHPWG.aspx

- Four-Factor Analysis for control measures
- Regional photochemical modeling
- Assessment of “unknowns” and uncertain categories (natural conditions, international emissions, fire, and dust emission, etc.)
- Development of RH SIP package content and progress report template
- Development of control strategies menu for major western state sources

For additional information on the origins of WRAP, see Section 1.E.2.

### 2.A.1 Technical Information and Data: WRAP TSS2.0

The WRAP TSS 2.0 is the data warehouse and online portal used by air quality planners to evaluate the technical data and analytical results to support regional haze implementation plans. The TSS 2.0 is a “system of systems” that integrates capabilities from many systems, including systems focused on: monitoring data analysis efforts, emissions data management systems, fire emissions tracking systems, photochemical aerosol regional modeling analyses, and visualization and summary data analyses.[70] These diverse data sets can be analyzed through the TSS and the resultant outputs can be downloaded for use in SIP reports. This SIP submittal relies on the data stored in and retrieved from the TSS 2.0 system.

## 2.B Consultation with Federal Land Managers

The federal land management 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). FLMs have a critical role in protecting air quality in national parks, wilderness, and other federally protected areas. They have an affirmative responsibility to protect air quality related values, including visibility, in all CIAs.[71] Utah primarily meets with the NPS and USFS for RH planning.

States must provide the FLMs with an opportunity for an early in-person consultation about the state’s long-term strategy to reduce emissions.[72] This consultation should happen early enough in the process so that the information and recommendations provided by the FLMs can meaningfully inform the State’s decisions.[73] The opportunity for consultation is sufficient if the consultation happened at least 120 days prior to any public hearing or other public comment opportunity on SIP or SIP revision.[74] The opportunity for consultation must also be provided no less than 60 days prior to said public hearing or public comment opportunity.[75]

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[70] https://views.cira.colostate.edu/tssv2/About/Default.aspx
[71] *See* 40 C.F.R. § 51.166(p)(2).
[72] *See* 40 C.F.R. § 51.308(i)(2).
[73] *See id*.
[74] *See id*.
[75] *See id*.

This consultation must include the opportunity for the affected FLMs to discuss their:

- Assessment of impairment of visibility in any mandatory CIA; and
- Recommendations on the development of the reasonable progress goal and on the development and implementation of strategies to address visibility impairment.[76]

FLM of any mandatory Class I area can submit any recommendations on the implementation of this subpart (40 C.F.R. Part 51, Subpart P: Protection of Visibility) including, but not limited to:

i. Identification of impairment of visibility in any mandatory CIA(s); and
ii. Identification of elements for inclusion in the visibility monitoring strategy required by § 51.305.[77]

Utah has engaged with the FLMs and shared the RH SIP with them on December 8, 2021. See Chapter 9 Consultation, Public Review, Commitment to Further Planning for full documentation of Utah's consultation with the FLMs during this implementation period.

Numerous opportunities were provided through the WRAP for states and FLMs to participate fully in the development of technical documents included in this SIP. This included the ability to review and comment on these analyses, reports, and policies. A summary of the WRAP-sponsored meetings and conference calls is provided on the WRAP website[78].

## 2.C Collaboration with Tribes

Tribal governments are responsible for coordinating with federal and state governments to protect air quality on their sovereign lands and to ensure emission sources on tribal lands meet federal requirements. The 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. For example, The Bonanza power plant, located on "Indian Country" in the Uinta Basin, has a Q/d value large enough to require a Four-Factor Analysis, but is not under the jurisdiction of the Utah Department of Environmental Quality. In order to further the environmental justice initiative in Utah, UDAQ shared its RH SIP draft with the tribes of Utah at the same time it was shared with the FLMs and EPA for a 60-day review on December 8, 2021.

## 2.D Consultation with Other States

States are required to share information with other states that have CIAs that are reasonably anticipated to be impacted by each other's emissions. States are also required to evaluate, though not necessarily implement, control measures requested by other states and document actions taken to resolve disagreements. The TSS 2.0 analyses tools, including emissions tools and source apportionment modeling results, aid states to determine if an in-state source could be impacting an out-of-state Class I area. Utah consulted with neighboring states, both through

[76] *See id*., § 51.308(i)(2)(i) and (ii).
[77] *See id*., § 51.308(i)(1)(i) and (ii).
[78] More information on WRAP-sponsored meetings and conference calls is available at https://www.wrapair2.org/RHPWG.aspx.

webinars and calls organized through the WRAP, and via state-to-state communication, to address the requirements of the RHR for coordinated emissions control strategies between states. Specifically, 40 CFR § 51.308(f)(2)(ii) requires that Utah consult with other states that have emissions that are reasonably anticipated to contribute to visibility impairment in Utah CIAs to develop coordinated emission management strategies containing the emission reductions necessary to make reasonable progress.

WRAP conducted technical analyses to evaluate interstate emissions impacts. These analyses include source apportionment modeling and area of influence/weighted emissions potential (AOI/WEP) analyses. Source apportionment modeling is used to identify states and sectors that are contributing haze. AOI/WEP analyses can identify what significant emission sources are upwind from a Class I area. Utah discussed the results of these analyses with surrounding states. Due to all of Utah's CIAs visibility being at or below their projected glidepath goals towards natural conditions in 2064, UDAQ will not ask for any additional controls from other states that may impact Utah's visibility in CIAs. Refer to sections 6.A.1 and 6.A.2 for a detailed analysis on out of state impacts on Utah's CIA's and Utah's impacts on out of state CIAs.

Utah has met with Colorado, New Mexico, Arizona, and Wyoming directly as well as attended Region 8, WRAP, WESTAR, and Four Corners States meetings as part of the second planning period SIP development. For additional details regarding individual consultation, see Chapter 9 as well as Appendix B or Utah's interstate consultation agreements with surrounding states.

## 2.E Public and Stakeholder Consultation

Many different agencies and interests come together to develop a RH SIP. Prior to formal public review and EPA action, states should communicate regularly with industry and the public. Utah communicated regularly with the regulated industry, including the sources that may be impacted by the Four-Factor Analysis, environmental advocates, as well as members of the public. Utah holds six meetings each for the industry stakeholders and environmental advocates. For additional details regarding stakeholder consultation, see Chapter 9.

# **Chapter 3:** Progress to Date

## 3.A Embedded Progress Report Requirements

Section 51.308(f)(5) of the RHR requires a state to address the requirements of subsections 51.308 (g)(1) through (5) in the plan revision. By fulfilling this requirement, the plan revision due in 2021 will also serve as a progress report for the period since submission of the progress report for the first implementation period. The progress report for the first implementation period included visibility levels, emissions, and implementation status up to a date prior to submittal.[79]

This chapter is meant to inform the public and EPA about implementation activities since the last regional haze SIP submission.

### 3.A.1 Implementation status of all measures in first planning period[80]

The RHR[81] requires certain major stationary sources to evaluate, install, operate and maintain BART technology or an approved BART alternative for $NO_x$ and PM emissions. The State of Utah chose to evaluate BART for PM under the case-by-case provisions of 40 CFR 51.308(e)(1) and BART for $NO_x$ through alternative measures[82]. BART for $SO_2$ is addressed through an alternative program[83] that is described in Part E of the 2019 Regional Haze SIP.

40 CFR 51.308(e)(1)(ii) requires states to determine which BART-eligible sources are also "subject to BART." BART-eligible sources are subject to BART if they emit any air pollutant that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory CIA.

Four BART-eligible electric generating units were identified in the State of Utah: PacifiCorp's Hunter Units 1 and 2 and Huntington Units 1 and 2. The units are located at fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input, one of the 26 specific BART source categories. The units had potential emissions greater than 250 tons per year of visibility impairing pollutants. The units had commenced construction within the BART time frame of August 7, 1962 to August 7, 1977. PacifiCorp Hunter Units 1 and 2 and Huntington Units 1 and 2 replaced first generation low-$NO_x$ burners with Alstom TSF 2000TM low-$NO_x$ firing system and installation of two elevations of separated overfire air with an emission limit of 0.26 lb./MMBtu on a 30-day rolling average.

In addition, PacifiCorp Hunter Unit 3 (not subject-to-BART) replaced first generation low-$NO_x$ burners with improved low-$NO_x$ burners with overfire air with an emission limit of 0.34 lb./MMBtu

[79] The 2017 Regional Haze Guidance document can be found at https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf
[80] (40 CFR 51.308(g)(1))
[81] 40 CFR 51.308(e) and 40 CFR 51.309(d)(4)(vii)
[82] 40 CFR 51.308(e)(2) and (3)
[83] 40 CFR 51.309

on a 30-day rolling average and PacifiCorp Carbon Units 1 and 2 (not subject-to-BART) were permanently retired by August 15, 2015.

**Table 1: 30-day Rolling Average Emission Limits for the Retrofitted Hunter and Huntington Units**

| Units | Utah Permitted Limits | | |
|---|---|---|---|
| | $SO_2$ (lb./MMBtu) | $NO_x$ (lb./MMBtu) | PM (lb./MMBtu) |
| **Hunter 1** | 0.12 | 0.26 | 0.015 |
| **Hunter 2** | 0.12 | 0.26 | 0.015 |
| **Hunter 3** | | 0.34 | |
| **Huntington 1** | 0.12 | 0.26 | 0.015 |
| **Huntington 2** | 0.12 | 0.26 | 0.015 |

### 3.A.2 Summary of emission reductions achieved by control measure implementation[84]

The enforceable retirement of Carbon Units 1 and 2 resulted in $SO_2$ reductions of 3,388 tons/year from Unit 1 and 4,617 tons per year from Unit 2, resulting in a total of 8,005 tons per year. Utah's emissions reductions are further detailed in Chapter 5.

### 3.A.3 Assessment of visibility conditions[85]

Please refer to Chapter 4 for information regarding Utah's visibility analyses.

[84] (40 CFR 51.308(g)(2)(5))
[85] (40 CFR 51.308(g)(3))

### 3.A.4 Analysis of any changes in emissions from all sources and activities within the state[86] [87]

The following figures[88] show Utah's statewide total emissions trends by sector from 1999 to 2017. This data comes from Utah's statewide emissions inventories. In 2011, there are certain spikes in emissions for area source emissions due to inventory method changes and an increase in the amount of Source Classification Codes (SCCs) defining area sources.

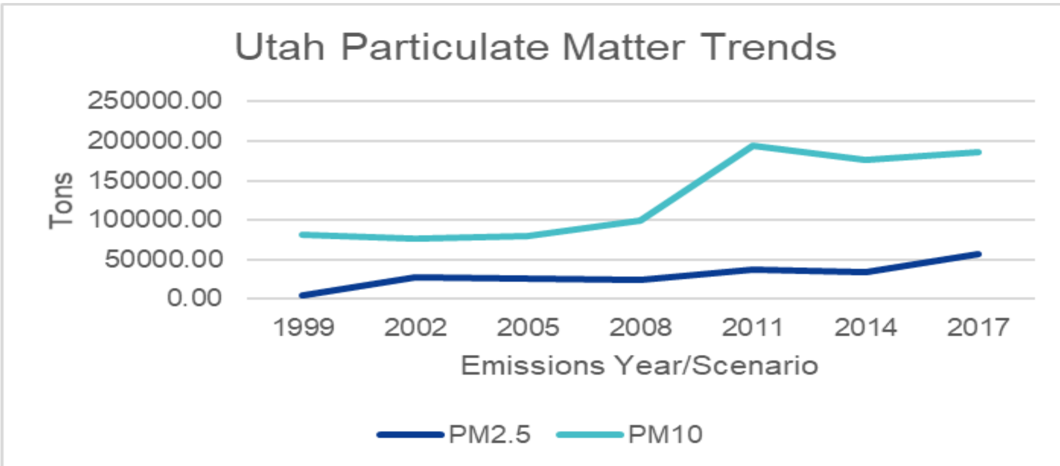


**Figure 16: Utah PM Emissions Trends**

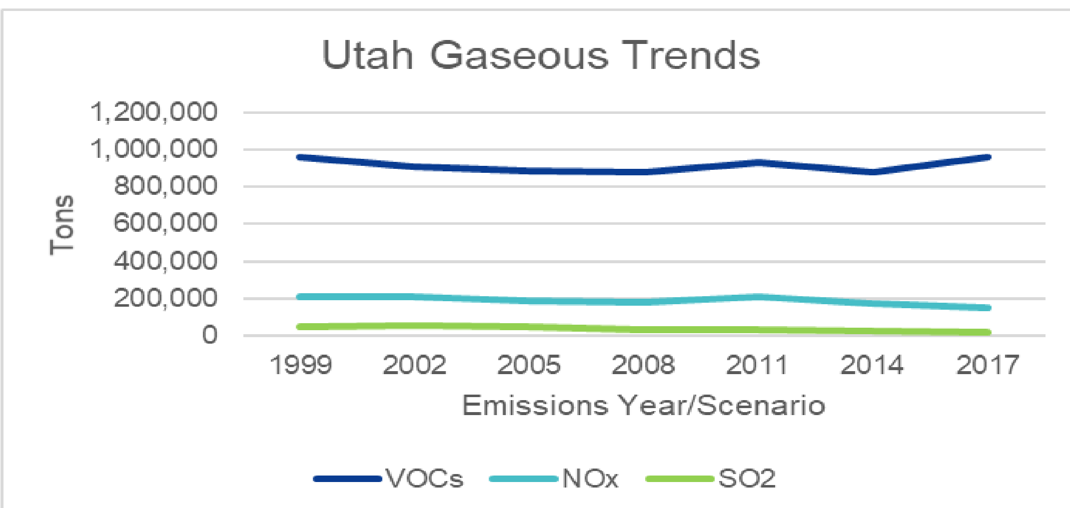


**Figure 17: Utah Gaseous ($NO_x$, $SO_2$, and VOC) Emissions (w/o biogenics)**

86 (40 CFR 51.308(g)(4))
87 These graphs use WRAP modeling data from scenarios 2014v2, RepBase2, and 2028Ota2. For area source calculations, the WRAP categories Oil and Gas – Non-Point, Residential Wood Combustion, Fugitive Dust, Agriculture, Remaining Non-Point, Agricultural Fire, and Wildland Prescribed Fire were added. For Non-Road Mobile sources, the categories Non-Road Mobile and Rail were added.
88 See figures 10-14 below

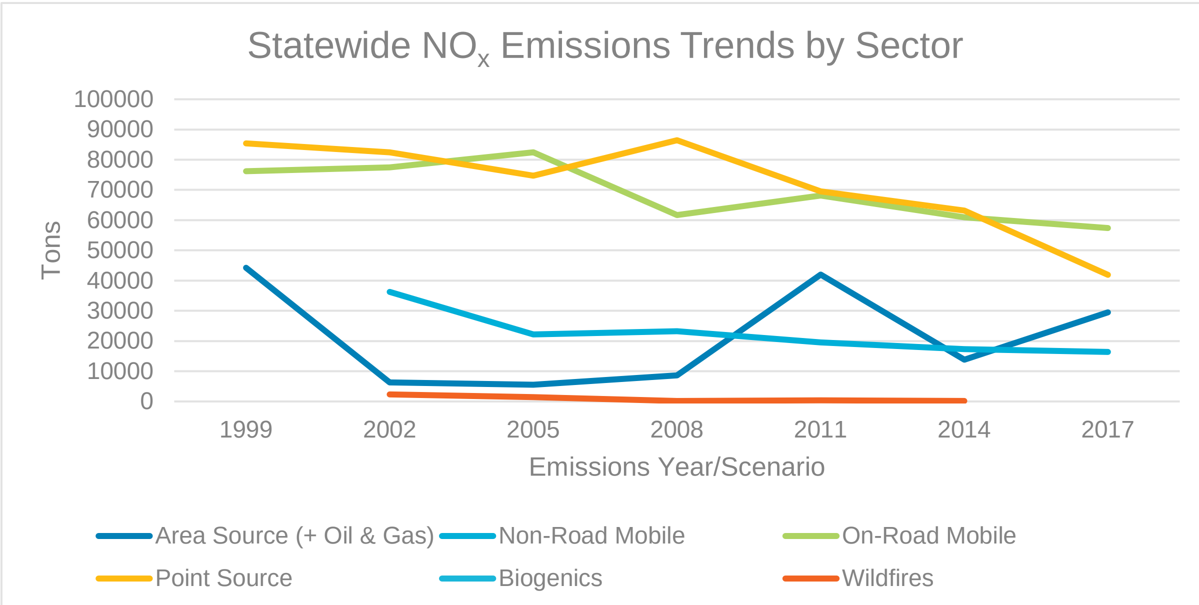


**Figure 18: NOx Emissions by Sector**

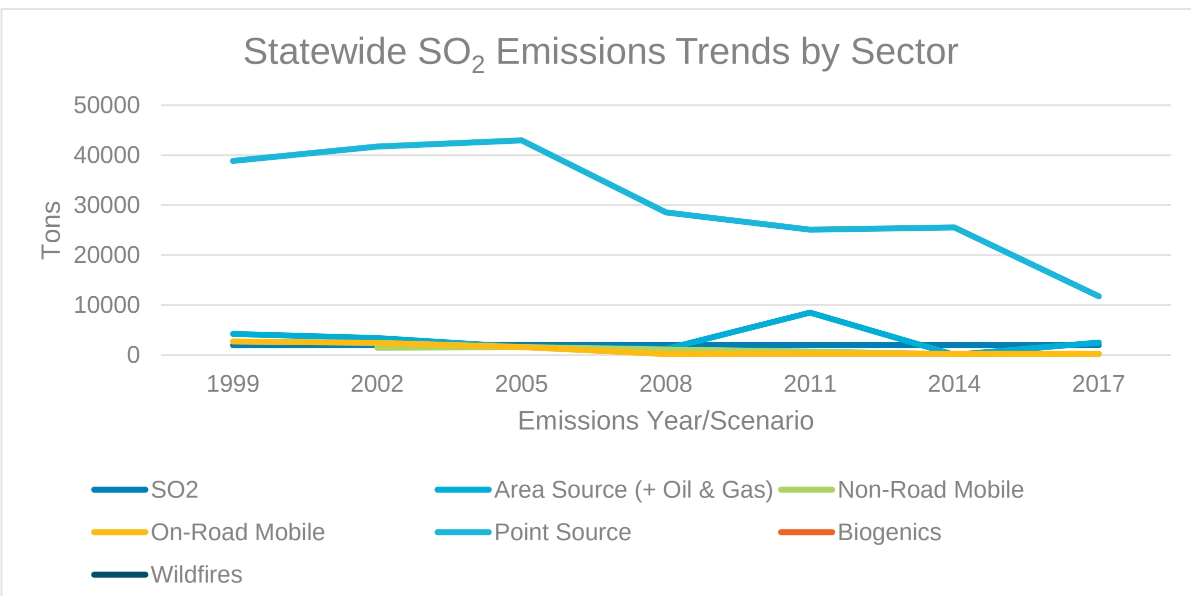


**Figure 19: SO2 Emissions by Sector**

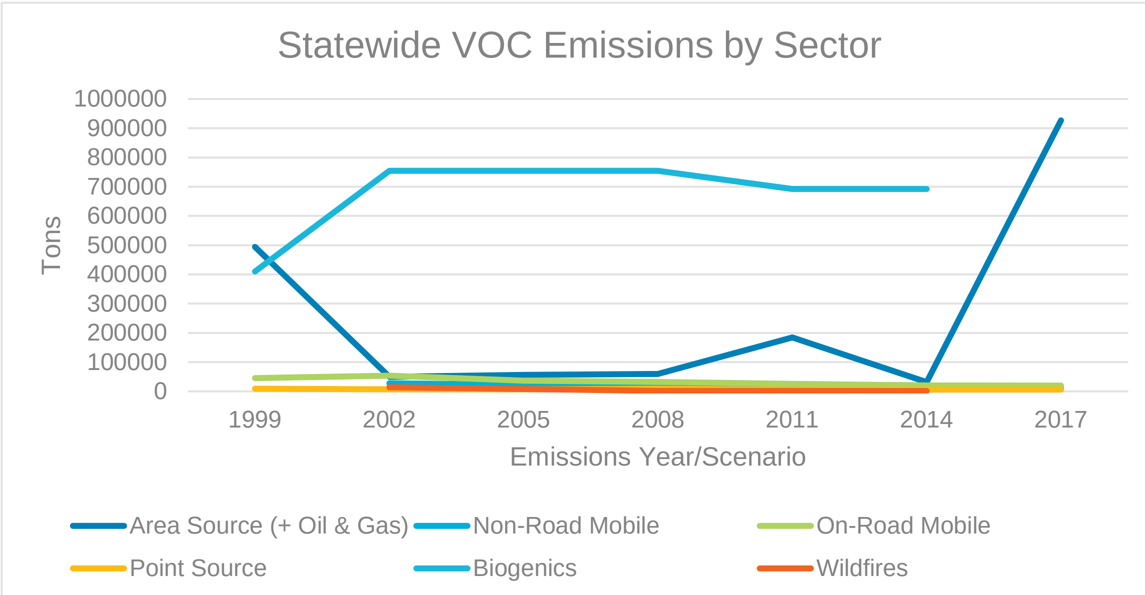


**Figure 20: VOC Emissions by Sector**

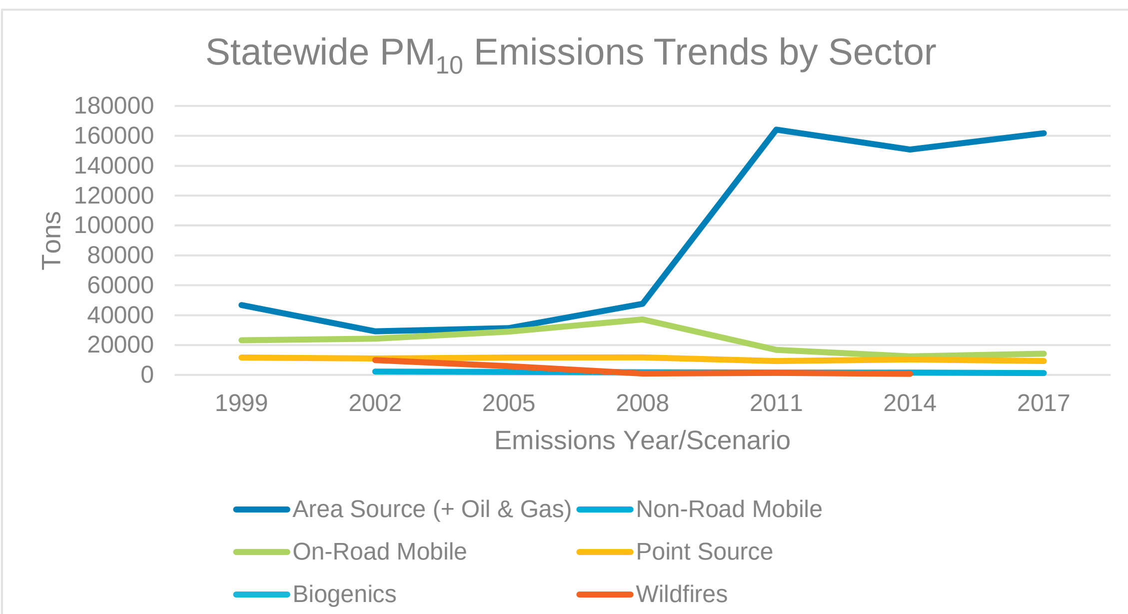


**Figure 21: $PM_{10}$ Emissions by Sector**

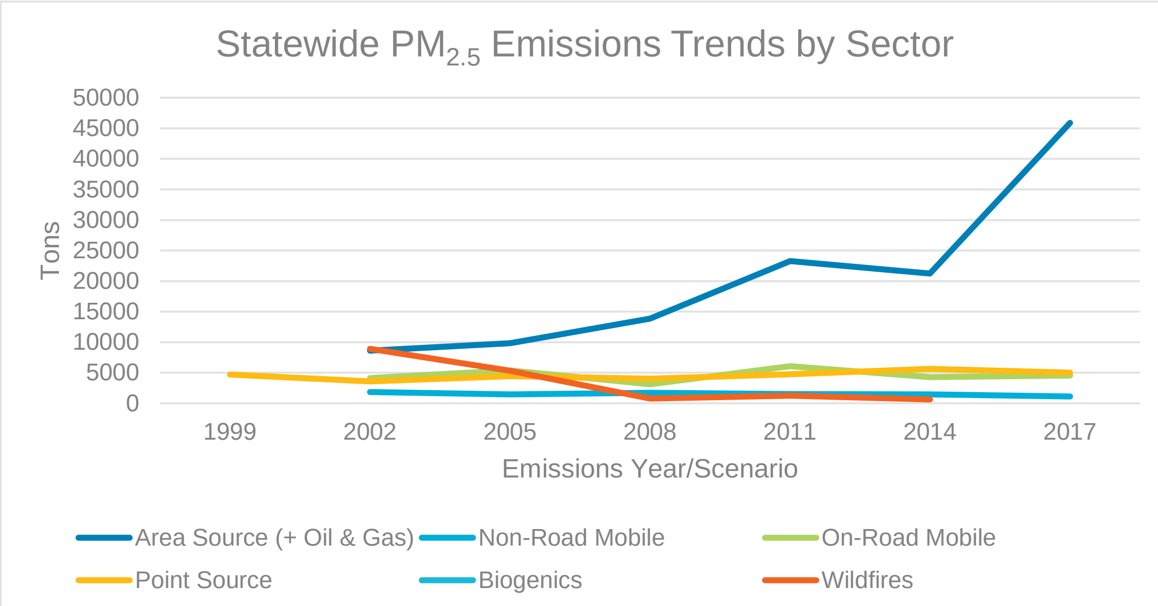


**Figure 22: $PM_{2.5}$ Emissions by Sector**

### 3.A.5 Assessment of any changes in emissions from within or outside the state.[89]

The Center for the New Energy Economy (CNEE) at Colorado State University conducted an analysis of current and future emissions of $NO_x$ and **$SO_2$ from fossil-fueled EGUs in 13-Western states1 for WESTAR and WRAP.[90] WRAP state air quality staff and representatives of Western electric utilities actively participated in the project and helped develop the study parameters, including information needed for Western regional air quality analyses and planning under the federal Clean Air Act.**

$SO_2$ and $NO_x$ emissions from the Western power sector have decreased dramatically over the last 20 years. As shown in Figure 23, 2018 EGU emissions of $SO_2$ were 84% below 1998 levels and $NO_x$ emissions were 71% below 1998.

[89] (40 CFR 51.308(g)(5))
[90] The Analysis of EGU Emissions for Regional Haze Planning by the CNEE can be found at http://www.wrapair2.org/%5C/pdf/Final%20EGU%20Emissions%20Analysis%20Report.pdf

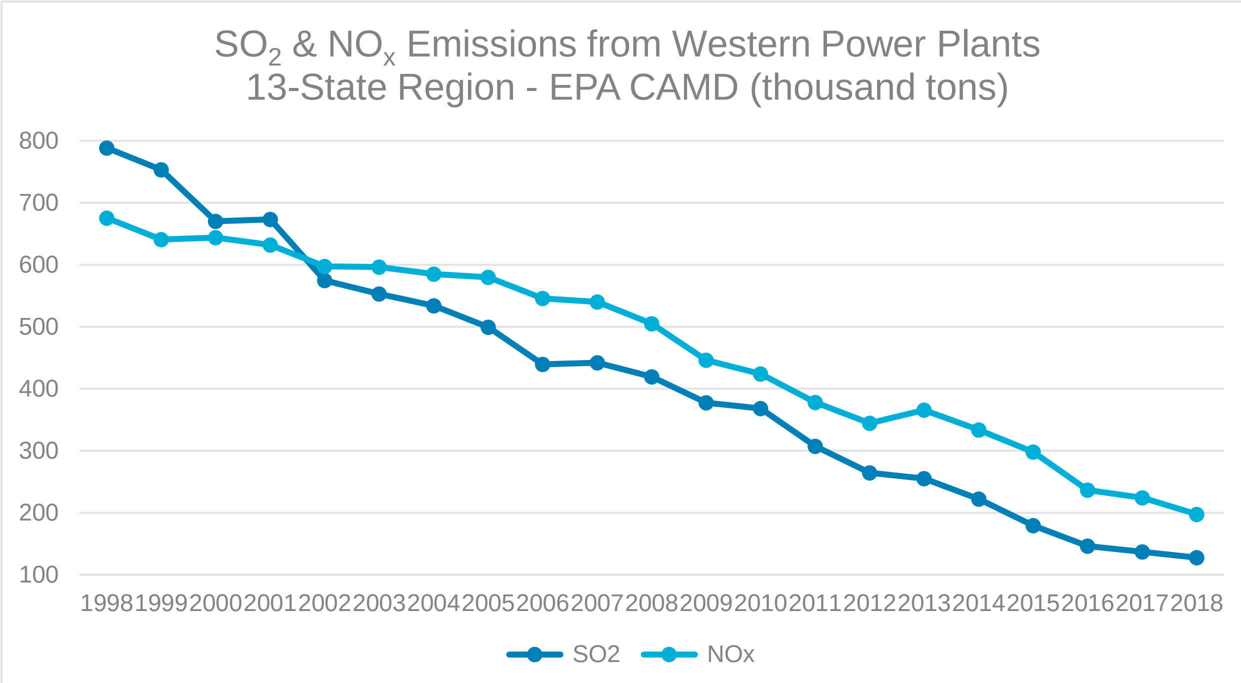


**Figure 23: $SO_2$ and $NO_x$ Emissions Trends for Western Power Plants[1]**

The table below shows that 29 of the 84 coal units operating in the West in 2018 have plans (not all federally enforceable) to retire by 2028. Emissions from these units were omitted from the 2028 projections produced by the CNEE, though some states opted to include emissions for some of the listed EGUs in the final WRAP 2028OTBa2 projections due to uncertainties about firm closures (e.g., North Valmy, San Juan Generating Station, etc.).

**Table 2: Western Coal Unit Retirement and Control Summary**

| State | Facility Name | Unit ID | Operating Year | Retirement Year | Notes |
|---|---|---|---|---|---|
| PLANNED RETIREMENTS - NO POST-COMBUSTION CONTROL FOR NO=x | | | | | |
| AZ | Cholla | 1 | 1962 | 2025 | APS IRP |
| AZ | Cholla | 3 | 1980 | 2025 | APS IRP |
| AZ | Cholla | 4 | 1981 | 2025 | PAC IRP |
| AZ | Navajo Generating Station | 1 | 1974 | 2019 | SRP IRP |
| AZ | Navajo Generating Station | 2 | 1975 | 2019 | SRP IRP |
| AZ | Navajo Generating Station | 3 | 1976 | 2019 | SRP IRP |
| CO | Comanche (470) | 1 | 1973 | 2022 | Xcel Colorado Energy Plan |
| CO | Comanche (470) | 2 | 1975 | 2025 | Xcel Colorado Energy Plan |
| CO | Craig | C1 | 1980 | 2025 | Legal/Regulatory |
| CO | Nucla | 1 | 1991 | 2022 | Legal/Regulatory |
| CO | Valmont | 5 | 1964 | 2017 | Retired |

| State | Facility Name | Unit ID | Operating Year | Retirement Year | Notes |
|---|---|---|---|---|---|
| **MT** | Colstrip | 1 | 1975 | 2022 | Legal/Regulatory |
| **MT** | Colstrip | 2 | 1976 | 2022 | Legal/Regulatory |
| **NM** | San Juan | 1 | 1976 | 2022 | PNM IRP (SNCR) |
| **NM** | San Juan | 2 | 1973 | 2017 | Retired |
| **NM** | San Juan | 3 | 1979 | 2017 | Retired |
| **NM** | San Juan | 4 | 1982 | 2022 | PNM IRP |
| **NV** | North Valmy | 1 | 1981 | 2025 | NV IRP (2019 per ID Power?) |
| **NV** | North Valmy | 2 | 1985 | 2025 | NV IRP |
| **NV** | Reid Gardner | 4 | 1983 | 2017 | Retired |
| **OR** | Boardman | 1SG | 1980 | 2021 | Legal/Regulatory |
| **UT** | Intermountain | 1SGA | 1986 | 2025 | Planned (new gas?) |
| **UT** | Intermountain | 2SGA | 1987 | 2025 | Planned (new gas?) |
| **WA** | Centralia | BW21 | 1972 | 2021 | Legal/Regulatory (12/31/2020) |
| **WA** | Centralia | BW22 | 1973 | 2026 | Legal/Regulatory (12/31/2025) |
| **WY** | Naughton | 3 | 1971 | 2018 | PAC IRP - gas in 2019? |
| **MT** | Hardin | | | 2017 | |
| **POTENTIAL RETIREMENTS - NO POST-COMBUSTION CONTROL FOR $NO_x$** | | | | | |
| **AZ** | Coronado Generating Station | U1B | 1979 | | Retire or install SCR in 2025 |
| **UT** | Bonanza | 1-Jan | 1986 | 2030 | Coal consumption cap |
| **WY** | Dave Johnston | BW41 | 1959 | 2027 | PAC IRP |
| **WY** | Dave Johnston | BW42 | 1961 | 2027 | PAC IRP |
| **WY** | Dave Johnston | BW43 | 1964 | 2027 | PAC IRP |
| **WY** | Dave Johnston | BW44 | 1972 | 2027 | PAC IRP |
| **WY** | Jim Bridger | BW71 | 1974 | 2028 | PAC IRP (SCR req'd 2022) |
| **WY** | Naughton | 1 | 1963 | 2029 | PAC IRP |
| **WY** | Naughton | 2 | 1968 | 2029 | PAC IRP |
| **POST 2028 RETIREMENT DATE - SCR INSTALLED** | | | | | |
| **AZ** | Coronado Generating Station | U2B | 1980 | | SCR 2014 |
| **AZ** | Springerville Generating Station | 4 | 2009 | | SCR |
| **AZ** | Springerville Generating Station | TS3 | 2006 | | SCR |
| **CO** | Comanche (470) | 3 | 2010 | | SCR |
| **CO** | Craig | C2 | 1979 | | SCR 2017 |
| **CO** | Hayden | H1 | 1965 | 2030 | Xcel IRP - SCR in 2015 |
| **CO** | Hayden | H2 | 1976 | 2036 | Xcel IRP - SCR 2016 |

| State | Facility Name | Unit ID | Operating Year | Retirement Year | Notes |
|---|---|---|---|---|---|
| **CO** | Pawnee | 1 | 1981 | 2034 | Xcel IRP - SCR 2014 |
| **NM** | Four Corners Steam Elec Station | 4 | 1969 | | 2031 per TEP&PNM - SCR 2017 |
| **NM** | Four Corners Steam Elec Station | 5 | 1970 | | 2031 per TEP&PNM - SCR 2017 |
| **NV** | TS Power Plant | 1 | 2008 | | SCR |
| **WY** | Dry Fork Station | 1 | 2011 | | SCR |
| **WY** | Jim Bridger | BW73 | 1976 | 2037 | PAC IRP - SCR 2015 |
| **WY** | Jim Bridger | BW74 | 1979 | 2037 | PAC IRP - SCR 2016 |
| **WY** | Laramie River | 1 | 1981 | | SCR 2019 |
| **WY** | Wygen I | 1 | 2003 | | SCR |
| **WY** | Wygen II | 1 | 2008 | | SCR |
| **WY** | Wygen III | 1 | 2010 | | SCR |
| **AZ** | Apache Station | 3 | 1979 | | SNCR 2017 |
| **CO** | Craig | C3 | 1984 | | SNCR 2017 |
| **WY** | Laramie River | 2 | 1981 | | SNCR 2018 |
| **WY** | Laramie River | 3 | 1982 | | SNCR 2018 |
| **POST 2028 RETIREMENT DATE - NO POST COMBUSTION CONTROLS FOR $NO_x$** | | | | | |
| **AZ** | Springerville Generating Station | 1 | 1985 | | |
| **AZ** | Springerville Generating Station | 2 | 1990 | | |
| **CO** | Martin Drake | 6 | 1968 | | |
| **CO** | Martin Drake | 7 | 1974 | | |
| **CO** | Rawhide Energy Station | 101 | 1984 | | |
| **CO** | Ray D Nixon | 1 | 1980 | | |
| **MT** | Colstrip | 3 | 1984 | | |
| **MT** | Colstrip | 4 | 1986 | | |
| **MT** | Lewis & Clark | B1 | 1958 | | |
| **NM** | Escalante | 1 | 1984 | | |
| **UT** | Hunter | 1 | 1978 | 2042 | PAC IRP - Haze Lawsuit |
| **UT** | Hunter | 2 | 1980 | 2042 | PAC IRP - Haze Lawsuit |
| **UT** | Hunter | 3 | 1983 | 2042 | PAC IRP |
| **UT** | Huntington | 1 | 1977 | 2036 | PAC IRP - Haze Lawsuit |
| **UT** | Huntington | 2 | 1974 | 2036 | PAC IRP - Haze Lawsuit |
| **WY** | Jim Bridger | BW72 | 1975 | 2032 | PAC IRP (SCR Req'd 2021) |
| **WY** | Neil Simpson II | 1 | 1995 | | |

| State | Facility Name | Unit ID | Operating Year | Retirement Year | Notes |
|---|---|---|---|---|---|
| **WY** | Wyodak | BW91 | 1978 | 2039 | PAC IRP - Haze Lawsuit |

Emissions from coal units that will retire by 2028 comprised 27% of the $SO_2$ and 34% of the $NO_x$ emitted in 2018 by all EGUs (coal and gas) in the 13-state Western region.[91] The figure below shows the portion of EGU emissions represented by remaining fossil units and retiring coal units. The table below contains data compiled by WESTAR-WRAP showing the changes in emissions from 1996-2018 and percent change throughout the GCVTC states.

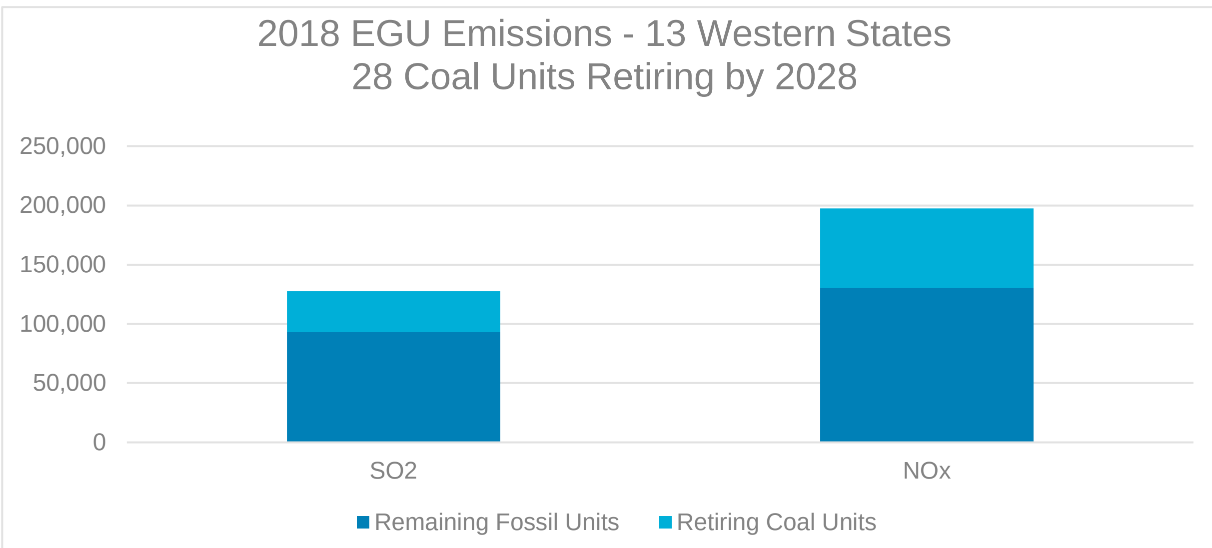


**Figure 24: Remaining and Retiring EGU Emissions Apportionment**

**Table 3: Changes in Emissions from 1996 - 2018 for 9 GCVTC States**

| Year | VOC | $NO_x$ | $SO_2$ | $PM_{2.5}$* | CM |
|---|---|---|---|---|---|
| **1996** | 3325 | 3952 | 1063 | 1197 | 1171 |
| **2002** | 2449 | 2241 | 675 | 832 | 1886 |
| **2018** | 2760 | 1683 | 503 | 832 | 2104 |
| **% Change** | -17 | -57 | -53 | -30 | 80 |

[91] The Analysis of EGU Emissions for Regional Haze Planning by the CNEE can be found at http://www.wrapair2.org/%5C/pdf/Final%20EGU%20Emissions%20Analysis%20Report.pdf

# **Chapter 4:** Utah Visibility Analysis[92]

The rule adopted in 1999 defined "visibility impairment" as "any humanly perceptible change" (i.e., difference) "in visibility (light extinction, visual range, contract, or coloration) from that which would have existed under natural conditions."[93] The 1999 rule directed states to track visibility impairment on the 20% "most impaired days" and 20% "least impaired days" in order to determine progress towards natural visibility conditions.[94] This iteration of the rule did not define "most impaired days" or "least impaired days" or clearly indicate whether they were the days with the highest and lowest values for both natural and anthropogenic impairment or for anthropogenic impairment only. However, the preamble to the 1999 final rule stated that the least and most impaired days were to be selected as the monitored days with the lowest and highest actual deciview levels, respectively, which encompass both natural and anthropogenic contributions to reduced visibility.[95] In 2003, the EPA issued a guidance detailing the steps for selecting and calculating light extinction on the "worst" and "best" visibility days, which also indicated that it is preferable for states to determine the least and most impaired days based on monitoring data rather than determining and selecting the days with the highest and lowest anthropogenic impacts.[96] For the assessment purposes in the first planning period, the GCVTC considered the average of the days representing the 20% best visibility conditions to be the least impaired days.

The "worst" visibility days for some CIAs are impacted by natural emissions (e.g., wildfires and dust storms). These natural contributions to haze vary in magnitude and duration. WRAP used regional photochemical grid models to project visibility improvement between the 2002 baseline and the 2018 future year and to set RPGs for the RHR state implementation plans. Despite western states projecting large emission reductions from EGUs, mobile sources and smoke management programs, the results of the 2018 visibility RPGs indicated many western CIAs were projected to achieve less progress than the glidepath.

As a result, EPA modified the way in which certain days during each year are to be selected for purposes of tracking progress towards natural visibility conditions in order to focus attention on days when anthropogenic emissions impair visibility and away from days when wildfires and natural dust storms are the greatest contributors to visibility impairment.[97] These changes will

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92 40 CFR 51.308(F)(1)

93 "64 Fed. Reg. 35714, 35764."

94 "40 CFR 51.308(d)(2)(i)-(iv)."

95 The 2019 EPA Guidance can be found at: https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

96 The EPA Guidance for Tracking Progress Under the Regional Haze Rule can be found at https://www.epa.gov/visibility/guidance-tracking-progress-under-regional-haze-rule

97 The 2019 EPA Guidance can be found at: https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

provide the public and public officials with more meaningful information on how emission reduction contribute to a decline in anthropogenic visibility impairment by reasonably reducing the distorting effects of wildfires and natural dust storms on estimates of reasonable progress.

The EPA method defined a threshold for the episodic portion of natural haze for the carbonaceous species (organic mass carbon (OMC), elemental carbon (EC)) and crustal material (fine soil plus coarse mass), components that are indicators of wildfires and dust storms, respectively.[98] EPA recommended nominal thresholds for each episodic species' combinations as the minimums of the yearly 95th%ile for the 15-year period from 2000 to 2014. The daily fraction of species extinction values greater than the 95th%ile threshold are assigned to the natural episodic bin. Smaller, routine natural contributions from biogenic or geogenic emissions are assumed to be a constant fraction of the measured IMPROVE species concentrations on each day, with the fraction calculated as the ratio of a previously estimated annual average natural concentration[99] (Natural Conditions II, NC-II) divided by the non-episodic annual average IMPROVE concentrations measured for each species. The metric calculates the

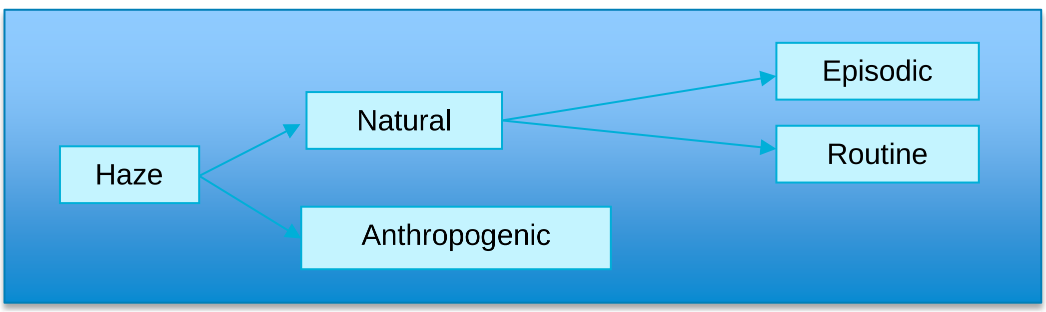


**Figure 25: Light extinction for Utah Class I Areas: natural and anthropogenic sources**

natural routine portion, such that its annual average (excluding episodic events) is equal to the site and species-specific NC-II concentrations.

Daily anthropogenic impairment is calculated as:

$$\Delta\ \mathbf{dv}_{\text{anthropogenic visibility impairment}} = \mathbf{dv}_{\text{total}} - \mathbf{dv}_{\text{natural}}$$

Daily anthropogenic impairment values are ranked from high to low impairment in order to select the 20% most impaired days (MIDs) each year. States must now determine the baseline (2000-2004) visibility condition for the 20% most anthropogenically impaired days. This approach differs from the previous round in which the 20% most impaired days were selected from days with the highest total impairment, not separating anthropogenic versus natural impairment. Once the most impaired days are selected, states must calculate the rate of visibility improvement over time that is required to reach natural conditions by 2064 for the 20% most impaired days. Using the metric described above for separating natural (episodic and routine)

98 Figure 17 shows how haze is separated into natural and anthropogenic causes
99 IMPROVE. 2007. Natural Haze Levels II: Application of the New IMPROVE Algorithm to Natural Species Concentrations Estimates. Interagency Monitoring of Protected Visual Environments. http://vista.cira.colostate.edu/Improve/gray-literature/ (accessed October 2021)

and anthropogenic, natural conditions are calculated as the average of the daily natural contributions on the 20% most impaired days, in the period 2000-2014. The figures below display the clearest and most impaired days calculated as described in EPA guidance. The line drawn from the baseline to the endpoint is termed the glidepath, or the “uniform rate of progress (URP),” and is calculated for each Class I area, and is used as a tracking metric for the path to natural conditions. The URP is calculated with the following formula:

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

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

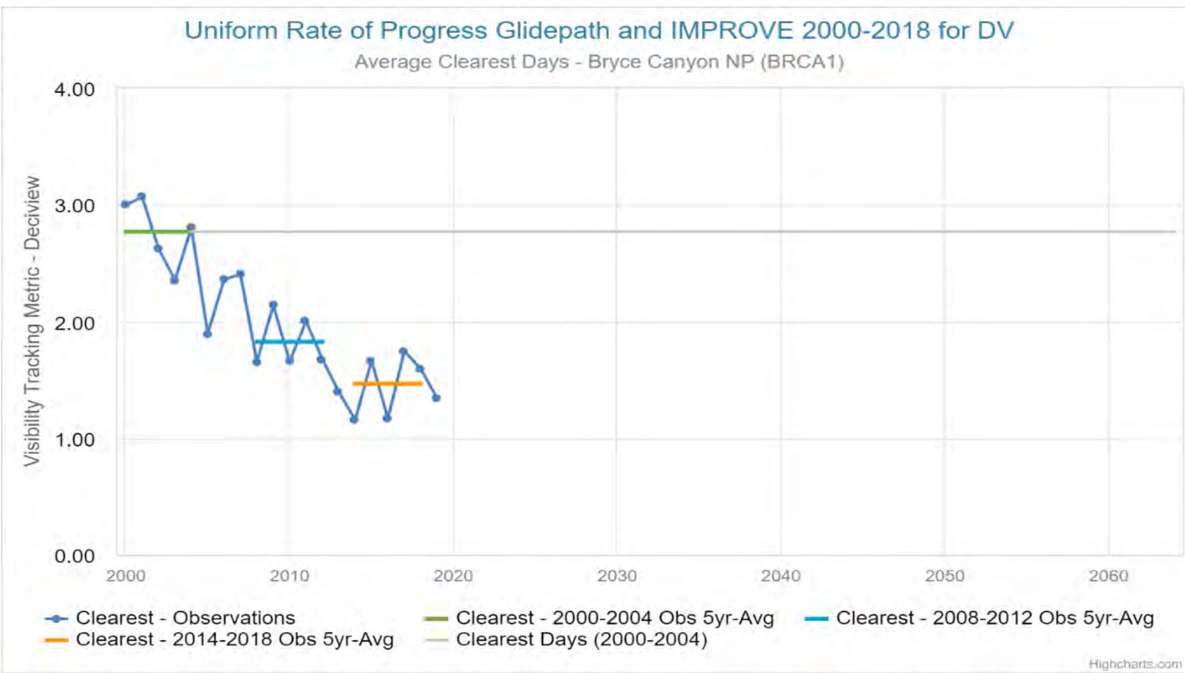


Figure 26: URP Glidepath for Clearest Days, Bryce Canyon NP

No changes were made from the previous implementation period in how the 20% clearest days are calculated. The 20% clearest days are calculated from the days with the lowest total impairment. As stated previously, the RHR requires states to demonstrate that there is no degradation in the 20% clearest days from the baseline period.[100]

[100] “64 Fed. Reg. 35714, 35764.”

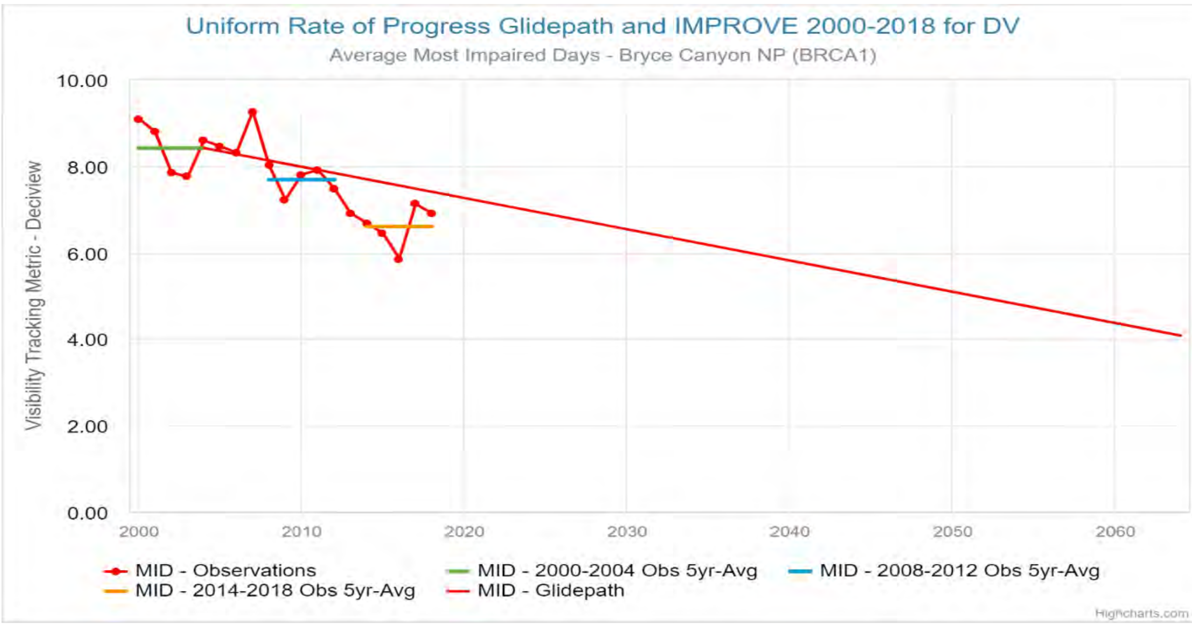


**Figure 27: URP Glidepath for most impaired days, Bryce Canyon NP**

## 4.A Baseline, Current Conditions and Natural Visibility Conditions

Section 51.308(f)(1) of the RHR requires Utah to calculate the baseline, current, and natural visibility conditions as well as to determine the visibility progress to date and the uniform rate of progress (URP) for each of its five CIAs. According to the RHR, baseline period visibility conditions, current visibility conditions, natural conditions, and the URP should be expressed in deciviews and calculated based on total light extinction.[101] Baseline visibility conditions are based on available monitoring data of the most impaired and clearest days during the period of 2000 to 2004. Current visibility conditions are to be calculated based upon the most recent five years of data by calculating the average of the annual deciview index values for the most impaired days and clearest days in this period, and averaging these respective annual values. Natural visibility conditions are to be calculated by estimating the average deciview index on most impaired and clearest days under natural conditions. Calculations were made in accordance with 40 CFR 51.308(d)(2) and EPA's Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program.[102]

**Table 4: Representative IMPROVE Monitoring Sites**

| Class I Area Name | Representative IMPROVE Site | Site ID |
|---|---|---|
| Arches National Park | Canyonlands NP | CANY1 |
| Bryce Canyon National Park | Bryce Canyon NP | BRCA1 |
| Canyonlands National Park | Canyonlands NP | CANY1 |

The 2019 EPA Guidance can be found at: https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf
[102] Tables 4 and 5 describe the IMPROVE site information for Utah's CIAs

| Class I Area Name | Representative IMPROVE Site | Site ID |
|---|---|---|
| Capitol Reef National Park | Capitol Reef NP | CAPI1 |
| Zion National Park | Zion NP | ZICA1 |

**Table 5: IMPROVE site information for CIAs**

| Site ID | Class I Area Name(s) | Latitude | Longitude | State | AQS Code |
|---|---|---|---|---|---|
| BRCA1 | Bryce Canyon National Park | 37.6184 | -112.1736 | UT | 49-017-0101 |
| CANY1 | Arches National Park, Canyonlands National Park | 38.4587 | -109.821 | UT | 49-037-0101 |
| CAPI1 | Capitol Reef National Park | 38.3022 | -111.2926 | UT | 49-055-9000 |
| ZICA1 | Zion National Park | 37.1983 | -113.1507 | UT | 49-053-0130 |

### 4.A.1 Baseline (2000-2004) visibility for the most impaired and clearest days[103]

Baseline visibility conditions are based on the available IMPROVE monitoring data of the 20% most impaired and clearest days during the period of 2000 to 2004. Table 6 shows the baseline visibility calculated for clearest days and most impaired days for each of Utah's CIAs.

**Table 6: Baseline Visibility for the 20% Most Impaired Days and 20% Clearest Days**

| Site ID | Class I Area Name(s) | Clearest Days (dv) | Most Impaired Days (dv) |
|---|---|---|---|
| BRCA1 | Bryce Canyon National Park | 2.77 | 8.42 |
| CANY1 | Arches National Park, Canyonlands National Park | 3.75 | 8.79 |
| CAPI1 | Capitol Reef National Park | 4.10 | 8.78 |
| ZICA1 | Zion National Park | 4.48 | 10.40 |

### 4.A.2 Natural visibility for the most impaired and clearest days[104]

Natural visibility conditions are to be calculated by estimating the average deciview index on most impaired and clearest days under natural conditions. Table 7 summarizes the natural visibility values calculated for the clearest and most impaired days in each of Utah's CIAs.

**Table 7: Natural Visibility values for Utah CIAs**

| Site ID | Class I Area Name(s) | Clearest Days (dv) | Most Impaired Days (dv) |
|---|---|---|---|
| BRCA1 | Bryce Canyon National Park | 0.57 | 4.08 |
| CANY1 | Arches National Park, Canyonlands National Park | 1.05 | 4.13 |

[103] (40 CFR 51.308(f)(1)(i))

[104] (40 CFR 51.308(f)(1)(ii))

| Site ID | Class I Area Name(s) | Clearest Days (dv) | Most Impaired Days (dv) |
|---|---|---|---|
| CAPI1 | Capitol Reef National Park | 1.28 | 4.00 |
| ZICA1 | Zion National Park | 1.83 | 5.26 |

### 4.A.3 Current (2014-2018) visibility for the most impaired and clearest days[105]

Current visibility conditions are to be calculated based upon the most recent five years of data by calculating the average of the annual deciview index values for the most impaired days and clearest days in this period, and averaging these respective annual values. Table 8 below shows the current visibility values calculated for the clearest and most impaired days in each of Utah's CIAs.

**Table 8: Current Visibility (2014-2018) conditions in Utah CIAs**

| Site ID | Class I Area Name(s) | Clearest Days (dv) | Most Impaired Days (dv) |
|---|---|---|---|
| BRCA1 | Bryce Canyon National Park | 1.46 | 6.60 |
| CANY1 | Arches National Park, Canyonlands National Park | 2.20 | 6.76 |
| CAPI1 | Capitol Reef National Park | 2.38 | 7.18 |
| ZICA1 | Zion National Park | 3.86 | 8.75 |

[105] (40 CFR 51.308(f)(1)(iii))

### 4.A.4 Progress to date: most impaired and clearest days[106]

Actual progress towards the natural visibility conditions goal has been calculated in relation to the baseline period for each of Utah's CIAs. This is exhibited by the difference between the average visibility condition during the 5-year baseline, previous implementation period, and each subsequent 5-year period up to and including the current period. The following table displays the progress in Utah's CIAs comparing the baseline values for clearest and most impaired days with the first implementation period and 2014-2018 values.

**Table 9: Progress to date for the most impaired and clearest days**

| Site ID | 2000-2004 Baseline (dv) | | 2008-2012 Previous implementation period (dv) | | 2014-2018 Current (dv) | |
|---|---|---|---|---|---|---|
| | 20% Clearest | 20% Most Impaired | 20% Clearest | 20% Most Impaired | 20% Clearest | 20% Most Impaired |
| BRCA1 | 2.77 | 8.42 | 1.82 | 7.69 | 1.46 | 6.60 |
| CANY1 | 3.75 | 8.79 | 2.93 | 8.12 | 2.20 | 6.76 |
| CAPI1 | 4.10 | 8.78 | 2.53 | 8.16 | 2.38 | 7.18 |
| ZICA1 | 4.48 | 10.40 | 4.22 | 9.17 | 3.86 | 8.75 |

### 4.A.5 Differences between current and natural for the most impaired and clearest days[107]

The following table compares the difference between the current deciview values for each CIA to the estimated natural visibility for the 20% most impaired days and clearest days.

**Table 10: Current visibility compared to natural visibility**

| Site ID | 2014-2018 Current (dv) | | Natural Visibility (dv) | | Difference (dv) | |
|---|---|---|---|---|---|---|
| | 20% Clearest | 20% Most Impaired | 20% Clearest | 20% Most Impaired | 20% Clearest | 20% Most Impaired |
| BRCA1 | 1.46 | 6.60 | 0.57 | 4.08 | 0.89 | 2.52 |
| CANY1 | 2.20 | 6.76 | 1.05 | 4.13 | 1.15 | 2.63 |
| CAPI1 | 2.38 | 7.18 | 1.28 | 4.00 | 1.1 | 3.18 |
| ZICA1 | 3.86 | 8.75 | 1.83 | 5.26 | 2.03 | 3.49 |

[106] (40 CFR 51.308(f)(1)(iv))
[107] (40 CFR 51.308(f)(1)(v))

## 4.B Uniform Rate of Progress[108]

Utah analyzed and determined the uniform rate of progress (URP) over time for each of its five CIAs, starting at the baseline period of 2000-2004, that would be needed to attain the natural visibility condition on the 20% most anthropogenically impaired days by the year 2064. Table 11 shows the URP for each IMPROVE site.

**Table 11: Uniform Rates of Progress**

| CIA IMPROVE Site | Baseline Conditions (Most Impaired Days) (dv) | 2064 Natural Conditions (Most Impaired Days) (dv) | Years to Reach Natural Conditions | Uniform Rate of Progress (URP) (dv/year) |
|---|---|---|---|---|
| BRCA1 | 8.42 | 4.08 | 60 | -0.072 |
| CANY1 | 8.79 | 4.13 | 60 | -0.078 |
| CAPI1 | 8.78 | 4.00 | 60 | -0.080 |
| ZICA1 | 10.40 | 5.26 | 60 | -0.086 |

Utah then used the URP to establish the level of visibility change needed from baseline conditions by 2028 as shown in Table 12. The 2028 URP level is used for comparison to WRAP photochemical modeling projections for 2028 shown in sections 6.A.10 and 8.C.

**Table 12: Calculation of 2028 Uniform Rate of Progress Level**

| CIA IMPROVE Site | Baseline Conditions (Most Impaired Days) (dv) | Visibility Change by 2028 (URPX24 years) (dv) | 2028 URP Level (dv) |
|---|---|---|---|
| BRCA1 | 8.42 | -1.74 | 6.68 |
| CANY1 | 8.79 | -1.87 | 6.92 |
| CAPI1 | 8.78 | -1.91 | 6.87 |
| ZICA1 | 10.40 | -2.06 | 8.35 |

## 4.C Adjustments to URP: International impacts and/or prescribed fire[109]

EPA added a provision in the 2019 guidance that allows EPA to approve adjustments to the URP to reflect the impacts of international and wildland prescribed fire sources of visibility impairment if an adjustment has been developed through scientifically valid data and methods. These adjustments would be developed and applied separately, although they would both be accomplished by adding an estimate of the impact of the relevant source type or types to the value of the natural visibility condition for the 20% most anthropogenically impaired days, for the purposes of calculating the URP.[110] The wildland prescribed fires that are eligible under the

[108] (40 CFR 51.308(f)(1)(vi))
[109] (40 CFR 51.308(f)(1)(vi)(B)(1) and (2))
[110] The 2019 EPA Guidance can be found at: https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

RHR to be included in this adjustment are those conducted with the objective to establish, restore, and/or maintain sustainable and resilient wildland ecosystems, to reduce the risk of catastrophic wildfires, and/or to preserve endangered or threatened species during which appropriate basic smoke management practices were applied.[111]

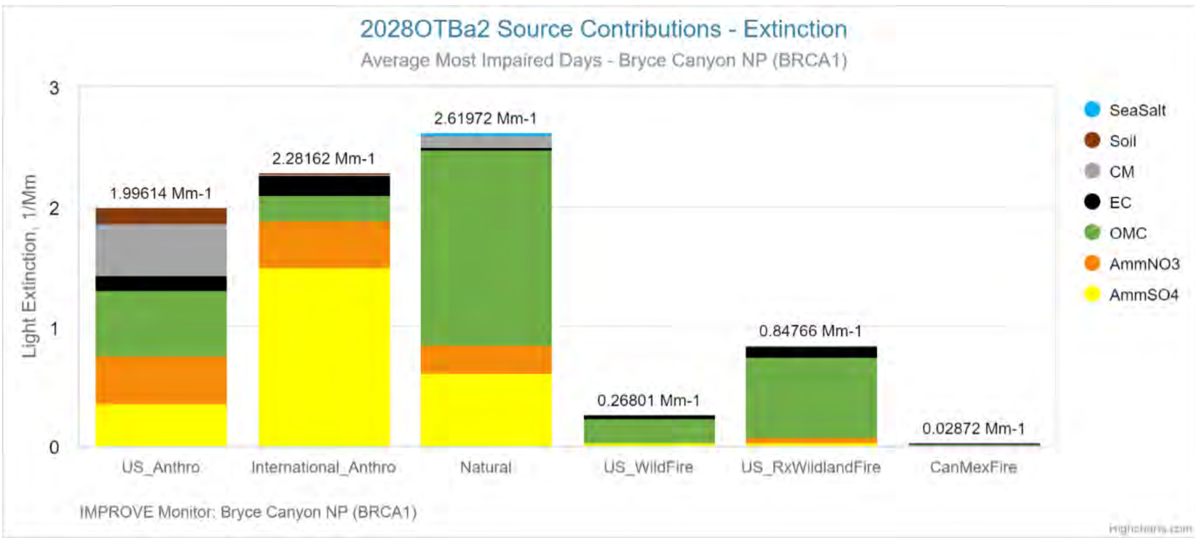


**Figure 29: Projected Source Contributions to Light Extinction in Bryce Canyon NP**

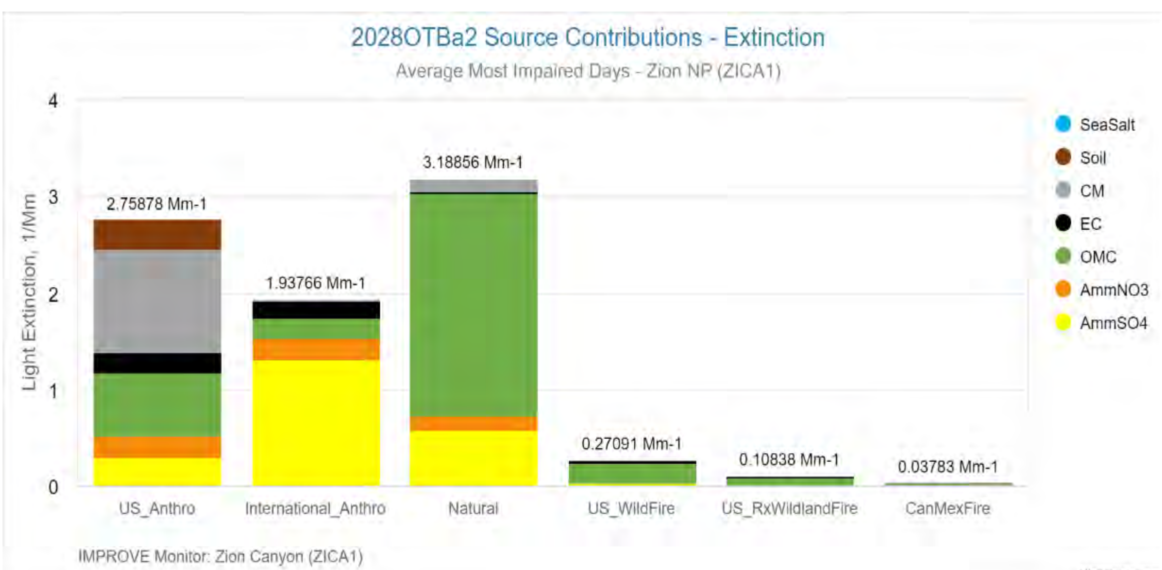


**Figure 28: Projected Source Contributions to Light Extinction in Zion NP**

[111] "64 Fed. Reg. 35714, 35764."

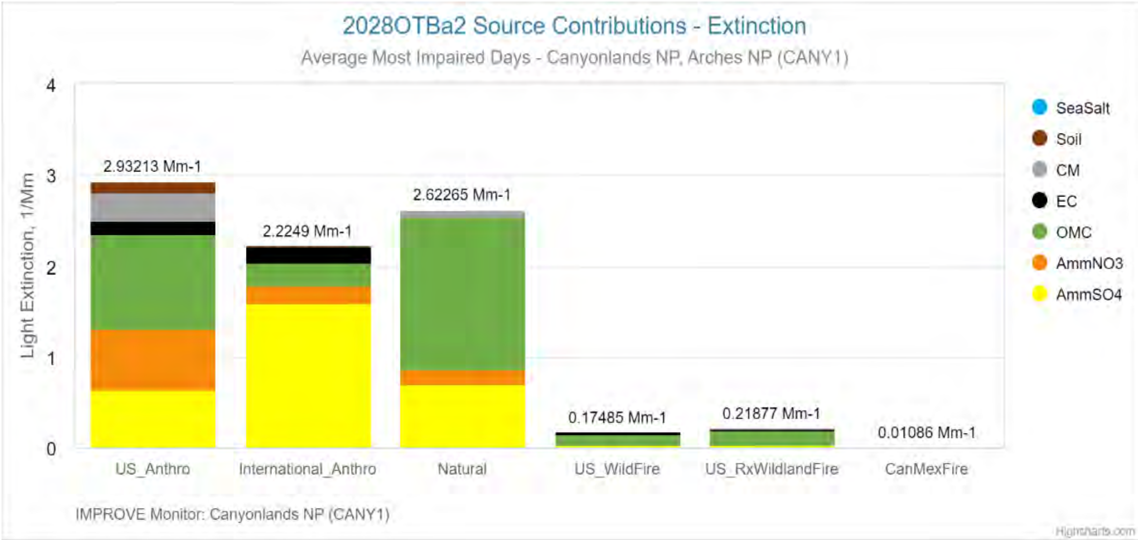


**Figure 30: Projected Source Contributions to Light Extinction in Canyonlands and Arches NP**

Modeling done by both EPA and WRAP shows that Utah is significantly impacted by international and wildland prescribed fire emissions (as shown by figures 29-31). Further detail on emission source apportionment can be found in Chapter 5: Utah Sources of Visibility Impairment.

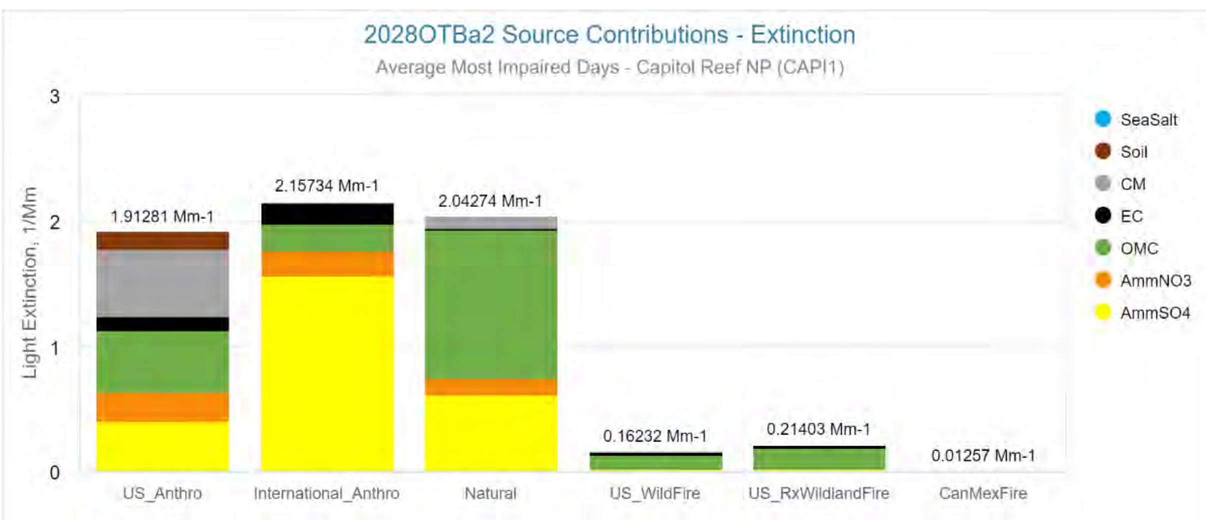


**Figure 31: Projected Source Contributions to Light Extinction in Capitol Reef NP**

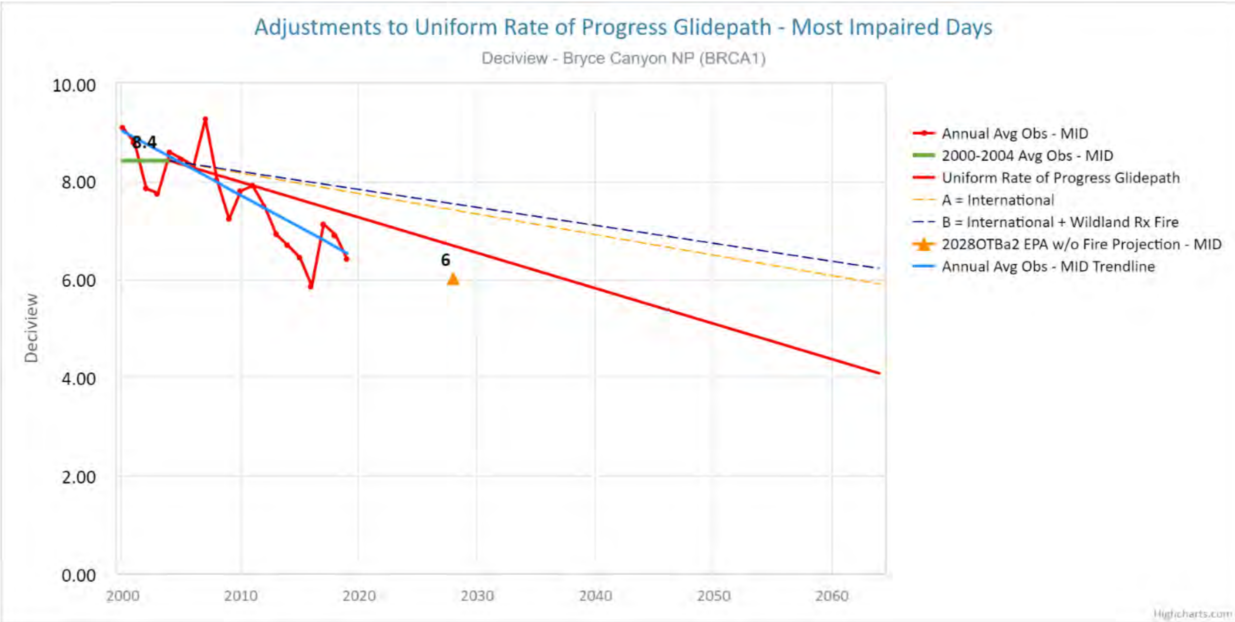


**Figure 32: Example URP Glidepath for Bryce Canyon National Park Showing Adjustment Options**

It should be noted that the prescribed fire adjustments for Utah's CIAs are small relative to those in other states. The international source adjustments, on the other hand, can be sizable. While the international and wildland prescribed fire adjustments are available for Utah's CIA glidepaths, UDAQ is choosing to remain conservative for the purposes of this implementation period by not using them. However, this choice does not preclude the use of glidepath adjustments in future planning periods, since international and wildland prescribed fire emissions do impact Utah CIAs and are largely beyond the control of individual states and since prescribed fires are seen to be an increasingly important tool for land managers in the future.

# **Chapter 5:** Utah Sources of Visibility Impairment

## 5.A Natural Sources of Impairment

Natural impairment sources include any non-anthropogenically caused visibility-reducing emissions and are often seasonally attributed to natural events such as rain, sea mists, windblown dust, wildfire, volcanic activity, and biogenic emissions. Natural sources of impairment are often caused by seasonal conditions and lead to high concentrations of visibility-impairing emissions that are short-term. Natural contributions to impairment are categorized into the "episodic" and "routine" types. Episodic contributions, such as large wildfires or dust storms, occur infrequently and vary yearly in number and size. Routine contributions include biogenic sources, sea salt, and incorporate the site-specific value for Rayleigh scattering, a term which refers to the scattering of light off of particles in the air. These contributions occur often and are more consistent on a yearly basis.

## 5.B Anthropogenic Sources of Impairment

Anthropogenic impairment sources include any visibility-decreasing emissions directly related to human-caused activities. These activities include industrial processes (utilities, smelters, refineries, etc.), mobile sources (cars, trucks, trains, etc.) and area sources (residential wood burning, prescribed burning on wild and agricultural lands, wind-blown dust from disturbed soils, etc.). Anthropogenic sources of emissions include those originating within Utah as well as neighboring states, Mexico, Canada, and maritime shipping emissions from across the Pacific Ocean. While Utah can consult with regional states about their anthropogenic emission contributions to impairment in Utah's CIAs, those international contributions cannot be controlled at the state level. The following table details the data sources used by WRAP for determining anthropogenic source emissions contributions.

**Table 13: Data sources for WRAP emissions sectors**[112]

| Source Sector | 2014v2 | RepBase2 | 2028OTBa2 |
|---|---|---|---|
| **California All Sectors 12WUS2** | CARB-2014v2 | CARB-2014v2 | CARB-2028 |
| **WRAP Fossil EGU w/ CEM** | WRAP-2014v2 | WRAP-RB-EGU [1] | WRAP-2028-EGU [1] |
| **WRAP Fossil EGU w/o CEM** | EPA-2014v2 | WRAP-RB-EGU [1] | WRAP-2028-EGU [1] |
| **WRAP Non-Fossil EGU** | EPA-2014v2 | EPA-2016v1 | EPA-2028v1 |
| **Non-WRAP EGU** | EPA-2014v2 | EPA-2016v1 | EPA-2028v1 |
| **O&G WRAP O&G States** | WRAP-2014v2 | WRAP-RB-O&G [2] | WRAP-2028-O&G [2] |
| **O&G WRAP Other States** | EPA-2014v2 | EPA-2016v1 | EPA-2016v1 [3] |
| **O&G non-WRAP States** | EPA-2014v2 | EPA-2016v1 | EPA-2016v1 [3] |
| **WRAP Non-EGU Point** | WRAP-2014v2 | WRAP-2014v2 [4] | WRAP-2014v2 [4] |
| **Non-WRAP non-EGU Point** | EPA-2014v2 | EPA-2016v1 | EPA-2016v1 |
| **On-Road Mobile 12WUS2** | WRAP-2014v2 | WRAP-2014v2 | WRAP-2028-Mobile [5] |
| **On-Road Mobile 36US** | EPA-2014v2 | EPA-2016v1 | EPA-2028v1 |
| **Non-Road 12WUS2** | EPA-2014v2 | EPA-2016v1 | WRAP-2028-Mobile [5] |
| **Non-Road non-WRAP 36US** | EPA-2014v2 | EPA-2016v1 [6] | EPA-2028v1 [6] |

[112] This data sources' table comes from the 2021 WRAP Technical Support System Emissions and Modeling Report and References document.

| | | | |
|---|---|---|---|
| **Other (Non-Point) 12WUS2** | EPA-2014v2 | EPA-2014v2 [7] | EPA-2014v2 [7] |
| **Other (Non-Point) 36US** | EPA-2014v2 | EPA-2016v1 | EPA-2016v1 |
| **Can/Mex/Offshore 12WUS2** | EPA-2014v2 | EPA-2016v1 | EPA-2016v1 |
| **Fires (WF, Rx, Ag)** | WRAP-2014-Fires | WRAP-RB-Fires [8] | WRAP-RB-Fires [8] |
| **Natural (Bio, etc.)** | WRAP-2014v2 | WRAP-2014v2 | WRAP-2014v2 |
| **Boundary Conditions (BCs)** | WRAP-2014-GEOS | WRAP-2014-GEOS | WRAP-2014-GEOS |

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

## 5.C Overview of Emission Inventory System - TSS

The WRAP 2014v2 inventory was based on the National Emissions Inventory (NEI) and updates provided by states through their Emissions and Modeling Protocol subcommittee. Specific data sources for each emissions sector are detailed below:

The CAMx Particle Source Apportionment tool (PSAT) is a photochemical model that tracks gaseous and particle air emissions from sources through atmospheric dispersion, photochemical reactions, and transport to receptors where IMPROVE monitors are located. These PSAT runs include aerosol concentrations of:

- $AmmNO_3$
- $AmmSO_4$
- Primary Organic Mass from Carbon (OMC)
- Primary Elemental Carbon (EC)
- Primary Fine Soil
- Primary Coarse Mass
- Sea salt
- Secondary Organic Aerosols
    - Anthropogenic (SOAA)
    - Biogenic (SOAB)

These particles are direct products of primary gaseous and particle emissions and secondary aerosol formation. Secondary organic aerosols (SOA) tracers are not used in these PSAT runs, rather SOAs at the receptor are assigned to anthropogenic (SOAA) or biogenic (SOAB) contributions based on the chemical signatures (e.g., isoprene is assigned as biogenic in origin; benzene is assigned as anthropogenic in origin).

WRAP modeled values for six source categories and 15 component source groups[113]:

- U.S. Anthropogenic (USAnthro)
    - U.S. anthropogenic (AntUS)
    - U.S. agricultural fire (AgfireUS)
    - Secondary Organic Aerosol-Anthropogenic (SOAA)
    - Commercial Marine Vessels (CMVUS)
    - U.S. anthropogenic contributions from outside the CAMx 36-km domain boundary as defined by the GEOS-Chem global model. (BC-US)
- U.S. Wildfire (WFUS)
- U.S. Wildland Prescribed fire (RxUS)
- Canadian and Mexican fires (OthFr)
- Natural
    - Natural (Nat)
    - Secondary Organic Aerosol -Biogenic (SOAB)
    - Natural contributions from outside the CAMx 36-km domain boundary as defined by the GEOS-Chem global model. (BC-Nat)
- International Anthropogenic (IntlAnthro)
    - International Anthropogenic contributions from outside the CAMx 36-km domain boundary as defined by the GEOS-Chem global model. (BC-Int)
    - Canadian Anthropogenic (AntCAN)
    - Mexican Anthropogenic (AntMEX)
    - Commercial Marine vessels – International (beyond 200km from U.S. coast) (CMV_nonUS)

Summaries of Utah's emissions data are located in Chapter 3 as well as tables 13-20 of this chapter.

## 5.D Wildland Prescribed Fires

Most forest ecosystems in the West have a general pattern in which fires naturally occur, otherwise called a fire regime. These regimes serve the purpose of helping a forest get rid of excess wood fuel and cause opportunities for regrowth and regeneration. Many forest ecosystems in the West depend on fire to create their optimal conditions. As human populations increase in the West, the Wildland-Urban Interface (WUI) has led to fire suppression which impedes natural fire regimes for the safety of residential areas. This causes an increase in fuel (burnable wood) in the forests of Utah that increases their chances of unintentionally catching fire. Further contributing to the dangers of uncontrolled fire is the increase in climate change every year. To better control the location and degree at which forest fires occur, fire can be prescribed for an area under certain weather conditions and with the appropriate permits. Utilizing prescribed fires and returning fire to an ecosystem in a controlled manner helps restore its health and reduce potentially catastrophic wildfires. Healthy ecosystems with restored natural fire regimes are more resistant to severe fire, disease, and insect infestations. The United

[113] Information on the TSS source apportionment data is located at http://views.cira.colostate.edu/tssv2/Reports2/Modeling/Src-App-DB-Avg-Bext-By-Source.aspx

States Forest Service (USFS) and other land management agencies in Utah closely monitor local precipitation, wind, fuel, moisture, and other elements to determine the best conditions to carry out prescribed burning.

The State of Utah and the USFS have developed mutual commitments to advance the strategy of “Shared Stewardship” in Utah. In August 2018, the Forest Service released a document outlining a new strategy for land management called “Toward Shared Stewardship Across Landscapes: An Outcome-Based Investment Strategy.” This strategy responds to the growing challenges faced by land managers including catastrophic wildfires. Of particular concern are longer fire seasons and the increasing size and severity of wildfires, along with the expanding risk to communities, water sources, wildlife habitat, air quality, and the safety of firefighters. Through Shared Stewardship, the State and Forest Service can work together and set landscape-scale priorities, implement projects at the appropriate scale, co-manage risks, share resources, and learn from each other while building long-term capacity to live with wildfire. Due to these initiatives, more frequent wildfires in the West, and thus increasing importance of prescribed fires, Utah does not consider reducing prescribed fires as a reasonable method to reduce visibility impairment.

## 5.E Utah Emissions

Federal visibility regulations[114] require a statewide emissions inventory of pollutants anticipated to contribute to visibility impairment in Utah’s CIAs. WRAP inventoried pollutants in Utah including $SO_2$, $NO_x$, VOCs, $PM_{2.5}$, $PM_{10}$, and $NH_3$. The WRAP 2014v2 inventory was based on the 2014v2 National Emissions Inventory (NEI) as well as updates provided by western states (including Utah). RepBase2, the representative baseline emissions scenario, updated the 2014v2 inventory originally used to account for changes and variations in emissions from 2014 to 2018. This version also accounted for duplicate records found and revised some EGU, non-EGU point, oil, and gas emissions. The 2028 On the Books Inventory (2028OTBa2) projection follows the methods presented by the EPA in their 2019 Technical Support Document. WRAP states updated projections for all anthropogenic source sectors. Oil and gas area emissions were also updated by Ramboll, Inc. and the WRAP Oil and Gas Workgroup and separated into Tribal and non-Tribal mineral ownership. The following table contains data compiled by WRAP with information on the status of EGU retirements in Utah that were used in the RepBase2 and 2028OTBa2 inventories.

**Table 14: Status of Utah EGU Retirements in RepBase2 and 2028OTBa2 Inventories**

| Facility Name | Unit ID | In-Service Year | Retirement Year | Notes | Operator | Unit Type |
|---|---|---|---|---|---|---|
| **Intermountain** | 1SGA | 1986 | 2025 | Announced retirement | Intermountain Power Service Corporation | Dry bottom wall-fired boiler |

114 40 C.F.R. § 51.308(d)(4)(v).

| Facility Name | Unit ID | In-Service Year | Retirement Year | Notes | Operator | Unit Type |
|---|---|---|---|---|---|---|
| **Intermountain** | 2SGA | 1987 | 2025 | Announced retirement | Intermountain Power Service Corporation | Dry bottom wall-fired boiler |
| **Bonanza** | 1-Jan | 1986 | 2030 | Coal consumption cap | Deseret Generation & Transmission | Dry bottom wall-fired boiler |
| **Hunter** | 1 | 1978 | 2042 | PAC IRP; Round 1 RH FIP in Litigation | PacifiCorp Energy Generation | Tangentially-fired |
| **Hunter** | 2 | 1980 | 2042 | PAC IRP; Round 1 RH FIP in Litigation | PacifiCorp Energy Generation | Tangentially-fired |
| **Hunter** | 3 | 1983 | 2042 | PAC IRP | PacifiCorp Energy Generation | Dry bottom wall-fired boiler |
| **Huntington** | 1 | 1977 | 2036 | PAC IRP; Round 1 RH FIP in Litigation | PacifiCorp Energy Generation | Tangentially-fired |
| **Huntington** | 2 | 1974 | 2036 | PAC IRP; Round 1 RH FIP in Litigation | PacifiCorp Energy Generation | Tangentially-fired |

The resulting inventories were then used by WRAP to model future visibility in Utah's CIAs.[115]

State and federal law require Utah to conduct a statewide emissions inventory program every three years. This inventory accounts for point, area, and mobile sources and accounts for the following criteria pollutants:

- Ammonia ($NH_3$)
- Carbon Monoxide (CO)
- Lead and Lead Compounds
- Nitrogen Oxides (NO)
- Particulate Matter ($PM_{10}$ and $PM_{2.5}$)
- Sulfur Oxides ($SO_2$)
- Volatile Organic Compounds (VOCs)

The following tables contain Utah's projected emissions inventories by species resulting from the RepBase2 and 2018OTBa2 modeling projections.

**Table 15: Utah $SO_2$ Emission Inventory – RepBase2 (2014-2018) and 2028OTBa2**

| Utah – Statewide $SO_2$ Emissions (TPY) | | | | |
|---|---|---|---|---|
| Type | **Source Category** | **2014v2 Actual** | **Representative Baseline 2** | **2028 OTB a2** |

[115] The complete methodology used to develop the WRAP emissions inventory can be found in "WRAP Technical Support System for Regional Haze Planning: Emissions and Modeling Methods, Results, and References" released on August 19, 2021.

| | | | | |
|---|---|---|---|---|
| **Anthropogenic** | Electric Generating Units (EGU) | 24,011 | 11,357 | 9,866 |
| **Anthropogenic** | Oil and Gas – Point | 664 | 545 | 570 |
| **Anthropogenic** | Industrial and Non-EGU Point | 2,400 | 2,402 | 2,402 |
| **Anthropogenic** | Oil and Gas – Non-point | 41 | 41 | 31 |
| **Anthropogenic** | Residential Wood Combustion | 24 | 24 | 24 |
| **Anthropogenic** | Fugitive dust | 0 | 0 | 0 |
| **Anthropogenic** | Agriculture | 0 | 0 | 0 |
| **Anthropogenic** | Remaining Non-point | 61 | 61 | 61 |
| **Anthropogenic** | On-Road Mobile | 275 | 275 | 185 |
| **Anthropogenic** | Non-road Mobile | 25 | 16 | 13 |
| **Anthropogenic** | Rail | 3 | 3 | 3 |
| **Anthropogenic** | Commercial Marine | 0 | 0 | 0 |
| **Anthropogenic** | Agricultural Fire | 5 | 5 | 5 |
| **Anthropogenic** | Wildland Prescribed Fire | 320 | 524 | 524 |
| | **Total Anthropogenic** | **27,829** | **15,253** | **13,684** |
| **Natural** | Wildfire | 375 | 1,295 | 1,295 |
| **Natural** | Biogenic | 0 | 0 | 0 |
| | **Total Natural** | **375** | **1,295** | **1,295** |
| | **Grand Total** | **28,204** | **16,548** | **14,979** |

The largest source of $SO_2$ emissions is fossil fuel combustion (mainly coal) at power plants and other industrial facilities. In Utah, the largest source of $SO_2$ emissions are EGUs. Smaller sources include metal extraction, mobile vehicles, and wood burning. Wildfires are the second largest source of $SO_2$ emissions in both the RepBase and 2028 scenarios. $SO_2$ emissions that lead to high concentrations of $SO_2$ in the air generally also lead to the formation of other sulfur oxides ($SO_x$). $SO_x$ can react with other compounds in the atmosphere to form small particles. These particles contribute to PM pollution. Ammonium sulfate particles can have a great impact on visibility due to their greater light scattering effects. According to the 2028 OTB a2 modeling, $SO_2$ emissions are projected to decline to 14,979 tons per year in 2028.

**Table 16: Utah NOx Emission Inventory – RepBase2 (2014-2018) and 2028OTBa2**

| Utah – Statewide $NO_x$ Emissions (TPY) | | | | |
|---|---|---|---|---|
| Type | **Source Category** | **2014v2 Actual** | **Representative Baseline 2** | **2028 OTB a2** |
| **Anthropogenic** | Electric Generating Units (EGU) | 54,497 | 31,882 | 23,848 |
| **Anthropogenic** | Oil and Gas – Point | 14,636 | 14,589 | 9,140 |
| **Anthropogenic** | Industrial and Non-EGU Point | 13,086 | 13,107 | 13,107 |
| **Anthropogenic** | Oil and Gas – Non-point | 1,811 | 1,806 | 1,428 |
| **Anthropogenic** | Residential Wood Combustion | 189 | 189 | 189 |

| Utah – Statewide $NO_x$ Emissions (TPY) | | | | |
|---|---|---|---|---|
| **Anthropogenic** | Fugitive dust | 0 | 0 | 0 |
| **Anthropogenic** | Agriculture | 0 | 0 | 0 |
| **Anthropogenic** | Remaining Non-point | 4,846 | 4,846 | 4,846 |
| **Anthropogenic** | On-Road Mobile | 74,643 | 74,643 | 25,539 |
| **Anthropogenic** | Non-road Mobile | 9,669 | 7,029 | 4,741 |
| **Anthropogenic** | Rail | 5,646 | 5,646 | 4,164 |
| **Anthropogenic** | Commercial Marine | 1 | 0 | 0 |
| **Anthropogenic** | Agricultural Fire | 19 | 19 | 19 |
| **Anthropogenic** | Wildland Prescribed Fire | 596 | 572 | 572 |
| | **Total Anthropogenic** | **179,639** | **154,328** | **87,593** |
| **Natural** | Wildfire | 704 | 2,063 | 2,063 |
| **Natural** | Biogenic | 12,602 | 12,602 | 12,602 |
| | **Total Natural** | **13,306** | **14,665** | **14,665** |
| | **Grand Total** | **192,945** | **168,993** | **102,258** |

$NO_x$ is a group of highly reactive gases formed in high-temperature combustion processes. This group includes $NO_2$, nitrous acid, and nitric acid. $NO_2$ emissions are primarily caused by fuel combustion from cars, trucks, buses, power plants, and off-road equipment. These substances are toxic by themselves and can react to form ozone or $PM_{10}$ in the form of nitrates. Large nitrate particles have a greater light-scattering effect than large sulfate particles or dust particles. Most $NO_x$ emissions in Utah are from EGUs. $NO_x$ emissions are projected to decline to 102,258 tons per year, according to the 2028 OTB a2 modeling.

**Table 17: Utah VOC Emission Inventory – RebBase2 (2014-2018) and 2028OTBa2**

| Utah - Statewide VOC Emissions (TPY) | | | | |
|---|---|---|---|---|
| Type | **Source Category** | **2014v2 Actual** | **Representative Baseline 2** | **2028 OTB a2** |
| **Anthropogenic** | Electric Generating Units (EGU) | 391 | 285 | 276 |
| **Anthropogenic** | Oil and Gas - Point | 111,225 | 110,906 | 71,207 |
| **Anthropogenic** | Industrial and Non-EGU Point | 3,146 | 3,152 | 3,152 |
| **Anthropogenic** | Oil and Gas - Non-point | 37,069 | 35,252 | 21,513 |
| **Anthropogenic** | Residential Wood Combustion | 1,589 | 1,589 | 1,589 |
| **Anthropogenic** | Fugitive dust | 0 | 0 | 0 |
| **Anthropogenic** | Agriculture | 2,120 | 2,120 | 2,120 |
| **Anthropogenic** | Remaining Non-point | 29,913 | 29,913 | 29,913 |
| **Anthropogenic** | On-Road Mobile | 28,356 | 28,356 | 11,589 |
| **Anthropogenic** | Non-road Mobile | 17,694 | 8,966 | 6,314 |
| **Anthropogenic** | Rail | 287 | 287 | 179 |
| **Anthropogenic** | Commercial Marine | 0 | 0 | 0 |
| **Anthropogenic** | Agricultural Fire | 31 | 31 | 31 |

| Utah - Statewide VOC Emissions (TPY) | | | | |
|---|---|---|---|---|
| **Anthropogenic** | Wildland Prescribed Fire | 8,675 | 23,415 | 23,415 |
| | **Total Anthropogenic** | **240,496** | **244,272** | **171,298** |
| **Natural** | Wildfire | 10,062 | 54,614 | 54,614 |
| **Natural** | Biogenic | 717,742 | 717,742 | 717,742 |
| | **Total Natural** | **727,804** | **772,356** | **772,356** |
| | **Grand Total** | **968,300** | **1,016,628** | **943,654** |

VOCs are volatile organic compounds that have high vapor pressure at room temperature. Many VOCs are human-made compounds that are used and produced in the manufacturing of paints, pharmaceuticals, and refrigerants. Companies in Utah must report all reactive VOC emissions (including fugitive emissions). Different VOCs have differing levels of reactivity that convert them to ozone. Therefore, changes in their emissions have limited effects on local or regional ozone pollution. VOCs also play a role in the formation of secondary particulates that can impact regional haze. The largest source of VOC emissions in Utah is oil and gas point sources. VOC emissions are expected to decline to 943,654 tons per year according to the 2028 OTB a2 projections.

**Table 18: Utah PM2.5 Emission Inventory – RepBase2 (2014-2018) and 2028OTBa2**

| Utah - Statewide $PM_{2.5}$ Emissions (TPY) | | | | |
|---|---|---|---|---|
| Type | **Source Category** | **2014v2 Actual** | **Representative Baseline 2** | **2028 OTB a2** |
| **Anthropogenic** | Electric Generating Units (EGU) | 2,799 | 2,195 | 1,310 |
| **Anthropogenic** | Oil and Gas - Point | 631 | 621 | 476 |
| **Anthropogenic** | Industrial and Non-EGU Point | 2,618 | 2,620 | 2,620 |
| **Anthropogenic** | Oil and Gas - Non-point | 81 | 81 | 61 |
| **Anthropogenic** | Residential Wood Combustion | 1,403 | 1,403 | 1,403 |
| **Anthropogenic** | Fugitive dust | 12,177 | 12,177 | 12,177 |
| **Anthropogenic** | Agriculture | 0 | 0 | 0 |
| **Anthropogenic** | Remaining Non-point | 1,181 | 1,181 | 1,181 |
| **Anthropogenic** | On-Road Mobile | 2,726 | 2,726 | 1,081 |
| **Anthropogenic** | Non-road Mobile | 1,103 | 706 | 447 |
| **Anthropogenic** | Rail | 165 | 165 | 108 |
| **Anthropogenic** | Commercial Marine | 0 | 0 | 0 |
| **Anthropogenic** | Agricultural Fire | 83 | 83 | 83 |
| **Anthropogenic** | Wildland Prescribed Fire | 3,580 | 7,092 | 7,092 |
| | **Total Anthropogenic** | **28,547** | **31,050** | **28,039** |
| **Natural** | Wildfire | 4,161 | 17,381 | 17,381 |
| **Natural** | Biogenic | 0 | 0 | 0 |
| | **Total Natural** | **4,161** | **17,381** | **17,381** |
| | **Grand Total** | **32,708** | **48,431** | **45,420** |

$PM_{2.5}$ particulates are fine, inhalable particles or droplets with a diameter of 2.5 microns or smaller. Within two years after the EPA revises NAAQS for criteria pollutants, it must designate areas according to their attainment status. These designations are based on the most recent three years of monitoring data, state recommendations, and other technical information. If an area is not meeting the standard, Utah must write a $PM_{2.5}$ SIP that includes necessary control measures to ensure future attainment. The sector with the largest contribution of $PM_{2.5}$ emissions in Utah is fugitive dust. $PM_{2.5}$ emissions are expected to decline somewhat according to the 2028 OTB a2 modeling.

**Table 19: Utah PM2.5 Emission Inventory – RepBase2 (2014-2018) and 2028OTBa2**

| Utah - Statewide $PM_{10}$ Emissions (TPY) | | | | |
|---|---|---|---|---|
| Type | **Source Category** | **2014v2 Actual** | **Representative Baseline 2** | **2028 OTB a2** |
| **Anthropogenic** | Electric Generating Units (EGU) | 3,671 | 2,534 | 1,607 |
| **Anthropogenic** | Oil and Gas - Point | 632 | 621 | 476 |
| **Anthropogenic** | Industrial and Non-EGU Point | 5,385 | 5,387 | 5,387 |
| **Anthropogenic** | Oil and Gas - Non-point | 81 | 81 | 61 |
| **Anthropogenic** | Residential Wood Combustion | 1,410 | 1,410 | 1,410 |
| **Anthropogenic** | Fugitive dust | 95,505 | 95,505 | 95,505 |
| **Anthropogenic** | Agriculture | 0 | 0 | 0 |
| **Anthropogenic** | Remaining Non-point | 1,317 | 1,317 | 1,317 |
| **Anthropogenic** | On-Road Mobile | 4,547 | 4,547 | 3,550 |
| **Anthropogenic** | Non-road Mobile | 1,165 | 745 | 477 |
| **Anthropogenic** | Rail | 179 | 179 | 111 |
| **Anthropogenic** | Commercial Marine | 0 | 0 | 0 |
| **Anthropogenic** | Agricultural Fire | 119 | 119 | 119 |
| **Anthropogenic** | Wildland Prescribed Fire | 4,224 | 8,097 | 8,097 |
| | **Total Anthropogenic** | **118,235** | **120,542** | **118,117** |
| **Natural** | Wildfire | 4,910 | 20,318 | 20,318 |
| **Natural** | Biogenic | 0 | 0 | 0 |
| | **Total Natural** | **4,910** | **20,318** | **20,318** |
| | **Grand Total** | **123,145** | **140,860** | **138,435** |

$PM_{10}$ is inhalable particulate matter that is 10 microns or smaller in diameter. Sources of $PM_{10}$ include:

- Vehicles
- Wood-burning
- Wildfires or open burns
- Industry

- Dust from construction sites, landfills, gravels pits, agriculture, and open lands

The NAAQS for PM specifies the maximum amount of PM present in outdoor air. PM concentration is measured in micrograms per cubic meter, or µg/m$^3$. For $PM_{10}$, most high values tend to occur during wintertime inversions. In the summertime, high wind events can also lead to unusually high $PM_{10}$ values. According to the 2028 OTB a2 projections, $PM_{10}$ emissions are expected to decrease to 138,435 tons per year in 2028. This is lower than the representative baseline from 2014 to 2017, but higher than the recalculated 2014 emissions.

**Table 20: Utah NH3 Emission Inventory – RepBase2 (2014-2018) and 2028OTBa2**

| Utah - Statewide $NH_3$ Emissions | | | | |
|---|---|---|---|---|
| Type | **Source Category** | **2014v2 Actual** | **Representative Baseline 2** | **2028 OTB a2** |
| **Anthropogenic** | Electric Generating Units (EGU) | 273 | 262 | 261 |
| **Anthropogenic** | Oil and Gas - Point | 0 | 0 | 0 |
| **Anthropogenic** | Industrial and Non-EGU Point | 400 | 400 | 400 |
| **Anthropogenic** | Oil and Gas - Non-point | 0 | 0 | 0 |
| **Anthropogenic** | Residential Wood Combustion | 63 | 63 | 63 |
| **Anthropogenic** | Fugitive dust | 0 | 0 | 0 |
| **Anthropogenic** | Agriculture | 12,982 | 12,982 | 12,982 |
| **Anthropogenic** | Remaining Non-point | 5,012 | 5,012 | 5,012 |
| **Anthropogenic** | On-Road Mobile | 1,025 | 1,025 | 1,039 |
| **Anthropogenic** | Non-road Mobile | 17 | 14 | 17 |
| **Anthropogenic** | Rail | 3 | 3 | 3 |
| **Anthropogenic** | Commercial Marine | 0 | 0 | 0 |
| **Anthropogenic** | Agricultural Fire | 70 | 70 | 70 |
| **Anthropogenic** | Wildland Prescribed Fire | 678 | 1,164 | 1,164 |
| | **Total Anthropogenic** | **20,523** | **20,995** | **21,011** |
| **Natural** | Wildfire | 787 | 2,702 | 2,702 |
| **Natural** | Biogenic | 0 | 0 | 0 |
| | **Total Natural** | **787** | **2,702** | **2,702** |
| | **Grand Total** | **21,310** | **23,697** | **23,713** |

$NH_3$ plays a role in light extinction since it is involved in the formation of ammonium nitrate and ammonium sulfate. The various industries that emit $NH_3$ include:

- Fertilizer manufacturing
- Fossil fuel combustion
- Livestock management
- Refrigeration methods

Currently, there is limited federal regulation of $NH_3$ emissions, although the CAA provides federal authority to regulate this pollutant. $NH_3$ emissions levels are consistent in each of the three WRAP projections for 2014, 2014-2017, and 2028.

# **Chapter 6:** Long-Term Strategy for Second Planning Period[116]

## 6.A LTS Requirements [117]

The Long-Term Strategy requirements under Subsections 51.308(d)(3) and (f)(2) include the following:

- Submit an initial LTS and 5-year progress review per 40 CFR 51.308(g) that addresses regional haze visibility impairment.
- Consult with other states to develop coordinated emission management strategies for CIAs outside Utah where Utah emissions cause or contribute to visibility impairment, or for CIAs in Utah where emissions from other states cause or contribute to visibility impairment.
- Document the technical basis on which the state is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each CIA it affects.
- Identify all anthropogenic sources of visibility impairing emissions (major and minor stationary sources, mobile sources, and area sources).
- Consider the following factors when developing the LTS:
    - Emission reductions due to ongoing air pollution control programs, including measures to address Reasonably Attributable Visibility Impairment (RAVI);
    - Measures to mitigate the impacts of construction activities;
    - Emission limitations and schedules for compliance to achieve the reasonable progress goal;
    - Source retirement and replacement schedules;
    - Smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for this purpose;
    - Enforceability of emission limitations and control measures; and
    - The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

Sections 6.A.1 through 6.A.8 detail how Utah addressed the above LTS factors.

### 6.A.1 States reasonably anticipated to contribute to visibility impairment in the Utah CIAs[118]

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[116] 40 CFR 51.308(f)(2)
[117] 40 CFR 51.308(d)(3) and (f)(2)

[118] 40 CFR 51.308 (f)(2)(ii)

### *Bryce Canyon National Park*

In Bryce Canyon National Park, California contributes the highest portion of U.S. anthropogenic ammonium nitrate-caused light extinction on most impaired days at 35%, followed by Utah at 23%. California also contributes the highest amount of U.S. anthropogenic ammonium sulfate light extinction in Bryce Canyon at 19% followed by non-WRAP states at 14%, Utah at 14%, Arizona at 12%, Wyoming at 12%, and New Mexico at 11%.

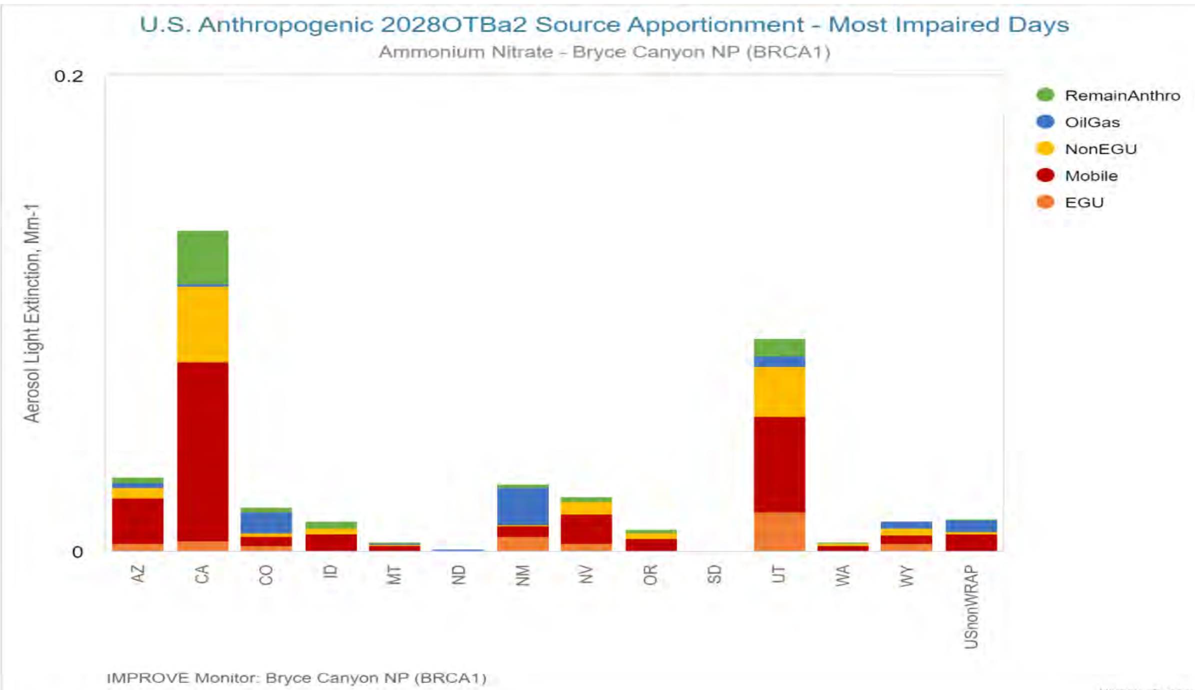


**Figure 33: WRAP States Ammonium Nitrate Source Apportionment for Most Impaired Days at Bryce Canyon National Park**

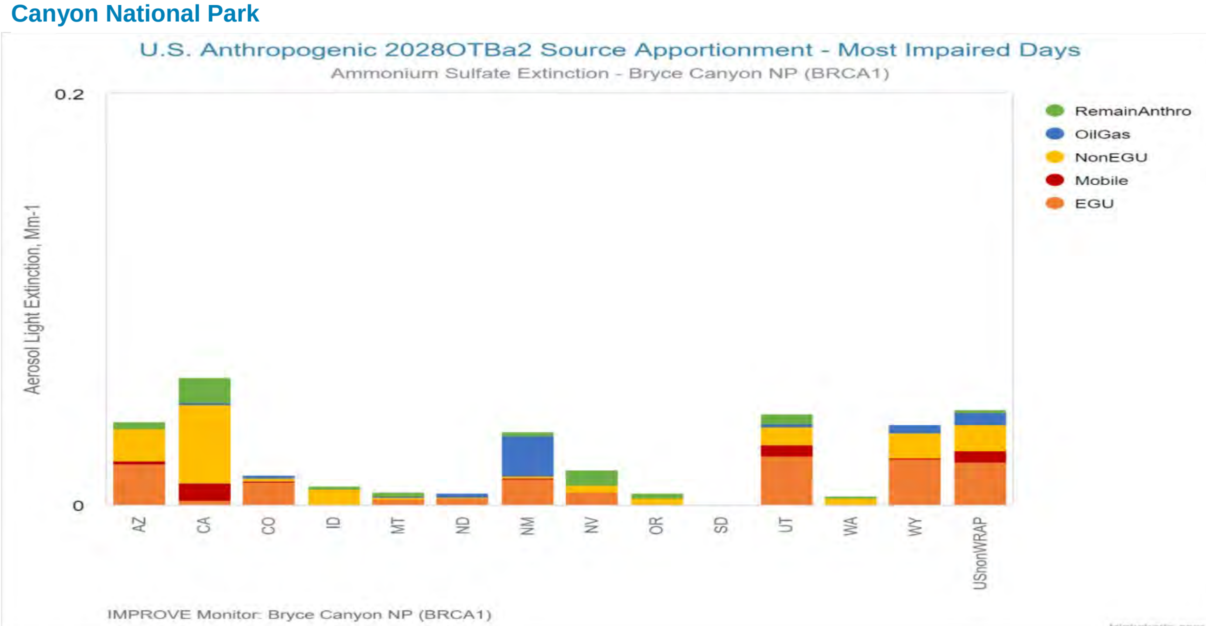


**Figure 34: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Bryce Canyon National Park**

### *Canyonlands and Arches National Park*

In Canyonlands and Arches National Park, Utah contributes the largest portion of U.S. ammonium nitrate light extinction (60%) followed by Colorado (14%). Utah also contributes the most U.S. ammonium sulfate light extinction (40%) on the park's most impaired days followed by New Mexico (13%) and non-WRAP US states (12%).

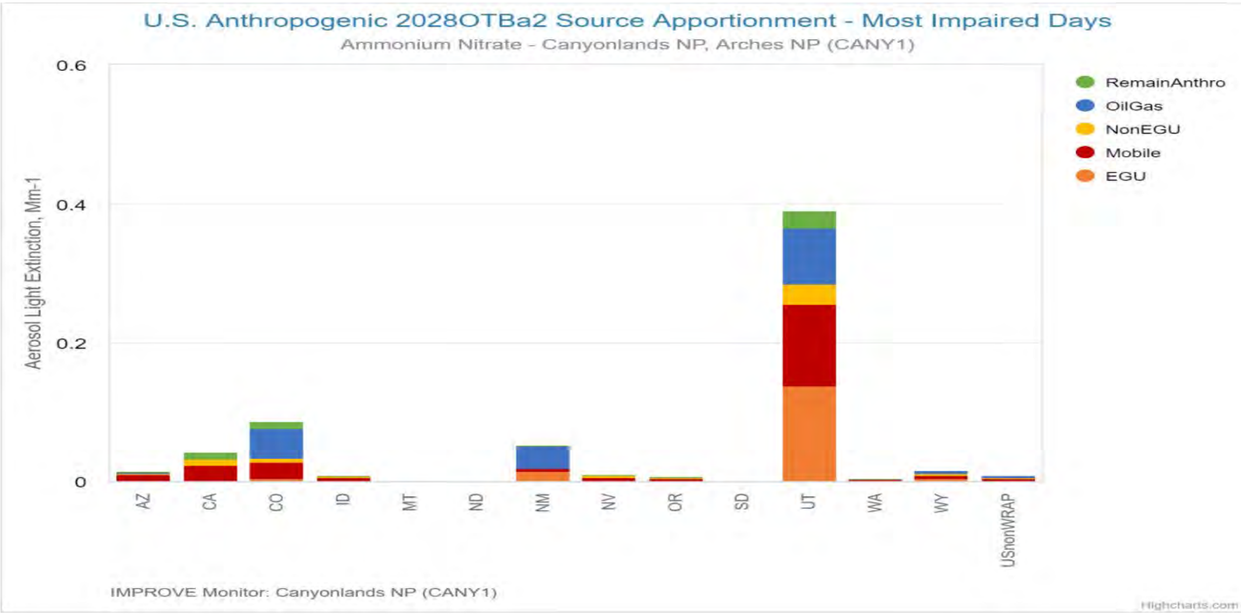


**Figure 35: WRAP States Ammonium Nitrate Source Apportionment for Most Impaired Days at Canyonlands and Arches National Park**

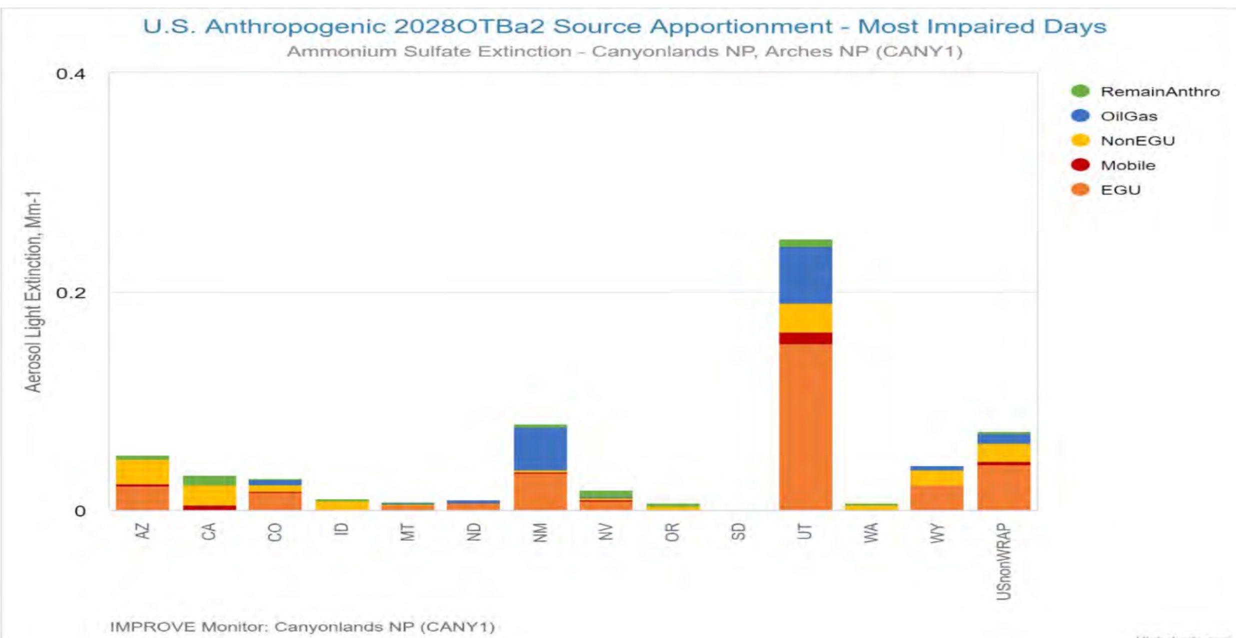


**Figure 36: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Canyonlands and Arches National Park**

### *Capitol Reef National Park*

Utah contributes the highest portion of U.S. anthropogenic ammonium nitrate light extinction on Capitol Reef's most impaired days at 35%. California contributes the second-highest amount at 21%. Utah also contributes the highest portion of U.S. anthropogenic ammonium sulfate light extinction at 20%, closely followed by non-WRAP states (15%), California (13%), and Wyoming (13%).

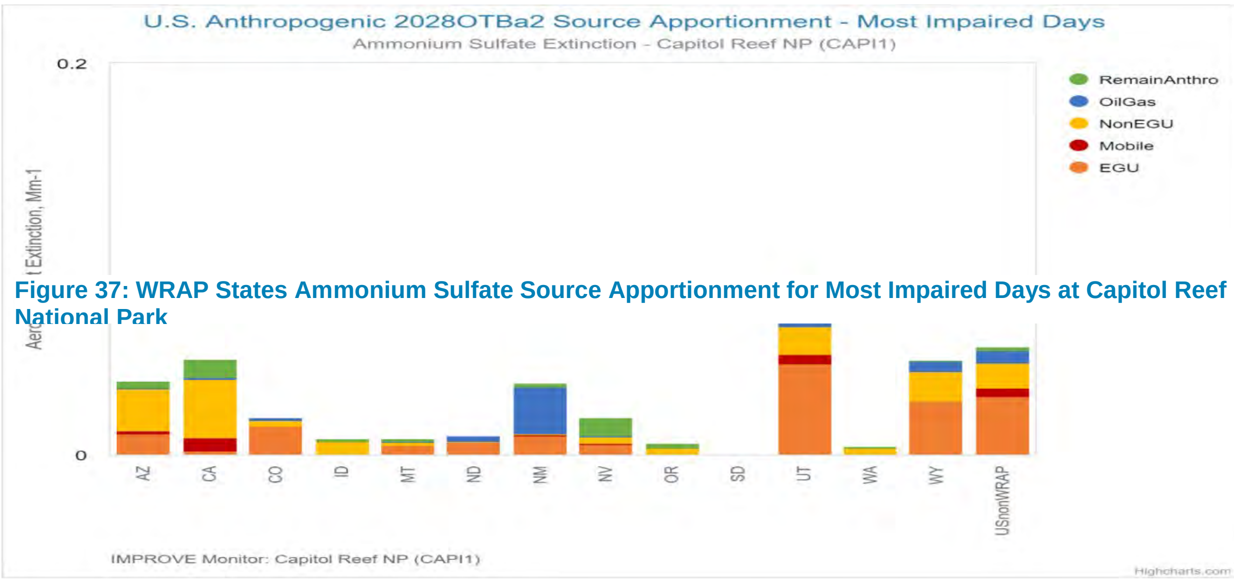


**Figure 37: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Capitol Reef National Park**

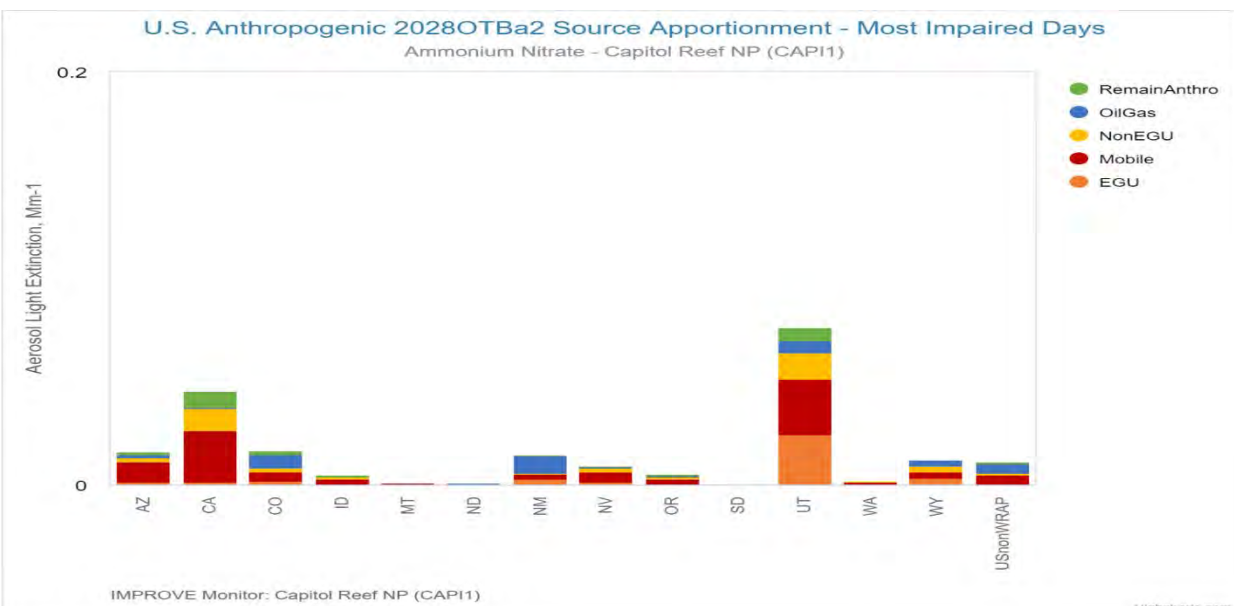


**Figure 38: WRAP States Ammonium Nitrate Source Apportionment for Most Impaired Days at Capitol Reef National Park**

*Zion National Park*

For Zion National Park's most impaired days, California contributes the highest portion of U.S. anthropogenic ammonium nitrate light extinction (49%) with mobile emissions comprising the majority of their impact (27%). California also contributes to the majority of U.S. anthropogenic ammonium sulfate light extinction (37%), most of which are from non-EGU sources (23%).

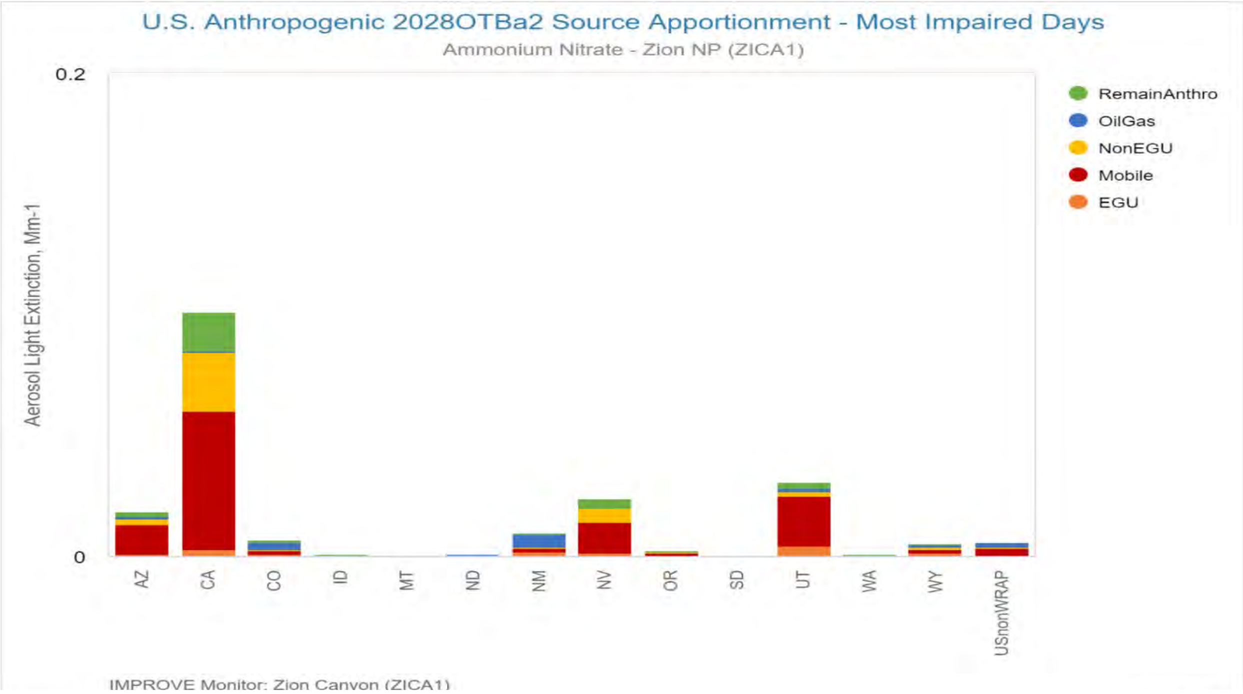


**Figure 39: WRAP States Ammonium Nitrate Source Apportionment for Most Impaired Days at Zion National Park**

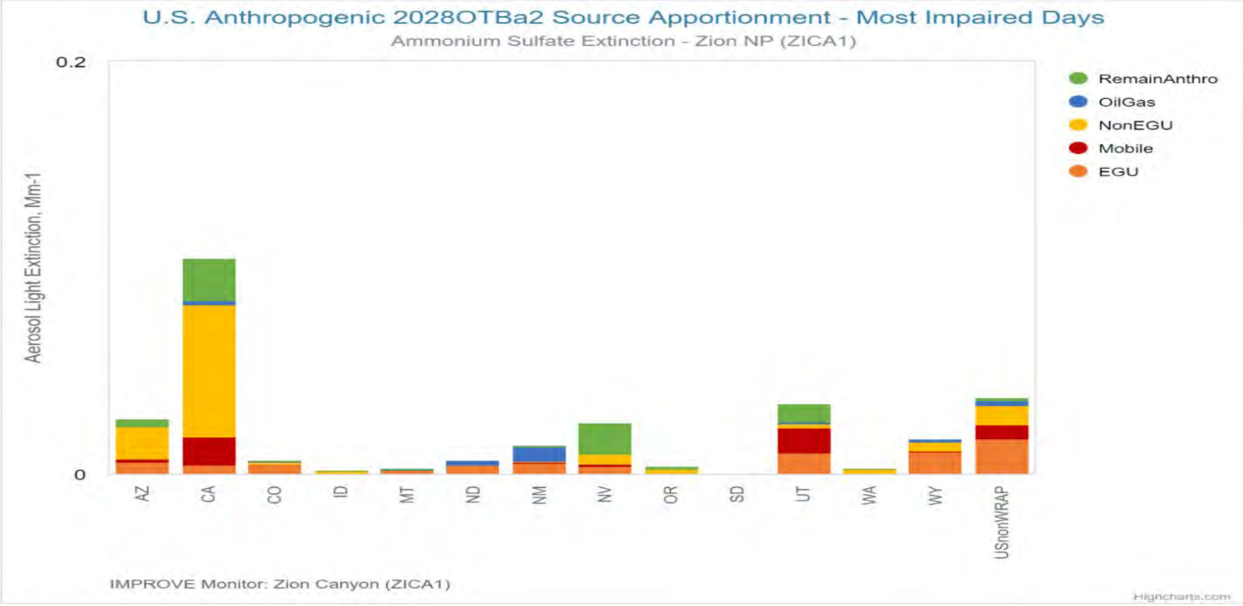


**Figure 40: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Zion National Park**

### 6.A.2 Utah sources identified by downwind states that are reasonably anticipated to impact CIAs[119]

Utah has analyzed the WRAP photochemical modeling for OTB 2028 and found that emissions from Utah can impact visibility at CIAs in other states. Table 21 and 22 below summarize Utah's percent contribution to total U.S. anthropogenic nitrate and sulfate light extinction at CIAs in neighboring states. As can be seen, Utah's highest nitrate impacts occur in Colorado, Idaho, and Wyoming CIAs and mostly stem from mobile source emissions. Utah's highest sulfate impacts also occur in Colorado, Idaho, and Wyoming (namely at MOZI1, WHRI1, CRMO1, and BRID1) and predominantly stem from EGU emissions and some non-EGU emissions in the case of CRMO1. It should be noted that the WRAP source apportionment results for Utah EGUs include impacts from the Bonanza power plant, which is located in Indian Country and which is not, therefore, a source regulated by UDAQ. A review of the weighted emissions potential (WEP) values for sulfate at the latter CIAs identified one Utah EGU, Kennecott Power Plant, with a top-ten sulfate WEP value for BRID1 (rank 2, 7.4% of total WEP). However, this facility was officially closed in 2020. The facilities with the two highest ranking non-EGU WEP sulfate values at CRMO1 were the Tesoro (now Marathon) refinery (rank 6, 6.8% of total WEP) and the Kennecott Smelter and Refinery (rank 10, 2.2% of total WEP), both of which recently underwent BACT analysis for the Salt Lake $PM_{2.5}$ serious area SIP and are well-controlled for $SO_2$.

As one might expect, when Utah anthropogenic impacts are compared to total nitrate and sulfate light extinction at the same CIAs, Utah's shares drop markedly, as shown in Table 23 and Table 24, respectively. And nitrate and sulfate are only two of several contributors to total visibility impairment. As such, Utah's shares of nitrate and sulfate impacts should be considered in this broader context. That said, the aforementioned source apportionment results were not used to screen out any sources from a requirement to conduct a four-factor analysis. Rather, UDAQ relied upon a preliminary Q/d analysis to identify sources with a Q/d of >=6. UDAQ then conducted a secondary screening to review the initial pool of Q/d-qualifying sources to account for factors such as recent emissions controls required by other air quality programs, facility closures, federal preemptions on state controls, etc. Finally, UDAQ reviewed WEP results for nitrate and sulfate to ensure that the remaining Q/d pool reasonably captured sources with impacts at Utah and non-Utah CIAs. This screening analysis is detailed in section 7.A.

**Table 21: Utah Share of U.S. Anthropogenic Nitrate Impacts on Neighboring State CIAs**

| State | Site | EGU | Mobile | Non-EGU | Oil & Gas | Remaining Anthro | Utah Total |
|---|---|---|---|---|---|---|---|
| **AZ** | BALD1 | 0.19% | 0.22% | 0.10% | 0.02% | 0.03% | 0.55% |
| **AZ** | CHIR1 | 0.76% | 0.68% | 0.29% | 0.19% | 0.13% | 2.05% |
| **AZ** | GRCA2 | 0.64% | 0.63% | 0.13% | 0.22% | 0.09% | 1.71% |
| **AZ** | IKBA1 | 0.21% | 0.29% | 0.10% | 0.05% | 0.07% | 0.73% |

[119] 40 CFR 51.308 (f)(2)(ii)(A)

| State | Site | EGU | Mobile | Non-EGU | Oil & Gas | Remaining Anthro | Utah Total |
|---|---|---|---|---|---|---|---|
| **AZ** | PEFO1 | 2.89% | 1.95% | 0.75% | 0.57% | 0.56% | 6.73% |
| **AZ** | SAGU1 | 0.35% | 0.32% | 0.10% | 0.08% | 0.07% | 0.93% |
| **AZ** | SIAN1 | 0.19% | 0.19% | 0.11% | 0.02% | 0.03% | 0.53% |
| **AZ** | SYCA_RHTS | 1.12% | 1.45% | 0.57% | 0.23% | 0.26% | 3.62% |
| **AZ** | TONT1 | 0.22% | 0.30% | 0.09% | 0.05% | 0.07% | 0.74% |
| **CO** | GRSA1 | 2.39% | 1.35% | 0.44% | 0.59% | 0.32% | 5.08% |
| **CO** | MEVE1 | 4.33% | 2.76% | 0.81% | 0.91% | 0.68% | 9.49% |
| **CO** | MOZI1 | 4.14% | 7.23% | 3.00% | 3.00% | 1.44% | 18.81% |
| **CO** | ROMO1 | 1.95% | 3.53% | 1.47% | 1.27% | 0.72% | 8.94% |
| **CO** | WEMI1 | 2.43% | 2.20% | 0.72% | 0.99% | 0.25% | 6.59% |
| **CO** | WHRI1 | 5.14% | 6.75% | 2.23% | 2.64% | 0.98% | 17.74% |
| **ID** | CRMO1 | 0.62% | 6.88% | 3.42% | 0.03% | 2.02% | 12.97% |
| **ID** | SAWT1 | 0.05% | 0.38% | 0.22% | 0.01% | 0.09% | 0.74% |
| **ID** | SULA1 | 0.09% | 0.96% | 0.45% | 0.01% | 0.13% | 1.63% |
| **NM** | BAND1 | 0.58% | 0.43% | 0.14% | 0.14% | 0.08% | 1.37% |
| **NM** | BOAP1 | 0.50% | 0.47% | 0.19% | 0.12% | 0.12% | 1.41% |
| **NM** | GICL1 | 0.27% | 0.38% | 0.15% | 0.07% | 0.06% | 0.93% |
| **NM** | GUMO1 | 0.17% | 0.27% | 0.09% | 0.06% | 0.02% | 0.60% |
| **NM** | SACR1 | 0.06% | 0.06% | 0.02% | 0.02% | 0.01% | 0.17% |
| **NM** | SAPE1 | 0.84% | 0.60% | 0.24% | 0.24% | 0.14% | 2.05% |
| **NM** | WHIT1 | 0.12% | 0.14% | 0.05% | 0.04% | 0.03% | 0.38% |
| **NM** | WHPE1 | 0.96% | 0.84% | 0.29% | 0.23% | 0.16% | 2.48% |
| **NV** | JARB1 | 0.43% | 1.32% | 0.54% | 0.10% | 0.23% | 2.63% |
| **WY** | BRID1 | 2.98% | 12.91% | 6.56% | 1.53% | 2.41% | 26.39% |
| **WY** | NOAB1 | 0.49% | 3.11% | 1.60% | 0.07% | 0.72% | 5.98% |
| **WY** | YELL2 | 0.63% | 5.90% | 2.94% | 0.07% | 1.43% | 10.97% |

**Table 22: Utah Share of U.S. Anthropogenic Sulfate Impacts on Neighboring State CIAs**

| State | Site | EGU | Mobile | Non-EGU | Oil & Gas | Remaining Anthro | Utah Total |
|---|---|---|---|---|---|---|---|
| **AZ** | BALD1 | 0.60% | 0.03% | 0.23% | 0.02% | 0.02% | 0.91% |
| **AZ** | CHIR1 | 1.26% | 0.04% | 0.33% | 0.08% | 0.03% | 1.74% |
| **AZ** | GRCA2 | 2.18% | 0.08% | 0.19% | 0.28% | 0.08% | 2.81% |
| **AZ** | IKBA1 | 1.29% | 0.07% | 0.29% | 0.10% | 0.06% | 1.81% |
| **AZ** | PEFO1 | 2.30% | 0.11% | 0.51% | 0.14% | 0.07% | 3.12% |
| **AZ** | SAGU1 | 1.36% | 0.06% | 0.34% | 0.06% | 0.04% | 1.86% |
| **AZ** | SIAN1 | 0.62% | 0.03% | 0.18% | 0.03% | 0.03% | 0.89% |
| **AZ** | SYCA_RHTS | 4.21% | 0.22% | 1.45% | 0.09% | 0.15% | 6.13% |
| **AZ** | TONT1 | 1.31% | 0.06% | 0.33% | 0.09% | 0.04% | 1.84% |
| **CO** | GRSA1 | 4.85% | 0.09% | 0.38% | 0.52% | 0.07% | 5.91% |
| **CO** | MEVE1 | 7.97% | 0.17% | 0.84% | 1.57% | 0.14% | 10.69% |
| **CO** | MOZI1 | 10.25% | 0.27% | 1.48% | 0.67% | 0.18% | 12.85% |

| State | Site | EGU | Mobile | Non-EGU | Oil & Gas | Remaining Anthro | Utah Total |
|---|---|---|---|---|---|---|---|
| **CO** | ROMO1 | 5.89% | 0.28% | 2.12% | 0.49% | 0.17% | 8.96% |
| **CO** | WEMI1 | 6.79% | 0.19% | 0.96% | 1.41% | 0.14% | 9.49% |
| **CO** | WHRI1 | 22.85% | 0.45% | 1.91% | 2.12% | 0.30% | 27.62% |
| **ID** | CRMO1 | 4.17% | 0.48% | 4.08% | 0.01% | 0.35% | 9.10% |
| **ID** | SAWT1 | 1.23% | 0.06% | 0.82% | 0.01% | 0.04% | 2.15% |
| **ID** | SULA1 | 0.79% | 0.11% | 0.70% | 0.01% | 0.08% | 1.70% |
| **NM** | BAND1 | 1.25% | 0.04% | 0.18% | 0.22% | 0.02% | 1.70% |
| **NM** | BOAP1 | 0.68% | 0.03% | 0.14% | 0.04% | 0.02% | 0.91% |
| **NM** | GICL1 | 0.89% | 0.04% | 0.26% | 0.04% | 0.03% | 1.25% |
| **NM** | GUMO1 | 0.49% | 0.02% | 0.12% | 0.03% | 0.01% | 0.66% |
| **NM** | SACR1 | 0.21% | 0.01% | 0.04% | 0.01% | 0.00% | 0.27% |
| **NM** | SAPE1 | 2.07% | 0.06% | 0.31% | 0.25% | 0.05% | 2.74% |
| **NM** | WHIT1 | 0.29% | 0.01% | 0.06% | 0.02% | 0.01% | 0.38% |
| **NM** | WHPE1 | 1.55% | 0.05% | 0.28% | 0.13% | 0.03% | 2.04% |
| **NV** | JARB1 | 2.05% | 0.12% | 0.85% | 0.03% | 0.07% | 3.13% |
| **WY** | BRID1 | 12.26% | 0.63% | 5.98% | 0.30% | 0.42% | 19.59% |
| **WY** | NOAB1 | 4.01% | 0.15% | 1.12% | 0.17% | 0.12% | 5.57% |
| **WY** | YELL2 | 5.29% | 0.35% | 3.22% | 0.05% | 0.24% | 9.15% |

### Table 23: Utah Share of Total Nitrate Impacts on Neighboring State CIAs

| State | Site | EGU | Mobile | Non-EGU | Oil & Gas | Remaining Anthro | Utah Total |
|---|---|---|---|---|---|---|---|
| **AZ** | BALD1 | 0.06% | 0.07% | 0.03% | 0.01% | 0.01% | 0.17% |
| **AZ** | CHIR1 | 0.17% | 0.15% | 0.06% | 0.04% | 0.03% | 0.45% |
| **AZ** | GRCA2 | 0.07% | 0.07% | 0.01% | 0.03% | 0.01% | 0.20% |
| **AZ** | IKBA1 | 0.12% | 0.16% | 0.06% | 0.03% | 0.04% | 0.41% |
| **AZ** | PEFO1 | 1.34% | 0.90% | 0.35% | 0.26% | 0.26% | 3.11% |
| **AZ** | SAGU1 | 0.18% | 0.17% | 0.05% | 0.04% | 0.04% | 0.48% |
| **AZ** | SIAN1 | 0.10% | 0.09% | 0.06% | 0.01% | 0.01% | 0.27% |
| **AZ** | SYCA_RHTS | 0.38% | 0.50% | 0.19% | 0.08% | 0.09% | 1.24% |
| **AZ** | TONT1 | 0.13% | 0.18% | 0.06% | 0.03% | 0.04% | 0.44% |
| **CO** | GRSA1 | 1.19% | 0.68% | 0.22% | 0.29% | 0.16% | 2.54% |
| **CO** | MEVE1 | 2.38% | 1.52% | 0.45% | 0.50% | 0.37% | 5.21% |
| **CO** | MOZI1 | 1.77% | 3.09% | 1.28% | 1.28% | 0.61% | 8.03% |
| **CO** | ROMO1 | 1.19% | 2.16% | 0.90% | 0.77% | 0.44% | 5.45% |
| **CO** | WEMI1 | 0.94% | 0.85% | 0.28% | 0.38% | 0.10% | 2.54% |
| **CO** | WHRI1 | 1.81% | 2.39% | 0.79% | 0.93% | 0.35% | 6.27% |
| **ID** | CRMO1 | 0.26% | 2.94% | 1.46% | 0.01% | 0.86% | 5.54% |
| **ID** | SAWT1 | 0.01% | 0.08% | 0.05% | 0.00% | 0.02% | 0.16% |
| **ID** | SULA1 | 0.02% | 0.18% | 0.08% | 0.00% | 0.02% | 0.31% |
| **NM** | BAND1 | 0.32% | 0.24% | 0.08% | 0.08% | 0.05% | 0.75% |

| State | Site | EGU | Mobile | Non-EGU | Oil & Gas | Remaining Anthro | Utah Total |
|---|---|---|---|---|---|---|---|
| **NM** | BOAP1 | 0.24% | 0.22% | 0.09% | 0.06% | 0.06% | 0.67% |
| **NM** | GICL1 | 0.01% | 0.01% | 0.00% | 0.00% | 0.00% | 0.03% |
| **NM** | GUMO1 | 0.06% | 0.09% | 0.03% | 0.02% | 0.01% | 0.20% |
| **NM** | SACR1 | 0.04% | 0.04% | 0.01% | 0.01% | 0.01% | 0.12% |
| **NM** | SAPE1 | 0.44% | 0.31% | 0.13% | 0.12% | 0.07% | 1.07% |
| **NM** | WHIT1 | 0.05% | 0.06% | 0.02% | 0.02% | 0.01% | 0.17% |
| **NM** | WHPE1 | 0.42% | 0.37% | 0.13% | 0.10% | 0.07% | 1.09% |
| **NV** | JARB1 | 0.11% | 0.33% | 0.13% | 0.03% | 0.06% | 0.65% |
| **WY** | BRID1 | 0.97% | 4.20% | 2.13% | 0.50% | 0.78% | 8.57% |
| **WY** | NOAB1 | 0.08% | 0.49% | 0.25% | 0.01% | 0.11% | 0.95% |
| **WY** | YELL2 | 0.18% | 1.69% | 0.84% | 0.02% | 0.41% | 3.14% |

**Table 24: Utah Share of Total Sulfate Impacts on Neighboring State CIAs**

| State | Site | EGU | Mobile | Non-EGU | Oil & Gas | Remaining Anthro | Utah Total |
|---|---|---|---|---|---|---|---|
| **AZ** | BALD1 | 0.06% | 0.00% | 0.02% | 0.00% | 0.00% | 0.10% |
| **AZ** | CHIR1 | 0.13% | 0.00% | 0.03% | 0.01% | 0.00% | 0.17% |
| **AZ** | GRCA2 | 0.93% | 0.03% | 0.08% | 0.12% | 0.03% | 1.19% |
| **AZ** | IKBA1 | 0.14% | 0.01% | 0.03% | 0.01% | 0.01% | 0.20% |
| **AZ** | PEFO1 | 0.46% | 0.02% | 0.10% | 0.03% | 0.01% | 0.63% |
| **AZ** | SAGU1 | 0.20% | 0.01% | 0.05% | 0.01% | 0.01% | 0.27% |
| **AZ** | SIAN1 | 0.06% | 0.00% | 0.02% | 0.00% | 0.00% | 0.09% |
| **AZ** | SYCA_RHTS | 0.50% | 0.03% | 0.17% | 0.01% | 0.02% | 0.72% |
| **AZ** | TONT1 | 0.15% | 0.01% | 0.04% | 0.01% | 0.00% | 0.21% |
| **CO** | GRSA1 | 1.31% | 0.02% | 0.10% | 0.14% | 0.02% | 1.60% |
| **CO** | MEVE1 | 1.98% | 0.04% | 0.21% | 0.39% | 0.03% | 2.66% |
| **CO** | MOZI1 | 2.68% | 0.07% | 0.39% | 0.18% | 0.05% | 3.36% |
| **CO** | ROMO1 | 1.64% | 0.08% | 0.59% | 0.14% | 0.05% | 2.50% |
| **CO** | WEMI1 | 1.45% | 0.04% | 0.20% | 0.30% | 0.03% | 2.02% |
| **CO** | WHRI1 | 4.16% | 0.08% | 0.35% | 0.39% | 0.05% | 5.02% |
| **ID** | CRMO1 | 0.46% | 0.05% | 0.45% | 0.00% | 0.04% | 1.01% |
| **ID** | SAWT1 | 0.08% | 0.00% | 0.05% | 0.00% | 0.00% | 0.13% |
| **ID** | SULA1 | 0.05% | 0.01% | 0.05% | 0.00% | 0.01% | 0.11% |
| **NM** | BAND1 | 0.41% | 0.01% | 0.06% | 0.07% | 0.01% | 0.55% |
| **NM** | BOAP1 | 0.19% | 0.01% | 0.04% | 0.01% | 0.00% | 0.25% |
| **NM** | GICL1 | 0.12% | 0.01% | 0.03% | 0.00% | 0.00% | 0.17% |
| **NM** | GUMO1 | 0.11% | 0.00% | 0.03% | 0.01% | 0.00% | 0.15% |
| **NM** | SACR1 | 0.06% | 0.00% | 0.01% | 0.00% | 0.00% | 0.08% |
| **NM** | SAPE1 | 0.54% | 0.01% | 0.08% | 0.07% | 0.01% | 0.71% |
| **NM** | WHIT1 | 0.07% | 0.00% | 0.01% | 0.00% | 0.00% | 0.10% |
| **NM** | WHPE1 | 0.44% | 0.01% | 0.08% | 0.04% | 0.01% | 0.58% |

| State | Site | EGU | Mobile | Non-EGU | Oil & Gas | Remaining Anthro | Utah Total |
|---|---|---|---|---|---|---|---|
| **NV** | JARB1 | 0.13% | 0.01% | 0.05% | 0.00% | 0.00% | 0.20% |
| **WY** | BRID1 | 2.01% | 0.10% | 0.98% | 0.05% | 0.07% | 3.21% |
| **WY** | NOAB1 | 0.35% | 0.01% | 0.10% | 0.02% | 0.01% | 0.49% |
| **WY** | YELL2 | 0.68% | 0.05% | 0.41% | 0.01% | 0.03% | 1.17% |

### 6.A.3 Technical Basis of Reasonable Progress Goals

Please refer to Chapter 4: Utah Visibility Analysis to view Utah's URP glidepaths and each CIAs' 2028 projections.

### 6.A.4 Identify Anthropogenic Sources

Please refer to sections 5.C and 5.E of Chapter 5: Utah Sources of Visibility Impairment for a detailed emissions inventory by sector. Please refer to sections 7.A and 7.A.1 of Chapter 7: Emissions Control Analysis for Utah's source screening processes and Q/d analysis for determining which sources have the highest potential impact on Utah's CIAs.

### 6.A.5 Emissions Reductions Due to Ongoing Pollution Control Programs

*RAVI*

RAVI refers to a process to identify and control visibility impairment that is caused by the emissions of air pollutants from one, or a small number of sources directly impacting a CIA. The three primary steps in this process are:[120]

- FLM certification of impairment
- State identification of existing sources causing or contributing to the impairment
- BART analysis to determine what controls, if any, are required on any existing source that meets BART criteria and has been identified as contributing to impairment

In the case that a FLM certifies impairment for any of Utah's CIAs, RAVI[121] will be addressed by the state through the following actions:

- Submittal of an initial RAVI LTS along with periodic revisions every three years
- Submittal of an LTS revision within three years of an FLM certification of impairment
- Consultation with FLMs
- Submittal of a report to the EPA and public on Utah's progress towards the national goal

UDAQ consulted with NPS who confirmed that none of Utah's CIAs have been certified as impaired by any FLMs.

[120] The Recommendations for Making Attribution Determinations in the Context of Reasonably Attributable BART can be found at:
http://www.westar.org/RA%20BART/final%20RA%20BART%20Report.pdf
[121] 40 CFR 51.302

### *National Ambient Air Quality Standards*

The CAA requires the EPA to set NAAQS for pollutants considered harmful to public health and the environment. The CAA establishes two types of air quality standards: primary and secondary. Primary standards are set to protect public health, including the health of sensitive populations such as asthmatics, children, and the elderly. Secondary standards are set to protect public welfare, including protection from decreased visibility and damage to animals, crops, vegetation, and buildings.

The EPA has established health-based NAAQS for the six criteria pollutants including CO, $NO_2$, $O_3$, PM, $SO_2$, and lead. The EPA establishes the primary health standards after considering both the concentration level and the duration of exposure that can cause adverse health effects. Pollutant concentrations that exceed the NAAQS are considered unhealthy for some portion of the population. At concentrations between 1.0 and 1.5 times the standard, while the general public is not expected to be adversely affected by the pollutant, the most sensitive portion of the population may be. However, at levels above 1.5 times the standard, even healthy people may see adverse effects. The UDAQ monitors these criteria pollutants, as well as meteorological conditions and several non-criteria pollutants for special studies at various monitoring sites throughout the state.

The CAA has three different designations for areas based on whether they meet the NAAQS for each pollutant. Areas in compliance with the NAAQS are designated as attainment areas. Areas where there is no monitoring data showing compliance or noncompliance with the NAAQS are designated as unclassifiable areas. Areas that are not in compliance with the NAAQS are designated as nonattainment areas. A maintenance area is an attainment area that was once designated as nonattainment for one of the NAAQS and has since been demonstrated as attaining and continuing to attain that standard for a period of a minimum of 10 years. Most of the State of Utah has been designated as either Attainment or Unclassifiable for all the NAAQS.

Utah has never been out of compliance with any NO2 standard, and has not exceeded the lead standard since the 1970s. Three cities in Utah (Salt Lake City, Ogden, and Provo) were at one time designated as nonattainment areas for carbon monoxide. Due primarily to improvements in motor vehicle technology, Utah has complied with the carbon monoxide standards since 1994. Salt Lake City, Ogden, and Provo were successfully redesignated to attainment status in 1999, 2001, and 2006, respectively.

### *Ozone ($O_3$)*

In October of 2015, the EPA strengthened the ozone NAAQS from 75 ppb to 70 ppb, based on a three-year average of the annual 4th highest daily eight-hour average concentration. The standard was reviewed again in 2020 and the EPA chose to retain the standard at 70 ppb. Ozone monitors operated by the UDAQ along the Wasatch Front show exceedances of the current standard in Weber, Davis, and Salt Lake counties. There were also exceedances in Uinta County and Duchesne County during the winter. In 2016, the Governor recommended that portions of the Wasatch Front and Uinta Basin be designated non-attainment and that the rest of the State be designated attainment/unclassifiable. The current status of attainment for ozone in the Uintah basin is marginal non-attainment.

The unique wintertime ozone issue in the Uinta Basin is caused by oil and gas extraction. UDAQ is working on rule amendments and potentially new rules for the oil and gas industry to stay in compliance with the ozone NAAQS.

### *$PM_{10}$*

The EPA established the 24-hour NAAQS for $PM_{10}$ in July 1987 as 150 µg/m3. The standard is met when the probability of exceeding the standard is no greater than once per year for a three-year averaging period. Salt Lake County and Utah County had been designated nonattainment for $PM_{10}$ shortly after the standard was promulgated. Ogden City was also designated as a nonattainment area due to one year of high concentrations (1992) but was determined to be attaining the standard in January 2013. State Implementation Plans (SIP) were written and promulgated in 1991 and included control strategies that resulted in the marked decrease in $PM_{10}$ concentrations observed in the early 1990s. Ogden City, and Salt Lake and Utah Counties were officially designated as attainment for $PM_{10}$ effective March 27, 2020. These three former nonattainment areas are now subject to the maintenance plans that were approved by EPA and the areas must continue to attain the standard for the first maintenance period of ten years. High values of monitored $PM_{10}$ sometimes result from exceptional events, such as dust storms and wildfires.

### *$PM_{2.5}$*

The EPA first established standards for $PM_{2.5}$ in 1997. In 2006, the EPA lowered the 24-hour $PM_{2.5}$ standard from 65µg/m3 to 35 µg/m3. The $PM_{2.5}$ NAAQS underwent a review in 2020 and the standards were retained. In 2009, three areas in Utah were designated nonattainment for $PM_{2.5}$. UDAQ wrote a moderate SIP for the Logan, UT-ID nonattainment area, including a vehicle emissions inspection program. Logan attained the standard, and has since been redesignated to attainment status. The Provo and Salt Lake $PM_{2.5}$ nonattainment areas were unable to attain by the moderate attainment date and were reclassified to serious nonattainment. A serious SIP was submitted to EPA for the Salt Lake nonattainment area, and the Provo nonattainment area attained the standard prior to a serious SIP due date. Best Available Control Measures and Technologies were still required in both nonattainment areas, significantly reducing VOCs, $NO_x$, and both primary and secondary $PM_{2.5}$ in the airsheds. Both areas have now attained the standard, and EPA is reviewing SIP elements and maintenance plans for official redesignation to attainment/maintenance.

### *Sulfur Dioxide ($SO_2$)*

In 1971, EPA established a 24-hour average $SO_2$ standard of 0.14 ppm, and an annual arithmetic average standard of 0.030 ppm. In 2010, EPA revised the primary standard for $SO_2$, setting it at 75 ppb for a three-year average of the 99$^{th}$%ile of the annual distribution of daily maximum one-hour average concentrations for $SO_2$. Throughout the 1970s, the Magna monitor routinely measured violations of the 1971 24-hour standard. Consequently, all of Salt Lake County and parts of eastern Tooele County above 5,600 feet were designated as nonattainment for that standard. Two significant technological upgrades at the Kennecott smelter costing the company nearly one billion dollars resulted in continued compliance with the $SO_2$ standard since 1981. In the mid-1990s, Kennecott, Geneva Steel, the five refineries in Salt Lake City, and several other large sources of $SO_2$ made dramatic reductions in emissions as part of an effort to curb concentrations of secondary particulates (sulfates) that were contributing to $PM_{10}$ violations. More recently, Kennecott closed Units 1, 2, and 3 of its coal-fired power plants in 2016 and Unit 4 in 2019, resulting in further $SO_2$ emissions reductions.

Utah submitted an $SO_2$ Maintenance Plan and redesignation request for Salt Lake and Tooele Counties to the EPA in April of 2005, but EPA never took formal action on the request. Because of changes in the emissions in subsequent years, and changes in the modeling used to demonstrate attainment of the standard, in November 2019, the State of Utah withdrew its 2005 Maintenance Plan and redesignation request. UDAQ is currently working very closely with EPA to develop a new maintenance plan and redesignation request to address the 1971 standard. UDAQ will conduct modeling and other analyses in 2021 with the goal of submitting an approvable maintenance plan and redesignation request to EPA by the end of that year. On November 1, 2016, Governor Herbert submitted a recommendation to EPA that all areas of the state be designated as attainment for the 2010 $SO_2$ NAAQS based on monitoring and air quality modeling data. On January 9, 2018, EPA formally concurred with this recommendation and designated all areas of the state as attainment/unclassifiable.

The NAAQS program and Utah's work to stay in compliance with all NAAQS has significantly decreased VOC, $NO_x$, $PM_{2.5}$, $PM_{10}$, and $SO_2$ emissions over time, benefiting the regional haze program.

#### *Air Quality Incentive Programs*

In addition to the NAAQS program, UDAQ administers multiple incentive programs created to encourage individuals and businesses to voluntarily reduce emissions. Funding for these programs comes from various sources, including settlement agreements, legislative appropriations, and federal grant programs. The emissions reductions from incentive programs are not included as part of any SIP, but the reductions do make an impact on monitored ambient values.

#### *Targeted Airshed Grants*

UDAQ has been a recipient of EPA targeted airshed grants in the past for $PM_{2.5}$ and ozone in Logan, Salt Lake, Provo, and the Uinta Basin nonattainment areas. Programs include woodstove/fireplace conversions, school bus replacements, vehicle repair and replacement assistance programs, and an oil and gas engine replacement program. UDAQ applied for the competitive grants and was awarded a total of $14.5 million for these projects that are still in process.

#### *Utah Clean Diesel Program*

The Utah Clean Diesel Program aims to cut emissions from heavy- duty diesel vehicles and equipment that operate in the State's nonattainment areas. Fleet owners receive a 25% incentive toward the purchase of new vehicles and equipment that meet the cleanest emissions standards. Retiring engine model years 2006 and older diesel trucks that are currently operational and have a minimum of three years remaining in their useful life and replacing them with current model years can achieve approximately 71 to 90% reductions in $NO_x$, 97 to 98%

reductions in $PM_{2.5}$, and 89 to 91% reductions in VOCs, according to the EPA Emissions Standards for Heavy-Duty Highway Engines and Vehicles. Nearly $24 million in federal grants have been awarded through the Utah Clean Diesel Program since 2008, resulting in thousands of tons reduced from diesel emissions.

### *Legislative Appropriations for Incentive Programs*

The woodstove and fireplace conversion funded by the targeted airshed grant was wildly successful, and the Utah State Legislature appropriated UDAQ an additional $9 million to convert wood burning appliance to gas or electric along Utah's Wasatch Front. This program is currently being administered. During the 2019 General Legislative Session, the State Legislature appropriated $4.9 million to be used as an incentive for the installation of electric vehicle supply equipment (EVSE) throughout the State. The EVSE Incentive Program allows businesses, non-profit organizations, and other governmental entities (excluding State Executive Branch agencies) to apply for a grant for reimbursement of up to 50% of the purchase and installation costs for a pre-approved EVSE project. Funds can be used for the purchase and installation of both Level 2 or DC fast charging EVSE. This program continues to be administered. During the 2019 Legislative Session, the Legislature appropriated $500,000 to the UDAQ to administer a Trip Reduction Program. A primary component of the Trip Reduction Program is a Free-Fare Day Pilot Project. The UDAQ has worked closely with the Utah Transit Authority (UTA) to provide free fares during inversion periods when air quality levels are increasing and projected to reach levels that are harmful to human health.

### *Clean Air Violation Settlement Dollars for Emissions Reduction Incentives*

The State of Utah is a beneficiary of over $35 million from the Volkswagen (VW) Environmental Mitigation Trust, part of a settlement with VW for violations of the CAA. UDAQ has developed an environmental mitigation plan to offset the $NO_x$ emissions from the vehicles in the State affected by the automaker's violations. The plan directs the $35 million settlement funds towards upgrades to government-owned diesel truck and bus fleets as well as the expansion of electric-vehicle (EV) charging equipment. Funding allocations are as follows:

- Class 4-8 Local Freight Trucks and School Bus, Shuttle Bus, and Transit Bus: 73.5%
- Light-Duty, Zero Emissions Vehicle Supply Equipment: 11%
- Administrative Costs: 8.5%
- Diesel Emission Reduction Act (DERA) options: 7%

Projects were prioritized and selected based on their reduction of $NO_x$, cost-per-ton of $NO_x$ reduced, value to the nonattainment areas, and community benefits. Awardees will have three years to complete their projects.

Using settlement money from General Motors, UDAQ runs an electric lawn equipment exchange each year. Participants receive a higher incentive dollar amount if they scrap an old gas-powered piece of equipment.

### 6.A.6 Measures to Mitigate the Impacts of Construction Activities

Fugitive dust is particles of soil, ash, coal, minerals, etc., which become airborne because of wind or mechanical disturbance. Fugitive dust can be generated from natural causes such as wind or from manmade causes such as unpaved haul roads and operational areas, storage, hauling and handling of aggregate materials, construction activities and demolition activities. Fugitive dust contributes particulate matter (PM) emissions to the atmosphere. PM emissions must be minimized to meet NAAQS. Fugitive dust is limited to an opacity of 20% or less on site, and 10% or less at the property boundary. Opacity is a measurement of how much visibility is obscured by a plume of dust. For example, if a plume of dust obscures 20% of the view in the background, the visible emissions from the dust plume is 20% opacity. The regulations described in this Subsection apply to the following areas of the state:

- all regions of Salt Lake and Davis counties
- all portions of the Cache Valley
- all regions in Weber and Utah counties west of the Wasatch Mountain range
- in Box Elder County, from the Wasatch Mountain range west to the Promontory Mountain range and south of Portage
- in Tooele County, from the northernmost part of the Oquirrh mountain range to the northern most part of the Stansbury Mountain range and north of Route 199.

In addition to opacity limits, any source 0.25 acre or greater in size is required to submit a Fugitive Dust Control Plan (FDCP) to the UDAQ. The FDCP is required to help sources minimize the amount of fugitive dust generated onsite. A source is required to submit a FDCP prior to initial construction or operation and prior to any modifications made on site that effect fugitive dust emissions. Sources are required to maintain records indicating compliance with the conditions of a FDCP. For high wind events (winds over 25 miles per hour) additional records are required. The sources must make these records available for review by the UDAQ upon request.

There are also regulations regarding possible fugitive dust from roadways:

- Any person whose activities result in fugitive dust from a road shall minimize fugitive dust to the maximum extent possible.
- Any person who deposits materials that may create fugitive dust on a public or private paved road shall clean the road promptly.
- Any person responsible for construction or maintenance of any existing road or having a right-of-way easement or possessing the right to use a road shall minimize fugitive dust to the maximum extent possible.
- Any person responsible for construction or maintenance of any new or existing unpaved road shall prevent, to the maximum extent possible, the deposit of material from the unpaved road onto any intersecting paved road during construction or maintenance. This includes site entrances and exits for vehicles.
- Demolition activities including razing homes, buildings, or other structures.

### 6.A.7 Basic smoke management practices

Subsection 51.309(d)(6) of Title 40 Code of Federal Regulations includes the following requirements for state implementation plans regarding programs related to fire: (1) documentation that all federal, state and private prescribed fire programs in the state evaluate and address the degree of visibility impairment from smoke in their planning and application; (2) a statewide inventory and emissions tracking system for VOCs, $NO_x$, elemental and organic carbon, and fine particle emissions from fire; (3) identification and removal of any administrative barriers to the use of alternatives to burning where possible; (4) inclusion of enhanced smoke management programs considering visibility as well as health and nuisance objectives based on specific criteria; (5) and establishment of annual emission goals for fire in cooperation with states, tribes, federal land managers and private entities to minimize emissions increases from fire to the maximum extent feasible.

Utah implements an EPA-approved Smoke Management Plan (SMP) to regulate open burning and prescribed fire activities. Utah has developed a smoke management regulation (found in Utah Administrative Code r. R307-204) that implements the Western Regional Air Partnership (WRAP) Enhanced Smoke Management Programs for Visibility Policy. The SMP considers smoke management techniques and the visibility impacts of smoke when developing, issuing or conditioning permits, and when making dispersion forecast recommendations. Pursuant to 40 CFR § 51.309(d)(6)(i), the State of Utah has evaluated all federal, state, and private prescribed fire programs in the state, based on the potential to contribute to visibility impairment in the 16 CIAs of the Colorado Plateau, and how visibility protection from smoke is addressed in planning and operation. The State of Utah relied upon the WRAP report Assessing Status of Incorporating Smoke Effects into fire Planning and Operation as a guide for making this evaluation. The State of Utah has also evaluated whether these prescribed fire programs contain the following elements: actions to minimize emissions; evaluation of smoke dispersion; alternatives to fire; public notification; air quality monitoring; surveillance and enforcement; and program evaluation.

The Utah Smoke Management Plan (SMP), revised March 23, 2000, provides operating procedures for federal and state agencies that use prescribed fire, wildfire, and wildland fire on federal, state, and private wildlands in Utah. The SMP includes the program elements listed in 40 CFR § 51.309(d)(6)(i), except for alternatives to fire. In a letter dated November 8, 1999, the EPA certified the Utah SMP under EPA’s April 1998 Interim Air Quality Policy on Wildland and Prescribed Fires (Policy). EPA’s Policy also includes the elements that are listed in 40 CFR § 51.309(d)(6)(i).

In 2001, the Utah SMP requirements were codified through rulemaking and comprise R307-204 of the Utah Administrative Code. R307-204 applies to all persons using prescribed fire or wildland fire on land they own or manage, including federal, state, and private wildlands. The Utah TSD Supplement includes copies of the Utah SMP.

Under R307-204, Land Managers are required to submit pre-burn information including the location of any CIAs within 15 miles of the burn, a map depicting the potential impact of the smoke from the burn on any CIAs, a description of fuels and acres to be burned, emission reduction techniques to be applied, and monitoring of smoke effects to be conducted. In addition, Land Managers are required to submit a more detailed burn plan that includes, at a minimum, information on the fire prescription or conditions under which a prescribed fire may be ignited.

Under R307-204, prescribed fires requiring a burn plan cannot be ignited and wildland fire used for resource benefits cannot be managed before the UDAQ Director approves the burn request. The burn approval requirement provides for the scheduling of burns to reduce impacts on visibility in CIAs.

After the burn is completed, the Land Manager is required to submit post-burn information (daily emission report) to evaluate the effectiveness of the burn and provide a record of acres treated by the burn, emissions information, public interest, daytime and nighttime smoke behavior, any emission reduction techniques applied, and evaluation of those techniques. The procedures listed above serve as an evaluation of the degree of visibility impairment from smoke from prescribed fires that are conducted on federal, state, and private wildlands.

Information on the types of management alternatives to fire considered by Land Managers are included in programmatic or long-term management plans. These programmatic plans are developed in accordance with the National Environmental Policy Act (NEPA) and are reviewed by the UDAQ on an individual basis. Typically, the Land Manager does not evaluate alternatives to fire once the decision has been made to use fire and the subsequent burn plan developed.

### 6.A.8 Emissions Limitations and Schedules for Compliance to Achieve the RPG

The 2028OTBa2 modeled visibility projections from WRAP for Utah are based on recent actual emissions and activities of in-state sources. These projections are compared to the URP glidepaths in section 8.C. As shown in table 26 (section 6.A.10), Utah is making reasonable progress in each of its parks and is projected to continue that progress through 2028 on the assumption that Utah sources continue operating within the confines of these “on-the-books” emissions trends. Section 8.D contains Utah’s reasonable progress determinations detailing emissions limits and controls UDAQ has deemed necessary for Utah to achieve reasonable progress in its CIAs. Emissions limitations and schedules for compliance for the second planning period may be found in SIP Subsection IX. Part H. 23.[122]

### 6.A.9 Source retirement and replacement schedules

The table below details the planned EGU retirement and replacement schedules for Utah sources used in WRAP’s RepBase2 and 2028OTBa2 modeling projections. Of all of the planned retirements, only the announced retirement of the Intermountain Generation Station in 2025 occurs within the second planning period. Though the IGS coal-fired units are expected to cease operation by mid-2025, Utah is establishing a firm closure date of no later than December

[122] See Appendix A of this draft SIP.

31, 2027, to ensure that these units will not continue to operate beyond the end of the second planning period. This date allows flexibility for closing the plant and the rescinding of the permit and approval order.

**Table 25: Status of Utah EGU Retirements in RepBase2 and 2028OTBa2 Inventories**

| Facility Name | Unit ID | In-Service Year | Retirement Year | Notes | Operator | Unit Type |
|---|---|---|---|---|---|---|
| **Intermountain** | 1SGA | 1986 | 2025 | Announced retirement | Intermountain Power Service Corporation | Dry bottom wall-fired boiler |
| **Intermountain** | 2SGA | 1987 | 2025 | Announced retirement | Intermountain Power Service Corporation | Dry bottom wall-fired boiler |
| **Bonanza** | 1-Jan | 1986 | 2030 | Coal consumption cap from settlement agreement | Deseret Generation & Transmission | Dry bottom wall-fired boiler |
| **Hunter** | 1 | 1978 | 2042 | PAC IRP; Round 1 RH FIP in Litigation | PacifiCorp Energy Generation | Tangentially-fired |
| **Hunter** | 2 | 1980 | 2042 | PAC IRP; Round 1 RH FIP in Litigation | PacifiCorp Energy Generation | Tangentially-fired |
| **Hunter** | 3 | 1983 | 2042 | PAC IRP | PacifiCorp Energy Generation | Dry bottom wall-fired boiler |
| **Huntington** | 1 | 1977 | 2036 | PAC IRP; Round 1 RH FIP in Litigation | PacifiCorp Energy Generation | Tangentially-fired |
| **Huntington** | 2 | 1974 | 2036 | PAC IRP; Round 1 RH FIP in Litigation | PacifiCorp Energy Generation | Tangentially-fired |

### 6.A.10 Anticipated net effect on visibility from projected changes in emissions during this planning period

According to the RHR, the 2028 RPG for the 20 percent most anthropogenically impaired days is to be compared to the 2000-2004 baseline period visibility condition for the same set of days and must provide for visibility improvement since the baseline period.[123] UDAQ has used modeling data from WRAP's TSS to project the anticipated net effect on visibility progress that will occur in the second planning period based on already adopted controls and "on-the-books" activities and emissions rates. UDAQ has chosen the "2028OTBa2 w/o fire" projection that excludes wildfire to more accurately represent future emissions from sources UDAQ is better able to control. This projection reduces the impact of elemental carbon and organic carbon from

[123] 40 CFR 51.308(f)(3)(i)

fires from the original 2028 EPA projection to remove additional fire impacts that were not fully eliminated by the move from haziest days metric (used during the first planning period) to most impaired days metric (used during the second planning period). These projections result from in-state emission reductions due to ongoing air pollution control programs, including source measures the state has already adopted to meet RHR requirements and CAA requirements other than for visibility protection. Please note that a 22.5-ton reduction in NOx resulting from the controls determination for US Magnesium's Riley Boiler located in section 8.D.6 was not included in these modeled projections. The 2028OTBa2 visibility projection also includes emissions from the now-closed Kennecott Power Plant, which was projected to have 1,152 tons of NOx, 2,152 tons of SO2, and 135 tons of PM10 emissions in 2028. The omission of these emissions reductions in the 2028OTBa2 projection make our glidepath comparisons conservative, as actual 2028 visibility can be expected to improve due to lower emissions levels.

Table 26 below compares the baseline visibility data for each of Utah's CIAs with the 2028 point along the URP glidepath and the 2028 modeled projections and calculates the resulting percentage of progress towards the 2028 URP made in each.

**Table 26: Comparison of baseline, 2028 URP, 2028 EPA w/o fire projection for worst and clearest days**

| CIA IMPROVE Site | WORST DAYS | | | | | CLEAREST DAYS | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Baseline (dv) | 2028 URP (dv) | 2028 EPA w/o Fire Projection (dv) | % Progress to 2028 URP | 2028 Below URP Glidepath? (Y/N) | Baseline (dv) | 2028 EPA Projection (dv) | 2028 EPA w/o Fire Projection (dv) | 2028 Below No Degradation Line? (Y/N) |
| BRCA1 | 8.42 | 6.68 | 6.03 | 137.60% | YES | 2.77 | 1.22 | 1.20 | YES |
| CANY1 | 8.79 | 6.92 | 6.19 | 139.10% | YES | 3.75 | 1.94 | 1.92 | YES |
| CAPI1 | 8.78 | 6.87 | 6.63 | 112.28% | YES | 4.10 | 2.17 | 2.10 | YES |
| ZICA1 | 10.40 | 8.35 | 8.27 | 103.73% | YES | 4.48 | 3.65 | 3.54 | YES |

The following figures compare the modeled 2002, representative baseline, and 2028 projections with source apportionment for most impaired days to show the visibility progress made in Utah's CIAs.

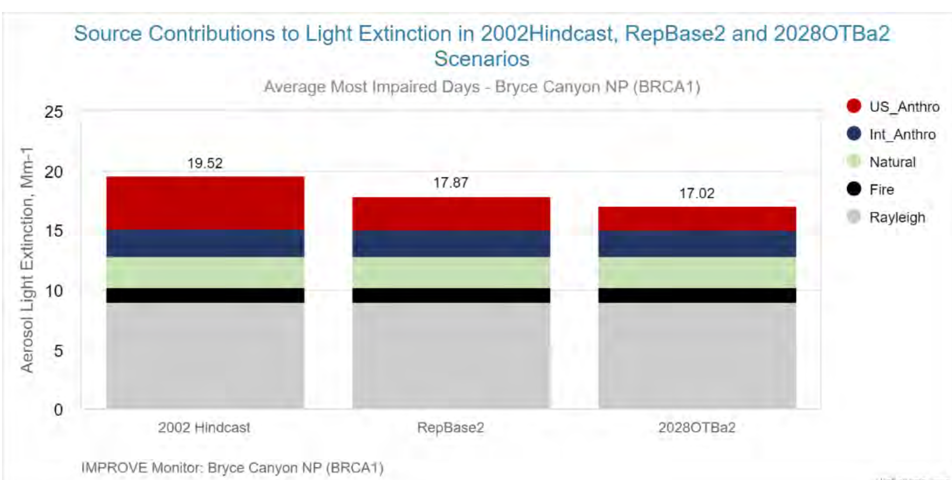

**Figure 41: Modeled Visibility Progress for MID at Bryce Canyon National Park**

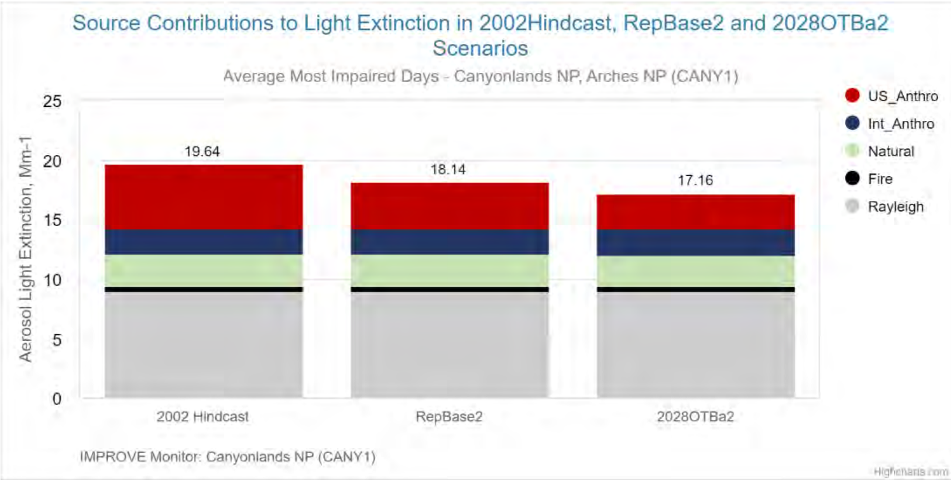


**Figure 42: Modeled Visibility Progress for MID at Canyonlands and Arches National Park**

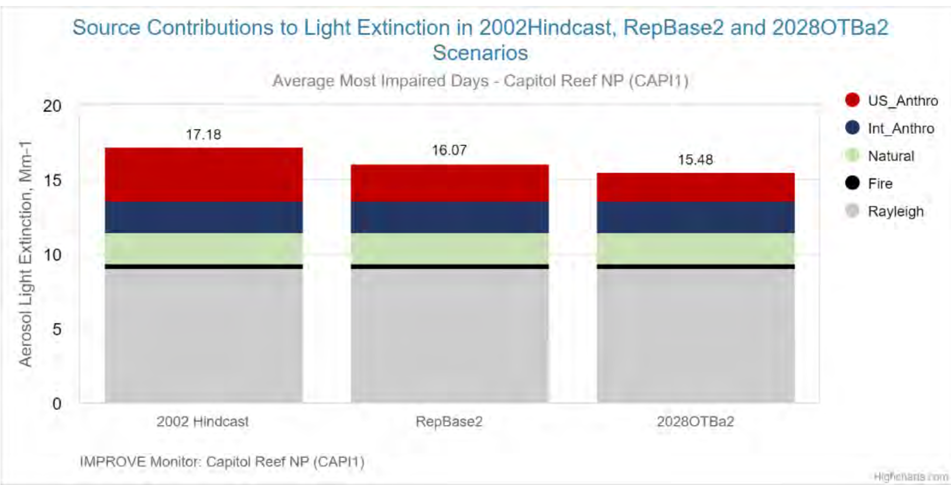


**Figure 43: Modeled Visibility Progress for MID at Capitol Reef National Park**

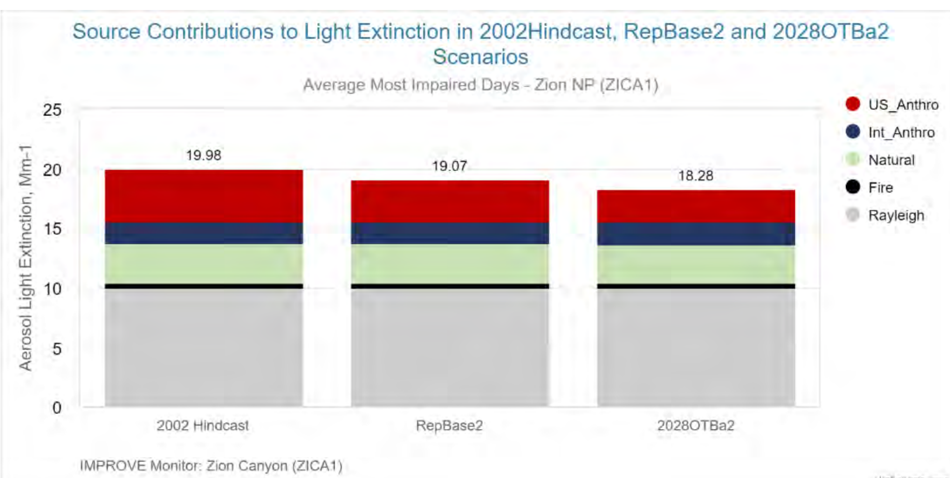

**Figure 44: Modeled Visibility Progress for MID at Zion National Park**

The following figures represent the visibility progress made in each CIA based on only US anthropogenic contribution with the same modeling projections for most impaired days.

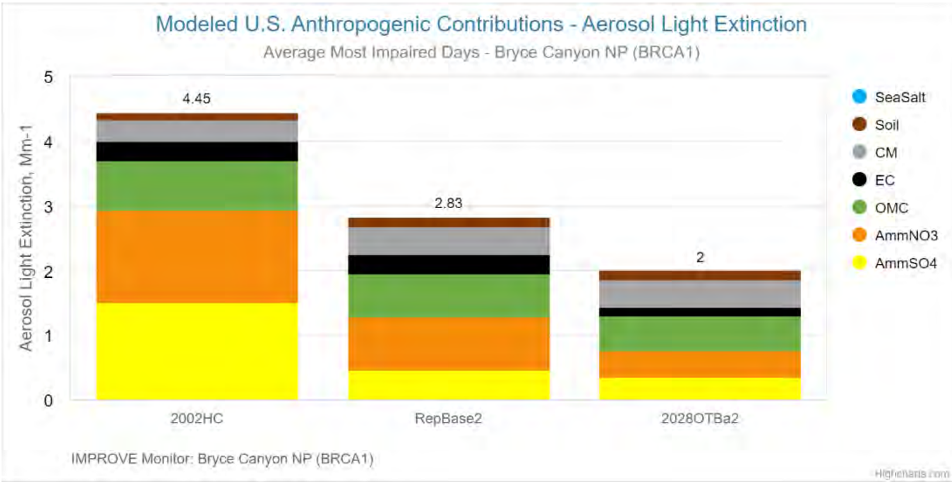


**Figure 45: Modeled Visibility Progress for US Anthropogenic Contributions to MIDs at Bryce Canyon National Park**

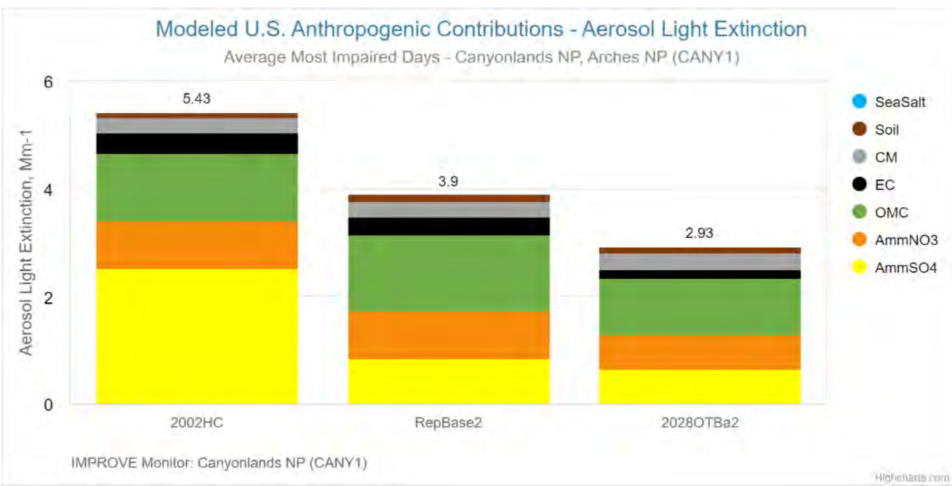


**Figure 46: Modeled Visibility Progress for US Anthropogenic Contributions to MIDs at Canyonlands and Arches National Park**

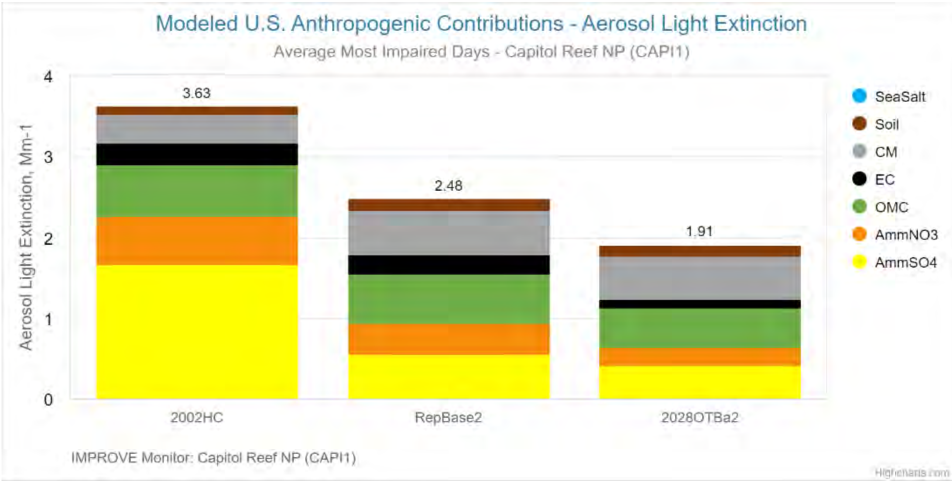


**Figure 47: Modeled Visibility Progress for US Anthropogenic Contributions to MIDs at Capitol Reef National Park**

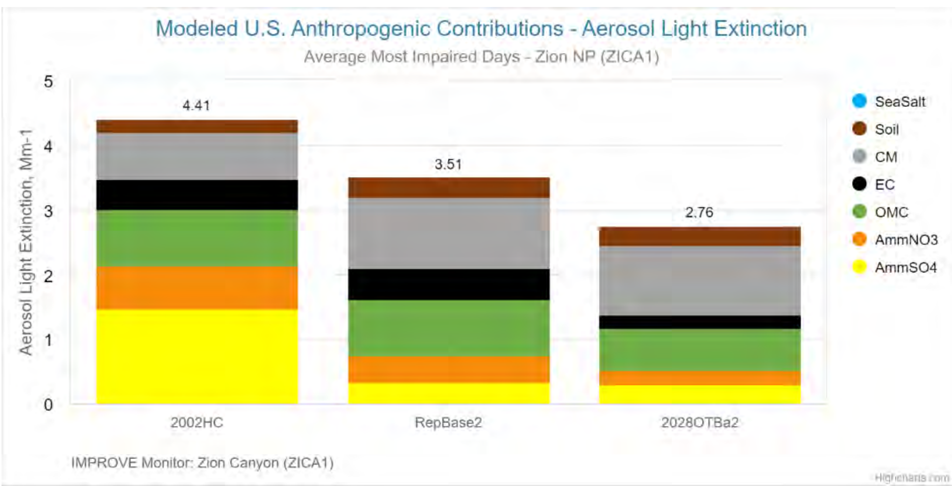


**Figure 48: Modeled Visibility Progress for US Anthropogenic Contributions to MIDs at Zion National Park**

## 6.A.11 Enforceability of Emissions Limitations

Any emissions limits and operating procedures Identified for the implementation of the RHR are listed in SIP Subsection IX. Part H. 21., 22., and 23, which are made enforceable through EPA approval and incorporation into the Utah Air Quality Rules. The proposed part H language can be found in Appendix A.

# **Chapter 7:** Emission Control Analysis[124]

## 7.A Source Screening

Through modeling done by WRAP with data collected at the IMPROVE sites in Utah's CIAs, UDAQ was able to assess the source apportionment for the most impaired days in Utah's National Parks. The figure below shows that, on most impaired days, US anthropogenic, international, and biogenic pollution are the most significant sources of light extinction. Figures 50 and 51 further apportions species contributing to each pollution source. US anthropogenic impairment consists primarily of organic mass carbon, coarse mass, ammonium nitrate, and ammonium sulfate. For this implementation period, Utah has focused on visibility impairing pollutants attributed to anthropogenic sources which can be controlled including ammonium nitrate and ammonium sulfate.

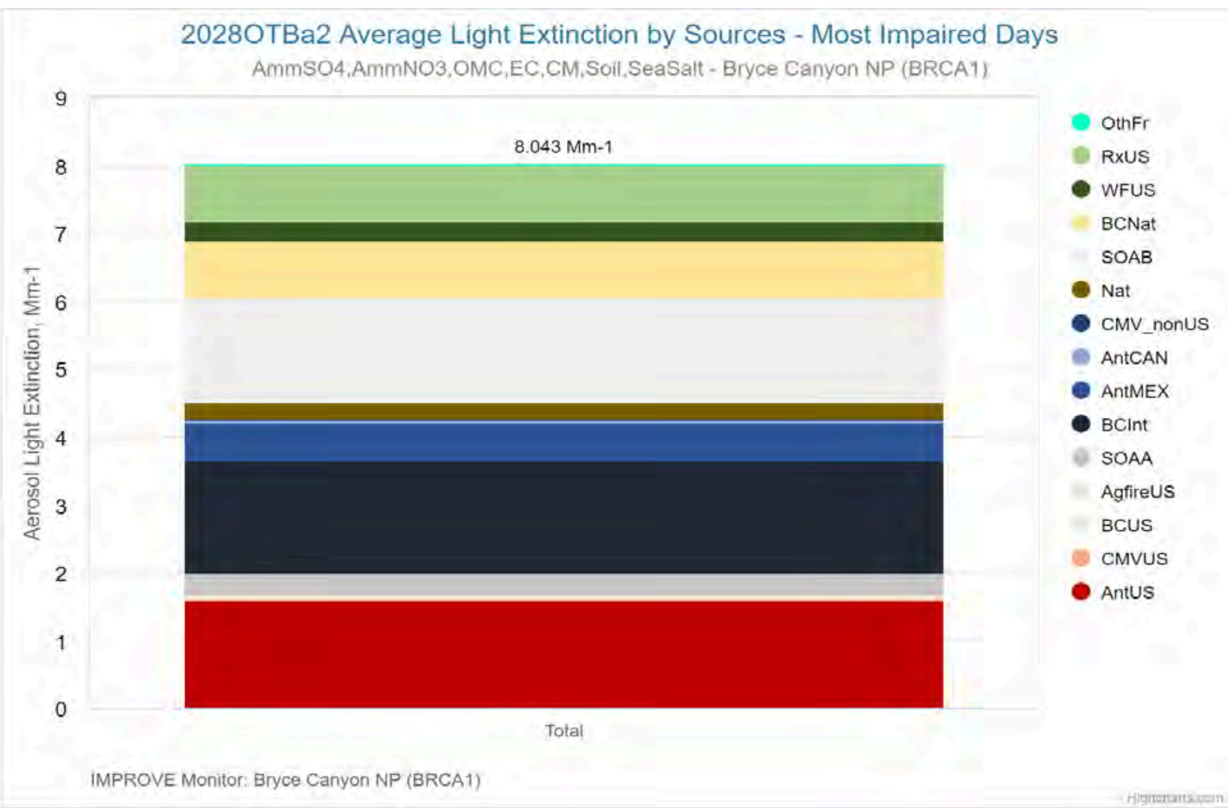


**Figure 49: Average Light Extinction by Sources in Bryce Canyon National Park**

[124] 40 CFR 51.308(f)(2)(i)

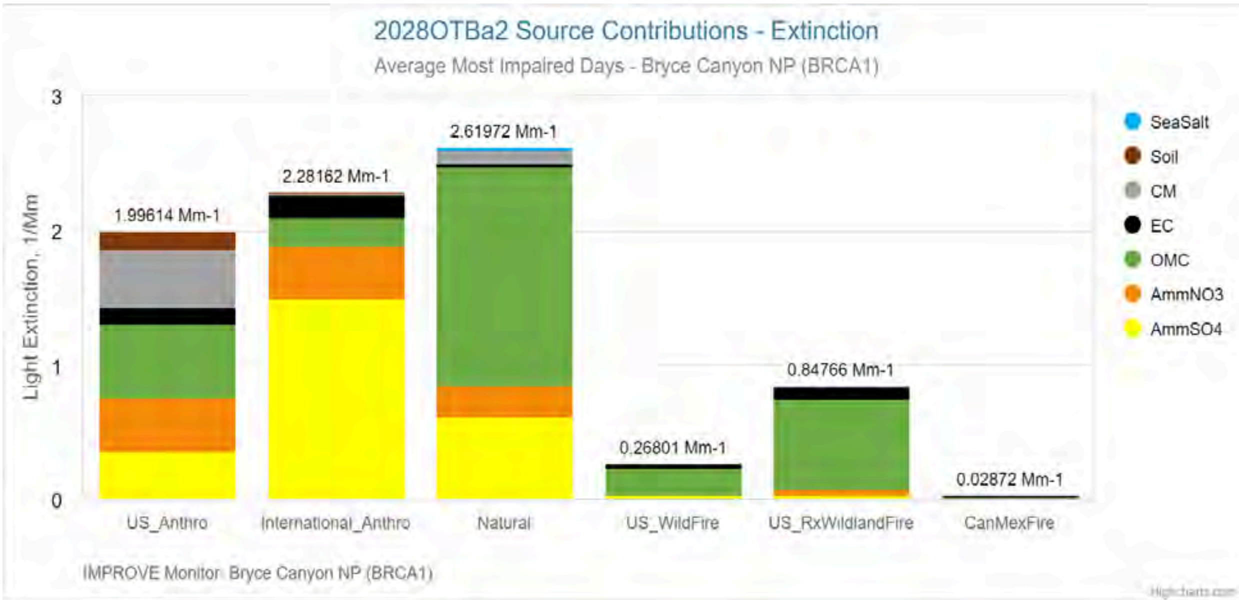


Figure 50: Source Contributions on Average Most Impaired Days in Bryce Canyon National Park

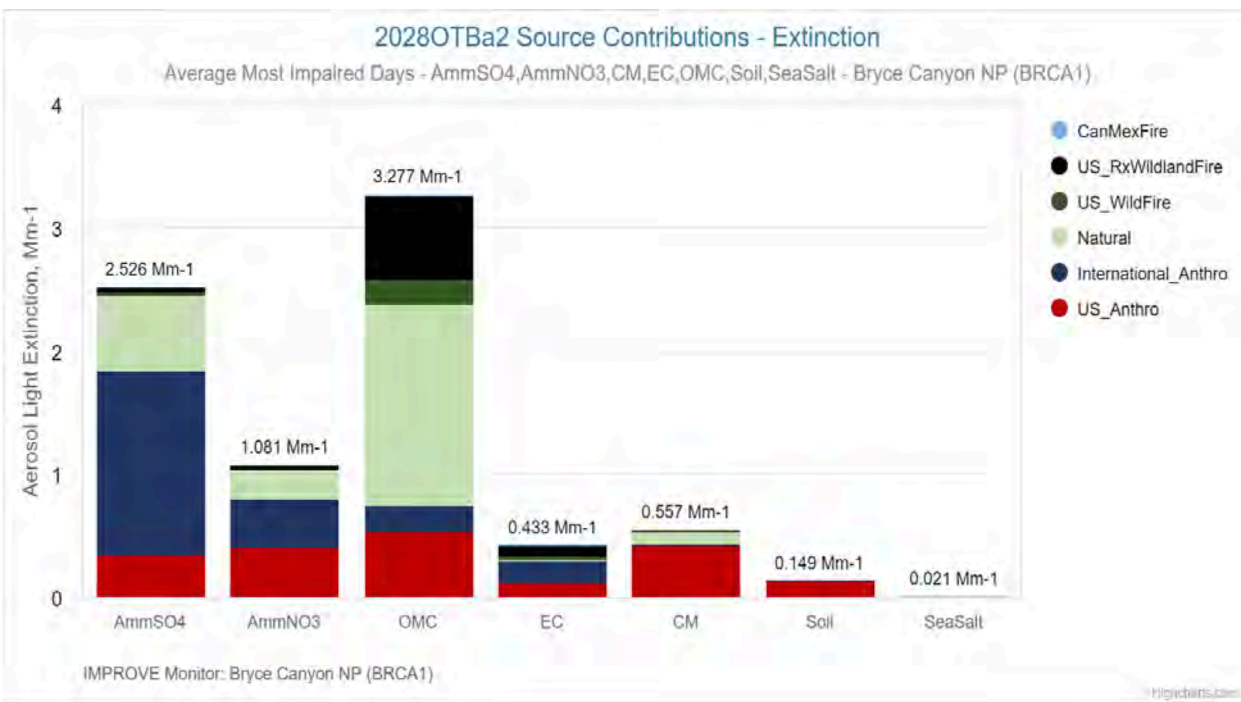


Figure 51: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Bryce Canyon National Park

The regulated sources included in the map below consist of point sources and oil and gas wells within Utah. There are 37 sources emitting pollutants greater than 100 TPY (major sources) and 511 other point sources emitting less than 100 TPY. There are 13,853 oil and gas wells in Utah, including all “shut-in” wells which are not currently in use, but could resume production at any time, which would be documented by reports from the Utah Division of Oil, Gas, and Mining (UDOGM).

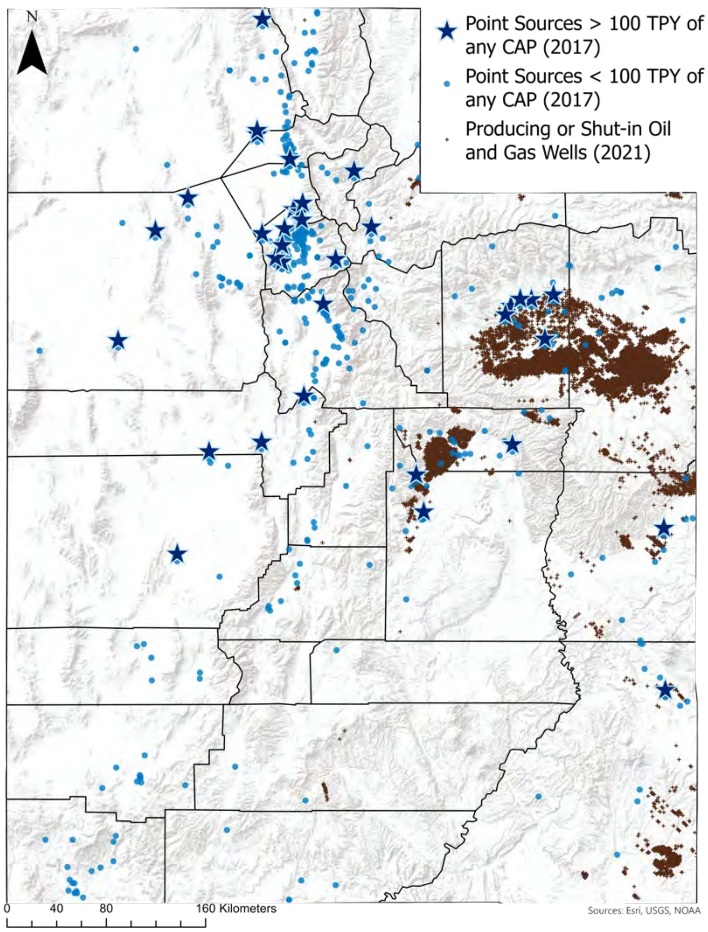


Figure 52: Map of Utah Regulated Sources with Emissions >100 TPY

### 7.A.1 Q/d Analysis

The RHR[125] requires states to consider anthropogenic sources of visibility impairment and should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. Sources in Utah were selected based on a Q/d analysis. The analysis is a ratio of a source's emissions in tons per year (Q) in 2014 divided by the distance (d) in kilometers to any Class I area. Emissions in tons per year of $SO_2$, $NO_x$, and PM were included in the analysis. WRAP's analysis suggested using a Q/d value of 10 as the threshold

[125] 40 C.F.R. § 51.308(f)(2).

for sources with the most potential to impact CIAs. However, UDAQ used a more conservative threshold of six.[126]

**Table 27: Sources initially selected to perform a Four-Factor analysis**

| Facility Name | Combined Q/d | Total Q tpy* | Distance to Nearest Class I area in km (D) | Class I Area | Q/d $NO_x$ | Q/D $SO_2$ | Q/D $PM_{10}$ | $NO_x$ tons per year (Q) | $SO_2$ tons per year (Q) | $PM_{10}$ tons per year (Q) |
|---|---|---|---|---|---|---|---|---|---|---|
| **Ash Grove Cement Company- Leamington Cement Plant** | 6.9 | 930.5 | 134.0 | Capitol Reef | 6.3 | 0.04 | 0.6 | 845.5 | 5.9 | 79.1 |
| **CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant†** | 20.9 | 747.1 | 35.8 | Canyonlands | 5.3 | 14.0 | 1.6 | 188.6 | 499.6 | 59.0 |
| **Graymont Western Us Incorporated- Cricket Mountain Plant** | 9.0 | 1,180.7 | 130.8 | Bryce Canyon | 7.0 | 0.3 | 1.7 | 916.5 | 40.8 | 223.4 |
| **Intermountain Power Service Corporation- Intermountain Generation Station†** | 193.6 | 28,945.7 | 149.5 | Capitol Reef | 153.3 | 29.2 | 11.1 | 22,909.2 | 4,371.5 | 1,665.0 |
| **Kennecott Utah Copper LLC- Mine & Copperton Concentrator†** | 22.1 | 5,234.5 | 237.2 | Capitol Reef | 17.7 | 0.01 | 4.4 | 4,199.6 | 2.0 | 1,032.9 |
| **Kennecott Utah Copper LLC- Power Plant, Lab, and Tailings Impoundment†** | 11.8 | 2,949.7 | 250.4 | Capitol Reef | 5.3 | 6.0 | 0.5 | 1,322.5 | 1,500.3 | 126.8 |
| **PacifiCorp- Hunter Power Plant** | 216.1 | 16,177.9 | 74.9 | Capitol Reef | 153.5 | 52.6 | 10.0 | 11,491.2 | 3,939.3 | 747.4 |
| **PacifiCorp- Huntington Power Plant** | 105.5 | 10,106.2 | 95.8 | Capitol Reef | 71.7 | 25.9 | 7.9 | 6,871.6 | 2,479.2 | 755.4 |
| **Sunnyside Cogeneration Associates- Sunnyside Cogeneration Facility** | 15.2 | 1,477.1 | 97.0 | Canyonlands | 3.6 | 10.9 | 0.8 | 348.9 | 1,054.8 | 73.4 |
| **US Magnesium LLC- Rowley Plant** | 7.4 | 2,124.2 | 288.7 | Capitol Reef | 3.6 | 0.1 | 3.7 | 1,052.1 | 17.9 | 1,054.2 |
| | *Tons per year: Data is from version 2 of the 2014 National Emissions Inventory<br>† Additional data from these sources, including 2018 emissions, projected 2028 emissions, and planned closure, allowed them to be exempt from a 4-factor analysis | | | | | | | | | |
| | | | | | | | | | | |

## 7.A.2 Secondary Screening of Sources

After performing Q/d analysis, UDAQ further narrowed down the list of sources required to undergo the four-factor analysis based on current emissions, projected emissions in 2028,

[126] See table 27

closure and controls put in place after the 2014 base year inventory. As a result of this secondary screening, the following sources were not required to provide a four-factor analysis:

The CCI Paradox Midstream, LLC - Lisbon Natural Gas Processing Plant

Regarding the CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant's exclusion from consideration. In 2009 the plant received a permit modification to lower the SO2 emissions from 1,593 tons down to 111 tons. The plant requested a reduction in emissions as it had installed both primary and secondary control systems to limit emissions of SO2. Unfortunately, in 2010 the plant requested a new modification and mistakenly restored the original 1,593 tons of SO2 emissions without explanation. While that PTE value has been carried forward in more recent permitting actions, actual emissions have never reached the 1,593-ton value. Rather, the actual emissions from the facility are more in line with the proper 2009 PTE of 111 tons.

During the original Q/d analysis, the combined Q/d (for $NO_x$, $SO_2$, and $PM_{10}$) for the facility was 13.68 for Arches and 20.87 for Canyonlands, both of which are above the Q/d threshold of 6 used to select significant sources of haze impairing pollutants to Utah's CIAs. However, based upon updated 2018 emissions for the plant, the combined Q/d values dropped to 3.30 for Arches and 5.03 for Canyonlands. For this reason, this source was ultimately not required to provide a four-factor analysis. In response to FLM feedback, however, UDAQ has requested additional information from Paradox Resources and will include this information in the final draft of this SIP.

Intermountain Power Service Corporation- Intermountain Generation Station

On September 29, 2006, the Governor of California approved California Senate Bill (SB) 1368, which directed the California Energy Commission to establish a greenhouse gas (GHG) emission performance standard (EPS) for electricity generation and which disallowed load-serving entities in California from entering into long-term financial commitments with electrical corporations unless the generation supplied under the financial commitment complies with that standard. Because approximately 98 percent of the power generated at the Intermountain Generation Station (IGS) is consumed by customers of California utilities and because the power generated by the IGS’s two coal-fired units exceeds California’s GHG EPS, the current contract for coal-fired generation, which expires in 2025, will not be renewed for power from those units. Instead, the permittee, Intermountain Power Service Corporation (IPSC), plans to replace the coal-fired units with an EPS-compliant combined-cycle natural gas plant, which will be highly thermally efficient and which will include state-of-the-art emissions controls such as SCR. As a result, regional haze-related pollutants (PM, $SO_2$, and $NO_x$) from the IGS are expected to decrease dramatically. Though the coal-fired units are expected to cease operation by mid-2025, Utah is establishing a firm closure date of no later than December 31, 2027, to ensure that the coal-fired units at IGS will not continue to operate beyond the end of the second planning period. This date allows flexibility for closing the plant and the rescinding of the permit and approval order. UDAQ did approach IPSC about the feasibility of improving the efficiency of existing controls, particularly SO2 scrubbing, at the facility in the three years between mid-2022 and mid-2025, but the company indicated that such improvements are logistically and economically infeasible over such a short time period. Furthermore, the operator's engineering and environmental staff and resources are fully engaged in the process of bringing the replacement gas-fired units online, the successful completion of which will bring about dramatic emissions reductions.

Kennecott Utah Copper LLC- Mine & Copperton Concentrator

The Kennecott Mine and Copperton Concentrator recently underwent BACT analysis as part of the Salt Lake $PM_{2.5}$ SIP. As a result, there are no additional controls that can be applied at this time[127]. The predominant visibility impairing pollutant from this facility is $NO_x$, the vast majority of which comes from mine haul trucks and other non-road equipment as shown in Table 28 below. Specifically, this equipment was responsible for 4,376.7 tons (82.5%) of the 5,308.3 tons of combined $PM_{10}$, $SO_2$, and $NO_x$ emissions from this facility. Section 209 of the Clean Air Act preempts the State from setting standards for non-road vehicles or engines.[128] Though Section IX.H of the Utah SIP does include in-use requirements capping total mileage per calendar day for this equipment in relation to both $PM_{10}$ and $PM_{2.5}$ emissions, UDAQ does not anticipate additional emissions reductions from this equipment until such time as the fleet turns over to more recent Tier 4 standards.[129]

**Table 28: 2017 Kennecott Utah Copper LLC – Mine & Concentrator Emissions and Revised Q/d**

| Source/Distance/Q/d | PM10 | SO2 | NOX | PM10+SO2+ NOX |
|---|---|---|---|---|
| Non-Truck Emissions | 926.4 | 0.0 | 5.2 | 931.6 |
| Haul Truck (non-road) Emissions | 170.0 | 2.7 | 4,204.0 | 4,376.7 |
| Total Emissions | 1,096.4 | 2.7 | 4,209.2 | 5,308.3 |
| Distance to nearest CIA (km) | 237.2 | 237.2 | 237.2 | 237.2 |
| Revised Q/d without haul truck emissions | 3.9 | 0.0 | 0.0 | 3.9 |

Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment

The coal-fired boilers at the Power Plant Lab Tailings impoundment were decommissioned and the Approval Order reflecting this change was updated on February 4, 2020[130]. The vast majority of emissions from that facility were associated with the boilers and the remaining equipment (a diesel emergency generator engine, cooling tower, degreasers and two natural gas-fired emergency generators to support the KUC electricity distribution control room). The

[127] Current requirements relating to the $PM_{2.5}$ SIP for this facility can be found at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2020-014982.pdf
[128] *See* 42 U.S.C. § 7543(e).
[129] See pages 24 and 131 of https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2020-014982.pdf.

[130] This Approval Order can be found at: https://daqpermitting.utah.gov/DocViewer?IntDocID=117327&contentType=application/pdf

emissions are small enough that this source is below the Q/d threshold for the four-factor analysis.

### 7.A.3 Weighted Emissions Potential Analysis of Sources in Utah and Neighboring States

WRAP released a Weighted Emissions Potential (WEP) analysis after UDAQ chose sources to submit a four-factor analysis. The WEP is obtained by overlaying extinction weighted residence time (EWRT) results with 2028OTBa2 emissions of light extinction precursors and shows which sources have the highest potential to impact visibility in CIAs.  Tables 29 and 30 list the point sources with the top ten WEP values for Utah CIAs for nitrate and sulfate, respectively, and summarize whether those sources were captured by Utah's initial Q/d screen and whether they were ultimately required to submit a four-factor analysis.  As can be seen, UDAQ's initial Q/d screen captured most of the point sources with the highest-ranking WEP values at Utah CIAs. For those sources that were ultimately excluded from submitting a four-factor analysis, the tables provide notes as to the rationale for the exclusion, including plant closures, recent BACT analysis/controls, revised emission inventories, and the predominance of emissions from sources that states are largely preempted from controlling (e.g., non-road).  The tables also include information regarding the status of non-Utah point sources with high-ranking WEP values, where available.

Tables 31 and 32 list Utah point sources that were among the top ten WEP values in the CIAs of neighboring states for nitrate and sulfate, respectively.  Again, the tables show that UDAQ's initial and secondary screening largely succeeded in identifying the sources with the potential to impact CIAs, while excluding some sources that were already well-controlled, closed/closing, or that have few options for state-level controls.

**Table 29: Nitrate Point Source WEP Rank for Utah CIAs**

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB $NO_x$ (tons) | Distance (meters) | $NO_x$ Q/d | WEP_$NO_3$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **BRCA1** | 1 | PacifiCorp-Hunter Power Plant | UT | 10,001.2 | 198,466.7 | 50.4 | 109,484.1 (18.6%) | YES | YES | |
| **BRCA1** | 2 | PacifiCorp-Huntington Power Plant | UT | 6,091.4 | 216,464.4 | 28.1 | 61,138.6 (10.4%) | YES | YES | |
| **BRCA1** | 3 | Kennecott Utah Copper LLC- Mine & Copperton Concentrator | UT | 4,199.6 | 329,072.0 | 12.8 | 52,048.8 (8.8%) | YES | NO | BACT for $PM_{2.5}$ Serious SIP; majority of $NO_x$ emissions from non-road sources |

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB $NO_x$ (tons) | Distance (meters) | $NO_x$ Q/d | WEP_$NO_3$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **BRCA1** | 4 | Graymont Western US Incorporated-Cricket Mountain Plant | UT | 916.5 | 155,620.0 | 5.9 | 34,304.4 (5.8%) | YES | YES | |
| **BRCA1** | 5 | Ash Grove Cement Company-Leamington Cement Plant | UT | 845.5 | 214,929.5 | 3.9 | 30,091.0 (5.1%) | YES | YES | |
| **BRCA1** | 6 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 1,157.5 | 342,148.6 | 3.4 | 20,954.3 (3.6%) | YES | NO | Power plant closed in 2020 |
| **BRCA1** | 7 | Salt Lake City Intl | UT | 784.0 | 350,666.3 | 2.2 | 17,677.6 (3.0%) | NO | NO | Q/d <6; majority of $NO_x$ emissions from non-road sources (aircraft take-offs and landings) |
| **BRCA1** | 8 | US Magnesium LLC- Rowley Plant | UT | 1,052.1 | 367,453.2 | 2.9 | 10,062.0 (1.7%) | YES | YES | |
| **BRCA1** | 9 | Chevron Products Co - Salt Lake Refinery | UT | 375.6 | 355,251.0 | 1.1 | 8,359.5 (1.4%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **BRCA1** | 10 | Tesoro Refining & Marketing Company LLC | UT | 358.1 | 351,572.8 | 1.0 | 8,053.0 (0.9%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **CANY1** | 1 | PacifiCorp-Hunter Power Plant | UT | 10,001.2 | 130,681.1 | 76.5 | 128,112.8 (13.9%) | YES | YES | |
| **CANY1** | 2 | PacifiCorp-Huntington Power Plant | UT | 6,091.4 | 148,607.2 | 41.0 | 68,616.5 (7.4%) | YES | YES | |
| **CANY1** | 3 | Bonanza | TR | 5,721.7 | 185,722.9 | 30.8 | 59,301.8 (6.4%) | NA | NA | Likely closure in 2030 due to settlement |
| **CANY1** | 4 | PNM - San Juan Generating Station | NM | 7,390.8 | 219,591.9 | 33.7 | 47,113.4 (5.1%) | NA | NA | PNM has announced plant closure in 2022 |

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB $NO_x$ (tons) | Distance (meters) | $NO_x$ Q/d | WEP_$NO_3$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **CANY1** | 5 | Kennecott Utah Copper LLC- Mine & Copperton Concentrator | UT | 4,199.6 | 307,168.4 | 13.7 | 45,956.2 (5.0%) | YES | NO | BACT for $PM_{2.5}$ Serious SIP; majority of $NO_x$ emissions from non-road sources |
| **CANY1** | 6 | Four Corners Power Plant | TR | 4,060.4 | 228,638.6 | 17.8 | 24,859.3 (2.7%) | NA | NA | APS has announced plant closure in 2031 |
| **CANY1** | 7 | Sunnyside Cogeneration Associates-Sunnyside Cogeneration Facility | UT | 442.2 | 129,762.3 | 3.4 | 22,940.9 (2.5%) | YES | YES | |
| **CANY1** | 8 | Chaco Gas Plant | NM | 2,053.4 | 264,690.7 | 7.8 | 14,056.2 (1.5%) | NA | NA | |
| **CANY1** | 9 | CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant | UT | 201.9 | 57,532.7 | 3.5 | 12,076.0 (1.3%) | YES | NO | 2018 emissions Q/d <6 |
| **CANY1** | 10 | RED ROCK GATHERING-PREMIER BAR X C.S. | CO | 73.3 | 118,289.1 | 0.6 | 11,567.0 (1.3%) | NA | NA | Low $NO_x$ Q/d |
| **CAPI1** | 1 | PacifiCorp-Hunter Power Plant | UT | 10,001.2 | 98,938.2 | 101.1 | 334,329.1 (37.2%) | YES | YES | |
| **CAPI1** | 2 | PacifiCorp-Huntington Power Plant | UT | 6,091.4 | 120,459.7 | 50.6 | 167,247.5 (18.6%) | YES | YES | |
| **CAPI1** | 3 | Kennecott Utah Copper LLC- Mine & Copperton Concentrator | UT | 4,199.6 | 263,195.8 | 16.0 | 42,259.0 (4.7%) | YES | NO | BACT for $PM_{2.5}$ Serious SIP; majority of $NO_x$ emissions from non-road sources |
| **CAPI1** | 4 | Graymont Western US Incorporated-Cricket Mountain Plant | UT | 916.5 | 148,543.7 | 6.2 | 26,049.6 (2.9%) | YES | YES | |
| **CAPI1** | 5 | Ash Grove Cement Company-Leamington Cement Plant | UT | 845.5 | 159,501.2 | 5.3 | 24,633.4 (2.7%) | YES | YES | |

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB $NO_x$ (tons) | Distance (meters) | $NO_x$ Q/d | WEP_$NO_3$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **CAPI1** | 6 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 1,157.5 | 275,718.8 | 4.2 | 13,860.1 (1.5%) | YES | NO | Power plant closed in 2020 |
| **CAPI1** | 7 | US Magnesium LLC- Rowley Plant | UT | 1,052.1 | 313,659.3 | 3.4 | 10,218.3 (1.1%) | YES | YES | |
| **CAPI1** | 8 | Bonanza | TR | 5,721.7 | 261,713.3 | 21.9 | 9,450.1 (1.1%) | NA | NA | Likely closure in 2030 due to settlement |
| **CAPI1** | 9 | Sunnyside Cogeneration Associates- Sunnyside Cogeneration Facility | UT | 442.2 | 158,414.3 | 2.8 | 8,764.7 (1.0%) | YES | YES | |
| **CAPI1** | 10 | Salt Lake City Intl | UT | 784.0 | 280,646.7 | 2.8 | 7,264.8 (0.8%) | NO | NO | Q/d <6; majority of $NO_x$ emissions from non-road sources (aircraft take-offs and landings) |
| **ZICA1** | 1 | St. George City Power- Red Rock Power Generation Station | UT | 34.3 | 38,429.0 | 0.9 | 13,108.2 (5.3%) | NO | NO | Q/d <6 |
| **ZICA1** | 2 | PacifiCorp- Hunter Power Plant | UT | 10,001.2 | 285,805.3 | 35.0 | 12,364.2 (5.0%) | YES | YES | |
| **ZICA1** | 3 | McCarran Intl | NV | 2,430.2 | 218,239.9 | 11.1 | 9,235.4 (3.7%) | NA | NA | Majority of $NO_x$ emissions from non-road sources (aircraft take-offs and landings) |
| **ZICA1** | 4 | Kern River Gas Transmission Company- Veyo Compressor Station | UT | 72.7 | 56,439.3 | 1.3 | 9,185.2 (3.7%) | NO | NO | Q/d <6 |
| **ZICA1** | 5 | Kennecott Utah Copper LLC- Mine & Copperton Concentrator | UT | 4,199.6 | 385,739.6 | 10.9 | 7,998.7 (3.2%) | YES | NO | BACT for $PM_{2.5}$ Serious SIP; majority of $NO_x$ emissions from non-road sources |

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB $NO_x$ (tons) | Distance (meters) | $NO_x$ Q/d | WEP_$NO_3$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **ZICA1** | 6 | Pg&E Topock Compressor Station | CA | 968.8 | 300,092.2 | 3.2 | 7,620.0 (3.1%) | NA | NA | |
| **ZICA1** | 7 | Millcreek Power | UT | 19.4 | 38,438.7 | 0.5 | 7,402.2 (3.0%) | NO | NO | Q/d <6 |
| **ZICA1** | 8 | PacifiCorp-Huntington Power Plant | UT | 6,091.4 | 300,744.4 | 20.3 | 7,156.5 (2.9%) | YES | YES | |
| **ZICA1** | 9 | Lhoist North America and Granite Const. (Apex) | NV | 1,361.8 | 181,728.8 | 7.5 | 7,041.9 (2.8%) | NA | NA | |
| **ZICA1** | 10 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 1,157.5 | 398,524.3 | 2.9 | 6,609.7 (2.7%) | YES | NO | Power plant closed in 2020 |

## Table 30: Sulfate Point Source WEP Rank for Utah CIAs

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB SO2 (tons) | Distance (meters) | SO2 Q/d | WEP_$SO_4$ (% of Total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **BRCA1** | 1 | CHEMICAL LIME NELSON PLANT | AZ | 2,040.6 | 253,654.7 | 8.0 | 43,684.7 (21.8%) | NA | NA | |
| **BRCA1** | 2 | PacifiCorp-Hunter Power Plant | UT | 3,498.2 | 198,466.7 | 17.6 | 22,430.8 (11.2%) | YES | YES | |
| **BRCA1** | 3 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 342,148.6 | 6.3 | 17,191.7 (8.6%) | YES | NO | Power plant closed in 2020 |
| **BRCA1** | 4 | PacifiCorp-Huntington Power Plant | UT | 2,449.0 | 216,464.4 | 11.3 | 14,397.6 (7.2%) | YES | YES | |
| **BRCA1** | 5 | ASARCO LLC - HAYDEN SMELTER | AZ | 3,062.1 | 527,077.3 | 5.8 | 14,391.7 (7.2%) | NA | NA | |
| **BRCA1** | 6 | Kennecott Utah Copper LLC- Smelter & Refinery | UT | 704.4 | 342,656.1 | 2.1 | 5,618.9 (2.8%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **BRCA1** | 7 | Four Corners Power Plant | TR | 2,537.7 | 341,751.7 | 7.4 | 5,413.2 (2.7%) | NA | NA | APS has announced plant closure in 2031 |

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB SO2 (tons) | Distance (meters) | SO2 Q/d | WEP_$SO_4$ (% of Total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **BRCA1** | 8 | Tesoro Refining & Marketing Company LLC | UT | 708.3 | 351,572.8 | 2.0 | 5,158.3 (2.6%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **BRCA1** | 9 | TUCSON ELECTRIC POWER CO - SPRINGERVILLE | AZ | 6,991.9 | 455,128.8 | 15.4 | 3,654.7 (1.8%) | NA | NA | |
| **BRCA1** | 10 | Phoenix Sky Harbor Intl | AZ | 275.1 | 463,195.4 | 0.6 | 3,615.9 (1.8%) | NA | NA | Majority of $NO_X$ emissions from non-road sources (aircraft take-offs and landings) |
| **CANY1** | 1 | PacifiCorp-Hunter Power Plant | UT | 3,498.2 | 130,681.1 | 26.8 | 78,098.2 (19.1%) | YES | YES | |
| **CANY1** | 2 | PacifiCorp-Huntington Power Plant | UT | 2,449.0 | 148,607.2 | 16.5 | 48,079.5 (11.8%) | YES | YES | |
| **CANY1** | 3 | CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant | UT | 534.9 | 57,532.7 | 9.3 | 39,468.2 (9.7%) | YES | NO | 2018 emissions Q/d <6 |
| **CANY1** | 4 | Four Corners Power Plant | TR | 2,537.7 | 228,638.6 | 11.1 | 32,557.0 (8.0%) | NA | NA | APS has announced plant closure in 2031 |
| **CANY1** | 5 | Sunnyside Cogeneration Associates-Sunnyside Cogeneration Facility | UT | 460.8 | 129,762.3 | 3.6 | 25,602.8 (6.3%) | YES | YES | |
| **CANY1** | 6 | Kennecott Utah Copper LLC-Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 317,050.4 | 6.8 | 21,266.8 (5.2%) | YES | NO | Power plant closed in 2020 |
| **CANY1** | 7 | TUCSON ELECTRIC POWER CO - SPRINGERVILLE | AZ | 6,991.9 | 463,072.9 | 15.1 | 13,923.7 (3.4%) | NA | NA | |
| **CANY1** | 8 | CHEMICAL LIME NELSON PLANT | AZ | 2,040.6 | 448,519.3 | 4.6 | 13,409.0 (3.3%) | NA | NA | |
| **CANY1** | 9 | Bonanza | TR | 1,281.3 | 185,722.9 | 6.9 | 11,908.4 (2.9%) | NA | NA | Likely closure in 2030 due to settlement |
| **CANY1** | 10 | PNM - San Juan Generating Station | NM | 823.1 | 219,591.9 | 3.7 | 10,995.1 (2.7%) | NA | NA | PNM has announced plant closure in 2022 |

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB SO2 (tons) | Distance (meters) | SO2 Q/d | WEP_$SO_4$ (% of Total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **CAPI1** | 1 | PacifiCorp-Hunter Power Plant | UT | 3,498.2 | 98,938.2 | 35.4 | 138,922.3 (34.7%) | YES | YES | |
| **CAPI1** | 2 | PacifiCorp-Huntington Power Plant | UT | 2,449.0 | 120,459.7 | 20.3 | 79,880.4 (20.0%) | YES | YES | |
| **CAPI1** | 3 | Kennecott Utah Copper LLC-Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 275,718.8 | 7.8 | 31,599.4 (7.9%) | YES | NO | Power plant closed in 2020 |
| **CAPI1** | 4 | CHEMICAL LIME NELSON PLANT | AZ | 2,040.6 | 356,269.4 | 5.7 | 25,448.1 (6.4%) | NA | NA | |
| **CAPI1** | 5 | Sunnyside Cogeneration Associates-Sunnyside Cogeneration Facility | UT | 460.8 | 158,414.3 | 2.9 | 10,823.1 (2.7%) | YES | YES | |
| **CAPI1** | 6 | ASARCO LLC - HAYDEN SMELTER | AZ | 3,062.1 | 589,323.9 | 5.2 | 10,351.8 (2.6%) | NA | NA | |
| **CAPI1** | 7 | Kennecott Utah Copper LLC-Smelter & Refinery | UT | 704.4 | 277,921.4 | 2.5 | 10,261.2 (2.6%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **CAPI1** | 8 | Tesoro Refining & Marketing Company LLC | UT | 708.3 | 280,166.8 | 2.5 | 6,278.1 (1.6%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **CAPI1** | 9 | NORTH VALMY GENERATING STATION | NV | 2,277.3 | 574,890.7 | 4.0 | 5,620.2 (1.4%) | NA | NA | Federally enforceable closure date of December, 31, 2028 |
| **CAPI1** | 10 | Bonanza | TR | 1,281.3 | 261,713.3 | 4.9 | 4,809.0 (1.2%) | NA | NA | Likely closure in 2030 due to settlement |
| **ZICA1** | 1 | CHEMICAL LIME NELSON PLANT | AZ | 2,040.6 | 186,619.3 | 10.9 | 38,687.4 (24.8%) | NA | NA | |
| **ZICA1** | 2 | Kennecott Utah Copper LLC-Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 398,524.3 | 5.4 | 9,186.4 (5.9%) | YES | NO | Power plant closed in 2020 |
| **ZICA1** | 3 | ASARCO LLC - HAYDEN SMELTER | AZ | 3,062.1 | 512,466.4 | 6.0 | 6,672.2 (4.3%) | NA | NA | |

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB SO2 (tons) | Distance (meters) | SO2 Q/d | WEP_SO₄ (% of Total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **ZICA1** | 4 | McCarran Intl | NV | 265.3 | 218,239.9 | 1.2 | 4,713.6 (3.0%) | NA | NA | Majority of $NO_x$ emissions from non-road sources (aircraft take-offs and landings) |
| **ZICA1** | 5 | PacifiCorp-Hunter Power Plant | UT | 3,498.2 | 285,805.3 | 12.2 | 4,557.8 (2.9%) | YES | YES | |
| **ZICA1** | 6 | Phoenix Sky Harbor Intl | AZ | 275.1 | 428,694.4 | 0.6 | 4,554.6 (2.9%) | NA | NA | Majority of $NO_x$ emissions from non-road sources (aircraft take-offs and landings) |
| **ZICA1** | 7 | California Portland Cement Co. | CA | 1,445.5 | 520,498.4 | 2.8 | 4,038.8 (2.6%) | NA | NA | |
| **ZICA1** | 8 | Republic Services Sunrise | NV | 209.5 | 201,737.4 | 1.0 | 4,025.8 (2.6%) | NA | NA | |
| **ZICA1** | 9 | TUCSON ELECTRIC POWER CO - SPRINGERVILLE | AZ | 6,991.9 | 480,561.1 | 14.5 | 3,447.7 (2.2%) | NA | NA | |
| **ZICA1** | 10 | PacifiCorp-Huntington Power Plant | UT | 2,449.0 | 300,744.4 | 8.1 | 3,032.3 (1.9%) | YES | YES | |

### Table 31: Nitrate Utah Point Source WEP Rank for Non-Utah CIAs

| CIA State | CIA | Rank | Facility Name | Source State | 2028 OTB $NO_x$ (tons) | Distance (meters) | $NO_x$ Q/d | WEP_NO₃ (% of total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **WY** | BRID1 | 5 | Kennecott Utah Copper LLC- Mine & Copperton Concentrator | UT | 4,199.6 | 328,062.1 | 12.8 | 23,190.1 (3.9%) | YES | NO | BACT for $PM_{2.5}$ Serious SIP; majority of $NO_x$ emissions from non-road sources |
| **WY** | YELL2 | 9 | Kennecott Utah Copper LLC- Mine & Copperton Concentrator | UT | 4,199.6 | 461,954.1 | 9.1 | 4,042.4 (1.8%) | YES | NO | BACT for $PM_{2.5}$ Serious SIP; majority of $NO_x$ emissions |

| CIA State | CIA | Rank | Facility Name | Source State | 2028 OTB $NO_x$ (tons) | Distance (meters) | $NO_x$ Q/d | WEP_$NO_3$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | from non-road sources |
| **WY** | YELL2 | 10 | Salt Lake City Intl | UT | 784.0 | 437,939.4 | 1.8 | 3,887.0 (1.7%) | NO | NO | Q/d <6; majority of $NO_x$ emissions from non-road sources (aircraft take-offs and landings) |
| **ID** | CRMO1 | 10 | Kennecott Utah Copper LLC- Mine & Copperton Concentrator | UT | 4,199.6 | 338,486.4 | 12.4 | 22,912.5 (2.5%) | YES | NO | BACT for $PM_{2.5}$ Serious SIP; majority of $NO_x$ emissions from non-road sources |

### Table 32: Sulfate Utah Point Source WEP Rank for Non-Utah CIAs

| CIA State | CIA | Rank | Facility Name | Source State | 2028 OTB $SO_2$ (tons) | Distance (meters) | $SO_2$ Q/d | WEP_$SO_4$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **CO** | MEVE1 | 6 | CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant | UT | 534.9 | 126,687.8 | 4.2 | 22,144.4 (1.3%) | YES | NO | 2018 emissions Q/d <6 |
| **CO** | MEVE1 | 9 | PacifiCorp-Hunter Power Plant | UT | 3,498.2 | 310,434.6 | 11.3 | 11,845.4 (0.7%) | YES | YES | |
| **CO** | WEMI1 | 3 | CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant | UT | 534.9 | 140,388.0 | 3.8 | 24,308.8 (3.8%) | YES | NO | 2018 emissions Q/d <6 |
| **CO** | WEMI1 | 6 | PacifiCorp-Hunter Power Plant | UT | 3,498.2 | 326,019.1 | 10.7 | 12,361.1 (1.9%) | YES | YES | |

| CIA State | CIA | Rank | Facility Name | Source State | 2028 OTB $SO_2$ (tons) | Distance (meters) | $SO_2$ Q/d | WEP_$SO_4$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **WY** | BRID1 | 5 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 317,383.8 | 6.8 | 53,003.7 (6.3%) | YES | NO | Power plant closed in 2020 |
| **WY** | BRID1 | 8 | Tesoro Refining & Marketing Company LLC | UT | 708.3 | 299,746.7 | 2.4 | 32,334.3 (3.9%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **WY** | NOAB1 | 8 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 499,395.1 | 4.3 | 15,792.1 (2.2%) | YES | NO | Power plant closed in 2020 |
| **WY** | YELL2 | 2 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 449,396.5 | 4.8 | 23,791.3 (7.4%) | YES | NO | Power plant closed in 2020 |
| **WY** | YELL2 | 8 | Tesoro Refining & Marketing Company LLC | UT | 708.3 | 435,882.7 | 1.6 | 10,963.7 (3.4%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **ID** | CRMO1 | 4 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 326,319.5 | 6.6 | 18,525.9 (6.8%) | YES | NO | Power plant closed in 2020 |
| **ID** | CRMO1 | 6 | Tesoro Refining & Marketing Company LLC | UT | 708.3 | 325,079.4 | 2.2 | 7,431.8 (2.7%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **ID** | CRMO1 | 10 | Kennecott Utah Copper LLC- Smelter & Refinery | UT | 704.4 | 323,667.2 | 2.2 | 6,113.6 (2.2%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **ID** | SAWT1 | 4 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 446,448.0 | 4.8 | 6,827.9 (5.4%) | YES | NO | Power plant closed in 2020 |
| **ID** | SAWT1 | 8 | Tesoro Refining & Marketing Company LLC | UT | 708.3 | 448,276.9 | 1.6 | 3,373.8 (2.7%) | NO | NO | Q/d <6; BACT for +$PM_{2.5}$ Serious SIP |

| CIA State | CIA | Rank | Facility Name | Source State | 2028 OTB $SO_2$ (tons) | Distance (meters) | $SO_2$ Q/d | WEP_$SO_4$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **ID** | SAWT1 | 10 | Kennecott Utah Copper LLC- Smelter & Refinery | UT | 704.4 | 442,899.3 | 1.6 | 2,252.8 (1.8%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **NV** | JARB1 | 10 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 304,126.8 | 7.1 | 5,105.3 (1.4%) | YES | NO | Power plant closed in 2020 |
| **AZ** | GRCA2 | 10 | PacifiCorp-Hunter Power Plant | UT | 3,498.2 | 363,743.3 | 9.6 | 2,321.3 (0.6%) | YES | YES | |

## 7.A.4 Other Sources

The foregoing Q/d analysis, secondary screening, and WEP analysis sections were used to help identify point sources with potential impacts at Utah and non-Utah CIAs. However, the emissions inventories detailed in section 5.A and the WRAP photochemical source apportionment results provided in section 6.A suggest that non-point sources in Utah may also impact visibility in CIAs. This section discusses the potential impacts of and state of emissions controls for non-point sources in Utah.

### *Oil and Gas*

The Uinta Basin (UB), located in northeast Utah, contains the majority of oil and gas extraction in Utah. The UB has been found to have high levels of ozone during the winter months. This phenomenon is associated with the geological basin, cold temperature inversion, and snow cover albedo in the presence of VOCs and $NO_x$. The majority of emissions for the ozone precursors of VOC and $NO_x$ come primarily from the oil and gas exploration and production in the area, not other urban or mobile sources. Since the discovery of these high ozone emissions, Utah has acted to control the oil and gas sources in the UB and the rest of the state. However, the jurisdictional complexity of the UB has led to inconsistency between state-controlled sources and EPA-controlled sources on Indian Country. Emission inventories show that about 80% of the emissions are under EPA regulatory control. The 2017 oil and gas emission inventory compared to the total emission inventory for the UB accounts for about 97% of the total VOC emissions and 68% of the total $NO_x$ emissions. The 2017 oil and gas emission inventory showed that 80% of emissions in the UB result from areas under EPA control. Therefore, the state of Utah can only address about 20% of the ozone-forming precursors VOC and $NO_x$ and cannot address air quality issues on their own in the UB. Over the past several years, UDAQ has proposed and adopted a series of statewide rules specific to oil and gas operations found in Utah's state administrative rules R301-500 to 511. Though these rules have been focused on controlling VOC emissions, there is also a state-specific rule for natural gas-powered engines associated with oil and gas production. Since the rule was put in place in 2018, several sources have provided engine stack test data that have led UDAQ, EPA, and the Tribes to initiate further research and compliance studies on engines in the Basin, with a focus on two-stroke smaller horsepower engines that power pump jacks associated with oil-producing wells. The data collected have indicated lower values for $NO_x$ emissions than what was reported in the 2017 oil and gas emission inventory for these engines, yet much higher emissions of VOCs. UDAQ will be evaluating this data and will be evaluating future rulemaking for engines associated with oil and gas operations that would be statewide. EPA did follow UDAQ's lead and has proposed the Uintah and Ouray Federal Implementation Plan that is similar to Utah's oil and gas rules, and will bring some regulatory consistency to the area. The UDAQ will continue to coordinate with EPA and the Tribe to encourage that rules are consistent across all regulatory jurisdictions, but ultimately any controls under EPA regulatory jurisdiction will be determined by EPA and the Tribe[131].

*Mobile*

As identified in section 6.A above, mobile source emissions are a leading Utah source for nitrate impacts at all Utah CIAs and in some neighboring states, namely Colorado, Idaho, and Wyoming. Under Section 209 of the Clean Air Act, states are largely preempted from setting standards for on-road and non-road mobile sources. Fortunately, federal emission standards for on-road vehicles and engines as well as non-road equipment are projected to result in dramatic reductions in NOx and PM emissions in Utah over the second planning period for regional haze. To help guarantee these emissions reductions, the State of Utah has worked with the petroleum refiners that supply the Utah market to ensure that suppliers produce gasoline that meets the Tier 3 sulfur requirement of 30 ppm and not just comply using credits. In addition, Utah has taken measures as part of other air quality programs to ensure that mobile source emissions are well-controlled. For example, Utah has vehicle inspection and maintenance programs in place in Utah, Salt Lake, Davis, Weber, and Cache counties, which accounted for 79.3% of the state's population in 2021[i] and 60.1% of total statewide on-road mobile source OTB2028a2 emissions. These programs also include diesel vehicle inspections which, while not creditable in Utah's various SIP revisions, help reduce NOx emissions that contribute to nitrate formation and CIA impacts.

*Remaining Anthropogenic*

The remaining anthropogenic category of the WRAP photochemical analysis represents non-oil and gas area source emissions, and specifically includes fugitive dust, agriculture, agricultural fire, residential wood combustion, and all remaining nonpoint sources (e.g., residential and commercial stationary source fuel combustion). As shown in section 6.A, the remaining anthropogenic impacts are relatively small for Utah and non-Utah CIAs. That said, these sources are relatively well-controlled as a result of rulemaking associated with other air quality programs in Utah (e.g., the PM2.5 SIP BACM review and resulting controls). For example, Utah restricts residential wood burning on so-called mandatory action days when conditions are ripe

[131] Please refer to sections 5.B and 9.C.2, response 24 for additional information concerning Utah's area sources.

for secondary formation of particulates. Utah has also adopted an ultra-low NOx water heater rule that applies statewide and, when fully implemented, will result in a 75% reduction in NOx emissions from residential and commercial water heating-related natural gas stationary source fuel combustion. Additional Utah area source rules to reduce NOx and/or PM emissions include those governing hydronic heaters, fugitive dust, and pilot lights.

## 7.B Four-Factor Analyses for Utah Sources[132]

Each source subject to submitting a four-factor analysis in this second planning period submitted a report on the available control technologies for $SO_2$ and $NO_x$ emission reductions and the application of each technology to that facility. The information on available controls should include the analysis of the following four factors when determining the possible emission reductions:

1. Factor 1 – The Costs of Compliance
2. Factor 2 – Time Necessary for Compliance
3. Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance
4. Factor 4 – Remaining Useful Life of the Source[133]

Although not specifically required, the recommended approach was to follow a step-by-step review of possible emission reduction options in a “top-down” fashion similar to EPA’s guidelines for reviewing BART or Best Available Retrofit Technology (as found in 70 Fed. Reg. 39,104, 39,108-09 (July 6, 2005)). The steps involved are as follows:

1. Identify all available retrofit control technologies
2. Eliminate technically infeasible control technologies
3. Evaluate the control effectiveness of remaining control technologies
4. Evaluate impacts and document results

The process is inherently similar to that used in selecting BACT (Best Available Control Technology) under the NSR/PSD (Title I) permitting program. UDAQ evaluated the submissions from each source following the methodology outlined above. Where a particular submission may have differed from the recommended process, UDAQ makes a note, and provides additional explanation as necessary.

### 7.B.1 Control Equipment Descriptions

*Available $NO_x$ Reduction Strategies and Technologies*[134]

The sources selected to provide additional analyses consistent with the four factors listed above-evaluated controls primarily for $NO_x$ emissions reductions. The following represents proven, available $NO_x$ reduction strategies and technologies for four-factor sources. The

[132] 40 CFR 51.308(f)(2)(i)
[133] *See* 40 C.F.R. § 51.308(f)(2)(i).
[134] More information on emission control strategies can be found at: https://www.epa.gov/sites/default/files/2015-07/documents/chapter_5_emission_control_technologies.pdf

sources selected to provide additional analyses consistent with the four factors listed above evaluated controls primarily for $NO_x$ emissions reductions.

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

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

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

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

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

*Staged combustion.* Either air or fuel injection can be staged, creating either a fuel-rich zone followed by an air-rich zone or an air-rich zone followed by a fuel-rich zone. Staged combustion can be achieved by installing a low-$NO_x$ staged combustion burner, or the furnace can be retrofitted for staged combustion. $NO_x$ reductions of more than 40% have been demonstrated with staged combustion.

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

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

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

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

### *Available $SO_2$ Reduction Strategies and Technologies*[135]

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

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

*Sorbent Injection.* Sorbent injection involves adding an alkali compound to the combustion gases for reaction with the $SO_2$. Typical calcium sorbents include lime and variants of lime.

[135] More information on emission control strategies can be found at: https://www.epa.gov/sites/default/files/2015-07/documents/chapter_5_emission_control_technologies.pdf

Sodium-based compounds are also used. Dry sorbent injection systems are simple systems, and generally require a sorbent storage tank, feeding mechanism, transfer line and blower, and injection device. Sorbent injection processes remove 30–60% of sulfur oxide emissions; however, if the sorbent is hydrated lime, then 80% or greater removal can be achieved. These systems are commonly called lime spray dryers.

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

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

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

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

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

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

### 7.B.2 Existing Controls on Active EGUs

The following tables summarize existing controls on all active coal and gas facilities in Utah. For more detailed information on control compliance schedules from the first implementation period and retirement dates, refer to section 3.A.1.

**Table 33: Existing controls on active coal units in Utah**

| Facility | Unit | Operator | $SO_2$ Control(s) | $NO_x$ Control(s) |
|---|---|---|---|---|
| Bonanza | 43101 | Deseret Generation & Transmission | Wet Limestone | Low $NO_x$ Burner Technology (Dry Bottom only) |
| Hunter | 1 | PacifiCorp Energy Generation | Wet Lime FGD | Low $NO_x$ Burner Technology w/ Closed-coupled OFA |
| Hunter | 2 | PacifiCorp Energy Generation | Wet Lime FGD | Low $NO_x$ Burner Technology w/ Separated OFA |
| Hunter | 3 | PacifiCorp Energy Generation | Wet Lime FGD | Low $NO_x$ Burner Technology w/ Overfire Air |
| Huntington | 1 | PacifiCorp Energy Generation | Wet Lime FGD | Low $NO_x$ Burner Technology w/ Closed-coupled OFA |
| Huntington | 2 | PacifiCorp Energy Generation | Wet Lime FGD | Low $NO_x$ Burner Technology w/ Separated OFA |

**Table 34: Existing controls on active gas units in Utah**

| Facility Name | Unit ID | Owner | $NO_x$ Control(s) |
|---|---|---|---|
| Lake Side Power Plant | CT03 | PacifiCorp Energy Generation | Selective Catalytic Reduction |
| Lake Side Power Plant | CT04 | PacifiCorp Energy Generation | Selective Catalytic Reduction |
| Lake Side Power Plant | CT02 | PacifiCorp Energy Generation | Selective Catalytic Reduction |
| Currant Creek Power Project | CTG1B | PacifiCorp Energy Generation | Selective Catalytic Reduction |

| Facility Name | Unit ID | Owner | $NO_x$ Control(s) |
|---|---|---|---|
| Currant Creek Power Project | CTG1A | PacifiCorp Energy Generation | Selective Catalytic Reduction |
| Nebo Power Station | U1 | Utah Associated Municipal Power Systems | Dry Low $NO_x$ Burners<br>Selective Catalytic Reduction |
| Millcreek Power | MC-1 | City of St. George | Dry Low $NO_x$ Burners |
| Millcreek Power | MC-2 | City of St. George | Dry Low $NO_x$ Burners<br>Selective Catalytic Reduction |
| Gadsby | 4 | PacifiCorp Energy Generation | Water Injection<br>Selective Catalytic Reduction |
| West Valley Power Plant | U4 | Utah Municipal Power Agency | Water Injection<br>Selective Catalytic Reduction |
| West Valley Power Plant | U2 | Utah Municipal Power Agency | Water Injection<br>Selective Catalytic Reduction |
| West Valley Power Plant | U3 | Utah Municipal Power Agency | Water Injection<br>Selective Catalytic Reduction |
| Gadsby | 5 | PacifiCorp Energy Generation | Water Injection<br>Selective Catalytic Reduction |
| West Valley Power Plant | U5 | Utah Municipal Power Agency | Water Injection<br>Selective Catalytic Reduction |
| Gadsby | 6 | PacifiCorp Energy Generation | Water Injection<br>Selective Catalytic Reduction |
| West Valley Power Plant | U1 | Utah Municipal Power Agency | Water Injection<br>Selective Catalytic Reduction |
| Gadsby | 2 | PacifiCorp Energy Generation | Low $NO_x$ Burner Technology (Dry Bottom only) |
| Gadsby | 1 | PacifiCorp Energy Generation | Low $NO_x$ Burner Technology (Dry Bottom only) |

## 7.C Source Consultation

UDAQ has kept regular contact with the sources selected to perform four-factor analyses on their units and offered guidance on developing control cost estimates using EPA's Air Pollution Control Cost Manual[136] and facility-specific data representing current emissions, projected future emissions, and potential control scenarios. UDAQ received and reviewed each source's initial four-factor analysis and sent an evaluation to each source with recommendations, requests for additional information, and explanations of any issues with calculations or assumptions made by sources in calculations. Refer to Chapter 9 to review detailed information on UDAQ's meetings with the sources. The following sections contain each source's four-factor

[136] The EPA Air Pollution Control Cost Manual can be found in at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

analysis, UDAQ's evaluation of their initial submittal, and the sources resulting responses and corrections.[137]

### 7.C.1 Ash Grove Cement Company- Leamington Cement Plant Four-Factor Analysis Summary and Evaluation[138]

#### *Facility Identification*

**Name:** Ash Grove Cement Company
**Address:** Hwy. 132, Leamington, Utah 84638
**Owner/Operator:** Ash Grove Cement Company
**UTM coordinates:** 4,379,850 m Northing, 397,000 m Easting, Zone 12

#### *Facility Process Summary*

Ash Grove Cement Company (Ash Grove) operates the Leamington Cement Plant. This plant has been in operation since 1981. At the Leamington cement plant, cement is produced when inorganic raw materials, primarily limestone (quarried on site), are correctly proportioned, ground and mixed, and then fed into a rotating kiln. The kiln alters the materials and recombines them into small stones called cement clinker. The clinker is cooled and ground with gypsum and additional limestone into a fine powdered cement. The final product is stored on site for later shipping. The major sources of air emissions are from the combustion of fuels for the kiln operation, from the kiln, and from the clinker cooling process.

#### *Facility Criteria Air Pollutant Emissions Sources*

This source consists of the following emission unit:

- Unit Designation: Kiln 1
  Kiln 1 has the following emission controls installed:
  SNCR for $NO_x$ control; $NO_x$, CO, Total Hydrocarbons (VOC), and Oxygen ($O_2$) CEMS on main stack; Mercury (Hg) CEMS or integrated sorbent trap monitoring system on main stack; TSP (PM) Continuous Parametric Monitoring System (CPMS) on main kiln and clinker cooler stack.

#### *Facility Current Potential to Emit*

The current PTE values for Ash Grove, as established by the most recent NSR permit issued to the source (DAQE-AN103030029-19) are as follows:

**Table 35: Ash Grove Leamington Cement Plant Current Potential to Emit**

| Pollutant | Potential to Emit (tons/year) |
|---|---|
| **$SO_2$** | 192.50 |
| **$NO_x$** | 1347.20 |

[137] Each source's full four-factor analysis submittals, UDAQ's four-factor analysis evaluations, and evaluation responses sent by sources can be found at https://deq.utah.gov/air-quality/regional-haze-in-utah in the "Current Regional Haze Planning" section.
[138] Ash Grove's full four-factor analysis submittal can be found in appendix C.1 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008930.pdf

### Ash Grove's Four-Factor Analysis Conclusion

Ash Grove believes that reasonable progress compliant controls are already in place. Ash Grove's actual $NO_x$ emission level of 1198 tpy is adequate and the Leamington facility does not propose any change to their current limit of 2.8 lbs./ton clinker on a 30-day rolling average basis.

### UDAQ Four-Factor Analysis Evaluation[139]

Although some additional information should be supplied by the source regarding SNCR efficiency, the Leamington Cement Plant appears to be adequately controlled at this time for purposes of Second Planning Period.

### Ash Grove's Evaluation Response[140]

AGC provided the actual SO2 emissions rates for the Leamington Plant's main kiln which are lower than their PTE. Lowering SO2 emissions further would require the addition of aluminum and iron which are not readily available to Ash Grove. The efficiency of the Leamington Plant's SNCR system was designed to be able to achieve 2.8 lb. NOx/ton clinker on a 30-day rolling average basis, and the plant typically operates in the 2.5-2.6 lb. NOx/ton clinker range. The system uses an Aqua NH3 solution as a chemical reagent. Adding additional solution is not feasible as the plant already requires reagent delivery by truck every two days and additional reagent would require the installation of larger nozzles and/or larger storage tanks. The system is also near solution saturation as it currently runs, and additional solution may not increase control efficiency, but rather cause NH3 to slip from the system and be emitted from the stack. Thus, Ash Grove believes that the current and $NO_x$ limits reflect a reasonable level of safety margin relative to actual emission rates.

### UDAQ Response Conclusion

UDAQ accepts the additional information provided by Ash Grove on their emission rate efficiency and agrees that their units are well controlled. Refer to section 8.D.1. for UDAQ's reasonable progress determination for Ash Grove.

## 7.C.2 Graymont Western US Incorporated- Cricket Mountain Plant Four-Factor Analysis Summary and Evaluation[141]

[139] UDAQs full evaluation of Ash Grove's four-factor analysis submittal can be found in appendix C.2 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2021-009636.pdf
[140] Ash Grove's full evaluation response can be found in appendix C.3 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2021-011724.pdf
[141] Graymont's full four-factor analysis submittal for the Cricket Mountain Plant can be found in appendix D.1 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008924.pdf

### *Facility Identification*

**Name:** Cricket Mountain Plant
**Address**: 32 Miles Southwest of Delta, Utah; Highway 257
**Owner/Operator:** Graymont Western US Incorporated
**UTM coordinates:** 4,311,010 m Northing, 343,100 m Easting, Zone 12

### *Facility Process Summary*

Graymont Western US Inc. (Graymont) operates the Cricket Mountain Lime Plant in Millard County. The Cricket Mountain Lime Plant consists of quarries and a lime processing plant, which includes five (5) rotary lime kilns (Kilns 1 through 5). The rotary kilns are used to convert crushed limestone ore into quicklime. The products produced for resale are lime, limestone, and kiln dust. The kilns operate on pet coke and coal. Sources of emissions at this source include mining, limestone processing, rotary lime kilns, post-kiln lime handling, and truck & loadout facilities.

### *Facility Criteria Air Pollutant Emissions Sources*

The source consists of the following emission units:

- Rotary Lime Kiln #1 rated at 600 tons of lime per 24-hour period with a preheater and baghouse emissions control system (D-85) rated at an exhaust gas flow rate 54,000 scfm and an Air to Cloth (A/C) ratio of 3.26:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA
- Rotary Lime Kiln #2 rated at 600 tons of lime per 24-hour period with a preheater, cyclone and baghouse emissions control system (D-275) rated at an exhaust gas flow rate of 48,000 scfm and an A/C ratio of 2.9:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA
- Rotary Lime Kiln #3 rated at 840 tons of lime per 24-hour period with a preheater, cyclone and baghouse emissions control system (D-375) rated at an exhaust gas flow rate of 55,000 scfm and a A/C ratio of 2.49:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA
- Rotary Lime Kiln #4 rated at 1266 tons of lime per 24-hour period with a preheater, cyclone and baghouse emissions control system (D-485) rated at an exhaust gas flow rate of 100,000 scfm and an A/C ratio of 5:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA
- Rotary Lime Kiln #5 rated at 1400 tons of lime per 24-hour period with a preheater and baghouse emissions control system (D-585) rated at an exhaust gas flow rate of 103,000 scfm and an A/C ratio of 3.5:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA

### *Facility Current Potential to Emit*

The current PTE values for Source, as established by the most recent NSR permit issued to the source (DAQE-AN103130044-21) are as follows:

**Table 36: Current Potential to Emit - Graymont**

| Pollutant | Potential to Emit (tons/year) |
|---|---|

| | |
|---|---|
| **$SO_2$** | 760.29 |
| **$NO_x$** | 3,883.85 |

### Graymont Four-Factor Analysis Conclusion

The facility currently uses low $NO_x$ burners in its five kilns to minimize $NO_x$ emissions. The use of low $NO_x$ burners is a commonly applied technology in current BACT determinations for new rotary preheater lime kilns today. The application of SCR has never been attempted on a lime kiln. SNCR has only one RBLC entry documenting implementation on a lime kiln. The use of these controls does not represent a cost-effective control technology given the limited expected improvements to $NO_x$ emission rates, high uncertainty of successful implementation, high capital investment, and high cost per ton $NO_x$ removed. Therefore, the emissions for the 2028 on-the-books modeling scenario are expected to be the same as those used in the "control scenario" for the Graymont Cricket Mountain facility.

### UDAQ Four-Factor Analysis Evaluation[142]

UDAQ disagrees with several points of Graymont's analysis. Aside from the lack of $SO_2$ analysis, UDAQ found several errors in the Graymont $NO_x$ analysis which must be corrected.

1. Two additional control technologies were identified by DAQ as potential ways of reducing $NO_x$ emissions: fuel switching and alternative production techniques. The Graymont Cricket Mountain Plant is fueled by coal – alternative fuels should be investigated. Secondly, the kilns at this facility are long horizontal rotary preheater/precalciner style kilns. Other types of kiln such as vertical lime kilns should also be investigated.
2. Graymont has claimed that SNCR is not technically feasible for installation on rotary preheater kilns. However, that is not accurate as there have been other SNCR retrofits done at preheater rotary lime kilns. Those lime kilns include the Lhoist North America O'Neal Plant in Alabama, the Unimin Corporation lime plant in Calera, Alabama, and the rotary lime kilns of the Lhoist North America Nelson Lime Plant in Arizona, as well as the Mississippi Lime Company plant in Illinois (specifically mentioned by Graymont as the only source listed on the RBLC).
3. A $NO_x$ reduction of 20% for SNCR is too low for use in the analysis, given that Graymont itself quoted the average $NO_x$ removal at cement kilns with SNCR was 40%, with the range of $NO_x$ removal efficiency between 35%-58%. At a minimum, Graymont should have evaluated the use of SNCR at 35% removal efficiency rather than merely 20%.
4. The current bank prime rate is 3.25% and not 4.75% as stated by Graymont. The economic analysis must be recalculated using the correct interest rate.

[142] UDAQ's full evaluation of Graymont's four-factor analysis submittal can be found in appendix D.2 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2021-009634.pdf

5. The cost of an air preheater was included – which appears to be a mistake based on an error (a typographical misprint) found in EPA's SNCR control cost spreadsheets. In one place the spreadsheet uses a value of 3.0 lb. $SO_2$/ton coal while in another the value is erroneously listed as 0.3 lb. $SO_2$/ton coal. Graymont apparently included the cost of the air preheater when burning coal which does not require such equipment as part of an SNCR installation.

Although DAQ has not fully evaluated these deficiencies, it has analyzed how Graymont's cost evaluation would change if the correct bank prime interest rate were used, if the cost of the air preheater were not included, and if the removal efficiency of the SNCR were increased to a minimum of 35%. To reflect the increased cost of a more efficient SNCR than that proposed by Graymont, the direct annual costs (energy, cost of ammonia, etc.) were doubled as a conservative estimate. The results of these changes are as follows:

**Table 37: Estimated Direct Annual Costs (doubled) Graymont**

| Kiln | Capital Costs ($) | Direct Annual Costs ($) | Total Annual Costs ($) | $NO_x$ Removed (tons) | cost-effectiveness ($/ton) |
|---|---|---|---|---|---|
| **1** | $3,616,821 | $180,574 | $328,281 | 30 | $10,943 |
| **2** | $3,878,230 | $186,204 | $343,367 | 22 | $15,608 |
| **3** | $4,321,811 | $208,776 | $377,952 | 18 | $20,997 |
| **4** | $5,285,030 | $258,458 | $461,703 | 38 | $12,150 |
| **5** | $5,031,753 | $289,720 | $485,174 | 122 | $ 3,977 |

Based on these revised results, the application of SNCR may appear to be feasible, at least for Kiln #5. Additional analysis should be provided by the source to further detail these deficiencies.

### Graymont's Evaluation Response[143]

In order to obtain a more accurate capital and operating cost estimate, Graymont commissioned a Class 4 engineering cost estimate to ascertain capital and operating costs associated with installing and operating Selective Non-Catalytic Reduction (SNCR) Nitrogen Oxides ($NO_x$) abatement systems on Cricket Mountain kilns. The cost estimations performed by a third-party engineer indicate that the total capital cost for installation of SNCR systems at Cricket Mountain exceeds $6.9 MMUSD and operating costs exceed $1.4 MMUSD annually, resulting in a cost of $17,561 per ton of $NO_x$ removed based upon a 20% removal efficiency. A factor of 20% was utilized based on the temperature and residence time limitations of the SNCR reaction zone for

[143] Graymont's full evaluation response can be found in appendix D.3 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2021-011722.pdf

each Cricket Mountain kiln combined with the Low $NO_x$ baseline concentration already achieved through the use of Low $NO_x$ Burners (LNB)[144].

Graymont also compared the current $NO_x$ emissions from Cricket Mountain to publicly available information for the Lhoist North America (LNA) rotary preheater kilns which utilize SCNR. Graymont offered the following observations:

- The existing LNBs at Cricket Mountain have effectively reduced the $NO_x$ emission intensity to a level more than three times less than the pre-control $NO_x$ intensity of LNA's Nelson Plant which utilizes SNCR.
- Any additive efficiency that might be gained from Cricket Mountain's use of SNCR would be marginal, at best, as SNCR $NO_x$ removal efficiency is highly dependent upon the inlet $NO_x$ concentration, reaction zone temperature and residence time, all of these factors reduce the anticipated efficiency that can reasonably be assumed for the Cricket Mountain Kilns.
- The LNA SNCR technology for rotary lime kilns is proprietary and not unconditionally commercially available to Graymont. The technology appears to be patented, adding to its cost and the uncertainty as to its technical feasibility.
- SNCR addition at Cricket Mountain would have unintended negative environmental impacts and visibility disbenefits, including the generation of condensable particulate, an identified regional haze primary pollutant.
- The Cricket Mountain facility operates 5 rotary preheat lime kilns, each of which are substantially different technology than mid-fired cement kilns (more conducive reaction zone temperatures, higher $NO_x$ concentrations, and longer residence times). As such, it is not appropriate to draw direct comparisons with application of SNCR between cement kilns and lime kilns as referenced in your letter.

Based on Graymont's findings, requiring the installation of SNCR at Cricket Mountain would be unreasonable because it would be infeasible, unnecessary and counterproductive to making reasonable progress towards the goal of preventing future, and remedying any existing, anthropogenic impairment of visibility in mandatory Class I Federal areas in the context of Utah's pending Round 2 Regional Haze State Implementation Plan (RH SIP). Cricket Mountain's successful implementation of LNBs effectively controls $NO_x$ at the point of generation in kilns.

These $NO_x$ rates are sufficient for inclusion in the UDAQ RH SIP since they are already some of the lowest achieved in the industry and far exceed what has been deemed BART at other kilns (such as the SNCR controlled kilns at the LNA Nelson Facility).

[144] Lhoist North America indicated in a November 2020 4-factor analysis that Kilns 1, 2 & 3 would be capable of a maximum $NO_x$ control of 20%.

### UDAQ Response Conclusion

UDAQ accepts Graymont's four-factor analysis amendments and additional justification on the unfeasibility of additional controls on the Cricket Mountain Facility's kilns. Refer to section 8.D.2 for UDAQ's controls for reasonable progress determination.

## 7.C.3 PacifiCorp's Hunter and Huntington Power Plants Four-Factor Analysis Summary and Evaluation[145]

*Facility Identification*

**Name:** Hunter Power Plant
**Address:** P.O. Box 569, Castle Dale, UT 84513
**Owner/Operator:** PacifiCorp
**UTM coordinates:** 497,800 m Easting, 4,335,800 m Northing, UTM Zone 12

*Facility Process Summary*

The Hunter Power Plant is located near Castle Dale in Emery County. The plant is classified as a PSD source and is a Phase II Acid Rain source. The source is PSD major for $SO_2$, $NO_x$, $PM_{10}$, and CO and also major for VOC and HAPs. The source is subject to the provisions of 40 CFR 52.21(aa); 40 CFR 60 Subparts A, D, Da, Y, and HHHH; and 40 CFR 63 Subparts A, ZZZZ, and UUUUU.

*Facility Criteria Air Pollutant Emissions Sources*

The source consists of the following emission units:

- Steam Generating Unit #1 - Nominal 480 MW gross capacity dry bottom, tangentially-fired boiler fired on subbituminous and bituminous coal using distillate fuel oil during start-up and flame stabilization. System is equipped with a low-$NO_x$ burner/overfire air system (OFA), baghouse, and $SO_2$ Wet FGD (WFGD) scrubber with no scrubber bypass.
- Steam Generating Unit #2 - Nominal 480 MW gross capacity dry bottom, tangentially-fired boiler fired on subbituminous and bituminous coal using distillate fuel oil during start-up and flame stabilization. System is equipped with a low-$NO_x$ burner/OFA, baghouse, and $SO_2$ WFGD scrubber with no scrubber bypass.
- Steam Generating Unit #3 - Nominal 495 MW gross capacity dry bottom, wall-fired boiler fired on subbituminous and bituminous coal using distillate fuel oil during start-up and flame stabilization. System is equipped with baghouse, a low $NO_x$ burner/OFA, and $SO_2$ FGD scrubber.

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[145] PacifiCorp's full four-factor analysis submittal for the Hunter and Huntington power plants can be found in appendix E.1 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008926.pdf

### *Facility Current Potential to Emit*

The current PTE values for the Hunter Power Plant, as established by the most recent NSR permit issued to the source (DAQE-AN102370028-18) are as follows:

**Table 38: Hunter Current Potential to Emit**

| Pollutant | Potential to Emit (Tons/Year) |
|---|---|
| **$SO_2$** | 5,537.5 |
| **$NO_x$** | 15,095 |

## PacifiCorp Four Factor Analysis Conclusion

When balanced for Hunter Units 1, 2, and 3 the four factors demonstrate that the RPEL is the best option for making reasonable progress during the second planning period. First, installation of SNCR or SCR are not cost effective (even with the skewed depreciable life assumptions) and would result in hundreds of millions of dollars in costs for PacifiCorp customers, and tens of millions in additional operating costs for PacifiCorp. Implementation of the Hunter RPEL would not result in any significant additional costs for customers and would result in minimal additional operating costs. Second, installation of SNCR or SCR would involve long-lead times for permitting, design, procurement, and installation before reductions and compliance can be achieved. The Hunter RPEL requires negligible time for compliance, and could be implemented as soon as the State's implementation plan is finalized and achieves federal approval. Third, SCR requires more energy to implement, and SNCR and SCR result in additional non-air environmental impacts over the Hunter RPEL. As documented, the Hunter RPEL has less potential consumption of natural resources, less GHG emissions, and less generation of CCR.

Fourth and finally, a requirement to install SCR or SNCR on Hunter Units 1, 2, and 3 would create uncertainty about the facility's remaining useful life. Many coal-fired power plants across the country have been forced to shut down due to the increased costs associated with SNCR and SCR. Implementing the Hunter RPEL would not be expected to either increase or decrease the remaining useful life of the facility. Based on this analysis, Utah should determine that the Hunter RPEL is the best option for achieving reasonable progress during the second planning period.

The Utah Division of Air Quality has indicated that photochemical grid modeling and analysis of visibility impacts will be performed by WRAP as part of the state's second planning period analysis. PacifiCorp anticipates that visibility modeling which incorporates the Hunter RPEL (and is compared to modeling of Hunter's current, permitted potential to emit) would assist the state in demonstrating reasonable progress at the CIAs impacted by emissions from the Hunter plant, supporting a conclusion that no additional installation of retrofit pollution control equipment is required at Hunter. However, if the State were to determine that the Hunter RPEL, as proposed, would not contribute to reasonable progress, PacifiCorp respectfully requests that the State propose an alternative RPEL ($NO_x$ +$SO_2$ limit) for Hunter (allowing time for PacifiCorp to analyze the feasibility of the alternative RPEL proposal) as opposed to pursuing a requirement to install SNCR or SCR retrofits. This reasonable progress analysis demonstrates that implementing a RPEL is a better option than installing SNCR or SCR retrofits under each of the four statutory factors.

## UDAQ Four-Factor Analysis Evaluation[146]

At this time, UDAQ is unable to proceed with its review and requests additional information as follows:

1. The source needs to resubmit the Four-factor analysis correcting the errors mentioned above.
2. Additional information must be provided regarding the infeasibility of SCR.
    a. This information can include additional details on economics as well as technical limitations.
3. Additional information must be provided regarding the infeasibility of SNCR.
    a. As with SCR, this information can include additional details on economics as well as technical limitations.
4. Supplemental details regarding the RPEL approach, including the selection of allowable limits should be provided. The methodology used for setting the allowable limits should be discussed in detail.
5. Any other pertinent information PacifiCorp feels is warranted should also be provided in order to assist UDAQ in the review process.

## Huntington Power Plant

### *Facility Identification*

Name: Huntington Power Plant

Address: P.O. Box 680, Huntington, UT 84528

Owner/Operator: PacifiCorp

UTM coordinates: 493,130 Easting 4,358,840 Northing, UTM Zone 12

### *Facility Process Summary*

The PacifiCorp Huntington Power Plant is a coal-fired steam electric generating facility consisting of two (2) boilers. Unit #1 is a 480 MW unit constructed in October 1973; Unit #2 is a 480 MW unit that commenced construction in April 1970. Bituminous and sub-bituminous coal is the primary fuel source for the dry bottom, tangentially-fired boilers. Fuel oil is used to start up the boilers from a cold start and for boiler flame stabilization. The Huntington Power Plant uses low-$NO_x$ burners, separated overfire air system, $SO_2$ FGD scrubber system, and pulse jet fabric filters for both units.

### *Facility Criteria Air Pollutant Emissions Sources*

The source consists of the following emission units:

- Boiler Unit #1 – Nominal 480 MW gross capacity dry bottom, tangentially-fired utility boiler fired on subbituminous and bituminous coal using fuel oil during startup and flame

[146] UDAQ's full four-factor analysis evaluation for the Hunter and Huntington power plants can be found in appendix E.2 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008926.pdf

stabilization. Equipped with a fabric filter baghouse, low $NO_x$ burners with overfire air system, and a $SO_2$ FGD scrubber. NSPS Subpart D.

- Boiler Unit #2 – Nominal 480 MW gross capacity dry bottom tangentially-fired utility boiler fired on subbituminous and bituminous coal using fuel oil during startup and flame stabilization. Equipped with a fabric filter baghouse, low-$NO_x$ burners with overfire air system, and a $SO_2$ FGD scrubber.

### *Facility Current Potential to Emit*

The current PTE values for the Huntington Power Plant, as established by the most recent NSR permit issued to the source (DAQE-AN102370028-18) are as follows:

**Table 39: Current Potential to Emit: Huntington**

| Pollutant | Potential to Emit (Tons/Year) |
|---|---|
| **$SO_2$** | 3,105 |
| **$NO_x$** | 7,971 |

## PacifiCorp Four Factor Analysis Conclusion

When balanced for Huntington Units 1 and 2, the four factors demonstrate that the RPEL is the best option for making reasonable progress during the second planning period. First, installation of SNCR or SCR are not cost effective (even with the skewed depreciable life assumptions) and would result in hundreds of millions of dollars in costs for PacifiCorp customers, and tens of millions in additional operating costs for PacifiCorp. Implementation of the Huntington RPEL would not result in any significant additional costs for customers and would result in minimal additional operating costs. Second, installation of SNCR or SCR would involve long-lead times for permitting, design, procurement, and installation before reductions and compliance can be achieved. The Huntington RPEL requires negligible time for compliance, and could be implemented as soon as the State's implementation plan is finalized and achieves federal approval. Third, SCR requires more energy to implement, and SNCR and SCR result in additional non-air environmental impacts over the Huntington RPEL. As documented, the Huntington RPEL has less potential consumption of natural resources, less GHG emissions, and less generation of CCR. Fourth and finally, a requirement to install SCR or SNCR on Huntington Units 1 and 2 would create uncertainty about the facility's remaining useful life. Many coal-fired power plants across the country have been forced to shut down due to the increased costs associated with SNCR and SCR. Implementing the Huntington RPEL would not be expected to either increase or decrease the remaining useful life of the facility. Based on this analysis, Utah should determine that the Huntington RPEL is the best option for achieving reasonable progress during the second planning period.

The Utah Division of Air Quality has indicated that photochemical grid modeling and analysis of visibility impacts will be performed by the Western Regional Air Partnership ("WRAP") as part of the state's second planning period analysis. PacifiCorp anticipates that visibility modeling which incorporates the Huntington RPEL (and is compared to modeling of Huntington's current, permitted potential to emit) would assist the state in demonstrating reasonable progress at the

CIAs impacted by emissions from the Huntington plant, supporting a conclusion that no additional installation of retrofit pollution control equipment is required at Huntington. However, if the State were to determine that the Huntington RPEL, as proposed, would not contribute to reasonable progress, PacifiCorp respectfully requests that the State propose an alternative RPEL ($NO_x$ +$SO_2$ limit) for Huntington (allowing time for PacifiCorp to analyze the feasibility of the alternative RPEL proposal) as opposed to pursuing a requirement to install SNCR or SCR retrofits. This reasonable progress analysis demonstrates that implementing a RPEL is a better option than installing SNCR or SCR retrofits under each of the four statutory factors.

### UDAQ's Four Factor Analysis Conclusion

At this time, UDAQ is unable to proceed with its review and requests additional information as follows:

1. The source needs to resubmit the Four-factor analysis correcting the errors mentioned above.
2. Additional information must be provided regarding the infeasibility of SCR.
    a. This information can include additional details on economics as well as technical limitations.
3. Additional information must be provided regarding the infeasibility of SNCR.
    a. As with SCR, this information can include additional details on economics as well as technical limitations.
4. Supplemental details regarding the RPEL approach, including the selection of allowable limits should be provided. The methodology used for setting the allowable limits should be discussed in detail.
5. Any other pertinent information PacifiCorp feels is warranted should also be provided in order to assist UDAQ in the review process.

### PacifiCorp's Four-Factor Analysis Evaluation Response for Hunter and Huntington[147]

PacifiCorp proposed that UDAQ make the following adjustments to obtain a more representative cost effectiveness value for the installation of SNCR at the Hunter and Huntington plants:

• Utilize an SNCR NOx control efficiency of 20% for the Hunter and Huntington boilers, which is expected to be achievable based on unit size and firing configuration;

• Utilize capital and O&M costs provided by S&L which are site specific and more accurate than the generalized costs provided by the CCM model;

• Utilize PacifiCorp's actual weighted average cost of capital of 7.303% as the interest rate in the model instead of the 3.25% rate originally used by UDAQ;

• Utilize the current and accurate net MW generation rates and net unit heat rate provided in Table 38 to calculate boiler heat input; and lastly;

[147] PacifiCorp's full evaluation response for the Hunter and Huntington Power Plants can be found in appendix E.3 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2021-011726.pdf

• Utilize the actual 2015-2019 average annual capacity factors in Table 40 instead of the rates included in Table 39, which are inaccurate.

PacifiCorp believed that use of the S&L capital and O&M cost data when combined with an SNCR 20% control efficiency and 7.303% interest rate will provide an accurate representation of unit-specific cost effectiveness. This is demonstrated by UDAQ's and PacifiCorp's SCR cost effectiveness determinations which provide essentially equivalent dollar-per-ton values. The following tables provide a summary of PacifiCorp's revised SNCR cost effectiveness values for the Hunter and Huntington plants applying these adjustments. The estimates are based on a systemwide SNCR control efficiency of 20% and an interest rate of 7.303%. Note that the provided values do not incorporate minor changes in annualized capital and O&M costs which will occur when the April 9, 2020, S&L studies are updated to incorporate the current 7.303% interest rate and use of the 20% SNCR NOx control efficiency versus the studies' original use of a 7% interest rate and anticipated SNCR-controlled permit limit emission rates.

**Table 40: PacifiCorp Updated Hunter SNCR Cost Effectiveness**

| Cost Effectiveness | Hunter 1 | Hunter 2 | Hunter 3 |
|---|---|---|---|
| **Baseline** | | | |
| **Heat Input (MMBtu/year)** | 28,482,643 | 30,101,030 | 31,182,279 |
| **NOx Emissions Rate (lb/MMBtu)** | 0.200 | 0.280 | 0.280 |
| **NOx Emissions (tons/year)** | 2,842 | 4,359 | 4,359 |
| **NOx Emissions w/ SNCR (20% efficiency)** | | | |
| **Controlled NOx Emissions Rate (lb/MMBtu)** | 0.160 | 0.154 | 0.224 |
| **Controlled NOx Emissions (tons/year)** | 2,273 | 2,322 | 3,487 |
| **SNCR Annual NOx Removal (tons/year)** | **568** | **580** | **872** |
| **SNCR Cost Effectiveness (7.303% interest rate)** | | | |
| **Annualized Capitalized Costs (20-yr life)** | $1,546,424 | $1,546,424 | $1,546,424 |
| **Total Annualized O&M Costs** | $2,168,400 | $2,208,800 | $3,176,600 |
| **Total Annual Cost ($/year)** | **$3,714,824** | **$3,755,224** | **$4,723,024** |
| **Cost effectiveness ($/ton)** | **$6,536** | **$6,469** | **$5,417** |

**Table 41: PacifiCorp Updated Huntington SNCR Cost Effectiveness**

| Cost Effectiveness | Huntington 1 | Huntington 2 |
|---|---|---|
| **Baseline** | | |
| **Heat Input (MMBtu/year)** | 28,063,728 | 27,150,145 |
| **NOx Emissions Rate (lb/MMBtu)** | 0.212 | 0.208 |
| **NOx Emissions (tons/year)** | 2,968 | 2,825 |
| **NOx Emissions w/ SNCR (20% efficiency)** | | |
| **Controlled NOx Emissions Rate (lb/MMBtu)** | 0.169 | 0.166 |
| **Controlled NOx Emissions (tons/year)** | 2,374 | 2,260 |
| **SNCR Annual NOx Removal (tons/year)** | **594** | **565** |
| **SNCR Cost Effectiveness (7.303% interest rate)** | | |
| **Annualized Capitalized Costs (20-yr life)** | $1,560,724 | $1,560,724 |
| **Total Annualized O&M Costs** | $2,256,200 | $2,156,000 |
| **Total Annual Cost ($/year)** | **$3,816,924** | **$3,716,724** |

| | | |
|---|---|---|
| **Cost effectiveness ($/ton)** | **$6,431** | **$6,579** |

In conclusion, PacifiCorp submitted that the above table's use of accurate annualized capital and O&M costs when combined with an appropriate SNCR NOx control efficiency of 20% provide reasonable SNCR cost effectiveness determinations for the Hunter and Huntington units. PacifiCorp has requested that S&L update their April 9, 2020, studies to utilize the current interest rate of 7.303% and the more conservative SNCR NOx control efficiency of 20% for all Hunter and Huntington units. These updates are currently being finalized and are not anticipated to materially impact the data provided here. PacifiCorp will notify UDAQ if any material changes occur.

## UDAQ Response Conclusion

### *$SO_2$*

As noted above, all five units at both plants have FGD in place to control $SO_2$ emissions and all units have $SO_2$ emission limits (generally 12 lb/mmbtu over various averaging periods) that correspond to these controls as included in the approval orders for both plants. Because Utah participated in the Section 309 compliance pathway for $SO_2$ in its round one SIP, $SO_2$ emissions limits were not included among the Section IX.H controls for regional haze. However, because the continued operation of these controls is essential to making reasonable progress as demonstrated by the WRAP photochemical modeling and helps eliminate the possibility of backsliding on past emissions reductions, UDAQ is adding the existing $SO_2$ emission limits for all five units to SIP Section IX.H23, Source Specific Emission Limitations: Regional Haze Requirements, Reasonable Progress Controls, to ensure federal enforceability in the regional haze context.

### *NOx*

Upon consulting with EPA staff and the control cost manual, UDAQ has found that it is preferable for a source's four-factor analysis to use a source-specific interest rate. After further discussion with the Utah Department of Public Utilities, UDAQ has confirmed that 7.34% is PacifiCorp's most recently approved interest rate in Utah.[148] However, as noted in the company's Four-Factor Analysis Evaluation Response for Hunter and Huntington above, "The actual weighted average cost of capital is calculated using the rates approved by the six state regulatory authorities where PacifiCorp conducts business and the percentage of energy delivered by PacifiCorp to each of those states." UDAQ accepts the resulting 7.303% interest rate as an appropriate source-specific rate across the company's service territory.

For SNCR and SCR, UDAQ concurs with PacifiCorp's remaining calculations supporting their four-factor analyses (as amended or further justified in the company's follow-up submittals). However, UDAQ does not concur with the company's four-factor analysis calculations for the proposed RPELs. First, the emissions reductions ascribed to the RPELs were based upon the application of SNCR controls -- a technology the company claimed not to be cost-effective -- to

[148] Source: https://pscdocs.utah.gov/electric/20docs/2003504/3168662003504ro12-30-2020.pdf

each plant's PAL. Furthermore, the control costs associated with the RPELs were estimated based solely on the cost of additional scrubbing of $SO_2$, while the estimated emissions reductions included both $NO_x$ and $SO_2$, and the RPEL cost-effectiveness analysis used a different baseline emissions scenario (i.e., the PAL) than that used for SNCR and SCR (2015-2019 actuals). As a result, the RPEL cost-effectiveness estimates cannot be meaningfully compared to those for physical controls. For these reasons, UDAQ rejects the proposed RPELs.

Regarding SCR and SNCR cost-effectiveness, the company's analysis was based upon applying recent (2015-2019) average heat inputs (in MMBTU/year) and emissions rates (in lb./MMBTU) to calculate emissions (MMBTU/year X lb./MMBTU = lb./year) compared to using the same heat inputs at the control emissions rates for SNCR and SCR. The delta between the recent actual emissions versus emissions with controls represented the emissions reductions associated with each control. The total annual cost of each control was then divided by tons reduced per year to establish a cost-effectiveness metric of dollars per ton ($/ton) of emissions reduced.

PacifiCorp's analysis yielded cost-effectiveness values ranging from $5,417/ton to $6,579/ton for SNCR and $4,401/ton to $6,533/ton for SCR, as summarized in the table below.

**Table 42: Cost-effectiveness of SNCR and SCR and Hunter and Huntington Power Plants**

| Unit | SNCR $/ton | SCR $/ton |
|---|---|---|
| **Hunter 1** | $6,536 | $6,533 |
| **Hunter 2** | $6,469 | $6,488 |
| **Hunter 3** | $5,417 | $4,401 |
| **Huntington 1** | $6,431 | $5,979 |
| **Huntington 2** | $6,579 | $6,294 |

Due to the relatively high $/ton estimates for SNCR, that control was deemed not to be cost-effective. UDAQ's remaining cost-effectiveness evaluation centers around the potential application of SCR at one or more units at the Hunter and Huntington power plants. In particular, the relatively lower estimated $/ton for SCR for Hunter 3 merits further evaluation of whether this control could be cost-effective.

As noted above, PacifiCorp's cost-effectiveness estimates were calculated using a baseline of recent actual emissions levels. However, as EPA notes in its 2019 guidance:

> *A state may choose a different emission control scenario as the analytical baseline scenario. Generally, the estimate of a source's 2028 emissions is based at least in part on information on the source's operation and emissions during a representative historical period. However, there may be circumstances under which it is reasonable to project that 2028 operations will differ significantly from historical emissions. Enforceable requirements are one reasonable basis for projecting a change in operating parameters and thus emissions; energy efficiency, renewable energy, or other such programs where*

*there is a documented commitment to participate and a verifiable basis for quantifying any change in future emissions due to operational changes may be another.*[149]

In its July 2021 clarifications memo, EPA adds that there may be instances in which state projections of changes in future utilization are unenforceable, leading to the need to establish utilization or production limits to ensure reasonable progress at existing emissions rates:

*. . . in some cases, states may have projected significantly lower total emissions due to unenforceable utilization or production assumptions and those projections are dispositive of the four-factor analysis. For example, a state that rejected new controls solely based on cost effectiveness values that were higher due to low utilization assumptions. In this circumstance, an emission limit that requires compliance with only an emission rate may not be able to reasonably ensure that the source's future emissions will be consistent with the assumptions relied upon for the reasonable progress determination. EPA anticipates these circumstances will be rare. One option a state may consider in this case is to incorporate a utilization or production limit corresponding to the assumption in the four-factor analysis into the SIP. Although not required, this approach is one way for states to address circumstances in which a specific emission rate does not, by itself, represent the reasonable progress determination.*[150]

Furthermore, EPA recognized that in instances in which control costs are dominated by a relatively high proportion of fixed capital costs, actual cost-effectiveness will be highly dependent on the future utilization levels of the facility. In instances where utilization is lower than initially projected, controls will be less cost-effective, while higher future utilization will result in improved cost-effectiveness, since there will be more tons reduced by a given control but for the same fixed costs when utilization increases. In such instances, EPA notes that a mass-based emissions limit may be appropriate to demonstrate reasonable progress:

*. . . if the annualized cost for a measure is dominated by fixed capital costs, the state may have determined that the measure is necessary to make reasonable progress if the operating level is high (making cost/ton and cost/Mm-1 relatively low) but not if the operating level is low (making cost/ton and cost/Mm-1 relatively high). In this case, a mass-based emission limit may be reasonable because it could relieve the source of the requirement to install the control if it manages its operating level strategically.*

[149] *See* Guidance on Regional Haze Implementation Plans for the Second Implementation Period (Aug. 20, 2019) (2019 Regional Haze Guidance) at 29, available at https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

[150] *See* Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021) (2021 Regional Haze Clarifications) at 12, available at https://www.epa.gov/system/files/documents/2021-07/clarifications-regarding-regional-haze-state-implementation-plans-for-the-second-implementation-period.pdf.

*. . . in addition to considering technology-based emission control measures, a state may consider restrictions on hours of operation, fuel input, or product output. Such restrictions could be implemented directly or by a time-based limit on mass emissions.*[151]

To further assess the appropriateness of installing SCR at these facilities, UDAQ developed a plant utilization sensitivity analysis for all five units at both plants. In this analysis, UDAQ assumed a baseline emission scenario using historical utilization levels (based on 2015-2019 actual emissions), and then varied potential future utilization relative to that baseline to create four alternative emissions scenarios:

- 125% of baseline utilization
- 75% of baseline utilization
- 50% of baseline utilization

UDAQ also scaled O&M costs by the same factors in an attempt to account for changes in variable costs but kept fixed capital costs constant. The figure below summarizes this sensitivity analysis.

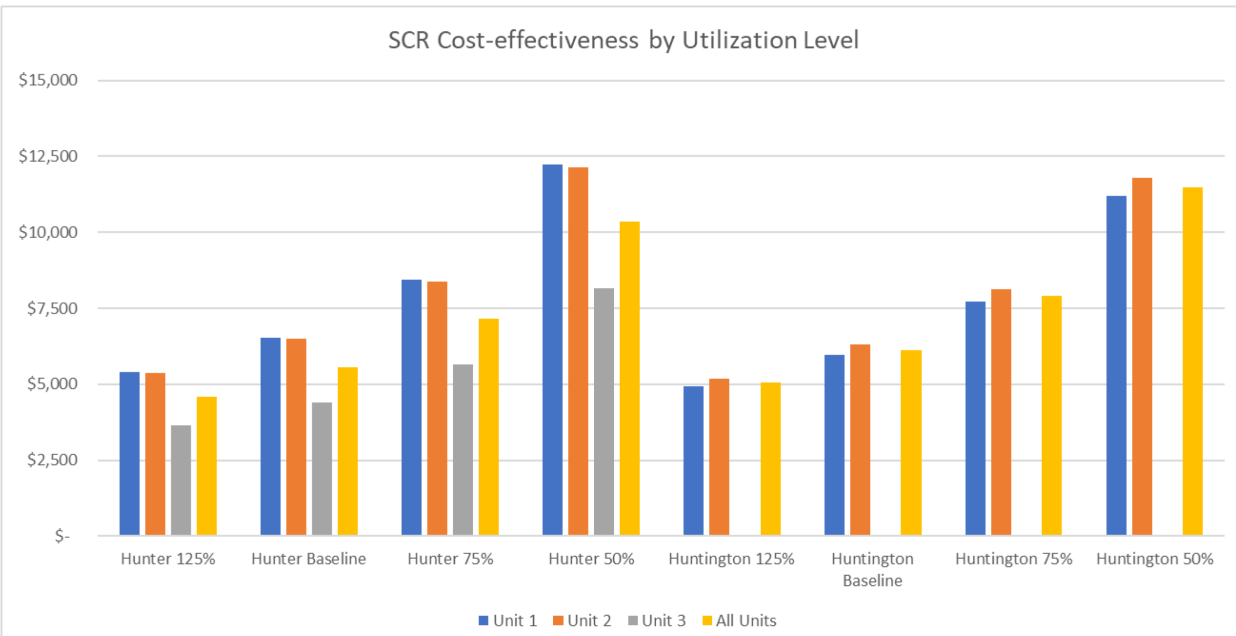


**Figure 53: SCR Cost-effectiveness by utilization level at Hunter and Huntington Power Plants**

As can be seen, higher unit and plant utilization yields lower $/ton estimates (more cost-effective), while lower utilization yields higher $/ton estimates (less cost-effective).

[151] *See* 2019 Regional Haze Guidance at 45, available at https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

This sensitivity analysis raises the question of how the units at both plants are likely to be utilized throughout the second regional haze planning period. In its attempt to address this question, WRAP relied on the Center for the New Energy Economy (CNEE) at Colorado State University to project 2028 emissions for coal- and gas-fired EGUs throughout the West for use in modeling to support WRAP states in their SIP development.[152] For coal-fired units, these estimates were based on 2016-2018 utilization (i.e., gross load), heat rates, and emissions rates, but were adjusted for certain known or "on-the-books" (OTB) changes in emissions controls, fuel switching, and unit closures. For example, in Utah, CNEE accounted for the previously announced closure of Intermountain Power Plant (IPP) Units 1 and 2 in 2025 by reducing emissions accordingly.

Using this OTB methodology, WRAP projected 2028 $NO_x$ emissions of 10,001 tons/year for Hunter and 6,091 tons/year for Huntington.[153] These emissions estimates are similar though not identical to PacifiCorp's recent actual emissions used in its four-factor analyses, with the differences stemming from the use of different averaging periods and methodologies. Arguably, PacifiCorp's cost-effectiveness estimates would apply should future emissions (and thus, utilization) conform to these 2028 OTB estimates. However, the electricity generation industry is experiencing significant change with the introduction of cheap natural gas and renewable sources such as wind and solar altering previous operating practices. Other factors affecting change include increased grid coordination (e.g., the Energy Imbalance Market (EIM), the potential establishment of a new Western regional transmission organization (RTO), new transmission capacity, etc.), dramatic improvements in lighting and other equipment efficiency, uncertainty regarding the future of climate regulation, and increased customer preference for cleaner energy resources.  Low-cost renewable electricity in particular has forced operators to switch "baseload" EGUs, such as Utah's coal-fired plants, to "follow" load between periods when renewables are available and unavailable.  For these reasons, recent actual emissions from fossil-fueled EGUs are down from the levels of previous decades, and there is great uncertainty regarding near- and medium-term operation of these units. This trend is reflected in the utilization[154] of the Hunter and Huntington power plants as shown in figures 54 and 55 below.

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[152] *See* http://www.wrapair2.org/pdf/Final%20EGU%20Emissions%20Analysis%20Report.pdf.
[153] CNEE originally estimated 9,992 tons/year for Hunter and 6,083 for Huntington, but the final WRAP projections included additional non-EGU sources at each plant to arrive at the values above.
[154] From Utah Geological Survey Energy *Utah Energy and Mineral Statistics,* Table 5.1 (https://geology.utah.gov/docs/statistics/electricity5.0/pdf/T5.1.pdf) and Table 5.15a (https://geology.utah.gov/docs/statistics/electricity5.0/pdf/T5.15.pdf).

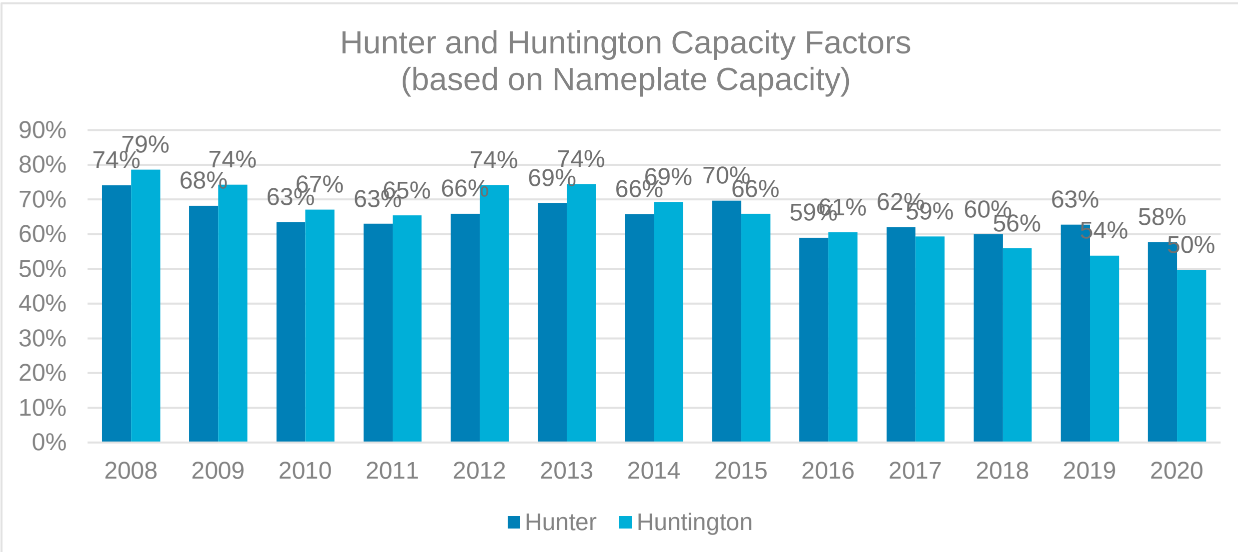


**Figure 54: Hunter and Huntington Capacity Factors**

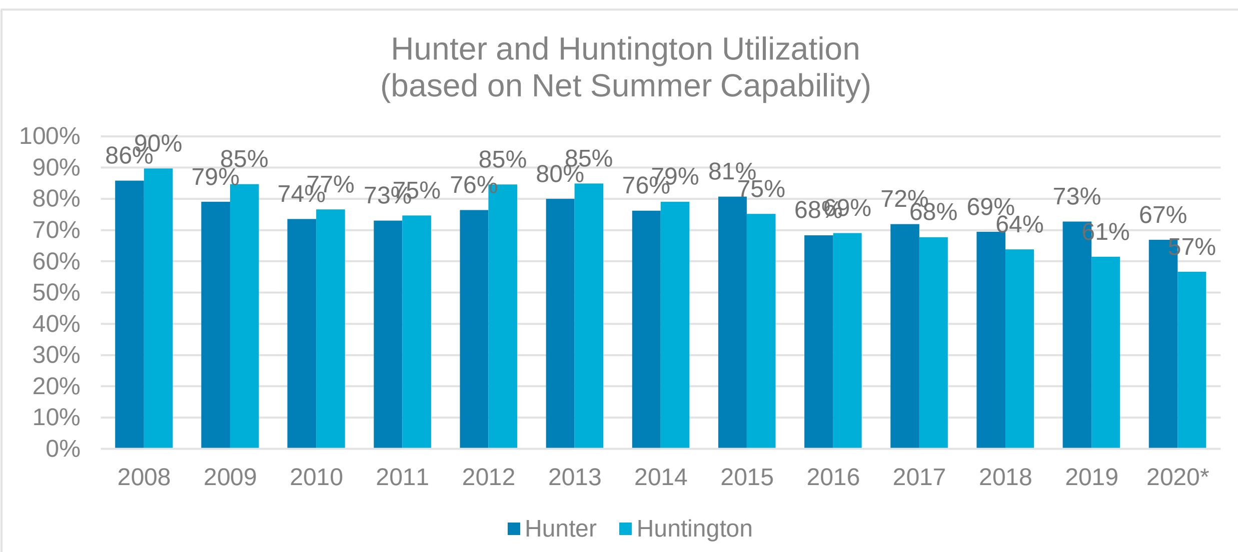


**Figure 55: Hunter and Huntington Utilization (based on Net Summer Capability)**

Given this uncertainty and the wide variability in cost-effectiveness estimates at various utilization levels, UDAQ finds installation of SCR not to be cost-effective at any of the five units at Hunter and Huntington at this time. However, because WRAP's photochemical modeling to demonstrate reasonable progress used projections based, in part, upon recent actual EGU


**Figure 56: Example of projected RPGs for Canyonlands and Arches CIAs**

emissions and because SCR appears to be more cost-effective at higher than recent utilization/emissions levels, UDAQ finds it compelling to incorporate enforceable mass-based emission limits at both plants to ensure that the EGU nitrate contribution to light extinction at Utah (and other states) CIAs does not exceed modeled or recent actual emissions levels.[155] Such mass-based emission limits would ensure that Utah is making reasonable progress as demonstrated by the WRAP modeling, while eliminating the possibility of backsliding on past emissions reductions. Specifically, mass-based emissions limits based on WRAP's 2028 OTB projections are explicitly accounted for in Utah's projected 2028 RPGs, such as the example shown for Canyonlands in Figure 56.

Establishing enforceable mass-based limits also keeps the plants from operating at higher utilization levels at which SCR controls might become cost-effective and, therefore, reasonable. Finally, this approach provides regulatory flexibility for PacifiCorp, which can meet the mass-based emission limits either by limiting or otherwise modifying operation, installing controls, switching fuels, closing units, or some combination of these options. Refer to section 8.D.3 for UDAQ's reasonable progress determinations for the Hunter and Huntington power plants.

[155] See Appendix A for UDAQ's proposed Part H language for emission limits and controls enforcement

### 7.C.4 Sunnyside Cogeneration Associates- Sunnyside Cogeneration Facility Four-Factor Analysis Summary and Evaluation[156]

*Facility Identification*

**Name:** Sunnyside Cogeneration Facility
**Address:** State Road 123, #1 Power Plant Road, Sunnyside, Utah
**Owner/Operator**: Sunnyside Cogeneration Associates
**UTM coordinates**: 552,984 m Easting, 4,377,786 m Northing, UTM Zone 12

*Facility Process Summary*

The Sunnyside Cogeneration Facility (Sunnyside) is in Sunnyside, Carbon County, Utah (approximately 25 miles southeast of Price). The nearest Class I areas and their respective distance from the facility are Canyonlands National Park, (91 miles), Capitol Reef National Park (95 miles), Bryce Canyon National Park (171 miles) and Zion National Park (217 miles). The Sunnyside power plant began operations in May of 1993. The electricity it produces is sold to PacifiCorp, operating as Utah Power and Light [UPLC). The plant qualifies as a small power production facility and qualifying cogeneration facility ("QF") under the Public Utility Regulatory Policy Act of 1997 ('PURPA"). The facility operates a coal-fired combustion boiler that features circulating fluidized bed (CFB), a baghouse and a limestone injection system. The facility also operates an emergency diesel engine and emergency generator. All process units are currently permitted in its UDAQ Title V air operating permit (Permit # 700030004) which was renewed on April 30, 2018. The CFB boiler is subject to the NESHAPS Part 63, Subpart UUUUU Mercury and Air Toxics Standards [MATSI Rule. As a result, Sunnyside is required to meet a standard of 0.2 lb./MMBtu of $SO_2$.

This standard requires continuous monitoring with a continuous emission monitor system (CEMS). The plant's CFB boiler, designed by Tampella Power, produces steam that drives a Dresser Rand turbine generator. The CFB boiler and baghouse uses limestone injection. Historically, CFB boilers have been one of the primary low emission combustion technologies for commercial and small utility installations using low grade fuels. This trend continues with CFB technology being considered for smaller coal fired units as a means to effectively utilize lower quality fuels and meet environmental requirements. The current boiler produces emissions from one stack at Sunnyside's cogeneration facility. For the purposes of a control technology review, only the emissions from the boiler stack itself are considered as well as the operations from the emergency diesel engine and emergency generator.

*Facility Criteria Air Pollutant Emissions Sources*

The source consists of the following emission units:

- Circulating Fluidized Bed Combustion Boiler – Rated at 700 MMBtu/hr and fueled by coal, coal refuse or alternative fuels, and fueled by diesel fuel during startup, shutdown, upset condition and flame stabilization. This boiler is equipped with a

[156] Sunnyside's full four-factor analysis can be found in appendix F.1 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008928.pdf

limestone injection system to the fluidized bed and a baghouse. This boiler is subject to 40 CFR 60, Subpart Da and CAM.

- One diesel engine, approximately 201 HP, used to power the emergency backup fire pump, and various portable I/C engines to power air compressors, generators, welders and pumps.
- A 500-kW emergency standby diesel generator, used in the event of disruption of normal electrical power and testing/maintenance. 1.4 Facility Current Potential to Emit The current PTE values for Sunnyside, as established by the most recent NSR permit issued to the source (DAQE-AN100960029-13) are as follows (in tons/year): $SO_2$ 1,289.26 $NO_x$ 771.2.

### *Facility Current Potential to Emit*

The current PTE values for Sunnyside, as established by the most recent NSR permit issued to the source (DAQE-AN100960029-13) are as follows:

**Table 43: Sunnyside: Current Potential to Emit (Tons/Year)**

| Pollutant | Potential to Emit (tons/yr) |
|---|---|
| **$SO_2$** | 1,289.26 |
| **$NO_x$** | 771.2 |

## Sunnyside Four Factor Analysis Conclusion

The facility currently uses CFB technology to lower $NO_x$ emissions and achieves Title V permitting $NO_x$ limits as currently operated. SCR is a technically feasible control option for this boiler but is not cost effective with a control cost greater than $10,000 per ton of $NO_x$ removed. While SNCR may represent a cost-effective option for $NO_x$ emissions reduction, the introduction of substantial ammonia slip has the potential to cause adverse environmental impacts. The ammonia and $PM_{2.5}$ emissions have the potential to cause direct health impacts for those in the area, and present additional safety concerns for the storage and transportation of ammonia. Despite not having SNCR or SCR installed, the Sunnyside boiler is achieving a $NO_x$ emission rate on a lb./MMBtu basis that is comparable to PSD BACT levels set on CFB boilers. Therefore, additional add-on controls for $NO_x$ emissions reductions are not necessary on the Sunnyside CFB boiler.

## UDAQ Evaluation Summary and Conclusion[157]

UDAQ noted several potential errors in Sunnyside's analysis:

[157] UDAQ's full evaluation of Sunnyside's four-factor analysis submittal can be found in appendix F.2 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2021-009630.pdf

1. The Sunnyside four-factor analysis for $SO_2$ eliminated both wet scrubbers and spray dry scrubbers from consideration as an $SO_2$ control because it does not have the water rights that would be needed for operation of the wet scrubber or a spray dry absorber.
2. Sunnyside Cogen did not provide justification for including the cost for a new replacement baghouse with a dry scrubbing option.
3. Sunnyside's analysis was inconsistent regarding the amount of sorbent required and the possible resulting efficiency.
4. The Sunnyside dry sorbent injection analysis assumed too high of a cost for auxiliary power.
5. The Sunnyside dry scrubbing cost analysis improperly included annual costs for taxes and insurance and assumed unreasonably high annual costs for administrative charges.
6. The Sunnyside dry scrubbing cost analysis improperly assumed a 30% increase in cost as a retrofit factor.
7. The Sunnyside dry sorbent injection cost analysis used too high of an interest rate and too short expected life when amortizing costs.
8. Sunnyside assumed too high of an interest rate and too short of a life of controls in determining the annualized capital costs of SNCR and SCR The Sunnyside SCR and SNCR cost effectiveness analyses assumed a 4.75% interest rate and a 20- year life of both SCR and SNCR.
9. Sunnyside assumed a very high cost for aqueous ammonia that was not justified. In its SNCR and SCR cost analyses, Sunnyside Cogen assumed a cost for 29.4% aqueous ammonia of $2.50 per gallon.
10. Sunnyside assumed a higher cost for electricity than it assumed in its dry sorbent injection analysis in its SCR and SNCR cost analysis.

At this time, UDAQ is unable to proceed with its review and requests additional information as follows:

1. The source needs to resubmit the Four Factor analysis correcting the errors mentioned above.
2. Additional information must be provided regarding the infeasibility of SCR. A. This information can include additional details on economics as well as technical limitations.
3. Additional information must be provided regarding the infeasibility of SNCR. A. As with SCR, this information can include additional details on economics as well as technical limitations.
4. Any other pertinent information Sunnyside feels is warranted should also be provided in order to assist UDAQ in the review process.

### Sunnyside's Evaluation Response[158]

1. HAR technology is not feasible as flue gas exiting the CFB boiler at Sunnyside typically contains approximately 10% unreacted calcium oxide in the in the fly ash and even less in the bottom ash.[159] Additionally, there is a significant amount of ash already entrained in the CFB boiler which would make additional ash infeasible. SDA technology requires significant amounts of water that Sunnyside is unable to adequately source, thus they find it infeasible. Given the configuration of existing units, there is not enough space between the CFB boiler and existing baghouse for the addition of a further CDS/CFBS unit without significant reconfiguration of existing equipment. Of all the add on control technologies considered, CDS/CFBS is the only potentially feasible option. Existing controls for $SO_2$ as defined in Sunnyside's Title V air operation permit (#700030004) Condition II.A.2 currently provide $SO_2$ controls to the circulating fluidized bed (CFB) boiler, which involves limestone injection.
2. Sunnyside included a cost analysis for a CDS/CFBS as per UDAQ request as it is the only technically feasible add-on unit. However, the average estimated cost for a CDS/CFBS able to achieve 90% $SO_2$ control ranges from $81 to $400 million plus another $1.7 million for a new baghouse required with this technology. Ash Grove does not consider this device economically feasible.
3. Sunnyside has updated this formula in the revised cost analysis to utilize the Sargent & Lundy formula for estimating the amount of lime needed for the Sunnyside CFB boiler. This formula now assumes that use of lime could achieve 74% $SO_2$ reduction resulting in a lime injection rate of 0.0921 tons per hour or 184 lb/hour.
4. Sunnyside has revised the cost for auxiliary power to be consistent with the UDAQ comments. Specifically, the busbar cost for electricity has now been calculated based on 2018 operating data. The resulting rate is $49.45 per MW. Additionally, the electrical usage rate has been updated to match the UDAQ comments and as displayed below: 0.028% x 58.33 MW x 8031 hours/yr x $49.45/MW-hr = $6,486 per year.
   The analysis provided under Question 2, 3, and 4 along with the attached cost analysis should replace information found in Sections 5.4 and 5.5 of the Four Factor Analysis.
5. The UDAQ suggested that there are tax exemptions in Utah for control equipment. UAC R307-120 exempts the purchase of control equipment from sales/use tax. As a result, sales tax is no longer included in CDS/CFBS cost analysis provided. Sales tax rates and property taxes are not used in either the SCR or SNCR cost analyses due to the equation format provided by EPA. Insurance rate was based on a 1% of the Total capital investment (TCI) which is documented in the EPA Cost Control Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, Subsection 2.6.5.8 Property Taxes, Insurance, Administrative Charges and Permitting Costs. The administrative cost calculation has been updated to be consistent with SCR as suggested by the UDAQ.

[158] Sunnyside's full evaluation response can be found in appendix F.3 or at: https://documents.deq.utah.gov/air-quality/pm25-serious-sip/DAQ-2021-017202.pdf
[159] Based on fly ash characterization results conducted at Sunnyside Cogeneration Associates.

6. The UDAQ questioned the retrofit factor (RF) of 1.3 used all cost analyses, as a result Sunnyside reevaluated the use of this factor on a technology specific basis. Referencing the EPA Control Cost Manual, Sunnyside believes the 1.3 retrofit factor is justified for use in their cost calculations for CDS/CFBS and SCR. They reconsidered their SNCR calculations and instead used a 1.0 retrofit factor.
7. A 20-year life span and 7% interest rate has been applied to the cost control analyses provided by Sunnyside.
8. The equipment life and interest rate explanations provided in Question 7 are not control technology specific. Thus, the same conclusions are applicable, namely, a 20-year life span and 7% interest rate are appropriate for the cost analyses provided.
9. In response to the UDAQ's request, Sunnyside obtained a cost estimate for 19% aqua ammonia from Thatcher Group, Inc (Thatcher). Thatcher quoted $0.18 per lb. of solution. Based on this value, if we assume a density of 19% ammonia is estimated to be 7.46 lbs/gal to 7.99 lbs/gal. This results in a cost per gallon ranges from 1.34 $/gal to 1.438 $/gal. This cost is significantly higher than the EPA estimate of $0.293, which is acceptable as it states, "User should enter actual value if known". Furthermore, it should be noted that the cost for ammonia based on the most recent U.S. Geological Survey, Minerals Commodity Summaries, which was quoted in the original Four Factor Analysis is also significantly higher and based on a density of 29% ammonia. Since the $1.438 is still less than the originally used $2.5 per gallon, these calculations have been updated to include the vendor quote.
10. As discussed in Question 4, Sunnyside has revised the cost for auxiliary power to be consistent with the UDAQ's comments. Please see section 4 for additional information. A revised cost analysis for SCR and SNCR have been provided in Attachment A to replace the cost analysis in the original Four Factor Analysis.

#### UDAQ Response Conclusion

UDAQ agrees with the amendments included in Sunnyside's evaluation response and finds the answer's provided in the facility's response satisfactory. Refer to section 8.D.5 for UDAQ's reasonable progress determinations for the Sunnyside Cogeneration Facility.

### 7.C.5 US Magnesium LLC- Rowley Plant[160]

*Facility Identification*

**Name: Rowley Plant Address: 12819 North Skull Valley Road 15 Miles North Exit 77, I-80, Rowley, Utah**
**Owner/Operator: US Magnesium LLC**
**UTM coordinates: 4,530,490 m Northing, 354,141 m Easting, Zone 12**

*Facility Process Summary*

US Magnesium LLC (USM) operates a primary magnesium production facility at its Rowley Plant, located in Tooele County, Utah. USM produces magnesium metal from the waters of the

[160] US Magnesium's full four-factor analysis submittal for the Rowley Plant can be found in appendix G.1 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2020-014024.pdf

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 (CRB) and converted into hydrochloric acid (HCl). 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 CO, $NO_x$, $PM_{10}$, $PM_{2.5}$, and VOCs.

### *Facility Criteria Air Pollutant Emissions Sources*

The source consists of the following emission units:

- Three (3) gas turbines/generators and duct/process burners (natural gas/fuel oil)
- Chlorine reduction burner (CRB), and associated equipment
- Riley Boiler, 60 MMBtu/hr (natural gas)
- Solar pond diesel engines, 30 engines rated between 90 and 420 hp
- Fire pump engine, one additional diesel engine rated at 292 hp

### *Facility Current Potential to Emit*

The current PTE values for the Rowley Plant, as established by the most recent NSR permit issued to the source (DAQE-AN107160050-20) are as follows:

**Table 44: Current Potential to Emit**

| Pollutant | Potential to Emit |
|---|---|
| **$SO_2$** | 24.10 |
| **$NO_x$** | 1,260.99 |

## US Magnesium Four-Factor Analysis Conclusion

This outlines USM's evaluation of possible retrofit options for all $NO_x$ emitting units onsite at their Rowley Plant located in Tooele County, Utah, in an attempt at reducing their $NO_x$ emissions facility wide and reducing their impact on visibility impairment issues. The results of this report found that it is potentially technologically and economically feasible to install a flue gas recirculation unit on the Riley boiler, reducing their $NO_x$ emissions by an estimated 22.6 tons annually. Aside from this change, there were currently no other technically or economically feasible options available for USM's Rowley Plant. Pending further technological and cost refinement, the implementation schedule for the installation of the FGR unit may be installed prior to the end of 2028. Therefore, the emissions for the 2028 modeling scenario could be an estimated 22.6 tons less than the 2018 baseline year $NO_x$ emissions.

## UDAQ Evaluation[161]

Several errors were made during the analysis of the various control options outlined in this document. While the errors ultimately do not change the outcome or results of the analysis, they should be corrected prior to final acceptance by DAQ. The following lists the errors noticed by DAQ and the resulting effect each error leads to in the final result:

Incorrect interest rate used for control cost calculation – rather than using the current bank prime rate of 3.25%, the source calculated all control costs with either an interest rate of 7% (used as the default in the control cost manual) or 5.5% (used as the default in the SCR control cost spreadsheet). Both calculations result in a higher control cost in $/ton. Second, the source used only a 20-year expected life for application of an SCR, which is lower than the standard 30-year lifespan. Again, this would artificially inflate the control cost by increasing the annualized cost. However, the overall cost of the SCR system as estimated by the source was lower than expected, with an initial cost of just $87,000. The low initial cost serves to lower the resulting control cost. DAQ reanalyzed the use of SCR on the Riley Boiler under two different scenarios. Under PTE, assuming full load, the application of SCR might be expected to remove as much as 188 tons of $NO_x$ at a control cost of $4,073/ton of $NO_x$ removed – assuming the same 90% removal efficiency as did the source. However, the Riley Boiler did not operate at that high an output level – reporting just 45.25 tons of actual emissions in 2018. Adjusting the emission reduction for 90% of the actual emissions gives a removal of 40.7 tons of $NO_x$ (as opposed to the 38 tons suggested by the source), at a control cost of $18,800/ton of $NO_x$ removed. Similar errors were made with respect to the FGR calculations on the Riley Boiler. The incorrect interest rate was used – 7% vs 3.25%. FGR systems typically have a potential lifespan of 15 years rather than the 20 years suggested by the source. DAQ recalculated the control costs correcting for these errors and obtained a modified value of 22.5 tons of $NO_x$ removed at a control cost of $1,880/ton of $NO_x$ removed. None of the other equipment requires additional evaluation, as each is currently well controlled. While the same types of errors were made in the source's analysis, the resulting outcomes and conclusions remain unchanged. DAQ recommends that FGR be considered for retrofit control application on the Riley boiler. Should the source increase utilization of the Riley boiler, then the application of SCR should be considered.

## US Magnesium's Evaluation Response[162]

US Magnesium re-evaluated the status of the Riley boiler and the Riley boiler $NO_x$ emission factor utilized in US Magnesium's 2018 air emission inventory (AEI) that was the basis for the 4-factor analysis of that unit. In summary, the US Magnesium 2018 AEI grossly overstated the $NO_x$ emissions associated with the Riley boiler in two ways: 1) the Riley boiler is a 60 MMBTU

[161] UDAQ's full evaluation of US Magnesium's four-factor analysis submittal can be found in appendix G.2 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2021-009628.pdf
[162] US Magnesium's full evaluation response can be found in appendix G.3 or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2021-011902.pdf

boiler but the AP42 emission factor in the 2018 AEI is for a >100 MMBTU boiler, and 2) the Riley boiler, from the time of its installation, is outfitted with a low $NO_x$ burner, but the AP42 emission factor in the 2018 AEI is for an "uncontrolled burner." The implications are summarized in the table below:

**Table 45: US Magnesium's Reevaluation of Riley Boiler Controls**

| Riley Boiler 2018 | $NO_x$ emission factor | AP 42 Table1.4-1. Emission Factors for $NO_x$ and CO from Natural Gas Combustion | | Estimated $NO_x$ emissions (TPY) |
|---|---|---|---|---|
| **AEI as submitted** | 190 lbs./MMscf | >100MMBTU (Large) | Uncontrolled | 45.2499 |
| **AEI corrected for actual status of Riley boiler** | 50 lbs./MMscf | <100MMBTU (Small) | Controlled - Low $NO_x$ burner | 11.9074 |

Corrected 2018 $NO_x$ emissions for the Riley boiler, implications on the 4-factor analysis:

- Using the same reductions assumed for FGR (up to 50% $NO_x$), the estimated reduction would be about 6 tons/year.
- Using the same reductions assumed for SCR (up to 90% $NO_x$), the estimated reduction would be about 10.7 tons/year.
- Using DAQ's modified calculation for FGR: $1,880/ton * 22.5 tons = $42,000/yr. Correcting to 6 ton/yr reduction = $7,050/ton.
- Using DAQ's modified calculation for SCR: $18,800/ton * 40.7 tons = $765,160/yr. Correcting to 11.9 ton/yr reduction = $64,300/ton.

### UDAQ Response Conclusion

UDAQ does not agree with US Magnesium's evaluation response. We do not possess any records of an LNB control on the Riley boiler. Using the original four-factor analysis submittal, FGR on the Riley boiler remains a cost-effective and viable control option. UDAQ would require proof of the existence of the LNB and its $NO_x$ removal efficacy before agreeing it is a satisfactory justification for altering the control cost calculations. Refer to section 8.D.6 to review UDAQ's reasonable progress and controls determination for the Rowley Plant.

## 7.D UDAQ Four-Factor Analysis Summary

Add 4-factor analysis summary matrix to show that each have been addressed for all sources

# **Chapter 8:** Determination of Reasonable Progress Goals

## 8.A Reasonable Progress Requirements

The RHR requires Utah to submit a long-term strategy (LTS) that includes measures necessary to achieve the Reasonable Progress Goals (RPGs) in each CIA. This strategy must consider major and minor stationary sources, mobile sources, and area sources. Section 169A (a)(4) and other subsections of the Clean Air Act call for reasonable progress "toward meeting the national goal" of eliminating anthropogenic (manmade) impairment of visibility. Utah is required under the RHR to establish visibility deciview goals for each of its five CIAs that allow them to meet the RPGs towards natural visibility by 2064. RPGs are interim goals that represent incremental visibility improvement over time toward the goal of natural background conditions and are developed in consultation with FLMs and nearby affected states. In determining the criteria for reasonable progress, Utah was required under Section 169A(g) of the CAA to consider four factors: cost of compliance, the time necessary for compliance, energy and non-air environmental impacts of compliance, and the remaining useful life of existing sources that contribute to visibility impairment.[163]

## 8.B. Regional Modeling of the LTS to set RPGs

The RHR requires states to demonstrate progress every ten years toward the CAA goal of no manmade visibility impairment. WRAP conducted the modeling necessary to track this progress for Utah. EPA guidance for tracking visibility progress[164] defines a visibility impairment tracking metric (measured in deciviews) using observations from the IMPROVE monitoring network sites that represent CIAs. EPA defined in the RHR and guidance a Uniform Rate of Progress (URP) glidepath for the 20% most impaired days as the straight line from the 2000-2004 IMPROVE 5-year average baseline to EPA estimates of future natural visibility conditions, plotted for 2064. In the first regional haze planning period, 2000-2018, EPA guidance[165] defined most impaired days as those days with highest total haze. States were required to demonstrate visibility progress by 2018 compared to the URP glidepath for the haziest days and no degradation of visibility on the clearest days from the 2000-2004 IMPROVE 5-year average baseline. Visibility on the clearest days improved between 2000 and 2018 across the Class I areas in the western U.S. However, smoke from wildfire and wildland prescribed fire events and dust events on the haziest days made tracking the visibility benefits due to reducing U.S. anthropogenic emissions more difficult.

[163] *See* 42 USC § 7492(g)(1).

[164] The EPA Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program can be found at: https://www.epa.gov/sites/default/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf

[165] The EPA Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program can be found at: https://www.epa.gov/sites/default/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf

For the second regional haze implementation period, 2018-2028, states are required to demonstrate visibility progress by 2028 for the most impaired days and no visibility degradation for the clearest days. EPA guidance[166] defined most impaired days as those days with the highest fractional contribution to aerosol light extinction from anthropogenic sources. EPA statistical methods use IMPROVE measurements of carbon and crustal materials to separate contributions from episodic extreme natural events (e.g., wildfire or dust) from routine natural and anthropogenic contributions. Ammonium sulfate and ammonium nitrate are assigned primarily to anthropogenic emissions with smaller contributions from routine natural sources. This statistical approach does not separate contributions due to U.S. anthropogenic emissions from those of international anthropogenic emissions. Since states do not have authority to reduce international emissions, WRAP conducted source apportionment modeling analyses to evaluate U.S. anthropogenic contributions to haze and progress in reducing U.S. anthropogenic contributions to haze over time.

## 8.C URP Glidepath Checks[167]

These charts illustrate the Uniform Rate of Progress (URP) Glidepath, as defined by EPA guidance,[168] compared to IMPROVE measurements for the period 2000-2018. The URP glidepath is constructed (in deciviews) for the 20% most impaired days (MID) or clearest days using observations from the IMPROVE monitoring site representing a Class I area. The URP glidepath starts with the IMPROVE MID for the 2000-2004 5-year baseline and draws a straight line to estimated natural conditions in 2064. For clearest days, the goal is no degradation of visibility from the 2000-2004 5-year baseline, therefore glidepath for clearest days is a straight line from the 2000-2004 baseline to 2064. In the second regional haze planning period, 2064 natural conditions estimates are the same as the 15-year average of natural conditions on most impaired days or clearest days in each year 2000-2014. IMPROVE annual average values are presented as points. IMPROVE 5-year average values are presented as solid lines covering the periods 2000-2004 and 2014-2018.

The 2028 On the Books (2028OTBa2) visibility projection in deciviews is illustrated as a point that can be compared to the Uniform Rate of Progress glidepath. UDAQ has chosen the "2028OTBa2 w/o fire" projection that excludes wildfire from MID to more accurately represent future emissions from sources UDAQ is better able to control. This projection reduces the impact of elemental carbon and organic carbon from fires from the original 2028 EPA projection to remove additional fire impacts that were not fully eliminated by the move from haziest days metric (used during the first planning period) to most impaired days metric (used during the second planning period). The 2028OTBa2 visibility projection reflects Utah's LTS, including the results of the reasonable progress determinations found in 8.D, with the exception of the anticipated 22.5 tons of NOx emissions reductions associated with the installation of FGR

[166] The EPA Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program can be found at: https://www.epa.gov/sites/default/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf
[167] 40 C.F.R. § 51.308(f)(3)(i)
[168] The EPA Guidance for Tracking Progress Under the Regional Haze Rule can be found at https://www.epa.gov/sites/default/files/2021-03/documents/tracking.pdf

controls on the Riley Boiler at U.S. Magnesium's Rowley Plant. However, the resulting reduction in NOx emissions is a small percentage of Utah's total 2028 NOx emissions. The 2028OTBa2 visibility projection also includes emissions from the now-closed Kennecott Power Plant, which was projected to have 1,152 tons of NOx, 2,152 tons of $SO_2$, and 135 tons of PM2.5 emissions in 2028. The omission of these emissions reductions in the 2028OTBa2 projection make our glidepath comparisons conservative, as actual 2028 visibility can be expected to improve due to lower emissions levels.

### 8.C.1 Bryce Canyon National Park

The 2000-2004 URP baseline in Bryce Canyon for MID is 8.4 dv. The 2014-2018 average observations for MID is 6.6, meaning visual range on the most impaired days has increased from 104.62 miles to 125.26 miles, an improvement of 20.64 miles. The projected visibility in 2028 without fire impacts is 6 dv, which, represented by the orange triangle on the graph, is below the URP glidepath. For clearest days, the 2000-2004 baseline for Bryce Canyon is 2.8 dv. The 2014-2018 average observations for clearest days are 1.5 dv meaning that visual range on the clearest days has increased from 183.16 miles to 208.59 miles, an increase of 25.43 miles. The projected 2028 visibility on clearest days is 1.2 dv, which, represented by the blue triangle, is below the no degradation limit for clearest days.


**Figure 57: Projected 2028 RPG Bryce Canyon National Park**

### 8.C.2 Canyonlands and Arches National Park

The 2000-2004 URP baseline in Canyonlands and Arches National Park for MID is 8.8 dv. The 2014-2018 average observations for MID is 6.8, meaning visual range on the most impaired days has increased from 100.52 miles to 122.78 miles, an improvement of 22.26 miles. The projected visibility for MID in 2028 without fire impacts is 6.2 dv, which is below the URP glidepath. For clearest days, the 2000-2004 baseline for Canyonlands and Arches is 3.7 dv. The 2014-2018 average observations for clearest days are 2.2 dv meaning that visual range on the clearest days has increased from 167.40 miles to 194.49 miles, an increase of 27.09 miles. The projected 2028 visibility on clearest days is 1.9 dv, which is also below the no degradation limit for clearest days.


**Figure 58: Projected 2028 RPG Canyonlands and Arches National Parks**

## 8.C.3 Capitol Reef National Park

The 2000-2004 URP baseline in Capitol Reef for MID is 8.8 dv. The 2014-2018 average observations for MID is 7.2, meaning visual range on the most impaired days has increased from 100.52 miles to 117.96 miles, an improvement of 17.44 miles. The projected visibility for MID in 2028 without fire impacts is 6.6 dv, which is below the URP glidepath. For clearest days, the 2000-2004 baseline for Capitol Reef is 4.1 dv. The 2014-2018 average observations for clearest days are 2.4 dv meaning that visual range on the clearest days has increased from

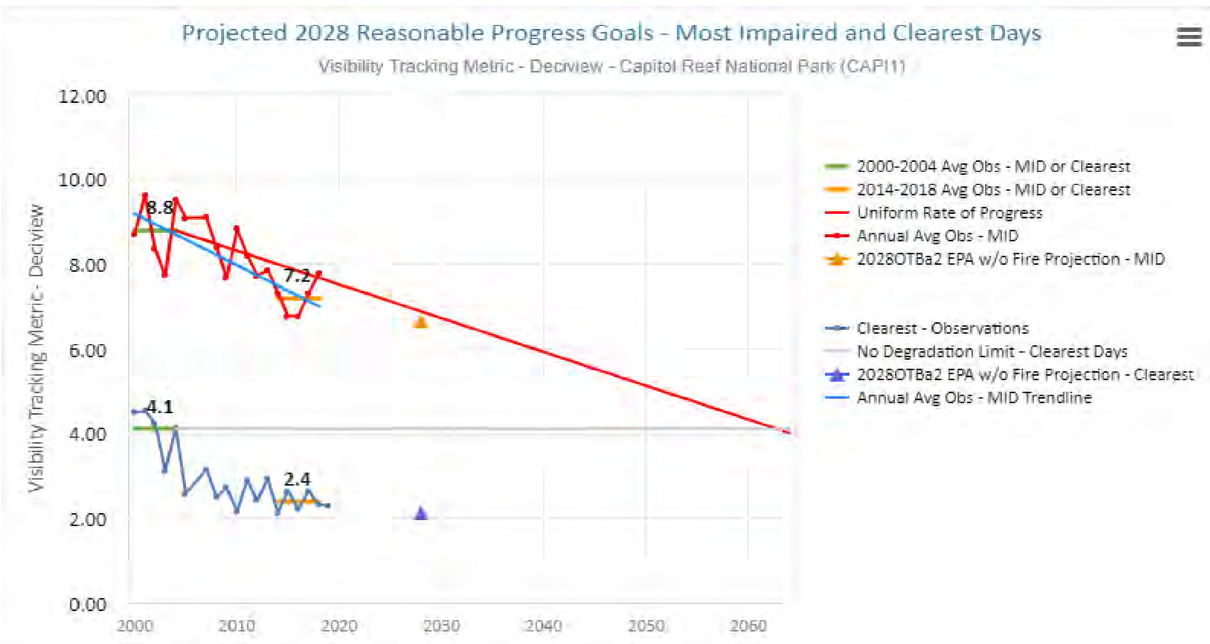


**Figure 59: Projected 2028 RPG Capitol Reef National Park**

160.83 miles to 190.64 miles, an increase of 29.81 miles. The projected 2028 visibility on clearest days is 2.1 dv, which is below Capitol Reef's no degradation limit for clearest days.

## 8.C.4 Zion National Park

The 2000-2004 URP baseline in Zion National Park for MID is 10.4 dv. The 2014-2018 average observations for MID is 8.7, meaning visual range on the most impaired days has increased from 85.66 miles to 101.53 miles, an improvement of 15.87 miles. The projected visibility for MID in 2028 without fire impacts is 8.3 dv, which is below the URP glidepath. For Zion's clearest days, the 2000-2004 baseline for is 4.5 dv. The 2014-2018 average observations for clearest days are 3.9 dv meaning that visual range on the clearest days has increased from 154.53 miles to 164.08 miles, an increase of 9.55 miles. The projected 2028 visibility on clearest days is 3.5 dv, which is below the no degradation limit for clearest days in Zion.


**Figure 60: Projected 2028 RPG Zion National Park**

## 8.C.5 Summary of URP Glidepaths

The table below summarizes the information from figures 57-60 above, comparing visibility on the most impaired and clearest days for the baseline, 2028 URP, and 2028 EPA w/o fire projection values for each of Utah's CIAs in addition to stating whether the CIA is below the URP glidepath and no degradation line.

**Table 46: Comparison of baseline, 2028 URP, 2028 EPA w/o fire projection for worst and clearest days**

| CIA IMPROVE Site | WORST DAYS | | | | | CLEAREST DAYS | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Baseline (dv) | 2028 URP (dv) | 2028 EPA w/o Fire Projection (dv) | % Progress to 2028 URP | 2028 Below URP Glidepath? (Y/N) | Baseline (dv) | 2028 EPA Projection (dv) | 2028 EPA w/o Fire Projection (dv) | 2028 Below No Degradation Line? (Y/N) |
| BRCA1 | 8.42 | 6.68 | 6.03 | 137.60% | YES | 2.77 | 1.22 | 1.20 | YES |
| CANY1 | 8.79 | 6.92 | 6.19 | 139.10% | YES | 3.75 | 1.94 | 1.92 | YES |
| CAPI1 | 8.78 | 6.87 | 6.63 | 112.28% | YES | 4.10 | 2.17 | 2.10 | YES |
| ZICA1 | 10.40 | 8.35 | 8.27 | 103.73% | YES | 4.48 | 3.65 | 3.54 | YES |

# 8.D Reasonable Progress Determinations

The following sections contain UDAQ's determinations on what controls are necessary for Utah's CIAs to make reasonable progress in this implementation period.

### 8.D.1 Reasonable Progress Determination for Ash Grove Cement Company – Leamington Cement Plant

Upon reviewing Ash Grove's four-factor analysis for the Leamington Cement Plant and their evaluation response, UDAQ finds that it is adequately controlled for the purposes of the Second Implementation Period. The plant already has SNCR installed and has provided this control's efficiency data, which adheres to the plant's current emissions limit. Refer to section 7.B.3 to review the four-factor analysis and evaluation response results for the Leamington Cement Plant.

### 8.D.2 Reasonable Progress Determination for Graymont Western US Incorporated – Cricket Mountain Plant

Upon reviewing the Graymont Western US Inc. four-factor analysis for their Cricket Mountain Plant and their evaluation response, UDAQ finds that additional controls are not required for reasonable progress in this implementation period based on their cost/ton and the potential proprietary costs of SNCR technology for the kilns. Refer to section 7.B.4 to review the four-factor analysis and evaluation response results for the Cricket Mountain Plant.

### 8.D.3 Reasonable Progress Determination for PacifiCorp: Hunter and Huntington Power Plants

Upon reviewing PacifiCorp's four-factor analysis and evaluation response, UDAQ finds SNCR and SCR not to be cost-effective at this time due to the uncertainty associated with future utilization of both plants. Instead, UDAQ is establishing mass-based emissions limits that reflect recent actual emissions and the 2028 "on-the-books" emissions projections modeled by WRAP and used in Utah's URP glidepath checks. UDAQ is also adding PacifiCorp's existing $SO_2$ emission limits from their title V permit for all five units to ensure federal enforceability in the regional haze context. These emission limits are to be implemented and enforced through SIP Subsection IX. Part H. 23 (b) and (c). Please refer to section 7.C.3 to view PacifiCorp's and UDAQ's complete analysis and conclusions.

### 8.D.4 Reasonable Progress Determination for Sunnyside Cogeneration Associated – Sunnyside Cogeneration Facility

Upon reviewing the Sunnyside Cogeneration Associated four-factor analysis and evaluation response containing corrections to their analysis of the Sunnyside Cogeneration Facility, UDAQ has found no cost-efficient control options for the facility for the purposes of the Second Implementation Period. Refer to section 7.B.6 to review the four-factor analysis and evaluation response results for the Sunnyside Power Plant.

### 8.D.5 Reasonable Progress Determination for US Magnesium LLC – Rowley Plant

Upon reviewing US Magnesium LLC's four factor analysis for their Rowley Plant, UDAQ does not agree with its assessment of an LNB on the Riley Boiler. UDAQ has no record of the existence of an LNB on this unit or it's $NO_x$ reducing efficacy. UDAQ therefore refers to US Magnesium's original four-factor analysis submittal information suggesting that FGR is a cost-effective and viable control option for the Riley Boiler. UDAQ recommends the installation of FGR on the Riley Boiler to ensure that Utah makes reasonable progress in this implementation period. The implementation of this control determination is to be enforced through SIP Subsection IX. Part H. 23 (d). Refer to section 7.B.7 to review the four-factor analysis and evaluation response results for the Rowley Plant.

### 8.D.6 Intermountain Power Service Corporation – Intermountain Generation Station

As discussed in section 7.A.2, the planned replacement of the IGS coal-fired units with an EPS-compliant combined-cycle natural gas plant is expected to dramatically decrease regional haze-causing pollutants (PM, $SO_2$, and NOx). Though the coal-fire units are expected to cease operation by mid-2025, UDAQ has established a firm closure date of no later than December 31, 2027 to ensure that the coal-fired units at IGS will not continue operation beyond the conclusion of the second implementation period while allowing flexibility for closing the plant in addition to rescinding its permit and approval order. The implementation of this closure is to be enforced through SIP Subsection IX. Part H. 23 (a).

# **Chapter 9:** Consultation, Public Review, Commitment to further Planning

## 9.A Federal requirements

In developing each reasonable progress goal, Utah must consult with those States which may reasonably be anticipated to cause or contribute to visibility impairment in CIAs within Utah.[169] Where the State has emissions that are reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area located in another State, Utah must consult with the other State(s) in order to develop coordinated emission management strategies.[170] Utah must demonstrate that it has included in its implementation plan all measures agreed to during state-to-state consultations or a regional planning process, or measures that will provide equivalent visibility improvement and document all substantive interstate consultations.[171] Utah must also provide the FLMs with an opportunity for consultation no less than 60 days prior to the SIP public hearing or public commenting opportunity.[172] This consultation must include the opportunity for FLMs to discuss their assessment of the visibility impairment at CIAs and their recommendations on the development and implementation of strategies to address visibility impairment.[173] Utah must include a description in their implementation period of how it addressed any comment provided by FLMs.[174]

## 9.B Interstate Consultation

Throughout the second implementation period, Utah has met regularly with its surrounding states. Utah also participates in WESTAR Planning Committee and Four Corners meetings for state RH planning coordination. See Appendix B for further documentation of interstate consultation and agreements.

**Table 47: Summary of Interstate Meetings with UDAQ**

| Date | Time | Entity | Topic | Result |
|---|---|---|---|---|
| **4/28/2021** | 10-11a | Wyoming | Wyoming and Utah Regional Haze Second Planning Period Update | Debrief after PacifiCorp meeting. Shared draft Montana SIP with Wyoming. They shared their draft SIP with us. We offered ours as soon as it is more complete. |
| **4/30/2021** | 1-2:30p | Four Corners' States | Regional Haze Consultations | Four corners states do not expect to require other states to enforce controls for emissions affecting their Class I Areas. NM discussed in length where they are in their SIP writing process. |

[169] *See* 40 CFR § 51.308 (d)(1)(iv)
[170] *See id*., § 51.308 (d)(3)(i)
[171] *See id*., § 51.308 (f)(2)(ii)(C)
[172] *See id*., § 51.308 (i)(ii)(2)
[173] *See id*., § 51.308 (i)(ii)(2)
[174] *See id*., § 51.308 (i)(4)

| | | | | |
|---|---|---|---|---|
| **5/5/2021** | 9-9:30a | Wyoming | WY-UT RH Coordination Call | Discussion emissions affecting the other state. |
| **5/5/2021** | 2-4p | WESTAR | Regional Haze Results Meeting #9 | Discussion of different modeling resources available and uses. |
| **5/6/2021** | 2-3p | WESTAR | WESTAR Planning Committee Call | RH updates and deadline considerations. |
| **5/12/2021** | 2:30-3:30p | New Mexico | NM-UT DEQ Regional Haze Consultation | NM described their SIP writing process and showed us the modeling tools they plan to use for the out of state emissions section. We offered to exchange draft SIPs. |
| **6/1/2021** | 1:30-2p | Colorado | CO-UT Regional Haze Consultation | Discussed controls implementation. |
| **9/9/2021** | 12-12:30p | Arizona | UT-AZ RH Consultation | Neither state is looking for additional controls in the other. Consulted about interest rates and control cost thresholds. |
| **9/9/2021** | 2-3:30p | WESTAR | State-Only RH Call | |
| **10/15/2021** | 10-11a | New Mexico (Mark Jones) | Control Cost Consultation | Discussed control cost thresholds and justification. |
| **11/04/2021** | 2-3p | WESTAR | Planning Committee Meeting | Discussed RH updates and interstate consultation documentation emails. |
| **11/08/2021** | 1-2p | Wyoming | RH Controls Implementation Consultation | Discussed sources and controls implementation. |
| **11/15-16,2021** | 10a-4p | 4 Corners | Annual AQ Meeting | Participated in giving RH updates with other 4 corners states. |
| **1/7/22** | 10-11a | New Mexico | WEP Analysis Consultation | Discussed WEP analysis methodologies and CAMx photochemical low-level source apportionment. |
| **1/13/22** | 1:30-3p | WVPPI | Western Visibility Protection and Planning Initiative | Discussion of the key components of Section 169a of the CAA. |
| **2/10/22** | 1:30-3p | WVPPI | Western Visibility Protection and Planning Initiative | Discussed, RH history, the relationship between reasonable progress and long-term strategies. Utah volunteered to help plan an in-person meeting between states, FLMs, and EPA. |
| **2/24/22** | 1-2p | RHPWG | Regional Haze Planning Work Group | Discussed the NGO actions letter submitted to EPA and 60-day notice to file suit. |

## 9.C Documentation of Federal Land Manager consultation and commitment to continuing consultation

UDAQ continuously met with the FLMs throughout the second implementation period planning process. A summary of the meetings UDAQ held with the FLMs is outlined in the table below. UDAQ will continue to consult and collaborate with the FLMs in its future regional haze planning efforts.

**Table 48: Summary of FLM Meetings with UDAQ**

| Date | Time | Entity | Topic | Result |
|---|---|---|---|---|
| **5/5/21** | 8-9a | Utah DEQ/US Forest Service | Prescribed Fire and Regional Haze | Brief history of Utah's smoke management program and policy regarding it. |
| **5/6/21** | 1-1:30p | FLM | FLM/UT – Regional Haze Check-In | Updated FLMs on timeline and current RH SIP progress. They informed us on their view that visibility should not be main focus of 2nd planning period and to follow the rule more than the guidance document. They are primarily concerned about 4-factor analyses. |
| **6/22/21** | 12-12:30p | US Forestry Service - Ples Mcneel | RH update, introductions | Introduction to Ples Mcneel. Wants to be included in updates to FLMs and Paul Corrigan. |
| **10/12/21** | 12-11a | NPS | Regional Haze Update/Timeline change | Discussed RH SIP draft submittal. |
| **2/9/22** | 11:30a-1p | NPS | NPS UT Regional Haze Consultation | NPS presented UDAQ with the results of their 60-day review period |
| **2/23/22** | 11a-12p | USFS – Ples Mcneel and Paul Corrigan | Rx Fire Endpoint Adjustments | Discussed the Rx fire endpoint adjustments available to Utah. |

### 9.C.1 FLM SIP Review[175]

UDAQ submitted its draft RH SIP for the second implementation period to the NPS on December 7th, 2021 and the USFS on December 15th, 2021. On February 14th, NPS and USFS provided UDAQ with their respective SIP reviews which can be found in Appendix D.

### 9.C.2 NPS Feedback Summary and UDAQ Responses[176]

1. In general, NPS agrees that Utah's source selection process resulted in a reasonable subset of sources to evaluate in the draft SIP. Utah's recommendation to use a lower emission over distance threshold of six versus ten—as recommended by the WRAP—is more rigorous and resulted in a reasonable selection of facilities for evaluation.

[175] See Appendix D for all FLM RH SIP review documents
[176] See Appendix D.1 and D.2 to view the full NPS review of Utah's RH SIP and supporting cost analyses

2. UDAQ has not identified a cost threshold under which the evaluated controls would be considered reasonable. Many of the controls identified in the four-factor analyses for Utah sources are cost-effective based on cost criteria/thresholds identified by other states. NPS also feels that PacifiCorp should be subject to a higher cost threshold due to their plant's proximity to Utah's CIAs. The SIP should document the full rationale upon which the reasonable progress decisions are based.

   UDAQ Response: UDAQ will not be establishing a control cost threshold at this time. Please refer to chapter 8 for Utah's reasonable progress determinations for the second implementation period and the accompanying justifications, which UDAQ believes are sufficient.

3. NPS recommends that UDAQ require all technically feasible, cost-effective controls identified through four-factor analysis in this planning period.

   UDAQ Response: UDAQ has required all controls it has deemed technically feasible and cost effective. Please refer to the updated part H language in Appendix A to view the enforceable actions resulting from UDAQ's reasonable progress determinations for the purposes of the second implementation period.

4. In the draft SIP UDAQ writes that "Utah has analyzed the WRAP photochemical modeling for OTB 2028 and found that emissions from Utah do not significantly impact visibility at CIAs in other states." While it does not appear that this conclusion impacted the source selection process, it is not clear how Utah used this conclusion or whether it influenced their control technology determinations. NPS believes UDAQ's conclusion is not compatible with their findings regarding the impact of Utah sources in Class I areas of neighboring states, and NPS recommends that UDAQ revise this section of the draft SIP by using a 1% threshold for determining significant impacts.

   UDAQ Response: Section 6.A.2 has been revised in response to this comment.

5. Utah requested more information regarding where Utah stands in terms of RAVI for Class I areas. RAVI is a separate process from periodic SIP revisions. This avenue is rarely used by the FLMs to address specific sources causing visibility impairment at Class I areas. The NPS will not likely pursue RAVI certification unless the approaches identified in the periodic SIP revisions do not adequately address documented impairment.

6. UDAQ asked for feedback on using prescribed fire data from USFS to adjust projections. NPS does not take a position on the adjustment of glidepath end points for prescribed

fire. We support UDAQ's determination to not use glidepath adjustments for estimated contributions from international emissions.

7. In Table 27 Sources initially selected to perform a Four-Factor analysis in draft SIP, section 7.A.1, NPS recommends identifying the nearest Class I area referenced in the "distance to nearest Class I area" column.

   UDAQ Response: A column identifying the nearest CIA has been added to Table 27 in section 7.A.1.

8. In section 8.D.6 there appears to be a typographical error listing Intermountain Generation Station closing in 2017.

   UDAQ Response: The typographical error in section 8.D.6 has been fixed and the closing year for IGS now reads as 2027.

9. NPS recommends UDAQ revise the permit limits for the Paradox Resources Lisbon Natural Gas Processing Plant to reflect the assumptions used to exclude this facility from four-factor analysis. NPS also recommends including the plant's recent actual emissions data in the SIP.

   UDAQ Response: UDAQ has contacted Paradox Resources and is in the process of obtaining information from them that will be available for review in this SIP after the public commenting period when the SIP is brought to the AQB again.

10. NPS recommends that UDAQ conducts or requires a four-factor analysis for the Intermountain Power Intermountain Generation Station exploring opportunities to improve the efficiency of the existing $SO_2$ scrubbers considering $NO_x$ emissions for the remaining useful life of the facility.

    UDAQ Response: UDAQ has been in contact with IGS concerning this matter. UDAQ believes the station's existing $SO_2$ scrubbers are sufficient and that the plant is well controlled. UDAQ has also included IGS's 2028 closure in the proposed part H language for this SIP located in Appendix A, which would make the closure federally enforceable.

11. NPS requests that UDAQ provide a breakdown of emissions from the Kennecott units the state can regulate versus those it cannot regulate. UDAQ should explain how its $PM_{2.5}$ SIP includes in-use requirements for this equipment.

    UDAQ Response: Section 7.A.2 was revised and a breakdown of Kennecott's emissions was included in response to this comment.

12. NPS recommends that UDAQ reduce haze causing $SO_2$ emissions from Hunter and Huntington facilities by requiring an evaluation of $SO_2$ scrubber optimization and potential efficiency improvements and implement any technically feasible and cost-effective options identified.

    UDAQ Response: PacifiCorp has provided additional information concerning their existing $SO_2$ scrubbing[177]. The existing FGD $SO_2$ controls at the Hunter and Huntington power plants all have control efficiencies of at least 90% and each unit at these plants are subject to an $SO_2$ emissions limit of 0.12 lb/mmBtu through their respective Title V permits. It is PacifiCorp's stance that these controls are running as efficiently as possible and there are no cost-efficient upgrades available. The "RPELs" proposed in PacifiCorp's original four-factor analysis "combined operational adjustments (such as reduced until utilization) with incremental capital and O&M costs". Additionally, PacifiCorp cited EPA's 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" ("2019 Guidance") which recognizes that it "may be reasonable for a state not to select an effectively controlled source. A source may already have effective controls in place as a result of a previous regional haze SIP or to meet another CAA requirement."[178] UDAQ is adding the existing $SO_2$ emission limits for all five units to SIP Section IX.H23, Source Specific Emission Limitations: Regional Haze Requirements, Reasonable Progress Controls, to ensure federal enforceability of PacifiCorp's $SO_2$ limits in the regional haze context. Section 7.C.3 has been revised to include this information and additional discussion in response to this NPS comment.

13. NPS generally agrees with UDAQ's revisions to PacifiCorp's $NO_x$ control technology cost analyses and used similar adjustments in their cost assessments. NPS also agrees with UDAQ that PacifiCorp's demonstration that the interest rate of 7.303% is their site-specific value and appropriate for use in their four-factor analyses.

14. NPS shares UDAQ's concerns with PacifiCorp's RPEL recommendation and support UDAQ's rejection of this proposal. RPEL would essentially be a "paper" reduction in emissions that would not reduce haze-causing emissions affecting visibility in Utah's CIAs.

15. NPS suggest that UDAQ could consider environmental co-benefits of $NO_x$ emission reduction as part of this factor. $NO_x$ is an ozone pre-cursor emission and ozone is known to affect both human and ecosystem health.

[177] Please refer to Appendix D.2.C to view PacifiCorp's document on Regional Haze Second Planning Period Issues Regarding $SO_2$ Controls for PacifiCorp's Power Plants
[178] See page 22 of https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf?VersionId=QC2nPZHuAH1VYmm3EuhV9ABIGm5rQynb.

UDAQ Response: UDAQ recognizes the co-benefits associated with pollutant emissions reductions and may highlight these benefits in the final draft of this SIP. However, UDAQ also recognizes the four-factor analysis[179] being the primary decision-making tool in this second implementation period and other benefits do not necessarily impact UDAQ's reasonable progress determinations.

16. NPS believes the cost of controls for the Sunnyside Cogeneration Facility are more economical than the company's estimates based on their calculations derived from the EPA Control Cost Manual. NPS disagrees with Sunnyside's use of a 7% interest rate and recommends UDAQ consider their control costs using the bank prime interest rate of 3.25%.

    UDAQ Response: Sunnyside Cogeneration provided additional justification found in Appendix D.2.A for the 7% interest rate they used in their control cost analysis. This rate was supported by a variety of institutions and most closely matched the financial indicators known by Sunnyside. UDAQ agrees with the final iterations of Sunnyside's estimated control costs.

17. NPS does not believe that Sunnyside has provided sufficient justification to exclude dry sorbent injection technology as technically feasible.

    UDAQ Response: UDAQ has requested additional information regarding the feasibility and cost-effectiveness of dry sorbent injection technology from Sunnyside and will include their response in the final draft of this SIP.

18. NPS's review of the Ash Grove Leamington Cement Plant suggests potential improvements may be available for their existing SNCR system. NPS recommends UDAQ request further evaluation of this opportunity to reduce $NO_x$ emissions from the facility.

    UDAQ's Response: In response to UDAQ's four-factor analysis evaluation, Ash Grove provided additional information on the efficiency of their SNCR system[180]. Based on this information, UDAQ believes this facility is well controlled for the purposes of this implementation period.

19. NPS's review of the Graymont Cricket Mountain Plant finds that their permitted emissions levels are significantly higher than their recent emissions levels. NPS believes the costs of controls would be more cost effective if emissions increased to permitted

[179] Please refer to section 7.B to view the four factors used to determine control feasibility in this implementation period.
[180] Located in section 7.C.1 in Ash Grove's Evaluation Response

levels. NPS recommends UDAQ consider tightening permitted emissions limits for $NO_x$ and $SO_2$ to reflect future potential emissions and prevent backsliding.

UDAQ Response: UDAQ contacted Graymont concerning their permitted emissions levels. The Cricket Mountain facility has seen a decrease in production over the past few years with special emphasis on the impacts of the COVID-19 pandemic. Graymont views this as a temporary decrease as the market is currently in the midst of recovery while they anticipate growth in their market. As this decrease is temporary, Graymont does not foresee the need to reduce its limits at this facility as it could reduce their flexibility to meet the market recovery and grow.h.

20. NPS recommends that numerical $NO_x$ and $SO_2$ emissions limits be incorporated into US Magnesium's current permit for the turbines/duct burners, chlorine reduction burner, melt/reactor, riley boiler, and the diesel engines would ensure that reasonable progress assumptions and determinations for the facility are adhered to.

    UDAQ Response: UDAQ has issued an order to US Magnesium to obtain the information required to respond to these comments. US Magnesium has been given a response deadline of April 11th, 2022 and the information they provide will be included in the final draft of this SIP.

21. NPS recommends UDAQ re-evaluate the feasibility and costs of US Magnesium installing SCR on their turbines.

    UDAQ Response: See response to comment 20.

22. NPS recommends UDAQ reconsider requiring implementation of SCR on US Magnesium's riley boiler as part of this implementation period. Additionally, actual emission assumptions relied on to eliminate SCR from consideration be reflected in permit limitations for this unit.

    UDAQ Response: See response to comment 20.

23. NPS requests additional information and emissions verification on US Magnesium's diesel engines and engine replacement and/or electrification be included as additional emission control options in their four-factor analysis.

    UDAQ Response: See response to comment 20.

24. NPS recognizes the jurisdictional complexity of the Uintah and Paradox basins with 80% of the land being under tribal and EPA control. However, NPS recommends that air quality improvement will require cooperative and commensurate efforts from all agencies involved in air quality management in the basin and suggests UDAQ implement

statewide rules to address oil and gas emission sources throughout Utah.

UDAQ Response: Over the past several years, UDAQ has proposed and adopted a series of statewide rules specific to oil and gas operations found in Utah's state administrative rules R307-500 to 511. Though these rules have been focused on controlling VOC emissions, there is also a state-specific rule for natural gas-powered engines associated with oil and gas production. Since the rule was put in place in 2018, several sources have provided engine stack test data that have led UDAQ, EPA, and the Tribes to initiate further research and compliance studies on engines in the Basin, with a focus on two-stroke smaller horsepower engines that power pump jacks associated with oil-producing wells. The data collected have indicated lower values for $NO_x$ emissions than what was reported in the 2017 oil and gas emission inventory for these engines, yet much higher emissions of VOCs. UDAQ will be evaluating this data and will be evaluating future rulemaking for engines associated with oil and gas operations that would be statewide. UDAQ will coordinate with EPA and the Tribe to encourage that rules are consistent across all regulatory jurisdictions, but ultimately any controls under EPA jurisdiction on sources in Indian Country will be determined by EPA and the Tribe.

The main pollutant of concern in the Uinta Basin is ozone, with VOCs and $NO_x$ being the actual precursor emissions that create ozone. Photochemical modeling has been a challenge in this area due to the complexity of the chemical reactions and unique geography and wintertime conditions. Therefore, it has not yet been determined what emission reductions will be the most effective to lower ozone values. However, initial thoughts are that the area is $NO_x$ limited. If this is shown to be the case, then $NO_x$ reductions will have a greater impact and as about 80% of $NO_x$ emissions in the Basin are associated with engines, UDAQ will definitely evaluate the reduction in $NO_x$ limits. As part of this evaluation, UDAQ will also keep in mind the NPS comments regarding the potential positive impacts on regional haze management. In summary, the evaluation of potentially lower VOC and $NO_x$ limits for engines associated with oil and gas production is actively in progress and Utah is working on further controlling $NO_x$ from engines for separate health standards.

### 9.C.3 USFS Feedback Summary and UDAQ Responses[181]

The USFS recognizes the emission reductions made in Utah over the past decade that have resulted in improvements in visibility at the Forest Service Class I Wilderness Areas and appreciates the working relationship among our respective staff. Overall, the USDA Forest Service found that the draft RH SIP is well organized and comprehensive. The Long-Term Strategies for this planning period appear to indicate that Forest Service Class I Wilderness Areas will continue to show visibility improvements better than the Uniform Rate of Progress

[181] See Appendix D.3 to view the full USFS RH SIP review document

(URP) through 2028, and USFS appreciates the commitment by UDEQ to evaluate progress in meeting the visibility goals during the 5-year progress reports.

40 CFR 51.308(f)(1)(vi)(B) allows states to adjust the glidepath to account for prescribed fire. The draft SIP states that no glidepath adjustment was made to account for prescribed fire emissions. The USFS encourages Utah DEQ to use the adjustment of glidepaths for the increased prescribed fire projections reflected in the “Future Fire Scenario 2” available in Product 18 of Modeling Express Tools of the WRAP TSS.

When considering the $R_x$ fire end-point adjustment, the USFS is concerned that industry or other groups could improperly argue that additional controls are not necessary to make further progress if modeling demonstrates that the Class I Area in Utah is below adjusted glidepaths, essentially arguing that the glidepath provides safe harbor from additional control requirements. The USFS believes this “safe harbor” argument is erroneous and is not supported by the Regional Haze Rule.

UDAQ Response: UDAQ appreciates the feedback from USFS as well as their work on the wildland prescribed fire adjustment. UDAQ acknowledges the visibility impacts expected future increases in wildland prescribed fire may have on Utah as well as the importance of prescribed fire for conservation. However, the impact of USFS’s glidepath adjustment is less significant for Utah’s CIAs than for those in other states. While the international and wildland prescribed fire adjustments are available for Utah’s CIA glidepaths, UDAQ is choosing to remain conservative for the purposes of this implementation period by not using them. However, this choice does not preclude the use of glidepath adjustments in future planning periods, since international and wildland prescribed fire emissions do impact Utah CIAs and are largely beyond the control of individual states and since prescribed fires are seen to be an increasingly important tool for land managers in the future.

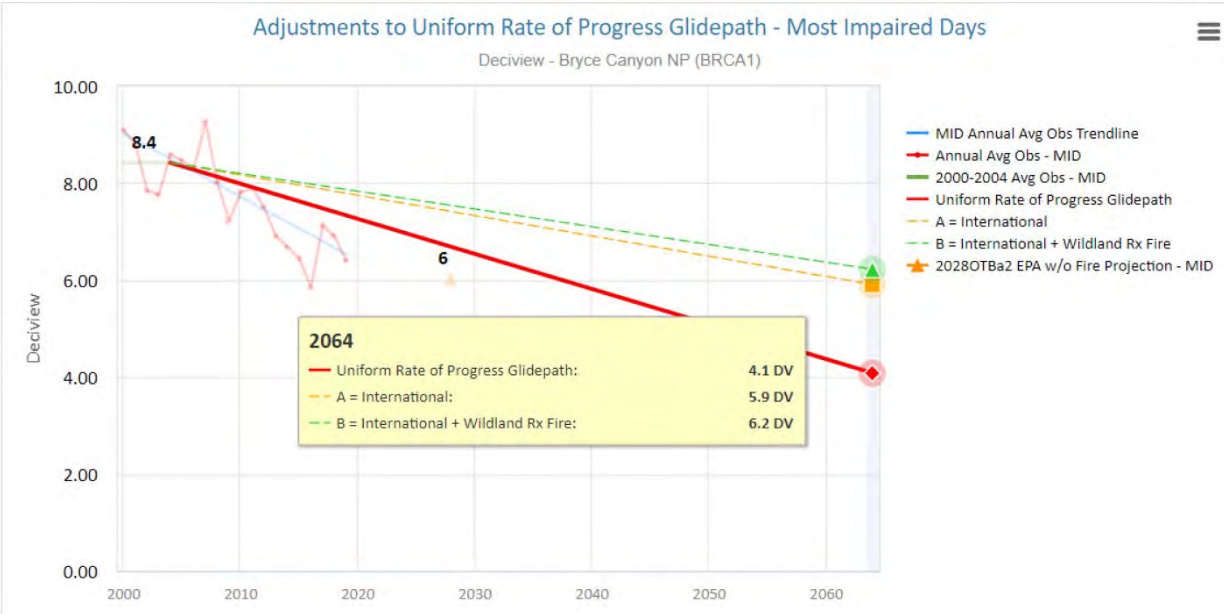


Figure 61: USFS Fire Glidepath Adjustment for Bryce Canyon

## 9.D Coordination with Indian tribes

Utah has five major tribes: the Ute, Dine' (Navajo), Paiute, Goshute, and Shoshone. There is one source in Northeast Utah where the Bonanza Power Plant is situated, but it resides in EPA jurisdiction. UDAQ sent the regional haze SIP draft to the tribes in Utah on December 8th, 2021, concurrently with submission to EPA and FLMs for a 60-day review. UDAQ has received no feedback from the tribes as of the submittal of this SIP.

## 9.E Stakeholder Outreach and Communication

In the process of developing this SIP, Utah has been in contact with the five major sources subject to a four-factor analysis for controls feasibility. Upon evaluation of the five source's original four-factor analysis submittals, Utah evaluated and requested responses from each of the sources. This correspondence is summarized in Chapter 7. Utah has had several meetings with PacifiCorp concerning the implementation of controls in its Hunter and Huntington facilities. Utah also holds regular industry stakeholder meetings and environmental advocate meetings to update these groups on Utah's regional haze planning progress and address any questions or concerns they have regarding regional haze. Throughout the second implementation period, Utah also met with other state departments for coordination including the Department of Public Utilities and the Office of Energy Development.

Table 49: Summary of Stakeholder Meetings with UDAQ

| Date | Time | Entity | Topic | Result |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| **4/27/21** | 4-5p | PacifiCorp and Wyoming | Regional Haze Pre-Meeting | Discussed possible controls and power plant planning. |
| **5/19/21** | 2-3p | Air Quality Advocates | DAQ-Utah Advocates Regional Haze Catch Up | Introduction to members of HEAL Utah, Sierra Club, and NPCA. They expect requirements for additional controls at power plants, especially Hunter and Huntington. |
| **6/23/21** | 12-1:05p | PacifiCorp | Presentation on legal risks and 4-factor evaluation | Discussed possible controls and issues with 4-factor analysis. |
| **7/7/21** | 10:30a-12p | RH Advocates Meeting | RH Update | Gave RH updates and discussed guidance vs rule issue. |
| **7/15/21** | 3:30-4:30p | DAQ, OED, DPU | RH and Power Plant Planning | Gave RH overview/update, informed them of PacifiCorp 4-factor eval, control options, and rule vs. guidance. |
| **7/19/21** | 9a | PacifiCorp | RH primer scheduling | Kirsten Merrit called about times for RH backgrounder. |
| **7/20/21** | 9:15a | PacifiCorp | RH primer scheduling | Kirsten Merrit called about invitees for RH backgrounder. |
| **10/27/21** | 8-9a | PacifiCorp | RH Follow-Up/Update | We discussed implementing new PALs for Hunter based on the emissions reductions installing SCR on Hunter 3 would have and Huntington based on their recent actuals in the 2028OTB modeling. |
| **11/3/21** | 10:30-11:30a | Air Quality Advocates | RH Update | Gave presentation with RH overview, Utah's RH history, current planning, and updated timeline for Utah's round two SIP. |
| **11/10/21** | 11a-12p | NPCA, Western Resources, & Sierra Club | RH Presentation Follow-Up | UDAQ addressed additional question resulting from the presentation given at the Air Quality Advocates Meeting. |
| **12/3/21** | 11a-12p | PacifiCorp | RH Update | Discussed control options for Hunter and Huntington. |
| **1/5/22** | 10:30-11:30a | Air Quality Advocates | RH Update | Offered to send the draft UT RH SIP to those who requested it via email. |
| **3/2/22** | 10-11:30a | Air Quality Advocates | RH Update | Offered to send the FLM comment documents to those who requested it via email. |
| **3/4/22** | 10-10:15a | PacifiCorp – Kirsten Merrit | RH Information | Offered technical responses to FLM comments concerning the Hunter and Huntington power plants |
| **3/14/22** | 2-3p | Paradox Resources | RH Planning | Met with Paradox Resources to discuss FLM comments regarding their source, updating their permit for the Lisbon Plant, and obtaining 2021 inventory data. |
| **3/17/22** | 3-4p | PacifiCorp | RH Planning | Discussed PacifiCorp's SO2 scrubbing equipment and efficiency as well as the possibility of optimization. |

## 9.F Public Comment Period

Utah's RH SIP for the second implementation period was presented to the Air Quality Board at their April 6th, 2022 meeting. The Board approved a 30-day public comment period beginning on May 1st, 2022 and ending on May 31st, 2022. Notices regarding the availability of the SIP draft will be published in the State Bulletin, posted on the UDAQ webpage and sent electronically through the RH listserv and the AQ board actions update.

## 9.G Comment Conclusions

*Section to be completed once the commenting period has ended and all comments are addressed.*

## 9.H Commitment to Further Planning

Utah will continue its regional haze planning efforts through consultation efforts, participation in regional haze work groups, and SIP development.

### 9.H.1 Process for conducting future emissions inventories and future monitoring strategy

Utah will continue to triennially update its statewide emissions inventory as dictated by the Air Emissions Reporting Requirements (AERR)[182] and Utah's Continuous Emissions Monitoring Program[183] to track regional haze progress, participate in regional haze modeling efforts, and track emissions trends.

### 9.H.2 Commitment to provide other elements necessary to report on visibility, including reporting, recordkeeping, and other measures

Utah will provide any additional reporting, recordkeeping, and other measures necessary to continue its regional haze progress deemed necessary by the EPA or the regional haze work groups Utah participates in. At this time, no such additional efforts have been identified.

### 9.H.3 Commitment to submit January 31, 2025 progress report

Under the RHR, states must submit periodic progress reports to EPA evaluating their progress towards their RPGs. The 2017 RHR amendments adjusted the next progress report due date to be submitted by January 31, 2025. Utah commits to submitting this progress report and confirms that it will contain the following elements pursuant to the RHR:[184]

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[182] 73 Fed. Reg. 76539, 76552 (Dec. 17 2008). The AERR rule can be found at https://www.epa.gov/air-emissions-inventories/air-emissions-reporting-requirements-aerr

[183] Utah Admin. Code r. R307-170.

- Status of implementation of SIP measures for RPGs in Utah's CIAs and those outside the State identified as being impacted by emissions from within the state.
- Summary of emissions reductions in Utah adopted or identified as part of the RPG strategy.
- A five-year annual average assessment of the most and least impaired days for each CIA in Utah including the current visibility conditions, difference between current conditions and baseline, and change in visibility impairment over the five-year period.

[i] See page 6 of https://gardner.utah.edu/wp-content/uploads/ERG2022-Full.pdf?x71849.

# Public Comments

# Responses to Public Comments

## Reasonable Progress Determinations:

**Commenters:** EPA, The Conservation Organizations

**Comment Summary 1:** Utah's choice of control measures during this planning period do not equate to actual reductions in emissions. UDAQ should reconsider its reasonable progress determinations.

**UDAQ Response:** UDAQ followed the RHR and guidance to identify and select sources that potentially impact in-state and out-of-state CIAs, considered feasible control options, and required four-factor analyses for these sources. UDAQ considered whether existing control measures for these facilities are needed for reasonable progress and included all necessary measures in the SIP. Please refer to Section 6.A.10 for a summary of the measures – both state and federal and existing and new – that are necessary for reasonable progress and included in the Long Term Strategy. This section shows that all measures relied upon to make reasonable progress are either federal measures or are state measures that are included in the existing Utah SIP or the round 2 SIP revisions. It also includes tables that quantify emissions reductions from existing and new measures and that compare these reductions to past (RepBase2) and projected (2028OTBa2) emissions.

**Commenters:** EPA

**Comment Summary 2:** UDAQ should clarify whether any existing measure that it is relying on to make reasonable progress is in its SIP. This includes sources that are above Utah's designated source-selection threshold of Q/d >6 but for which the state does not conduct a four-factor analysis on the basis of existing effective controls. UDAQ must adopt emissions limits based on existing controls if they are deemed necessary for reasonable progress (to the extent they do not already exist in the SIP). Measures that are necessary to make reasonable progress must be in the SIP, new measures are always necessary to make reasonable progress, and existing measures are necessary to make reasonable progress unless the state has affirmatively demonstrated that they are not necessary. If UDAQ can demonstrate that a source will continue to implement its existing measures and will not increase its emission rate, it may be reasonable for the state to conclude that the existing controls are not necessary.

**UDAQ Response:** As the guidance makes clear, Q/d thresholds are a useful tool to help identify sources for a reasonable progress determination. UDAQ applied additional screens as supported by guidance including WEP analysis, consideration of existing controls, and the technical feasibility of additional controls. Two facilities of the originally screened-in 10 have either closed or will soon close. For the source that has already closed, the KUC Power Plant, the approval order has been revised and the Title V permit was rescinded. Furthermore, $PM_{2.5}$ BACT emissions limits for this source are already included in IX.H.23 of the SIP, including SCR-level $NO_x$ limits for Unit 4. For the source that will soon close, IGS, UDAQ has included an enforceable closure date in IX.H.23 of the SIP. One of the sources, the KUC Mine and Concentrator, is dominated by emissions from non-road sources that are outside the regulatory authority of UDAQ. When those sources are removed, the Q/d for this source falls below 6 to 3.9. Additionally, this source already underwent a $PM_{2.5}$ BACT analysis, and any required controls and in-use limits are included in IX.H.23 of the SIP. The final screened-out source, the Paradox Lisbon Gas Plant, had anomalous $SO_2$ emissions levels in the original 2014 NEI-based q/d analysis. A review of recent actuals for the facility reveals 2018-2021 $SO_2$ emissions that are between 0.01 and 0.13% of 2014 values. UDAQ is working with new owners of this source to identify options for potential reductions in emission limits and, if appropriate, will update their permit accordingly. UDAQ has also clarified which existing measures it is relying on for reasonable progress and has added the existing measures for the sources Ash Grove, Graymont, Sunnyside, and US Magnesium to IX.H.23.

**Commenters:** EPA, IPSC

**Comment Summary 3:** We recommend UDAQ clearly state its determination for each source and explain whether it is including either existing or new emission limits for each source in the long-term strategy and SIP (or whether emission limits already exist in the SIP).

**UDAQ Response:** UDAQ acknowledges this comment and includes all necessary controls in the SIP. UDAQ has added a table summarizing the recent controls with emission limits that are already in Utah's SIP Section IX.H. UDAQ has clarified which existing measures it is relying on for reasonable progress which new measures have been identified in section 8.D and added to SIP Sections XX.A and IX.H.23.

**Commenters:** EPA

**Comment Summary 4:** EPA believes that rejection of $NO_x$ controls on the basis (in whole or in part) of ammonia slip, requires technical documentation that would be evaluated by EPA for its reasonableness in light of previous regional haze actions.

**UDAQ Response:** Although Sunnyside did submit general statements on both ammonia slip and the storage and transport of ammonia for use in SNCR and SCR systems, UDAQ did not take these statements into consideration when evaluating the technical and economic feasibility of $NO_x$ controls at the Sunnyside facility. Although there are some minor environmental and related costs associated with use of ammonia in $NO_x$ controls such as SCR and SNCR, these controls are well-established. In this case, the economic infeasibility of SCR or SNCR was the deciding factor.

**Commenters:** Eliza Cowie, O2 Utah

**Comment Summary 5:** We urge the DAQ and the AQB to act on the will of Utahns and step up to proactively set pollution reduction standards that will hold polluters accountable and make an outsized impact on the health of our economy and our residents.

**UDAQ Response:** The proposed SIP revision is consistent with current requirements of the regional haze program under the Clean Air Act. UDAQ notes that regional haze is a visibility program and UDAQ addresses health standards in other programs under the Clean Air Act.

**Commenters:** The Conservation Organizations

**Comment Summary 6:** UDAQ improperly concludes that no new reductions in pollution are warranted for most of Utah’s sources. The Conservation Organizations request UDAQ reconsider their RPDs.

**UDAQ Response:** UDAQ acknowledges and disagrees with this comment. Please refer to the response to comment summary 1.

**Commenters:** The Conservation Organizations

**Comment Summary 7:** UDAQ should evaluate non-power plants including manufacturing plants in its RPDs

**UDAQ Response:** UDAQ acknowledges and appreciates this comment. All four-factor analyses, supplements, and additional information documents submitted by sources are included in appendix C and D.2. Please refer to section 8.D to view UDAQ's reasonable progress determinations as well as their justification, which UDAQ stands by.

**Commenters:** The Conservation Organizations

**Comment Summary 8:** As drafted, Utah’s reasonable progress goals are based on modeling results that do not reflect the outcome of requirements in adequate Four-Factor Analyses and therefore do not meet the Regional Haze Rule requirement that the RPGs are to be based on enforceable SIP measures. UDAQ must first conduct the Four-Factor Analyses, determine measures for reducing visibility impairing emissions based on the Act's Four-Factor Analysis and then use the results to develop proposed revisions to the RPGs.

**UDAQ Response:** UDAQ has followed EPA guidance in the development of this SIP and required a four-factor analysis from all sources identified through UDAQ's Q/d analysis and additional screening. In the proposed SIP, UDAQ did rely upon uncertainty regarding the future utilization of the Hunter and Huntington power plants to make a determination that additional $NO_x$ controls are not cost-effective. The agency then proposed a mass-based limit based upon the WRAP OTB2028a2 $NO_x$ emissions projections for the two plants in an effort to keep the plants from backsliding on emissions progress. In the final SIP, UDAQ instead establishes annual mass-based limits for both plants that ensure that these facilities cannot operate at levels at which SNCR and SCR would be cost-effective as determined by a revised cost-effectiveness evaluation of physical controls that utilizes the new limits as the 2028 emissions baseline. The final RPGs are in fact enforceable SIP measures as the new limits are listed in IX.H.23.

**Commenters:** The Conservation Organizations

**Comment Summary 9:** The Utah Proposed SIP fails to meet the intent, purpose, and direction of the Clean Air Act.

**UDAQ Response:** UDAQ notes that this is a general comment made in the conclusion and summarizes the previous specific comments made by the Clean Air Advocates. The agency has responded to each of the Clean Air Advocates' specific comments in this response to comments document. These responses explain how the SIP satisfies the requirements of the Clean Air Act.

**Commenters:** Jim Ireland, Superintendent Bryce Canyon National Park

**Comment Summary 10:** NPS has an affirmative legal responsibility to protect clean air and national parks. Statutory responsibility requires them to protect all units from the harmful effects of air pollution. NPS technical team has identified and recommended significant opportunities to improve the draft and make more rapid progress.

**UDAQ Response:** UDAQ appreciates this comment as well as the valuable input and consultation efforts of the National Parks Service.

**Commenters:** Jeff Bradybaugh, superintendent of Zion National Park

**Comment Summary 11:** NPS continues to recommend requiring cost effective measures to reduce haze forming pollutants identified through the four-factor analysis. NPS encourages Utah to take timely opportunities to reduce emissions from Hunter and Huntington. NPS recommends

$SO_2$ scrubber upgrades and SCR controls for both. NPS estimates scrubber upgrades could reduce $SO_2$ emissions by 3,300 tons per year at $400-$900 per ton. SCR could reduce $NO_x$ emissions by 12,300 tons per year for $6,000 per ton or less. Utah SIP falls short of securing the most significant emission reductions available. Co-benefits of controls would also include addressing ozone and fine PM in nonattainment areas and nitrogen deposition affecting sensitive Park ecosystems.

**UDAQ Response:** UDAQ appreciates this comment as well as the valuable input and consultation efforts of the National Parks Service. These comments were included in NPS's public comment period submission, all of which are addressed individually within this document.

## Long Term Strategy:

**Commenters:** EPA

**Comment Summary 12:** The list of LTS factors in section 6.A does not include "must include the emission reduction measures that are necessary to make reasonable progress as determined through consideration and application of the four statutory factors.

**UDAQ Response:** This requirement has been added to section 6.A.

**Commenters:** IPSC, PacifiCorp

**Comment Summary 13:** UDAQ should emphasize its discretion and flexibility in RH planning under the RHR and CAAs by emphasizing that EPA's 2021 Guidance was released late in the planning process after completion of much of WRAP's modeling. Divergence from EPA's 2021 Guidance should not be the sole basis EPA makes its SIP review.

**UDAQ Response:** UDAQ acknowledges this comment and agrees with its discretion to develop SIPs under the applicable laws and regulations.

**Commenters:** IPSC

**Comment Summary 14:** UDAQ appropriately developed its LTS and RPGs. IPSC encourages UDAQ to include a summary of how it developed its LTS and RPGs consistent with the regulations and guidance.

**UDAQ Response:** UDAQ acknowledges this comment and has included a summary of how it developed its long term strategy and reasonable progress goals consistent with the regional haze rule and the guidance in section 6.A.10.

## URP Glidepath:

**Commenters:** EPA

**Comment Summary 15:** The URP glidepath is not a safe harbor and a CIA's position underneath the glidepath does not justify a decision not to require controls.

**UDAQ Response:** UDAQ acknowledges this comment and notes that we state in the proposed SIP that a CIA's position below the glidepath is not "safe harbor" from emissions controls. Instead, we base our control determinations on the four-factor analyses for the selected sources and -- where appropriate based upon balancing the four-factors -- select controls for inclusion in the SIP. We address this issue on a source-specific basis elsewhere in our response to comments.

**Commenters:** PacifiCorp and IPSC

**Comment Summary 16:** UDAQ should use the available adjustments to the URP glidepaths of UT's CIAs because non-anthropogenic sources are a large part of their visibility impairment. The Utah SIP fails to fully explain the extent to which non-U.S. anthropogenic emissions (i.einternational anthropogenic emissions) currently impacts light pollution in Class I areas, and how much these emissions will impact visibility in the future. $SO_2$ emissions from international sources in Zion National Park will contribute 3 to 4 times greater light pollution than U.S. sources in 2028, the percentages are not provided nor are the graphs adequately explained.

**UDAQ Response:** UDAQ appreciates and acknowledges this comment, but maintains its decision that making international and prescribed fire adjustments is unnecessary for the second planning period. The proposed SIP takes a conservative approach to demonstrating reasonable progress, while affirming Utah's prerogative to make such adjustments in future planning periods consistent with the regional haze rule (both current and future).

## Cost Threshold:

**Commenters:** The Conservation Organizations, National Parks Conservation Association, NPS

**Comment Summary 17:** UDAQ should establish a cost-effectiveness threshold for reasonable progress that is in line with other state thresholds so UDAQ's RPDs are not arbitrary.

**UDAQ Response:** EPA guidance states the following about the use of thresholds: "A state may find it useful to develop thresholds for single metrics to organize and guide its decision-making. As the Ninth Circuit explained in NPCA v. EPA, 788 F.3d at 1142, the Regional Haze Rule does not prevent states from implementing “bright line” rules, such as thresholds, when considering costs and visibility benefits. However, the state must explain the basis for any thresholds or other rules[1]. If a state applies a threshold for any particular metric to remove control measures from further consideration before all other relevant factors are considered, it should explain why its selected threshold is appropriate for that purpose, i.e., why its application is consistent with the requirement to make reasonable progress." Regarding cost per ton thresholds, the 2019 guidance goes on to state: "If a state applies a threshold for cost/ton to evaluate control measures, we recommend that the SIP explain why the selected threshold is appropriate for that purpose and consistent with the requirement to make reasonable progress. As explained below, a cost/ton metric and comparisons to the cost/ton values for measures that have been previously implemented may or may not be useful in determining the reasonableness of compliance costs." UDAQ maintains that a "bright line" threshold is unnecessary and that the use of one detracts from consideration of the remaining three reasonable progress factors and the agency's discretion in balancing all four factors in making its determination. That said, in instances where UDAQ found a control not to be cost-effective, the cost/ton estimates for rejected controls were in line with cost-effectiveness thresholds and/or ranges used in other states.

**Commenters:** PacifiCorp, IPSC, UMA, UPA

**Comment Summary 18:** Defining a cost-effectiveness threshold is neither appropriate nor necessary for assessing reasonable progress given past EPA and UDAQ decisions. Controls determinations must depend on the four-factor analysis.

**UDAQ Response:** UDAQ appreciates and concurs with this comment.

## *Mass-Based vs. Rate-Based Limits:*

**Commenters:** NPS and The Conservation Organizations

**Comment Summary 19:** Rate-based limits achieved through emissions controls are more appropriate than rate-based limits in that they are more protective and require actual emissions reductions.

**UDAQ Response:** UDAQ acknowledges this comment. UDAQ utilizes both mass- and rate-based limits in the final SIP, both of which are consistent with the regional haze rule and guidance. For Hunter and Huntington power plants, UDAQ conducted a four-factor analysis which found additional physical $NO_x$ controls (and their associated rate-based limits) not to be cost-effective at the plant utilization and emissions levels that result from a 2028 mass-based limit. However,

[1] See 40 CFR 51.308(f)(2)

UDAQ does retain the rate-based limits for existing $NO_x$ and $SO_2$ controls at these plants in the final SIP.

**Commenters:** The Conservation Organizations

**Comment Summary 20:** UDAQ must impose a rate-based $NO_x$ limit in terms of lb/MMBtu because EPA states that, when a state “has determined that a technology-based measure is necessary to make reasonable progress,” emission limits should be expressed in a rate-based format (such as pounds of pollutant per throughput).

**UDAQ Response:** UDAQ acknowledges and disagrees with this comment. For Hunter and Huntington power plants specifically, UDAQ did not determine that additional $NO_x$ controls are necessary to make reasonable progress. In general, page 44 of the 2019 EPA Guidance states that "...a mass-based emission limit may be reasonable because it could relieve the source of the requirement to install the control if it manages its operating level strategically". The 2019 EPA Guidance does not state that emissions limits must be expressed in a rate-based format.

**Commenters:** The Conservation Organizations

**Comment Summary 21:** If mass-based emissions limits are used, the regulatory language should also specify recordkeeping on the amount of fuel used per month and make clear that compliance with the 12-month rolling total emission limit shall be calculated based on the fuel use or heat input over that time period.

**UDAQ Response:** UDAQ disagrees with this comment. Heat input is not a necessary component of measuring or determining compliance with a mass-based emission limit.

**Commenters:** PacifiCorp

**Comment Summary 22:** Massed-based emissions limits provide PacifiCorp flexibility, can be implemented quicker than controls, reduce CO2 emissions as well, and work well for the remaining useful lives of the Utah Units.

**UDAQ Response:** UDAQ acknowledges and concurs with this comment.

**Commenters:** UPA/UMA

**Comment Summary 23:** UPA and UMA do not support requiring limits to be either mass-based limits or rate-based limits; UDAQ should have the flexibility to determine the type of limit most appropriate for any individual source.

**UDAQ Response:** UDAQ acknowledges and concurs with this comment.

## Oil and Gas Area Sources:

**Commenters:** EPA, NPS, The Conservation Organizations, National Parks Conservation Association

**Comment Summary 24:** UDAQ should evaluate upstream oil and gas $NO_x$ measures under the state's jurisdiction or provide a technical basis, such as a derived Q/d value, as part of its justification.

**UDAQ Response:** UDAQ acknowledges that oil and gas extraction in the Uinta Basin produces emissions that may affect visibility in CIAs. The oil and gas wells are spread over a very large area making a traditional Q/d analysis impossible, and the airshed is regulated by both the State (on state land) and EPA (on tribal land). As discussed in the SIP, approximately 80% of oil and gas source emissions are under EPA regulatory jurisdiction. The Uinta Basin is currently a marginal ozone nonattainment area, and UDAQ has been working diligently since 2015 to reduce oil and gas emissions, including promulgation of 11 rules, and subsequent rule amendments to improve these rules. EPA has yet to publish the final Federal Implementation Plan that will catch up with Utah oil and gas regulations. There have been a number of studies in the basin over the last several years that have led to a much better understanding of the oil and gas emissions, and the inventory has significantly improved as a result. For example, a recent pump jack engine stack test study showed 52% less $NO_x$ (and much higher VOCs) than was previously in the inventory. UDAQ does not consider the WRAP inventories to be adequate for any type of Q/d emissions analysis. UDAQ will continue to address oil and gas emissions in the Uinta Basin through the health-based standards, in cooperation with EPA. Because of the large number of stakeholders involved, overlapping jurisdictions, and uneven existing regulatory requirements among jurisdictions, developing new reasonable progress controls beyond those already under development for ozone is unrealistic during the SIP development timeframe.

## Non-RH Pollution Controls:

**Commenters:** EPA

**Comment Summary 25:** Utah must not rely solely on the non-regional haze air pollution control programs to automatically reject potentially cost-effective and otherwise reasonable controls during this second planning period.

**UDAQ Response:** UDAQ does not rely solely upon non-regional haze air pollution control programs to automatically reject potentially cost-effective and otherwise reasonable controls in the SIP. Instead, the agency considered control options at each screened-in source on a case-by-case basis, and -- where additional controls are rejected -- UDAQ provides the basis for said rejection. Please refer to Section 6.A.10 for a summary of the measures – both state and federal and existing and new – that are necessary for reasonable progress and included in the Long Term Strategy. This section shows that all measures relied upon to make reasonable progress are either federal measures or are state measures that are included in the existing Utah SIP or the round 2 SIP revisions. It also includes tables that quantify emissions reductions from existing and new measures and that compare these reductions to past (RepBase2) and projected (2028OTBa2) emissions.

**Commenters:** The Conservation Organizations

**Comment Summary 26:** UDAQ's anticipated additional emissions reductions from "Ongoing Pollution Control Programs" are neither justified nor secured by enforceable SIP measures. UDAQ identifies multiple federal and state control programs aimed at reducing emissions across various sectors. UDAQ fails to provide the details and quantify emission reductions from these ongoing programs, and lacking this required information, UDAQ cannot take credit for "other programs" that are unsupported and not quantified.

**UDAQ Response:** Considering emissions reductions due to ongoing air pollution control programs is part of the Long-Term Strategy requirements under Subsections 51.308(d)(3) and (f)(2) of the Regional Haze program requirements. Section 6.A.5 was written to satisfy these requirements and only includes efforts done by UDAQ. UDAQ did not use these emissions reductions when making the reasonable progress determinations for the second implementation period of Utah's regional haze program. Please refer to Section 6.A.10 for a more thorough summary of the measures – both state and federal and existing and new – that are necessary for reasonable progress and included in UDAQ's LTS. This section shows that all measures relied upon to make reasonable progress are either federal measures or are state measures that are included in the existing Utah SIP or the round 2 SIP revisions. It also includes tables that quantify emissions reductions from existing and new measures and that compare these reductions to past (RepBase2) and projected (2028OTBa2) emissions.

## Source Selection:

**Commenters:** EPA

**Comment Summary 27:** If emissions data prior to the 2017 NEI was used, we request that UDAQ analyze and present updated 2017 emissions information to show that there are no additional sources that should have been selected and analyzed for controls, or for changes to its selected sources. UDAQ should also indicate whether any additional sources would be screened-in through Q/d by using 2017 or later NEI data.

**UDAQ Response:** UDAQ re-calculated the Q/d thresholds of its major sources using 2017 NEI data to ensure that additional sources did not exceed a Q/d of 6 and found that no additional sources would be screened-in using the newer data. This information can be found in section 7.A.1.

**Commenters:** IPSC

**Comment Summary 28:** Utah's Approach to Source Selection is Reasonable and Consistent with EPA Regulations and Guidance. Utah selected sources for further review of controls based on application of a Q/d threshold > 6, despite WRAP's recommendation to use a threshold of 10 and applies a "secondary screening process," to further assess the reasonableness of controls

**UDAQ Response:** UDAQ appreciates and concurs with this comment.

## Q/d Analysis:

**Commenters:** The Conservation Organizations

**Comment Summary 29:** UDAQ originally identified 10 sources for consideration in the emission control analyses, but only six sources were required to conduct a full review of emissions reducing measures in its implementation plan.

**UDAQ Response:** This statement is correct. As documented in the SIP, 10 sources were originally screened-in for further controls consideration using a Q/d threshold of 6 or greater, which is more stringent than WRAP's suggested threshold of 10. UDAQ then conducted a secondary screen, taking into account recent control determinations for other programs, plant closures (past or future), and other considerations. Four out of the original 10 sources were screened-out as a result of this secondary screening: 1. KUC Mine and Concentrator (recent BACT and vast majority of emissions from non-road sources); 2. KUC Power Plant (facility closure and rescinding of Title V permit, limits already in IX.H.23); 3. Lisbon Gas Plant (anomalous $SO_2$ emissions during 2014 screen year, subsequent plant idling/ownership changes, and dramatically lower $SO_2$ emissions from 2017-2021, resulting in Q/d values <6); and 4. Intermountain Generation Station (planned closure of coal-fired units in 2025, establishment of enforceable closure date in the SIP). A Q/d analysis, while helpful, does not take into consideration trajectory or air chemistry, nor past or future changes in operation. EPA states that the Q/d metric is a "simple surrogate metric"[2] that is "a less reliable indicator of actual visibility impact" and "therefore, it is recommended that use of this technique be limited to

[2] See 2019 EPA Guidance at 10

source selection for the purpose of developing a list of sources for which a state may conduct a four-factor analysis."[3] As such, it is -- at best -- a first step in the process of source selection, and states may take into account other factors in determining which sources should be required to complete further analyses.

**Commenters:** The Conservation Organizations

**Comment Summary 30:** UDAQ should have conducted a four-factor analysis for the Holcim Devil's Slide facility. UDAQ shouldn't have excluded this facility based on their voluntary proposal to install SNCR. UDAQ should enforce SNCR installation in the SIP, set a $NO_x$ limit according to the proposed SNCR control and evaluate the cost-effectiveness of installing catalytic ceramic filters as well as ammonia injection in the existing baghouse.

**UDAQ Response:** UDAQ disagrees with this comment, UDAQ did not exclude the Holcim Devil's Slide facility on any basis other than its maximum Q/d value of 5.19 for Canyonlands National Park which is below UDAQ's threshold of 6.

## Four-Factor Analyses:

**Commenters:** The Conservation Organizations

**Comment Summary 31:** UDAQ failed to provide the "Four- Factor Analysis Summary" on page 140 of the Proposed SIP and instead only included a statement that said "[a]dd 4-factor analysis summary matrix to show that each have been addressed for all sources[.]" To comply with public notice and comment requirements, UDAQ must provide the public with a complete Proposed SIP. UDAQ should reissue a revised and completed draft for public comment.

**UDAQ Response:** UDAQ considered adding a section 7.D with a four-factor analysis summary and made the final decision not to. Section 7.D was erroneously left in the draft and has now been removed. This proposed section would not have included any new information not already included in the draft SIP. The draft SIP proposed to the Air Quality Board passed for public comment, the purpose of which was to inform the public and gather comments such as this one was fulfilled.

**Commenters:** NPS, The Conservation Organizations

**Comment Summary 32:** UDAQ should correct all cost-effectiveness analyses in accordance with EPA recommended methods as current analyses generally inflate the cost of control.

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[3] See 2019 EPA Guidance at 13

**UDAQ Response:** UDAQ has made revisions and included supplements for multiple sources' four-factor analysis. Please review all of UDAQ's responses to public comments to review these updates to the SIP. UDAQ has reviewed all source's four-factor analysis submittals alongside their supplemental information and found the resulting information accurate and sufficient for determining measures necessary for reasonable progress in this implementation period.

**Commenters:** Pacificorp

**Comment Summary 33:** Utah's cost analysis methods are consistent with the regional haze program's goals and guidance.

**UDAQ Response:** UDAQ appreciates this comment.

**Commenters:** The Conservation Organizations

**Comment Summary 34:** UDAQ's four-factor analyses are legally deficient. The state has a duty to conduct a "robust" analysis of potential reasonable progress controls, and must "document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I Federal area it affects." If a source prepares a flawed, incomplete, or undocumented Four-Factor Analysis, the state must either require the source to make the necessary corrections or make the corrections itself and ensure that the Four-Factor Analyses is accurately and completely documented before the start of the public notice and comment period.

**UDAQ Response:** UDAQ notes that this comment does not identify any specific problems, so the agency will respond to each of the Clean Air Advocate's specific comments regarding the four-factor analyses within this SIP revision.

## Ash Grove:

**Commenters:** The Conservation Organizations, National Parks Conservation Association

**Comment Summary 35:** UDAQ should require actual, measurable emissions reductions from the Leamington Cement Plant

**UDAQ Response:** UDAQ acknowledges this comment. A review of the Leamington Cement Plant's actual and allowable emissions concluded that the current $NO_x$ limits reflect a reasonable level of safety margin relative to actual emissions rates. As a result, UDAQ has determined that no additional controls were economically feasible.

**Commenters:** The Conservation Organizations, NPS

**Comment Summary 36:** Ash Grove's four-factor analysis should be updated with further evaluation of the cost/ton and $NO_x$ removal efficiency of an SNCR control, information on the type of fuel used and tons of clinker in 2019, as well as the installation of ceramic catalytic filtration bags in the existing baghouse.

**UDAQ Response:** UDAQ is satisfied with the Leamington Plant's SNCR system's ability to operate in the 2.5-2.6 lb. $NO_x$/ton clinker range and agrees with Ash Grove that neither additional solution nor the addition of catalytic ceramic filtration bags will significantly increase control efficiency.

**Commenters:** The Conservation Organizations

**Comment Summary 37:** UDAQ must reconsider imposing control measures on $SO_2$ emissions from the cement kiln to ensure that emissions do not increase from the current baseline emissions of 8.0 tons per year to the allowable potential to emit 192.5 tons per year.

**UDAQ Response:** UDAQ disagrees with this comment, believes the Leamington Cement Plant is well controlled, and stands by its determination not to require new control measures for this facility in this implementation period. UDAQ has included the Leamington Cement Plant's existing emissions limits as part of the controls necessary to make reasonable progress which can be found in section 8.D and IX.H.23 in appendix A.

## Graymont:

**Commenters:** The Conservation Organizations, National Parks Conservation Association

**Comment Summary 38:** UDAQ should identify and review all of the emissions units at the Graymont Western Cricket Mountain Plant and the units' actual and allowable emissions through an emissions inventory and require $NO_x$ and $SO_2$ emissions reductions.

**UDAQ Response:** UDAQ acknowledges this comment. A review of Graymont's actual and allowable emissions was conducted as part of reviewing the four-factor analysis submission for the company. As a result of that analysis, UDAQ determined that no additional controls were economically feasible. UDAQ has included the Cricket Mountain Plant's existing emissions limits as part of the controls necessary to make reasonable progress which can be found in section 8.D and IX.H.23 in appendix A.

**Commenters:** The Conservation Organizations, NPS

**Comment Summary 39:** UDAQ should require Graymont Western to install SNCR and the use of catalytic ceramic filtration bags in the existing baghouse.

**UDAQ Response:** UDAQ agrees with Graymont's amendments to their four-factor analysis stating that the LNA SNCR technology is proprietary and not unconditionally commercially available for their use. Based on Graymont's four-factor analysis, UDAQ believes the Cricket Mountain Plant is well controlled and the addition of catalytic ceramic filtration bags would not significantly reduce their $NO_x$ emissions.

## Sunnyside:

**Commenters:** EPA, The Conservation Organizations

**Comment Summary 40:** Provide documentation from the source as to the infeasibility of $SO_2$ emissions controls based on water rights

**UDAQ Response:** Sunnyside provided further details on the infeasibility of expanding emission controls based on water usage. Indeed, Sunnyside's statement about the lack of water availability is representative of over a decade of data and studies for the availability of water for use onsite for existing power plant operations. On average the plant has been utilizing 668 gallons per minute (gpm) for cooling tower makeup whereas the plant was designed for an average of 680 gpm through the year. Sunnyside is only able to sustain plant operations with this water usage through efficient water use, timing maintenance shutdowns, and equipment's operation/shutdown. Sunnyside has provided documentation on the limits of available water, which can be found in appendix D.2I.

**Commenters:** EPA, NPS, The Conservation Organizations

**Comment Summary 41:** Sunnyside's four-factor analysis indicates that $SO_2$ and $NO_x$ controls are not cost effective or feasible. Use NPS' information and data on DSI feasibility to update the remaining useful life assumptions and 7% interest rate in Sunnyside's four-factor analysis and consider DSI as a cost effective control

**UDAQ Response:** UDAQ notes that Sunnyside revised their four-factor analysis with supplemental information on May 27, 2022. In the revised submission, the company performed a second cost analysis using a 30-year remaining useful life. The 7% interest rate was also further justified with site specific details and supporting documentation. UDAQ has accepted this revised submission and agrees with the company's conclusions. The inclusion of dry sorbent injection is not warranted at this facility.

**Commenters:** The Conservation Organizations, National Parks Conservation Association

**Comment Summary 42:** UDAQ must require actual, measurable emissions reductions from Sunnyside

**UDAQ Response:** UDAQ stands by its reasonable progress determination that additional control measures from Sunnyside are neither technically feasible nor cost effective. Additionally, UDAQ has included Sunnyside's existing emission limits as measures necessary for reasonable progress which have been added to IX.H.23 and section 8.D.

**Commenters:** The Conservation Organizations

**Comment Summary 43:** Sunnyside's four-factor analysis should not include property taxes and insurance

**UDAQ Response:** UDAQ notes that Sunnyside revised their four-factor analysis with supplemental information on May 27, 2022. In the revised submittal, the company included additional information pertaining to the inclusion of taxes and insurance - which are in-line with the Control Cost Manual. UDAQ has accepted this supplemental information. No changes are necessary in the revised four-factor analysis.

**Commenters:** The Conservation Organizations

**Comment Summary 44:** Sunnyside's four-factor analysis doesn't have proper justification for dismissing DSI on the basis of space

**UDAQ Response:** UDAQ notes that Sunnyside revised their four-factor analysis with supplemental information on May 27, 2022 (located in appendix D.2.I). In the revised submission, the company further justified the technical and economic cost considerations for elimination of DSI at the facility. Both physical space and air flow mechanics are among the technical difficulties shown by the company in this revised submission. UDAQ agrees with the issues raised by the company and agrees with the conclusion that DSI is not economically feasible for this facility.

**Commenters:** The Conservation Organizations

**Comment Summary 45:** Sunnyside's four-factor analysis improperly used a 1.3 retrofit cost factor

**UDAQ Response:** UDAQ notes that Sunnyside revised their four-factor analysis with supplemental information on May 27, 2022. In the revised submission, the company further justified the use of a retrofit factor of 1.3. Specifically, site access and infrastructure, incorporation of existing structural elements, and engineering redesigns, are all valid justifications for an elevated retrofit factor. UDAQ has accepted the retrofit factor used by the company in this revised analysis.

**Commenters:** The Conservation Organizations

**Comment Summary 46:** Sunnyside's four-factor analysis does not properly justify the need to replace its baghouse. If the baghouse needs replacement, it should not be included in the cost-effectiveness calculations of $SO_2$ controls.

**UDAQ Response:** Commenter misstates the extent and intent of Sunnyside's claim. The company does not state that the baghouse has reached the end of its useful life and would need to be replaced regardless of whether regional haze controls are imposed. Rather, the company stated that "A dry scrubbing control system will require additional particulate loading in the flue gas, thereby increasing the volume to be handled which will put a burden on the existing baghouse system and result a [sic] larger baghouse control system to capture PM emissions exiting from the stack." This was further clarified in the company's revised four-factor analysis from May 27, 2022 which included: "Even if re-engineering of the duct work allowed the existing baghouse to be used, it is likely that the flow patterns produced by the CDS/CFBS would disrupt the flow through the plenum of the baghouse thereby redirecting air flow and eliminating the distribution of air evenly across the compartments." The company has merely stated that the existing baghouse system is most likely insufficient for the additional particulate loading generated by further $SO_2$ controls. UDAQ is in agreement with this conclusion.

**Commenters:** The Conservation Organizations

**Comment Summary 47:** Sunnyside's four-factor analysis improperly double counts installation costs by using a projected equipment cost of $66,600,000 for a CDS scrubber.

**UDAQ Response:** In Sunnyside’s Response to National Park Service questions on Sunnyside Cogeneration Associates Four Factor Analysis – Dry Sorbent Injection Considerations, it was acknowledged that the exact total installed equipment cost for a CDS is highly variable and cannot be confirmed without site specific quotes and engineering. As a result, Sunnyside provided three alternative economic analyses in a subsequent response to UDAQ’s questions on the original four-factor analysis submittal, which varied the total installed equipment costs: average, minimum, and maximum. The minimum cost analysis presented by Sunnyside addresses the Clean Air Advocates comments as it includes only EPA established installation costs and appropriate retrofit factors. UDAQ has reviewed the supplemental information provided by Sunnyside and accepted this additional information.

**Commenters:** The Conservation Organizations

**Comment Summary 48:** Sunnyside's four-factor analysis assumed 74% $SO_2$ removal efficiency with a CDS when it can achieve up to 98% removal

**UDAQ Response:** Sunnyside supplemented their original four-factor analysis with additional information on May 27, 2022. In the revised submission, the 74% $SO_2$ removal efficiency was further explained by comparing the expected emission rate after controls, using similarly controlled facilities as a baseline, with current emission levels. The 74% therefore represents an additional removal efficiency, and not the removal efficiency from an uncontrolled state.

**Commenters:** The Conservation Organizations

**Comment Summary 49:** Sunnyside's four-factor analysis improperly assumed too high of an annual coal throughput of 883,413,174 lbs/coal/yr

**UDAQ Response:** The coal throughput utilized in the SCR and SNCR cost analysis presented by Sunnyside represented a maximum annual throughput between 2015 and 2019. This reflects actual coal properties rather than high heating value. If the theoretical maximum coal throughput were utilized, which is representative of the maximum heat input capacity, 8,760 hours of operation per year, and high heating value, a total of 867,081,448 pounds of coal could be used in a calendar year. The use of this coal throughput increases the cost per ton removed by \$130 per ton for SNCR and \$231 per ton for SCR for a total cost removed of \$9,398 and \$13,676 per ton of $NO_x$, respectively. UDAQ has reviewed and agrees with these revised calculations.

**Commenters:** NPS

**Comment Summary 50:** Request for public review opportunity of Sunnyside's supplemental documents and four-factor analysis updates

**UDAQ Response:** UDAQ sent Sunnyside's supplemental documents to NPS on 4/21/22, 6/7/22, and 6/26/2022 for their review. These documents can also be found in appendix D.2.

**Commenters:** NPS

**Comment Summary 51:** NPS agrees with Sunyside's 7% interest rate

**UDAQ Response:** UDAQ acknowledges this comment.

**Commenters:** Sunnyside

**Comment Summary 52:** After a complete review of possible DSI control technologies, the only add-on DSI configuration considered potentially technically feasible is the CDS/CFBS configuration. As a result, this technology was the only technology further evaluated. Based on Sunnyside's calculations, Sunnyside anticipates that the installation of a CDS/CFBS system could achieve a theoretical maximum of 74% further reduction of $SO_2$, or further removal of 319 ton/year compared to these similar sources. Sunnyside anticipates a cost per ton of $SO_2$ removed between $27,889/ton removed and $118,553/ton removed for this control.

**UDAQ Response:** UDAQ appreciates and concurs with this comment.

**Commenters:** Sunnyside

**Comment Summary 53:** The existing baghouse is essential to the design and effectiveness of a CDS/CFBS unit. As demonstrated by photos provided by Sunnyside, there is insufficient space to install a CDS/CFBS between the boiler and existing baghouse

**UDAQ Response:** UDAQ appreciates and concurs with this comment.

**Commenters:** Sunnyside

**Comment Summary 54:** Sunnyside's Title V permit already enforces $SO_2$ limits through a CEMS

**UDAQ Response:** UDAQ appreciates and concurs with this comment.

## PacifiCorp:

**Commenters:** EPA

**Comment Summary 55:** UDAQ cites uncertain future utilization at Hunter and Huntington to justify not requiring SCR but does not adequately justify why it is unreasonable to reduce emissions based on the sources' current operation.

**UDAQ Response:** UDAQ indeed cites uncertainty about the future utilization of Hunter and Huntington, but also includes strong evidence that utilization of these facilities is likely to decrease in the future, potentially eroding the cost-effectiveness of additional physical emission control installation. In the final SIP, UDAQ further augments the evidence that future utilization of Hunter and Huntington is likely to decline. In addition, UDAQ establishes enforceable plantwide annual mass-based $NO_x$ emissions limits in an effort to reduce uncertainty regarding future utilization. The agency provides a revised cost-effectiveness analysis of SNCR and SCR at the utilization/emission levels imposed by these mass-based limits and finds that the installation of physical controls is not cost-effective at or below those utilization/emission levels.

**Commenters:** EPA, The Conservation Organizations, City of Moab, Grand County Commission, Dr. Paula Decker, National Parks Conservation Association (NPCA), Alex Veilleux (HEAL Utah), 657 individuals

**Comment Summary 56:** UDAQ should consider revising its reasonable progress determinations for Hunter and Huntington to require controls which will ensure real emissions reductions rather than capping allowable annual emissions above recent actuals for $NO_X$ and $SO_2$.

**UDAQ Response:** Under the regional haze rule, the reasonableness of any incremental pollution reduction from the Hunter and Huntington power plants is determined using a four-factor analysis. In the proposed SIP, UDAQ evaluated potential controls based upon the PacifiCorp's four-factor submittal and determined that additional physical controls (e.g., SCR, SNCR) are not cost-effective under likely future plant utilization. In the final SIP, UDAQ establishes enforceable plantwide annual mass-based $NO_x$ emissions limits in an effort to reduce uncertainty regarding future utilization. The agency provides a revised cost-effectiveness analysis of SNCR and SCR at the utilization/emission levels imposed by these mass-based limits and finds that the installation of physical controls is not cost-effective at or below those utilization/emission levels.

**Commenters:** EPA

**Comment Summary 57:** PacifiCorp's four-factor analysis should provide additional support for PacifiCorp's $SO_2$ scrubber efficiency.

**UDAQ Response:** UDAQ solicited additional information from PacifiCorp regarding $SO_2$ scrubbing efficiency. As they note in their comments, the scrubbing efficiencies they included in their four-factor analysis were an artifact of their RPEL calculation methodology and are not representative of levels that can be achieved without significant additional capital expenditures. PacifiCorp provided additional clarification on this topic in a letter found in appendix C.3.D. UDAQ evaluated $SO_2$ emission rates from all units at both plants and found them to vary between approximately 0.06 and 0.10 lb/MMBtu over the four-factor analysis period, which is in line with the scrubber system design specifications and supplier guaranties. Additional detailed information would be required to further assess the potential for incremental efficiency improvements using the existing controls. However, the 2019 Guidance suggests that such an evaluation is not necessary and is unlikely to be cost-effective. EPA believes it may be reasonable for a state not to select a source for further analysis under certain scenarios, including:

> *For the purpose of SO2 control measures, an EGU that has add-on flue gas desulfurization(FGD) and that meets the applicable alternative SO2 emission limit of the*

*2012 Mercury Air Toxics Standards (MATS) rule47 for power plants. The two limits in the rule (0.2 lb/MMBtu for coal-fired EGUs or 0.3 lb/MMBtu for EGUs fired with oil-derived solid fuel) are low enough that it is unlikely that an analysis of control measures for a source already equipped with a scrubber and meeting one of these limits would conclude that even more stringent control of SO2 is necessary to make reasonable progress.*

UDAQ has included the existing $SO_2$ rate-based limits for Hunter and Huntington in IX.H.23 to ensure that these plants continue implementing their $SO_2$ scrubbing measures and that their emission rates will not increase in the context of the round 2 regional haze SIP.

**Commenters:** EPA, NPS, The Conservation Organizations

**Comment Summary 58:** Scrubber systems are expected to achieve a control effectiveness of 95% or higher, there may be opportunities to further increase PacifiCorp's control efficiency.

**UDAQ Response:** UDAQ disagrees that all scrubber systems are expected to achieve a control effectiveness of 95% or higher. An analysis of Hunter and Huntington's SO rantes reveals that the existing systems are operating within their design specifications and supplier guarantees. UDAQ agrees with PacifiCorp's comments that the Utah units' $SO_2$ scrubbers all have control efficiencies that surpass 90%, but cannot achieve lower $SO_2$ emission rates. To achieve dramatically improved $SO_2$ rates, costly new capital expenditure would be required.

**Commenters:** EPA, NPS

**Comment Summary 59:** PacifiCorp's proposal for RPEL's indicates that $SO_2$ emissions could be reduced to 0.032 lb/MMBtu at a cost of $301,000. UDAQ should consider these reductions in PacifiCorp's four-factor analysis

**UDAQ Response:** As noted in PacifiCorp's comments, the scrubbing efficiencies they included in their four-factor analysis were an artifact of their RPEL calculation methodology and are not representative of levels that can be achieved without significant additional capital expenditures. PacifiCorp provided additional clarification on this topic in a letter found in appendix C.3.D.

**Commenters:** EPA, The Conservation Organizations

**Comment Summary 60:** UDAQ should either adopt a utilization limit corresponding to the assumption of future use or perform a four-factor analysis using recent historical utilization. This analysis is speculative and the state should support its control determination based on an assumption of projected 2028 $NO_X$ emissions (an actual average of 2015-2019 historical emissions). Less utilization is only relevant if joined by a requirement to limit capacity to the rates assessed.

**UDAQ Response:** UDAQ appreciates this feedback. In the final SIP, UDAQ has included a cost-effectiveness evaluation of SCR and SNCR based upon enforceable mass-based $NO_x$ emission limits for Hunter and Huntington. This analysis shows that physical controls are not cost-effective at the enforceable $NO_x$ emission limit levels for 2028.

**Commenters:** Deseret Power

**Comment Summary 61:** Deseret supports PacifiCorp's comments regarding the proposed RH SIP and opposes additional controls for Hunter 2. Deseret specifically believes that mandating the addition of Selective Catalytic Reduction ("SCR") controls at Hunter II is unwarranted and could pose unacceptable financial risks to Deseret. The SCR for Hunter II will cost approximately $165 million according to EPA's estimate[4]. Of that amount, Desert would be responsible for contributing approximately $41 million. Deseret cannot borrow or pay that amount from existing cash resources – it would require the consent of the creditor under the debt forbearance to borrow Deseret's share. Under the forbearance arrangement, Deseret must provide annual revised forward projections to its creditors of anticipated cash flows (or deficits) through 2026. Should the revised cash flow projection indicate a projected deficit in available cash flows to meet minimum scheduled debt payments for the coming year, immediate restrictions on Deseret's use of available cash flow are triggered.

**UDAQ Response:** UDAQ acknowledges this comment. UDAQ was unaware of this situation and has taken this information into consideration in its final controls determination.

**Commenters:** The Conservation Organizations

**Comment Summary 62:** PacifiCorp used an improper interest rate of 7.303% without justification.

**UDAQ Response:** PacifiCorp provided UDAQ with the latest interest rate order approved by the Utah Public Service Commission (PSC), which includes substantial documentation in support of a rate of 7.34%[5]. UDAQ contacted EPA to determine whether the Utah PSC order provided reasonable justification of this source-specific rate received feedback that "... there is sufficient

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[4] Table 5, Response to Comments, EPA-R08-OAR-2015-0463-0208 at p. 205

[5] PacifiCorp's interest rate order can be found at:
https://pscdocs.utah.gov/electric/20docs/2003504/3168662003504ro12-30-2020.pdf

justification for the rate of 7.34% established by the UT PSC order."[6] PacifiCorp ultimately revised this rate downward to 7.303% to account for a weighted average of rates approved by all six service territory states using the methodology found in appendix A of their August 31, 2021, four-factor response[7]. UDAQ is satisfied with the approach and since the revised rate is lower than that approved by the Utah PSC, UDAQ is confident that the 7.303% rate is appropriate.

**Commenters:** The Conservation Organizations

**Comment Summary 63:** UDAQ should verify that PacifiCorp's calculations for capital costs don't account for income tax costs.

**UDAQ Response:** UDAQ has verified that PacifiCorp's calculations for capital costs do not include income taxes. Please refer to their original four-factor analysis submittal in appendix C.3.A on page 13.

**Commenters:** The Conservation Organizations

**Comment Summary 64:** PacifiCorp's four-factor analysis incorrectly assumes an annual average $NO_X$ rate of 0.05 lb/MMBtu.

**UDAQ Response:** UDAQ's analysis of control equipment followed EPA's recommendations for equipment life as laid out in EPA's updated control cost spreadsheets for each equipment type. For example, SCR systems are analyzed with an expected lifespan of 30 years, while SNCR systems are reviewed using a 20-year lifespan. UDAQ believes that an average $NO_x$ rate of 0.05 lb/MMBtu is appropriate for typical SCR controls.

**Commenters:** The Conservation Organizations

**Comment Summary 65:** PacifiCorp's four-factor analysis improperly includes air preheater modifications in its SNCR costs.

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[6] See appendix D.2.H for documentation of EPA correspondence on interest rates.

[7] PacifiCorp's four-factor response can be found at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2021-011726.pdf

**UDAQ Response:** PacifiCorp updated the information relative to SNCR and installation of a new air preheater would not be required. Upgrades to the system may be required due to increased ammonia slip, thus accounting for the cost shown in the original four-factor analysis estimate.

**Commenters:** The Conservation Organizations

**Comment Summary 66:** PacifiCorp's four-factor analysis improperly assumes a 20-yr SNCR life rather than a 30-yr life.

**UDAQ Response:** UDAQ's analysis of control equipment followed EPA's recommendations for equipment life as laid out in EPA's updated control cost spreadsheets for each equipment type. For example, SCR systems are analyzed with an expected lifespan of 30 years, while SNCR systems are reviewed using a 20-year lifespan.

**Commenters:** The Conservation Organizations

**Comment Summary 67:** UDAQ should not have evaluated capacity factors on a plantwide basis when cost-effectiveness is determined on a unit-specific basis.

**UDAQ Response:** UDAQ provided plantwide capacity factors in the proposed SIP to illustrate that utilization has trended downward over time. This metric is sufficient for this general purpose. Later, in its cost-effectiveness sensitivity analysis, UDAQ shows how the cost-effectiveness of individual units changes as utilization changes.

**Commenters:** PacifiCorp

**Comment Summary 68:** Hunter and Huntington are very important to the local economies. SCR installation may result in a shutdown of the unit which was not EPA's intent through the RHR and could result in a 20-25% employee reduction.

**UDAQ Response:** UDAQ acknowledges and appreciates this comment.

**Commenters:** PacifiCorp

**Comment Summary 69:** The first planning period SIP for $NO_x$ lowered $NO_x$ emissions limits, resulted in the installation of physical $NO_x$ controls, and formalized the closure of the Carbon plant (thereby eliminating all of its emissions). PacifiCorp began these installations of the $NO_x$ combustion controls in 2006 and completed them in 2014, as required by the 2008 SIP. EPA noted that “combustion control upgrades at the Hunter and Huntington facilities have been achieving significant $NO_x$ reductions since the time of their installation between 2006 and 2014.”

**UDAQ Response:** UDAQ acknowledges and appreciates this comment.

**Commenters:** PacifiCorp

**Comment Summary 70:** PacifiCorp requests UDAQ consider the additional costs of inflation, fuel availability, and supply-chain issues concerning control cost-effectiveness. EPA RH BART guidelines allow decision makers to consider a source's ability to afford technology if the installation of controls could affect continued plant operations. A cost-effectiveness assessment doesn't represent all of the considerations to determine whether SCR and additional $SO_2$ scrubbing are reasonable controls for the Utah Units.

**UDAQ Response:** UDAQ acknowledges this comment and has included a discussion of affordability considerations in the final SIP.

**Commenters:** PacifiCorp

**Comment Summary 71:** PacifiCorp is a PSC-regulated entity that must determine the least-cost, least risk option for its consumers. PacifiCorp has found that the Utah units would be viable least-cost and low risk assets through the end of their projected operating lives on the assumption that SCR installation is not required.

**UDAQ Response:** UDAQ acknowledges this comment and gave consideration to these concerns in developing the final SIP.

**Commenters:** PacifiCorp

**Comment Summary 72:** PacifiCorp plans to add nearly 11,000 MW of new renewable resources over the next 20 years and the 2021 IRP includes the retirement of 14/22 coal units by 2030

**UDAQ Response:** UDAQ acknowledges and concurs with this comment.

**Commenters:** PacifiCorp

**Comment Summary 73:** Coal divestment in the surrounding western states makes any SCR requirement likely to be unaffordable.

**UDAQ Response:** UDAQ acknowledges this comment and gave consideration to these concerns in developing the final SIP.

**Commenters:** PacifiCorp

**Comment Summary 74:** UDAQ should consider the visibility impacts of controls when determining measures necessary for reasonable progress including a dollar per deciview approach. Utah's RH SIP 2 should include a discussion of whether certain controls or additional requirements will further the visibility goals of the underlying statutes. The State of Utah has the duty to consider "visibility improvement" as part of its reasonable progress determinations and should do so here. In Montana, where EPA issued the FIP directly, it found a 0.18 deciview improvement to be a "low visibility improvement" that "did not justify proposing additional controls" for $SO_2$ on the source. While PacifiCorp acknowledges that the "visibility improvement" at an individual site does not need to reach the level of human perception, it is also not reasonable to require exorbitant expenditures that result in no real modeled, discernible improvement in visibility. UDAQ has not provided analysis that additional $SO_2$ limits will improve visibility in CIAs.

**UDAQ Response:** EPA's 2021 Clarifications Memo states that a state should not use visibility to summarily dismiss cost-effective potential controls.[8]

**Commenters:** PacifiCorp

**Comment Summary 75:** The State developed a sensitivity analysis to demonstrate the impact of plant utilization on cost-effectiveness at PacifiCorp's Utah Units. The analysis indicates that lower plant utilization leads to an increase in cost effectiveness. The electricity generation industry is experiencing significant change, which increases uncertainty regarding medium to long-term operations of Hunter and Huntington. As such, the State correctly determined the costs for controls were not prudent, and instead implemented $NO_X$ mass-based emission limits that conform to the Western Regional Modeling and Analysis ("WRAP") projected 2028 $NO_X$ "on the books" estimates. The State's use of WRAP's on-the-books estimates to set emissions limits in its utilization sensitivity analysis is consistent with past EPA practice.

**UDAQ Response:** UDAQ acknowledges this comment and has established plantwide annual mass-based $NO_X$ limits for Hunter and Huntington to constrain $NO_X$ emissions to levels at which the installation of additional physical controls is found not to be cost-effective in the final SIP.

[8] See EPA's Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period at 13

These limits, however, are no longer based directly upon the WRAP 2028OTBa2 emissions projections.

**Commenters:** PacifiCorp

**Comment Summary 76:** The Utah Units are necessary to support grid stability, transmission services, and low-cost energy. The Utah Units are load-following and provide energy at times when renewable energy sources are scarce. Early retirement of these units could restrict the level of renewables that can be accommodated until replacements can be constructed or purchased.

**UDAQ Response:** UDAQ acknowledges this comment and gave consideration to these concerns in developing the final SIP.

**Commenters:** PacifiCorp

**Comment Summary 77:** PacifiCorp supports Utah's determination of an $SO_2$ limit of 0.12 lb/MMBtu42 30-day rolling average for the Utah Units. This permit limit for the plants is the appropriate limit because the $SO_2$ controls at the plants: (1) are efficient and effective (over 90% control efficiencies on all Utah Units); (2) cannot be upgraded to become more efficient in a cost-efficient manner; and (3) align with EPA guidance recognizing that a State may forego further analysis of $SO_2$ controls at a plant with modern, efficient controls. All of PacifiCorp's Utah coal plants have FGD installed, and each unit has a permitted limit of 0.12 lb/MMBtu for $SO_2$ emissions, which is significantly lower than the 0.2 lb/MMBtu $SO_2$ limit addressed in the 2019 Guidance. Therefore, under the applicable EPA guidance, no further $SO_2$ controls are needed for the Utah Units.

**UDAQ Response:** UDAQ concurs with these comments, but is revising the proposed limits to remove startup, shutdown, and malfunction provisions in response to EPA comments.

**Commenters:** PacifiCorp

**Comment Summary 78:** The $NO_X$ and $SO_2$ rates discussed in the 2020 RP Analysis are artificial rates which resulted from the RPEL calculation methodology. The existing Utah Units' scrubbers cannot control lower $SO_2$ emission rates. To achieve a 0.03 lb/MMBtu $SO_2$ rate, new scrubbers would have to be constructed at an estimated capital cost of $180 million for each unit.

**UDAQ Response:** UDAQ appreciates this clarification regarding the calculation of RPELs and reiterates that we are not pursuing the RPELs proposed by the company. UDAQ notes that

PacifiCorp provided additional clarification on this topic in a letter that can be found in appendix C.3.D.

**Commenters:** PacifiCorp

**Comment Summary 79:** EPA's proposed 2022 CSAPR overlaps with the RH Second Implementation Period on controlled pollutants and controlled sources. UDAQ should account for the 2022 CSAPR, if finalized, when making reasonable progress determinations.

**UDAQ Response:** UDAQ is aware of the 2022 CSAPR proposal and believes that the mass-based limits in the proposed SIP provide meaningful $NO_x$ reductions at a lower cost while providing more compliance flexibility.

**Commenters:** PacifiCorp

**Comment Summary 80:** PacifiCorp suggests UDAQ include the additional information provided in PacifiCorp's comments in the RH SIP 2

**UDAQ Response:** UDAQ appreciates these comments and will utilize them, where applicable, in conjunction with other public comments received to improve the final SIP.

**Commenters:** UAMPS

**Comment Summary 81:** UAMPS supports the comments submitted by PacifiCorp and opposes any regulatory requirement to install SCR on Hunter Unit 2

**UDAQ Response:** UDAQ acknowledges UAMPS' support of PacifiCorp's comments and opposition to a requirement to install SCR on Hunter Unit 2.

**Commenters:** NPS

**Comment Summary 82:** NPS estimates that the scrubber upgrades proposed by PacifiCorp could reduce $SO_2$ emissions by over 3,300 tons/yr at $400-900/ton $SO_2$ removed based on the proposed $SO_2$ emissions rates applied to the average heat inputs for 2017-2019 and adapted from PacifiCorp's 4/21/2020 submittal. NPS recommends that UDAQ require these upgrades.

**UDAQ Response:** UDAQ notes that these calculations are based upon information supporting PacifiCorp's RPEL proposal which UDAQ did not agree with and rejected. UDAQ agrees with PacifiCorp's comments that the Utah Units' $SO_2$ scrubbers all have control efficiencies surpassing

90% and cannot cost-effectively achieve lower $SO_2$ emissions rates. PacifiCorp provided additional clarification on this topic in a letter found in appendix C.3.D.

**Commenters:** EPA, NPS, The Conservation Organizations

**Comment Summary 83:** We agree with UDAQ that PacifiCorp's RPELs for Huntington and Hunter power plants should not be adopted.

**UDAQ Response:** UDAQ appreciates this comment.

## U.S. Magnesium:

**Commenters:** EPA, The Conservation Organizations, National Parks Conservation Association

**Comment Summary 84:** UDAQ should implement $NO_X$ and $SO_2$ limits for the Riley Boiler

**UDAQ Response:** UDAQ acknowledges this comment. Modifying the Operating Permits of the RH sources is outside the scope of this SIP. Section IX.H.23 imposes specifically those limitations found to be both technically feasible and cost effective for each RH source.

**Commenters:** EPA

**Comment Summary 85:** Include additional justification that the solar pond engines are well controlled.

**UDAQ Response:** On May 11, 2022, UDAQ received supplemental information from USM regarding the technical and economic feasibility of electrification of the pump engines. UDAQ has reviewed this supplemental information and concurs with the company's analysis. Conversion of the pumps to electric power is not warranted at this facility.

**Commenters:** EPA

**Comment Summary 86:** Consider engine replacement or electrification at the Riley Boiler

**UDAQ Response:** See UDAQ's response to the above comment.

**Commenters:** EPA, NPS, The Conservation Organizations

**Comment Summary 87:** Update USM's four-factor analysis with SCR feasibility in the downstream configuration as a control option

**UDAQ Response:** On May 11, 2022, UDAQ received supplemental information from USM regarding the technical and economic feasibility of SCR installation on the spray dryer turbines. This supplemental information clarified the technical difficulties relating to stack gas temperature, acid gas entrainment, particulate fouling, and physical limitations of the exhaust stack configuration. In addition, expansion of the cost analysis for application of SCR was also provided using acceptable values for interest rate and expected end-of-life. UDAQ has reviewed this supplemental information and concurs with the company's analysis. The installation of SCR is not warranted on the spray dryer turbines at this facility.

**Commenters:** The Conservation Organizations

**Comment Summary 88:** USM's four-factor analysis did not consider engine size, tier rating, and operating hours into account.

**UDAQ Response:** On May 11, 2022, UDAQ received supplemental information from USM regarding the technical and economic feasibility of electrification of the pump engines. UDAQ has reviewed this supplemental information and concurs with the company's analysis. Conversion of the pumps to electric power is not warranted at this facility.

**Commenters:** NPS

**Comment Summary 89:** Request for public review opportunity of USM's supplemental documents and four-factor analysis updates.

**UDAQ Response:** UDAQ provided NPS with USM's information order letters on 4/22/22 and 5/17/22. USM's responses can be found in appendix D.2.

**Commenters:** The Conservation Organizations

**Comment Summary 90:** USM's four-factor analysis did not include boiler-specific data when considering low-$NO_X$ burners.

**UDAQ Response:** On April 26, 2022, UDAQ received supplemental information regarding the Riley Boiler (letter originally dated March 12, 2021). Although labeled as "low-$NO_X$" at the time of installation (1972), the burner assembly currently qualifies as a standard burner under modern standards. A review of the original engineering specifications and schematics included with the April 26 submittal demonstrates the technical infeasibility of installing current low-$NO_X$ or ultra-low-$NO_X$ burners at the Riley Boiler.

**Commenters:** The Conservation Organizations

**Comment Summary 91:** A 22.6 ton per rolling 12-month enforceable emissions limit should be implemented with the installation of FGR. If UDAQ continues to only impose a mass-based emission limit, the regulatory language must also specify recordkeeping on the amount of fuel used per month at the Riley boiler so that 12-month heat input can be calculated. The proposed regulatory language should also make clear that compliance with the 12-month rolling total emission limit shall be calculated based on the fuel use or heat input over that time period and based on the $NO_X$ emission rates from the most recent stack test.

**UDAQ Response:** UDAQ agrees that the proposed regulatory language should be revised and appropriate language will be added to IX.H.23 of the SIP. However, UDAQ disagrees with the comment that recordkeeping on the amount of fuel is needed, heat input is not a necessary component of measuring or determining compliance with a mass-based emission limit.

**Commenters:** The Conservation Organizations

**Comment Summary 92:** UDAQ must include enforceable regulatory language requiring testing at least once a year

**UDAQ Response:** UDAQ agrees with this comment. An annual stack test is appropriate and has been added to SIP Sections XX.A and IX.H.23.

**Commenters:** NPS

**Comment Summary 93:** USM's four-factor analysis does not include the estimated level of control including the assumed $NO_X$ reduction or revised cost per ton of $NO_X$ removed estimate to conclude SCR is not cost effective.

**UDAQ Response:** UDAQ notes that the emissions controlled by the SCR system would remain unchanged from USM's original submission - only the annualized cost evaluation was redone. Thus, total annualized cost of $261,411 divided by tons removed of 38 (from page 24 of USM's original submission), yields a final cost effectiveness value of 6,879.24 $/ton. USM's final analysis does not rely on reduced capacity - the company was merely making an observation that operations at less than maximum capacity would lower tons removed without lowering annualized costs, thus lowering cost effectiveness. A fact which UDAQ acknowledges.

**Commenters:** NPS

**Comment Summary 94:** Request to verify USM's annual emissions assumptions.

**UDAQ Response:** On May 11, 2022, UDAQ received supplemental information regarding the pump engines. Specifically, USM investigated the costs for replacement of the pump engines with tier 4 equivalents, and converting the pumps to electrically driven models. In both cases, the conclusion reached was that replacement was not economically viable. UDAQ has reviewed the approach and analysis undertaken by USM and agrees with the company's conclusion. See also UDAQ's responses to USM's comments on this topic.

**Commenters:** USM

**Comment Summary 95:** The most feasible place for SCR installation is after the preheater/concentrator tanks and the estimated cost-effectiveness is $12,316/ton $NO_X$ removed.

**UDAQ Response:** UDAQ has reviewed USM's revised four-factor analysis and concurs with the conclusion reached by the company. Technical and cost feasibility issues have eliminated the use of SCR as a viable control option at this facility.

**Commenters:** USM

**Comment Summary 96:** The cost effectiveness of replacing the 30 existing diesel engines with tier 4 diesel engines will emit 71.65 tons of $NO_X$ annually and reduce existing emissions by 88% (63.15 tons/year) is $55,906/ton $NO_X$ removed.

**UDAQ Response:** Although UDAQ disagrees that each engine at the USM facility is exactly identical in terms of emission profile and total hours of use, the general conclusion reached by the company is still valid. Regardless of any variations in use or exact $NO_x$ emission rate, the economic viability of engine replacement is not warranted at this facility.

**Commenters:** USM

**Comment Summary 97:** The cost effectiveness of converting to Pump P-0 electric pumps is $32,478/ton removed.

**UDAQ Response:** UDAQ agrees with the approach and analysis undertaken by USM in evaluating the cost effectiveness of electrical conversion. Based upon the conclusion reached under this approach, it is not cost effective to convert these pumps to electric power.

## Intermountain Generation Station:

**Commenters:** The Conservation Organizations

**Comment Summary 98:** The enforceable shut down date for IGS should be December 31, 2025

**UDAQ Response:** UDAQ acknowledges these comments. Based upon comments received from IPSC noting its contractual power provision requirements and potential for project delays in an economy facing serious supply chain constraints as well as information gleaned from UDAQ's ongoing deliberations in the development of the IGS natural gas conversion project permit (e.g., the project is already six months behind schedule). IPSC has also stated that they must have flexibility in order to ensure the new natural gas-fired units are fully commissioned prior to decommissioning the coal units to ensure IPSC fulfills their responsibility to supply energy. As such, UDAQ feels it is appropriate to retain the closure date of December 31, 2027 as outlined in section 8.D as well as the enforceable measures in IX.H.23.

**Commenters:** The Conservation Organizations, Cory McnNulty

**Comment Summary 99:** UDAQ should conduct a four-factor analysis for IGS including the proposed two new combined combustion cycle combustion turbines.

**UDAQ Response:** UDAQ acknowledges this comment. The agency disagrees that a four-fact analysis needs to be completed for IGS when the closure of coal units 1 and 2 have been secured by this SIP revision. EPA guidance explains that source shutdowns could be considered as the most stringent measure for future reduction necessary to make reasonable progress and may be relied upon to either forgo a four-factor analysis or shorten the remaining useful life of a source. That said, NPS reviewed the potential for additional $SO_2$ reductions at IGS and concluded that, "The addition of DSI would not reduce emissions significantly, Therefore, we have no further comments on improving the efficiency of the existing scrubbers at IGS."

**Commenters:** The Conservation Organizations

**Comment Summary 100:** Any proposed retirements or operation changes included in Utah's LTS must be federally enforceable with compliance deadlines for retirement by the end of the second planning period.

**UDAQ Response:** UDAQ has included the retirement of IGS's coal units 1 and 2 in SIP Subsection IX.H.23. These retirements will become federally enforceable upon EPA approval of the round 2 SIP revision.

**Commenters:** NPS

**Comment Summary 101:** The largest air quality benefit of requiring an earlier closure date is assurance of fewer emissions sooner.

**UDAQ Response:** UDAQ acknowledges this comment.

**Commenters:** NPS

**Comment Summary 102:** NPS reviewed the potential for additional $SO_2$ emission reductions at IGS. $SO_2$ emissions at IGS are 0.06 lb/MMBtu. The addition of DSI would not reduce emissions significantly. Therefore, we have no further comments on improving the efficiency of the existing scrubbers at IGS.

**UDAQ Response:** UDAQ acknowledges and concurs with this comment.

**Commenters:** IPSC

**Comment Summary 103:** IPSC plans on transitioning to natural gas and hydrogen by 2025. However, IPA cannot commit to a permanent closure of the coal units prior to December 31, 2027 because IPA needs to ensure the gas units are fully commissioned prior to closing the coal units.

**UDAQ Response:** UDAQ acknowledges and concurs with this comment.

**Commenters:** IPSC

**Comment Summary 104:** IPA plans to replace the coal-fired units with a combined-cycle natural gas plant before December 31, 2027, which will include state-of-the-art emissions controls, such as SCR.

**UDAQ Response:** UDAQ acknowledges and concurs with this comment.

**Commenters:** IPSC

**Comment Summary 105:** IPSC Concurs with Utah's Determination that IPSC is Effectively Controlled and Further Controls are Not Reasonable Prior to Transition to Natural Gas and Hydrogen. The only remaining efficiency improvements to the existing control equipment for both $NO_X$ and $SO_2$ would require capital improvements—and there is simply not enough time for engineering, procurement, and construction of these upgrades before the coal units are shuttered.

**UDAQ Response:** UDAQ acknowledges and concurs with this comment.

**Commenters:** IPSC

**Comment Summary 106:** UDAQ has incorporated an enforceable deadline for shutdown during the second Regional Haze planning period and therefore has met its statutory and regulatory obligations.

**UDAQ Response:** UDAQ acknowledges and concurs with this comment.

**Commenters:** IPSC

**Comment Summary 107:** UDAQ has clearly demonstrated reasonable progress is being made, and imposing an arbitrary deadline prior to December 31, 2027 could have devastating consequences for IPP as it transitions to natural gas and hydrogen.

**UDAQ Response:** UDAQ acknowledges and concurs with this comment.

## Paradox Lisbon:

**Commenters:** The Conservation Organizations, National Parks Conservation Association

**Comment Summary 108:** UDAQ should conduct a four-factor analysis for the Paradox Lisbon Plant if it does not revise the permit limits for this facility of 111 tons $SO_2$/year including appropriate testing, recordkeeping, and reporting language.

**UDAQ Response:** Based on updated 2018 and 2021 inventory data (the plant was not in operation in 2017 or 2019), the Q/d analysis for the Paradox Lisbon Plant has been updated and found to be below UDAQ's Q/d threshold of 6. The updated information can be found in section 7.A.2.

**Commenters:** NPS

**Comment Summary 109:** Requests to review Paradox's additional information prior to the submission of this SIP.

**UDAQ Response:** UDAQ has included Table 28 in section 7.A.2 which includes data from the emissions inventory for the Lisbon Plant from 2017-2021 and their resulting Q/d values for both Canyonlands and Arches National Park, all of which are below UDAQ's threshold of 6.

**Commenters:** EPA

**Comment Summary 110:** EPA recommends UDAQ provide additional information on the excluded Paradox Lisbon Plant source including recent actual $SO_2$ information supporting the statement that their recent emissions are more in line with their 2009 data showing 111 tons $SO_2$/yr or conduct a four-factor analysis for them.

**UDAQ Response:** UDAQ reviewed emissions data from 2018 through 2021 and identified that the Lisbon plant did not meet or exceed a Q/d of 6 in any of those years. In particular, combined Q/d values ranged between 4.4 and 5.8, and $SO_2$ emissions between 2018 and 2021 ranged from 0.1 to 0.6 tons per year.

## Kennecott:

**Commenters:** The Conservation Organizations, National Parks Conservation Association

**Comment Summary 111:** UDAQ should conduct a four-factor analysis on all units of the Kennecott Copper facility and the Kennecott Mine and Copperton Concentrator including providing a breakdown of emissions from emission units UDAQ can regulate versus those it cannot regulate.

**UDAQ Response:** UDAQ disagrees that it should conduct a four-factor analysis on the Kennecott Mine and Copperton Concentrator. UDAQ has included a breakdown of emissions UDAQ cannot regulate and their resulting Q/d values in SIP Section 7.A.2, which clearly demonstrates that this source was appropriately screened-out. Furthermore, as identified by EPA[9], the anticipated $NO_x$+NMHC emissions reduction from replacing a Tier 1 haul truck with a Tier 4 truck is 65.9%, and the $NO_x$+NMHC emissions reduction from replacing a Tier 2 haul truck with a Tier 4 truck is 42.3%. This gives UDAQ a degree of comfort that emissions from this source will continue to improve over time as older vehicles are replaced. Additionally, this source recently underwent a thorough BACT analysis as part of the Salt Lake Serious Nonattainment Area PM 2.5 SIP. As a result, there are no additional controls that can be applied at this time beyond those already included in the SIP. UDAQ has added a table to Section 7.A.2 which outlines all of the existing enforceable controls in Utah's SIP for all applicable sources identified in the round 2 SIP revision.

**Commenters:** The Conservation Organizations

**Comment Summary 112:** UDAQ should impose a requirement in the Proposed SIP stating that Units 1-4 of Kennecott Utah Copper LLC Power Plant shall remain permanently closed.

**UDAQ Response:** UDAQ acknowledges and disagrees with this comment. Not only is the decommissioning of Kennecott's coal-fired boilers reflected in the Approval Order which was updated on February 4, 2020, and in a letter rescinding the Title V permit on February 12, 2020, but the BACT requirements imposed through Utah's $PM_{2.5}$ SIP include fuel-switching to natural

[9] EPA's Nonroad Compression-Ignition Engines: Exhaust Emission Standards can be found at: https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100OA05.pdf

gas and an SCR-level $NO_x$ emissions limits rate of 0.04 lb/MMBtu for Unit 4, which are included in IX.H.23 of the SIP. As such, UDAQ believes it is unnecessary to include the permanent closure of these units in this SIP revision. Please see comment 113 for additional information.

**Commenters:** EPA

**Comment Summary 113:** For the Kennecott Power Plant Lab Tailing Impoundment, EPA recommends Utah provide further explanation on the meaning of "decommissioned" as it relates to Unit 4. The February 4, 2020, Approval Order indicates that Units 1-3 are prohibited to operate, yet Unit 4 is listed as voluntarily decommissioned without details on its ability to restart or prohibition on its operation.

**UDAQ Response:** The February 2020 AO removed any ability for Kennecott to operate coal fired boilers as all the coal-fired boilers were removed from the approved equipment list. The AO summarizes the updates in the project description. Units 1-3 were prohibited to operate under the recently approved $PM_{2.5}$ SIP, and a specific SIP condition set their closure date. Thus, due to that applicable condition, Units 1 – 3 were removed from the permit. Kennecott proposed the removal of Unit 4 from the permit because they planned to decommission the unit. The AO project summarizes that Kennecott made that decision voluntarily, and -- based on that decision -- Unit 4 was removed from the permit. The AO only lists remaining ancillary equipment. It does not list Units 1-3 or Unit 4 as equipment for the facility and -- for this reason -- Kennecott does not have approval to operate any coal-fired boilers. Based on this equipment change, UDAQ also rescinded the Title V permit for the facility on February 12, 2020.[10]

## Chevron and Tesoro:

**Commenters:** EPA

**Comment Summary 114:** EPA recommends UDAQ further explain not analyzing the Chevron and Tesoro facilities. Recent BACT determination alone is not sufficient justification to exclude these sources from additional emission reductions for reasonable progress.

**UDAQ Response:** UDAQ's original Q/d screening using 2014 NEI data yielded values below 6 for the Chevron and Tesoro facilities. At EPA's request, UDAQ re-calculated the Q/d thresholds of its major sources using 2017 NEI data to ensure that additional sources did not exceed a Q/d of 6 and confirmed that no additional sources would be screened-in using the newer data. Specifically, neither the Chevron or Tesoro refineries had a revised Q/d of 6 or greater. Here it should be noted that UDAQ chose a more stringent Q/d threshold of 6 rather than the Q/d value

[10] See appendix G which includes document DAQO-RP0105720009-20 confirming that the Title V operating permit number 3500346002 has been rescinded

of 10 recommended by WRAP. This screen-out alone should be sufficient to exempt these sources the need for further analysis.

UDAQ is unclear as to why EPA is singling out these sources for additional scrutiny, but presumably it is because both sources had Top 10 (i.e., high ranking) weighted emissions potential values for sulfate or nitrate and various in-state and out-of-state CIAs. Specifically, Chevron ranked 9th for nitrate at BRCA1 with a % of total point WEP of 1.4%. Chevron had no high-ranking sulfate impacts. Tesoro ranked 10th at BRCA1 for nitrate at BRCA1 (0.9%) and had the following rankings and % values for sulfate:

BRCA1: Rank 8 (2.6%)

CAPI1: Rank 8 (1.6%)

BRID1: Rank 8 (3.9%)

YELL2: Rank 8 (3.4%)

CRMO1: Rank 6 (2.7%)

SAWT1: Rank 8 (2.7%)

Though top 10 ranked, these WEP values represented a relatively small portion of total point WEP at each CIA, as indicated above.

The 2019 Guidance states that it "may be reasonable for a state not to select an effectively controlled source" (pg 22) and that "the statutory considerations for selection of BACT and LAER are also similar to, if not more stringent than, the four statutory factors for reasonable progress"[11]. Both Chevron and Tesoro underwent a thorough BACT analysis for the Serious Area $PM_{2.5}$ Salt Lake Nonattainment Area SIP that resulted in additional controls and limits being added to SIP Section IX.H. Specifically, Tesoro installed a wet gas scrubber unit to control $SO_2$ emissions and is now subject to a source-wide annual $SO_2$ limit of 300 tons per year. For comparison, WRAP's WEP analyses used a 2028OTBa2 projection of 708.3 tons. Tesoro's actual $SO_2$ emissions for 2019-2021 since the installation of new controls ranged between 22 and 23 tons per year. As a result, the sulfate WEP values for this source – which were already a tiny fraction of total point source sulfate WEP for each potentially impacted CIA – are not

[11] See 2019 EPA Guidance at 23

representative of either the enforceable limits or the recent actuals for this facility. Please refer to section 7.A.2 to review the existing controls resulting from the recent $PM_{2.5}$ and $PM_{10}$ SIP revisions for Chevron and Tesoro which include both source-wide and equipment-specific limits for $NO_x$, $SO_2$, $PM_{10}$, and $PM_{2.5}$. Please refer to section 6.A.10 to review the projected emissions reductions resulting from Tesoro's existing controls.

## *Permit Revisions/Emissions Limit Tightening:*

**Commenters:** EPA

**Comment Summary 115:** EPA recommend UDAQ evaluate whether a source can or is achieving lower emissions rates using existing measures than assumed in their permit and consider revising their permit to reflect these lower emissions for reasonable progress

**UDAQ Response:** UDAQ has evaluated each source's emissions in sections 7.C.1 through 7.C.5 and has clarified which new and existing emissions reductions have been deemed necessary for reasonable progress. Where applicable, UDAQ evaluated whether a source can achieve or is achieving lower emissions rates to determine if permit revisions are appropriate (e.g., SO2 controls and Hunter and Huntington). These determinations are detailed in sections 6.A.10 and 8.D of this SIP revision and enforceable through IX.H.23.

**Commenters:** EPA

**Comment Summary 116:** UDAQ should consider whether equipment upgrades, optimization, or retrofit for source's existing controls are reasonable. EPA recommends UDAQ conduct four-factor analysis including such options or explain why it is reasonable not to do so. These protective measures have positive impacts on air quality outside the context of RH.

**UDAQ Response:** UDAQ acknowledges this comment and is aware of co benefits of regional haze controls for general air quality under and for purposes of attaining or maintaining the NAAQS. UDAQ addresses equipment upgrades, optimization, or retrofits where appropriate in its source-specific comment responses elsewhere in this document.

### IX.H.23:

**Commenters:** EPA

**Comment Summary 117:** Explain and provide technical documentation for the basis of the proposed successive $NO_X$ tpy emissions limits for Hunter and Huntington. How do these successive emission limits for future years align with the determination that it is not currently reasonable to require additional emission reductions from Hunter and Huntington?

**UDAQ Response:** In the proposed SIP, three successive $NO_x$ ton per year limits were developed to provide a reasonable compliance glidepath for Hunter and Huntington. For Hunter, the starting limit of 10,514 tons per year was based upon the 5-year high $NO_x$ actual emissions between 2016 and 2020 (with 2020 being the most recently available data year when the limits were developed) and was designed to take effect upon Utah Air Quality Board approval of the SIP, which is why no applicability date was given. The 2028 limit, as EPA notes, was based upon WRAP 2028OTBa2 projected emissions of 10,001 tons. The 10,257 ton per year interim limit was simply the average (i.e. midpoint) between the initial and final limits, thus creating a three-level compliance glidepath. The same methodology was used to set three successive limits for Huntington.This approach was selected to provide flexibility for PacifiCorp to adjust utilization levels at its facilities to comply with the limits.

In the final SIP, UDAQ did not use the WRAP 2028OTBa2 projections to set the 2028 mass-based NOx limits. Instead, UDAQ establishes 2028 plantwide NOx limits that ensure that the plants operate at or below emissions levels at which the installation of additional physical controls is not cost-effective. Specifically, UDAQ is establishing a 2028 plantwide NOx limit of 9,843 tons per year for Hunter and a 2028 plantwide NOx limit of 6,240 tons per year for Huntington. In addition, UDAQ is establishing an initial plantwide NOx limit for Hunter of 11,041 tons per year and an initial plantwide NOx limit for Huntington of 6,604 tons per year, both effective upon SIP approval. These initial levels are based on each plant's highest emission value over the past five years (2017-2021). Finally, UDAQ is establishing an interim 2025 plantwide limit of 10,442 tons per year for Hunter and an interim 2025 plantwide limit of 6,422 tons per year for Huntington, to create a compliance glidepath to aid in the transition from recent actual utilization levels to the final 2028 limits. The interim limits for each plant were calculated as the average of (i.e., the midpoint between) the initial and 2028 plantwide limits for each plant. Such glidepaths are commonly used by states and EPA to provide compliance flexibility (e.g., plantwide applicability limits; Tier 3 fuel averaging, banking, and trading; the Tier 3 vehicle fleet averaging glidepath from 2017-2025; cap and trade programs, etc.).

**Commenters:** EPA

**Comment Summary 118:** No short-term limits have been chosen for the Hunter and Huntington power plants to make reasonable progress although short-term emissions limits are commonly imposed as power plants control measures. Such limits may reduce the likelihood of excess emissions impacting Class I areas during periods of high electricity demand days (peak load days). Please explain and document the rationale for not incorporating short-term limits into the IX.H.23 permit revisions.

**UDAQ Response:** PacifiCorp's annual load curve has two peaks, one in the summer during high air conditioning usage and the other in the winter, when heating and lighting demand increases. Nitrate impacts at Utah's CIAs, on the other hand, peaks in the wintertime when conditions are ideal for the secondary formation of particulates. Because PacifiCorp needs to maintain headroom for summertime peaking under UDAQ's mass-based $NO_x$ limits, they are unlikely to utilize all of their $NO_x$ budget during the winter nitrate peak. This data is shown in figures within section 7.C.3. For this reason, UDAQ concludes that short-term limits are unnecessary and may limit flexibility to provide support for PacifiCorp's energy transition to intermittent non-emitting resources like renewables.

**Commenters:** EPA

**Comment Summary 119:** EPA recommends the startup, shutdown, maintenance/planned outage, or malfunction exemptions be removed from the $SO_2$ emissions limits for Hunter and Huntington

**UDAQ Response:** UDAQ concurs with EPA's comment and has amended SIP Sections XX.A and IX.H.23 to remove these exemptions.

## Utah Sources identified by downwind states that are reasonably anticipated to impact CIAs:

**Commenters:** EPA

**Comment Summary 120:** We recommend that the state reassess the information presented for sulfate and nitrate impacts individually, by summing the total impairment from Utah emissions sources (i.e., the total Utah share of summed nitrate and sulfate visibility impairment, in addition to the separate matrices for nitrate and sulfate).

**UDAQ Response:** UDAQ does not concur with the recommendation to sum nitrate and sulfate impairment estimates at in-state and out-of-state CIAs, since the potential control options for each pollutant are evaluated separately in our reasonable progress determination. Furthermore, UDAQ did not use the impact assessment matrices to eliminate any Q/d >= 6 sources from further evaluation.

## Interstate Consultation/Emissions:

**Commenters:** The Conservation Organizations

**Comment Summary 121:** UDAQ failed to meet its state-to-state consultation obligations, and its Proposed SIP lacks the information, documentation, and necessary enforceable measures. Instead of proper consultation with other states, Utah took an “agree to ask for nothing” approach to consultation. UDAQ must go back and properly consult with other states and thoroughly document that consultation for public review.

**UDAQ Response:** Utah met extensively with its surrounding states regarding each other's regional haze efforts , modeling results, facilities which may affect each other's CIAs, and reasonable progress determinations. The documents provided in appendix B serve to prove these consultation efforts occurred but do not represent the full extent of western interstate consultation. In addition to Utah's multiple state-state meetings, Utah is part of the Western Regional Air Partnership and the Western States Air Resources Council. The regional haze coordinators of all the states downwind of Utah are also part of these organizations, who take part in monthly meetings where we jointly collaborate on our regional haze planning efforts and progress. According to the July 2021 Clarification Memo, "A state receiving a request to select a particular source(s) should either perform a four-factor analysis on the source(s) or provide a well-reasoned explanation as to why it is choosing not to do so." Utah received no such requests from other states. Furthermore, in our consultation with neighboring states, when UDAQ inquired about out-of-state sources that might have potential visibility impacts at Utah CIAs (e.g., as identified by high WEP values or photochemical source apportionment results), those states either confirmed that those sources were undergoing four-factor analyses or provided "well-reasoned explanation(s)" as to why they thought four-factor analyses weren't necessary. UDAQ conducted further consultation and SIP review for New Mexico, Colorado, California, Nevada, and Arizona and included additional information on out-of-state regional haze proposals concerning the out-of-state sources identified in UDAQ's WEP analysis in Table 31 within section 7.A.3. UDAQ notes that the PNM - San Juan Generating Station has announced a plant closure in 2022, the Four Corners Power Plant has announced plant closure in 2031, and the North Valmy Generating Station has a federally enforceable closure date of December 21, 2028.

**Commenters:** IPSC

**Comment Summary 122:** IPSC recommends Utah explain why additional controls at out of state sources are not required for the state to make reasonable progress—taking into account its discussions during interstate consultations, including the existing and future controls anticipated at out of state sources and the results of the four- factor analyses conducted at these sources. UDAQ's SIP conclusions could be strengthened with additional explanation of how these sources were addressed during interstate consultation and why additional controls are not required to make reasonable progress.

**UDAQ Response:** UDAQ conducted further consultation and SIP review of the second implementation period status of non-Utah sources identified in UDAQ's WEP analysis and included this information in section 9.B.

## National Park Service Comments:

**Commenters:** The Conservation Organizations

**Comment Summary 123:** UDAQ should revise its SIP to adequately respond to NPS comments

**UDAQ Response:** UDAQ has consulted with the NPS throughout our iterative regional haze SIP process. As UDAQ stated in their responses to the NPS, additional information from sources have been provided to NPS as UDAQ has received and reviewed it.

## Tribe Consultation:

**Commenters:** The Conservation Organizations

**Comment Summary 124:** UDAQ failed to provide more information regarding outreach efforts with the Tribes of Utah. EO/2014/005: Executive Agency Consultation with Federally-Recognized Indian Tribes that requires each state agency develop a formal tribal consultation policy to ensure Tribes have input when the state contemplates actions that have implications on Tribes. UDAQ should meaningfully consult with Tribes prior to finalizing the State's SIP.

**UDAQ Response:** UDAQ shared its draft Regional Haze SIP with the Tribes of Utah on 12/9/21 and requested their input. Utah did not receive any response or feedback. Documentation of this outreach is included in appendix E.

## Public Notice:

**Commenters:** NPS

**Comment Summary 125:** FLM conclusions and recommendations presented during consultation were not included in the UDAQ notice for this public comment period.

**UDAQ Response:** UDAQ disagrees with this comment. The public notice published on UDAQ's web page from April 25th to June 2nd, 2022 included the statement "Prior to action by the Air Quality Board, the National Parks Service (NPS) and US Forest Service (USFS) reviewed the documents and provided comments. Their comments are summarized with DAQ responses in section 9.C.1 of the SIP (Section XX.A) and their full reviews are included in an appendix file." Proof of this statement in the public notice can be found in appendix F.

## Environmental Justice:

**Commenters:** EPA, The Conservation Organizations

**Comment Summary 126:** UDAQ should thoroughly assess environmental justice and equity impacts on any potentially affected communities inside or outside the state under title VI of the Civil Rights Act.

**UDAQ Response:** UDAQ appreciates this comment and has completed an analysis of the environmental justice impacts surrounding the 10 original sources identified in UDAQ's WEP analysis and included this information in section 7.A.5 Environmental Justice Considerations.

## General Issues:

**Commenters:** IPSC

**Comment Summary 127:** IPSC notes a few technical errors in the Utah SIP and encourages the UDAQ to review these sections and make changes prior to final submission to the EPA. On Page 65 – "Table 19: Utah $PM_{2.5}$ Emission Inventory – RepBase 2 (2014-2018) AND 2028otbA2" $PM_{2.5}$ should be $PM_{10}$.

**UDAQ Response:** UDAQ appreciates IPSC's identification of this issue and has corrected the title of this table.

**Commenters:** EPA, NPS

**Comment Summary 128:** PacifiCorp's letter to UDAQ in the appendix justifying that additional $SO_2$ controls are unnecessary is difficult to read as it is presented in the appendix.

**UDAQ Response:** UDAQ has fixed this issue, see appendix D.2.C.

# Final Effective Rule

**R307. Environmental Quality, Air Quality.**
**R307-110. General Requirements: State Implementation Plan.**
**R307-110-1. Incorporation by Reference.**

To meet requirements of the Federal Clean Air Act, the Utah State Implementation Plan (SIP) must be incorporated by reference into these rules. Copies of the SIP are available on the division's website.

**R307-110-2. Section I, Legal Authority.**

The Utah State Implementation Plan, Section I, Legal Authority, as most recently amended by the Air Quality Board on December 18, 1992, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-3. Section II, Review of New and Modified Air Pollution Sources.**

The Utah State Implementation Plan, Section II, Review of New and Modified Air Pollution Sources, as most recently amended by the Utah Air Quality Board on December 18, 1992, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-4. Section III, Source Surveillance.**

The Utah State Implementation Plan, Section III, Source Surveillance, as most recently amended by the Utah Air Quality Board on December 18, 1992, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-5. Section IV, Ambient Air Monitoring Program.**

The Utah State Implementation Plan, Section IV, Ambient Air Monitoring Program, as most recently amended by the Utah Air Quality Board on December 18, 1992, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-6. Section V, Resources.**

The Utah State Implementation Plan, Section V, Resources, as most recently amended by the Utah Air Quality Board on December 18, 1992, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-7. Section VI, Intergovernmental Cooperation.**

The Utah State Implementation Plan, Section VI, Intergovernmental Cooperation, as most recently amended by the Utah Air Quality Board on December 18, 1992, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-8. Section VII, Prevention of Air Pollution Emergency Episodes.**

The Utah State Implementation Plan, Section VII, Prevention of Air Pollution Emergency Episodes, as most recently amended by the Utah Air Quality Board on December 18, 1992, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-9. Section VIII, Prevention of Significant Deterioration.**

The Utah State Implementation Plan, Section VIII, Prevention of Significant Deterioration, as most recently amended by the Utah Air Quality Board on March 8, 2006, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-10. Section IX, Control Measures for Area and Point Sources, Part A, Fine Particulate Matter.**

The Utah State Implementation Plan, Section IX, Control Measures for Area and Point Sources, Part A, Fine Particulate Matter, as most recently amended by the Utah Air Quality Board on December 4, 2019, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-11. Section IX, Control Measures for Area and Point Sources, Part B, Sulfur Dioxide.**

The Utah State Implementation Plan, Section IX, Control Measures for Area and Point Sources, Part B, Sulfur Dioxide, as most recently amended by the Utah Air Quality Board on January 5, 2005, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-12. Section IX, Control Measures for Area and Point Sources, Part C, Carbon Monoxide.**

The Utah State Implementation Plan, Section IX, Control Measures for Area and Point Sources, Part C, Carbon Monoxide, as most recently amended by the Utah Air Quality Board on June 6, 2018, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-13. Section IX, Control Measures for Area and Point Sources, Part D, Ozone.**

The Utah State Implementation Plan, Section IX, Control Measures for Area and Point Sources, Part D, Ozone, as most recently amended by the Utah Air Quality Board on January 3, 2007, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-14. Section IX, Control Measures for Area and Point Sources, Part E, Nitrogen Dioxide.**

The Utah State Implementation Plan, Section IX, Control Measures for Area and Point Sources, Part E, Nitrogen Dioxide, as most recently amended by the Utah Air Quality Board on December 18, 1992, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-15. Section IX, Control Measures for Area and Point Sources, Part F, Lead.**

The Utah State Implementation Plan, Section IX, Control Measures for Area and Point Sources, Part F, Lead, as most recently amended by the Utah Air Quality Board on December 18, 1992, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-16. (Reserved.)**

Reserved.

**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 July 6, 2022, pursuant to Section 19-2-104, is incorporated by reference and made a part of these rules.

**R307-110-18. Reserved.**

Reserved.

**R307-110-19. Section XI, Other Control Measures for Mobile Sources.**

The Utah State Implementation Plan, Section XI, Other Control Measures for Mobile Sources, as most recently amended by the Utah Air Quality Board on February 9, 2000, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-20. Section XII, Transportation Conformity Consultation.**

The Utah State Implementation Plan, Section XII, Transportation Conformity Consultation, as most recently amended by the Utah Air Quality Board on May 2, 2007, pursuant to 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-21. Section XIII, Analysis of Plan Impact.**

The Utah State Implementation Plan, Section XIII, Analysis of Plan Impact, as most recently amended by the Utah Air Quality Board on December 18, 1992, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-22. Section XIV, Comprehensive Emission Inventory.**

The Utah State Implementation Plan, Section XIV, Comprehensive Emission Inventory, as most recently amended by the Utah Air Quality Board on December 18, 1992, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-23. Section XV, Utah Code Title 19, Chapter 2, Air Conservation Act.**

Section XV of the Utah State Implementation Plan contains Utah Code Title 19, Chapter 2, Air Conservation Act.

**R307-110-24. Section XVI, Public Notification.**

The Utah State Implementation Plan, Section XVI, Public Notification, as most recently amended by the Utah Air Quality Board on December 18, 1992, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-25. Section XVII, Visibility Protection.**

The Utah State Implementation Plan, Section XVII, Visibility Protection, as most recently amended by the Utah Air Quality Board on March 26, 1993, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-26. Section XVIII, Demonstration of GEP Stack Height.**

The Utah State Implementation Plan, Section XVIII, Demonstration of GEP Stack Height, as most recently amended by the Utah Air Quality Board on December 18, 1992, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-27. Section XIX, Small Business Assistance Program.**

The Utah State Implementation Plan, Section XIX, Small Business Assistance Program, as most recently amended by the Utah Air Quality Board on December 18, 1992, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**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 July 6, 2022, pursuant to Section 19-2-104, is incorporated by reference and made a part of these rules.

**R307-110-29. Section XXI, Diesel Inspection and Maintenance Program.**

The Utah State Implementation Plan, Section XXI, Diesel Inspection and Maintenance Program, as most recently amended by the Utah Air Quality Board on July 12, 1995, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-30. Section XXII, General Conformity.**

The Utah State Implementation Plan, Section XXII, General Conformity, as adopted by the Utah Air Quality Board on October 4, 1995, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-31. Section X, Vehicle Inspection and Maintenance Program, Part A, General Requirements and Applicability.**

The Utah State Implementation Plan, Section X, Vehicle Inspection and Maintenance Program, Part A, General Requirements and Applicability, as most recently amended by the Utah Air Quality Board on September 4, 2019, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-32. Section X, Vehicle Inspection and Maintenance Program, Part B, Davis County.**

The Utah State Implementation Plan, Section X, Vehicle Inspection and Maintenance Program, Part B, Davis County, as most recently amended by the Utah Air Quality Board on March 4, 2020, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-33. Section X, Vehicle Inspection and Maintenance Program, Part C, Salt Lake County.**

The Utah State Implementation Plan, Section X, Vehicle Inspection and Maintenance Program, Part C, Salt Lake County, as most recently amended by the Utah Air Quality Board on October 6, 2004, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-34. Section X, Vehicle Inspection and Maintenance Program, Part D, Utah County.**

The Utah State Implementation Plan, Section X, Vehicle Inspection and Maintenance Program, Part D, Utah County, as most recently amended by the Utah Air Quality Board on December 5, 2012, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-35. Section X, Vehicle Inspection and Maintenance Program, Part E, Weber County.**

The Utah State Implementation Plan, Section X, Vehicle Inspection and Maintenance Program, Part E, Weber County, as most recently amended by the Utah Air Quality Board on March 4, 2020, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-36. Section X, Vehicle Inspection and Maintenance Program, Part F, Cache County.**

The Utah State Implementation Plan, Section X, Vehicle Inspection and Maintenance Program, Part F, Cache County, as most recently adopted by the Utah Air Quality Board on September 4, 2019, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**R307-110-37. Section XXIII, Interstate Transport.**

The Utah State Implementation Plan, Section XXIII, Interstate Transport, as most recently adopted by the Utah Air Quality Board on February 7, 2007, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

**KEY: air pollution, PM10, PM2.5, ozone**
**Date of Last Change: July 7, 2022**
**Notice of Continuation: December 1, 2021**
**Authorizing, and Implemented or Interpreted Law: 19-2-104**

# Final Effective Plans

# Utah State Implementation Plan

# Emission Limits and Operating Practices

## Section IX, Part H.21 and Part H.23

Adopted by the Air Quality Board July 6, 2022

## H.21. General Requirements: Control Measures for Area and Point Sources, Emission Limits and Operating Practices, Regional Haze Requirements

a. Except as otherwise outlined in individual conditions of this Subsection IX.H.21 listed below, the terms and conditions of this Subsection IX.H.21 shall apply to all sources subsequently addressed in Subsection IX.H.22. Should any inconsistencies exist between these two subsections, the source specific conditions listed in IX.H.22 shall take precedence.

b. The definitions contained in R307-101-2, Definitions and R307-170-4, Definitions, apply to Section IX, Part H. In addition, the following definition also applies to Section IX, Part H.21 and 22:

   *Boiler operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler. It is not necessary for fuel to be combusted for the entire 24-hour period.

c. The terms and conditions of R307-107-1 and R307-107-2 shall apply to all sources subsequently addressed in Subsection IX.H.22.

d. Any information used to determine compliance shall be recorded for all periods when the source is in operation, and such records shall be kept for a minimum of five years. All records required by IX.H.21.c shall be kept for a minimum of five years. Any or all of these records shall be made available to the Director upon request.

e. All emission limitations listed in Subsections IX.H.22 shall apply at all times, unless otherwise specified in the source specific conditions listed in IX.H.22. Each source shall submit a report of any deviation from the applicable requirements of Subsection IX.H, including those attributable to upset conditions, the probable cause of such deviations, and any corrective actions or preventive measures taken. The report shall be submitted in accordance with the requirements of R307-170, Continuous Emission Monitoring Program. Deviations due to breakdowns shall be reported according to the breakdown provisions of R307-107.

f. Stack Testing:

i. As applicable, stack testing to show compliance with the emission limitations for the sources in Subsection IX.H.22 and IX.H.23 shall be performed in accordance with the following:

A. Sample Location: The testing point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or the most recent version of the EPA-approved test method if approved by the Director.

B. Volumetric Flow Rate: 40 CFR 60, Appendix A, Method 2, or other EPA-approved testing methods acceptable to the Director.

C. Particulate (PM): 40 CFR 60, Appendix A, Method 5B, or the other EPA-approved testing methods acceptable to the Director. A test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. The back half condensables shall also be tested using Method 202. The back half condensables shall not be used for compliance demonstration but shall be used for inventory purposes.

D. Nitrogen Oxides (NOx): 40 CFR 60, Appendix A, Method 7E, or other EPA approved testing methods acceptable to the Director.

E. Calculations: To determine mass emission rates (lb/hr, etc.) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors to give the results in the specified units of the emission limitation.

F. Notification: The Director shall be notified at least 30 days prior to conducting any required emission testing. A source test protocol shall be submitted to DAQ when the testing notification is submitted to the Director.

G. The source test protocol shall be approved by the Director prior to performing the tests. The source test protocol shall outline the proposed test methodologies, stack to be tested, and procedures to be used. A pretest conference shall be held, if directed by the Director.

H. Source Operation and Testing Frequency: The production rate during all compliance testing shall be no less than 90% of the maximum production achieved in the previous three (3) years.

g. Continuous Emission and Opacity Monitoring.

i. For all continuous monitoring devices, the following shall apply:

A. Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of an affected source shall continuously operate all required continuous monitoring systems and shall meet minimum frequency of operation requirements as outlined in R307-170 and 40 CFR 60.13.

B. The monitoring system shall comply with all applicable sections of R307-170; 40 CFR 60.13; and 40 CFR 60, Appendix B – Performance Specifications.

C. For any hour in which fuel is combusted in the unit, the owner/operator of each unit shall calculate the hourly average NOx concentration in lb/MMBtu.

D. At the end of each boiler operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/MMBtu from the arithmetic average of all valid hourly emission rates from the CEMS for the current boiler operating day and the previous 29 successive boiler operating days.

E. An hourly average NOx emission rate in lb/MMBtu is valid only if the minimum number of data points, as specified in R307-170, is acquired by the owner/operator for both the pollutant concentration monitor (NOx) and the diluent monitor (O2 or CO2).

## 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:

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 $NO_x$ 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).

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 ($NO_x$ or $PM_{10}$ only), or emergency conditions ($SO_2$ only).

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 NOx 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 NOx 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 NOx 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 NOx 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 $SO_2$ 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  NOx and SO2 emissions shall be determined by CEM as outlined in IX.H.21.g.

g. US Magnesium LLC - Rowley Plant

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.

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 NOx 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 NOx limits shall be performed at least once every five years.

# Utah State Implementation Plan

# Regional Haze Second Implementation Period

## Section XX.A

*[August 1, 2022]*

# List of tables

# List of figures

# List of acronyms

| | |
|---|---|
| **BACT** | Best Available Control Technology |
| **BACM** | Best Available Control Measures |
| **CIA** | Class 1 Area |
| **CAA** | Clean Air Act |
| **CAMx** | Comprehensive Air Quality Model with Extensions |
| **CCR** | Consumer Confidence Report |
| **CF** | Code of Federal Regulations |
| **CIRA** | Cooperative Institute for Research in the Atmosphere |
| **CO** | Carbon Monoxide |
| **CSU** | Colorado State University |
| **DAQ** | Division of Air Quality |
| **DEQ** | Department of Environmental Quality |
| **EPA** | Environmental Protection Agency |
| **FLM** | Federal Land Manager |
| **FWS** | US Fish and Wildlife Service |
| **GCVTC** | Grand Canyon Visibility Transportation Commission |
| **IMPROVE** | Interagency Monitoring of Protected Visibility Elements |
| **LTS** | Long Term Strategy |
| **NAAQS** | National Ambient Air Quality Standards |
| **NOI** | Notice of Intent |
| **NO2** | Nitrogen Dioxide |
| **$NO_x$** | Nitrogen Oxides |
| **NPS** | National Parks Service |
| **O3** | Ozone |
| **PAL** | Plantwide Applicability Limit |
| **PB** | Lead |
| **PM** | Particulate Matter |
| **$PM_{10}$** | Particulate Matter Smaller Than 10 Microns in Diameter |
| **$PM_{2.5}$** | Particulate Matter Smaller Than 2.5 Microns in Diameter |
| **RH** | Regional Haze |
| **RHR** | Regional Haze Rule |
| **RHPWG** | Regional Haze Planning Work Group (WRAP) |
| **RPEL** | Reasonable Progress Emissions Limit |
| **RPG** | Reasonable Progress Goals |
| **SCR** | Selective Catalytic Reduction |
| **SIP** | State Implementation Plan |
| **SNCR** | Selective Non-Catalytic Reduction |
| **$SO_2$** | Sulfur Dioxide |
| **$SO_x$** | Sulfur Oxides |
| **TSS** | Technical Support System |
| **UDOGM** | Utah Division of Oil, Gas, and Mining |
| **URP** | Uniform Rate of Progress |
| **UAC** | Utah Administrative Code |
| **USFS** | US Forest Service |
| **VOCs** | Volatile Organic Compounds |
| **WESTAR** | Western States Air Resources |

| | |
|---|---|
| **WRAP** | Western Regional Air Partnership |

# EXECUTIVE SUMMARY

This document comprises the State of Utah's State Implementation Plan (SIP) submittal to the U.S. Environmental Protection Agency (EPA) under the Regional Haze Rule.[1] The purpose of this SIP revision is to comply with the requirements of the Regional Haze Rule (RHR).[2] Specifically, this SIP addresses requirements for periodic comprehensive revisions of implementation plans for regional haze.[3] The RHR requires Utah to address regional haze in each mandatory Class I Area (CIA) located within Utah and in each mandatory CIA located outside Utah that may be affected by primary pollutants emitted from sources within Utah. Utah is required to submit a SIP addressing the specific elements required by the rule.

The objectives of the RHR are to improve existing visibility in 156 national parks, wilderness areas, and monuments (termed Mandatory Class I Areas or CIAs), prevent future impairment of visibility by manmade sources, and meet the national goal of natural visibility conditions in all mandatory CIAs by 2064. Utah’s CIAs consist of: Arches National Park, Bryce Canyon National Park, Canyonlands National Park, Capitol Reef National Park, and Zion National Park.[4]

The RHR establishes several planning periods extending from 2005 to 2064. The State of Utah is required to develop a Regional Haze (RH) SIP for each period. The first implementation period spanned from 2008 to 2018. This SIP revision consists of the second implementation period spanning from 2018 to 2028. This SIP was originally due for submittal to the EPA on July 31st, 2018. However, the deadline was extended to July 31st, 2021. In this revision, UDAQ demonstrates the visibility progress to date[5] in each of Utah’s CIAs and analyzes Utah’s emissions trends and sources of visibility impairment[6]. Utah is required to set reasonable progress goals which 1) must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and 2) ensure no degradation in visibility for the least impaired days over the same period.[7] For this purpose, Utah has outlined its Long-Term Strategy (LTS) in this document[8] as well as determination of reasonable progress goals (RPGs) for CIAs in Utah.

The RH SIP must also address mandatory CIAs outside of the state that are reasonably anticipated to be affected by emissions from Utah as well as out-of-state sources impacting Utah CIAs. For this requirement, UDAQ analyzed Western Regional Air Partnership (WRAP) photochemical modeling and found that Utah does not significantly impact visibility at out-of-

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[1] 40 CFR 51.308(f) and (g)

[2] 40 CFR 51
[3] 40 CFR 51.308(f)
[4] See chapter 1 for more information on the RHR and Utah’s regional haze history
[5] See chapter 3 to view Utah’s visibility and emissions reduction progress to date
[6] See chapter 5 to review Utah’s sources of visibility impairment
[7] See chapter 8 for more information on Utah’s reasonable progress goals
[8] See chapter 6 for Utah’s Long-Term Strategy

state CIAs.[9] Utah has also determined that Utah's CIAs are not significantly impacted by out-of-state sources. Upon consultation with Utah's surrounding states, Utah will not require any actions from other states for impacts on Utah's CIAs and Utah has received no requests for actions regarding Utah sources' impacts on out-of-state CIAs.[10]

Throughout this second implementation period, UDAQ has participated in the WRAP, which has conducted modeling and technical analysis for the purposes of supporting state RH planning. UDAQ has also consulted with Federal Land Managers (FLMs), Tribes, Utah's surrounding states, as well as environmental advocates, industry stakeholders, and the public.[11]

This SIP revision also determines what control measures are necessary for reasonable progress in the second implementation period. The examination required to determine new control measures for this period is known as a four-factor analysis[12] and consists of four criteria: 1) cost of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts, and 4) remaining useful life. In order to determine which sources must submit a four-factor analysis to the State, UDAQ performed a Q/d (emissions/distance) analysis to determine which of Utah's sources have the highest potential visibility impact on Utah's CIAs. These facilities include the Ash Grove Cement Company Leamington Cement Plant, the Graymont Western US Inc. Cricket Mountain Plant, the PacifiCorp Hunter and Huntington Plants, the Sunnyside Cogeneration Associated Sunnyside Cogeneration Facility, and the US Magnesium LLC Rowley Plant. UDAQ requested each facility to submit a four-factor analysis for the purpose of this second implementation period. UDAQ has received each facility's four-factor analysis, provided each with an evaluation of their analysis, received evaluation responses from each, and subsequent information submittals[13]. After consideration of the information provided, as well as the modeling results provided by the WRAP, UDAQ has made the following reasonable progress determinations[14] for Utah's second implementation period of regional haze planning.

UDAQ identified several existing measures necessary for reasonable progress, including federal on-road and non-road vehicle and equipment standards, BACM measures and BACT controls included in the recently completed Serious Area PM2.5 SIP for the Salt Lake Nonattainment Area, as well as the following first implementation period regional haze controls:

- Existing $NO_x$ control rate-based limits and Hunter power plant
- Existing $NO_x$ control rate-based limits and Huntington power plant

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[9] See sections 6.A.1 and 6.A.2 for Utah's impacts on out of state CIAs and other state's impacts on Utah's CIAs

[10] See Appendix B for interstate consultation agreement documentation

[11] See chapter 9 for details on Utah's consultation efforts

[12] See chapter 7 for Utah's source selection and the four-factor analyses, evaluations, responses, and conclusions for each source

[13] See Appendix D.2 to view additional information submittals by sources

[14] See sections 6.A.10 to view Utah's Long-Term Strategy, 8.D to view UDAQ's reasonable progress determinations, and IX.H in appendix A to view the enforceable language for these determinations.

- Existing $SO_2$ limits for Hunter power plant (Section 309 control added to SIP in round 2)
- Existing $SO_2$ limits for Huntington power plant (Section 309 control added to SIP in round 2)
- Closure of the Carbon power plant

UDAQ also identified and included the following existing control measures to ensure ongoing enforceability in the second implementation period:

- Ash Grove
- Graymont
- Sunnyside
- US Magnesium
- Intermountain Generation Station

Finally, UDAQ identified and included the following new control measures as necessary for reasonable progress:

- A plantwide enforceable mass-based $NO_x$ limit on Hunter power plant
- A plantwide enforceable mass-based $NO_x$ limit on Huntington power plant
- Installation of FGR on the US Magnesium Rowley Plant Riley Boiler
- An enforceable closure date for Units 1 and 2 of the Intermountain Generation Station

# **Chapter 1:** Background and Overview of the Federal Regional Haze Rule

## 1.A Regional Haze Planning Periods and Due Dates

Utah took part in early regional haze planning through participation in the Grand Canyon Visibility Transport Commission (GCVTC), which originally consisted of nine states and 211 tribal lands. In 1996, the GCVTC submitted a report containing recommendations for improving western vistas.[15] In 2000, Utah established Sulfur Dioxide ($SO_2$) milestones with an Annex[16] to the original GCVTC report through the Western Regional Air Partnership. Based on the recommendations of the GCVTC and the Annex, in 2003 Utah's Air Quality Board adopted section XX[17] of the State Implementation Plan (SIP) to address regional haze and the many source categories and pollutants contributing to the regional haze in Utah. The first state plans were due in 2007 and the last date for states to submit initial regional haze control plans for all Mandatory Federal CIAs was in 2008. Utah submitted its evaluation of the Best Available Retrofit Technology (BART) in 2015[18] along with a revision in 2019[19]. Progress reports are due every five years and full plan revisions are required every 10 years. The first revision was originally due in 2018, but in 2017 EPA extended the deadline to July 31, 2021 with the latest revision of the Regional Haze Rule (RHR)[20]. As part of the RH SIP process, Utah must work towards the overarching goal of achieving natural visibility in its CIAs by 2064. This timeline is summarized in the figure below.

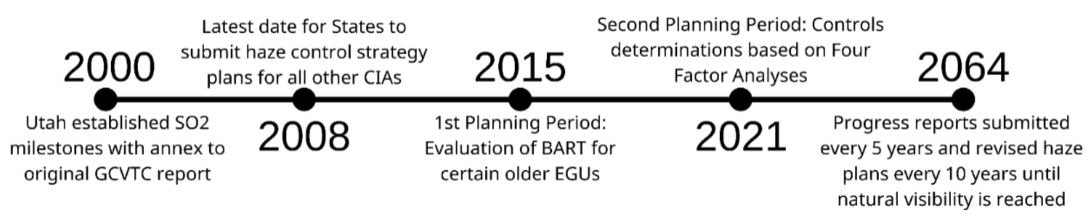


**Figure 1: Regional Haze Timeline option for GCVTC areas**

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[15] The original 1996 report of The Grand Canyon Visibility Transport Commission can be found at https://www.phoenixvis.net/PDF/GCVTCFinal.pdf

[16] The EPA Notice of Availability of the Annex to the Report of The Grand Canyon Visibility Transport Commission can be found at https://www.federalregister.gov/documents/2000/11/15/00-29226/notice-of-availability-of-annex-to-the-report-of-the-grand-canyon-visibility-transport-commission

[17] Section XX of Utah's Regional Haze SIP can be found at https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008934.pdf

[18] Utah's 2015 RH SIP can be found at https://documents.deq.utah.gov/legacy/laws-and-rules/air-quality/sip/docs/2015/07Jul/SecXXRegHaze201Final.pdf

[19] Utah's 2019 RH SIP revision can be found at https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2019-012208.pdf

[20] 40 C.F.R. § 51.308(f). For the purposes of this SIP submittal, the RHR acronym refers to the most current 2017 Regional Haze Rule revisions.

## 1.B Class I Areas in Utah

In the 1977 Clean Air Act, Congress established requirements for the prevention of significant deterioration of air quality in areas within the United States and for the review of pollution controls on new sources. Coupled with this, Congress established a visibility protection program for those larger national parks and wilderness areas designated as mandatory Federal CIAs. This program establishes a national goal of "the prevention of any future, and remedying of any existing, impairment of visibility in mandatory CIAs which impairment results from manmade air pollution"[21] and requires states to develop long-term strategies to assure reasonable progress toward this national goal. 40 CFR 81.400 Scope: Subpart D, §§ 81.401 through 81.437, lists Mandatory Federal CIAs, where the Administrator, in consultation with the Secretary of the Interior, has determined visibility to be an important value.

As shown in Figure 2, there are five Mandatory Federal CIAs in Utah, all of which are National Parks: Arches National Park, Bryce National Park, Canyonlands National Park, Capitol Reef National Park and Zion National Park. The following sections include data from the National Parks Service (NPS) Stats website.[22]

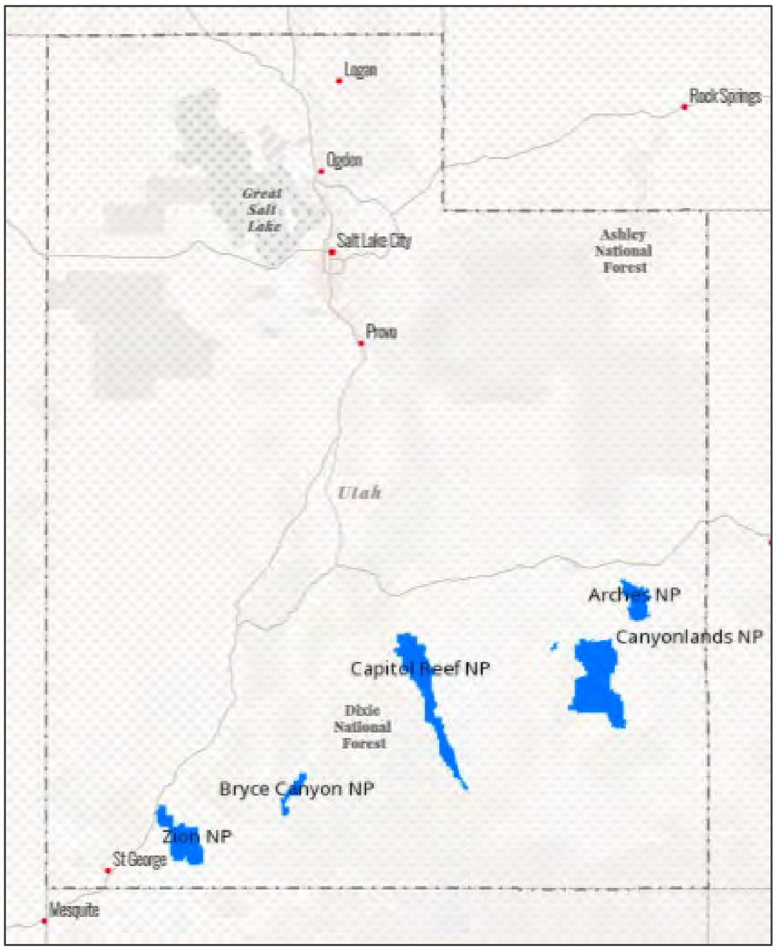


**Figure 2: Map of Utah CIAs**

[21] 42 U.S.C.A. § 7491(a)(1) (West).
[22] Statistics for all the National Parks discussed in this section come from the NPS Stats website at: https://irma.nps.gov/STATS/

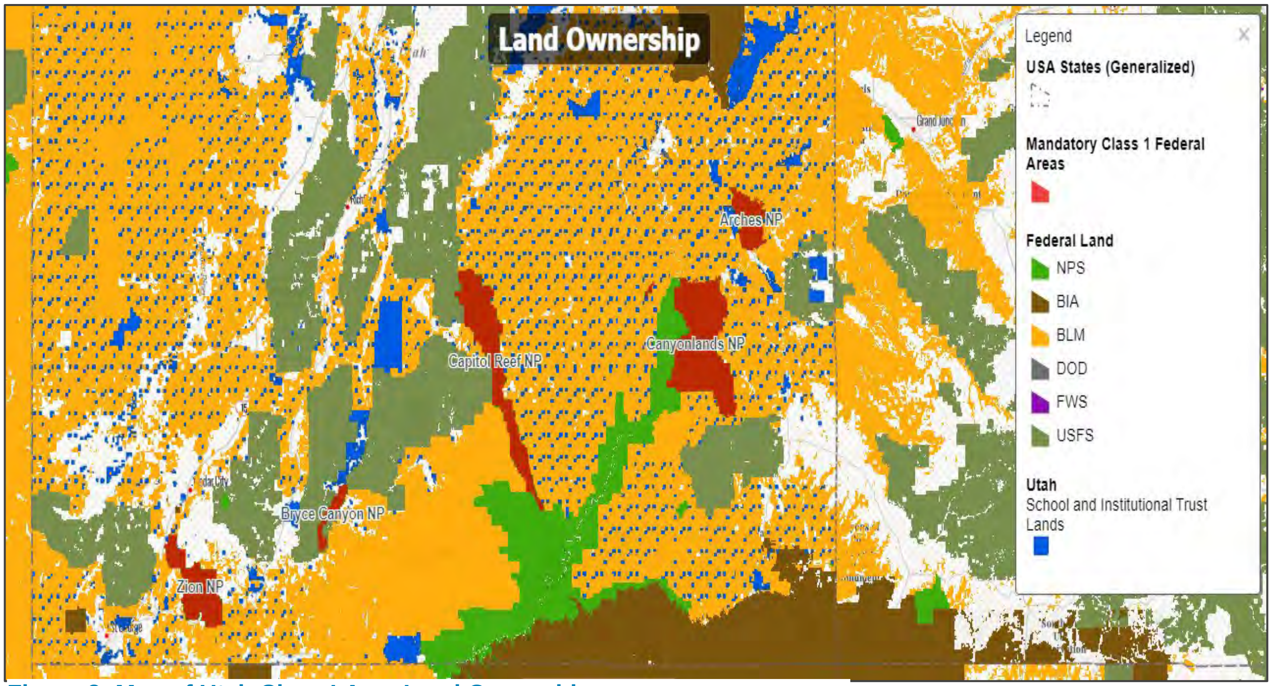

Figure 3: Map of Utah Class I Area Land Ownership

### 1.B.1 Arches National Park


Figure 4: Arches National Park

Arches National Park was originally designated as a National Monument in 1929 and became a national park in 1978. Congress established the park "to protect extraordinary examples of geologic features including arches, natural bridges, windows, spires, balanced rocks, as well as other features of geologic, historic, and scientific interest, and to provide opportunities to experience these resources and their associated values in their majestic natural settings."[23] Located in southwest Utah, Arches National Park is home to over 2,000 cataloged, naturally formed, sandstone arches. These 76,679 acres of red sandstone are surrounded by thousands of acres of additional natural lands, administered mainly by the Bureau of Land Management and Utah's School and Institutional Trust Lands Administration (See Figure 3). Over 1.6 million people visited Arches in 2019.[24] Over the past 10 years, park visitation has increased, on average, five percent each year.[25] The largest population center near Arches National Park is Moab. This town of over 5,300 residents[26] is about five miles south of the Park. It is the major hub for recreation in Arches, Canyonlands National Park, and the surrounding areas.

### 1.B.2 Bryce Canyon National Park

Bryce Canyon was originally established as a National Monument in June 1923. One year later it was designated a national park. According to its foundation document, the purpose of the park was to "protect and conserve resources integral to a landscape of unusual scenic beauty exemplified by highly colored and fantastically eroded geological features, including rock fins and spires, for the benefit and enjoyment of the people."[27] Bryce Canyon contains the highest concentration of irregular rock columns (Hoodoos) on Earth. Located in southern Utah near the city of Bryce, the national park sits along the edge of a high plateau on top of the Grand Staircase. At 35,835 acres, Bryce Canyon is Utah's smallest National Park. However, nearly 2.6 million people visited Bryce Canyon in 2019.[28]


**Figure 5: Bryce Canyon National Park**

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[23] Arches National Park Foundation Document, website: https://www.nps.gov/arch/learn/management/foundation-document.htm#CP_JUMP_5740028
[24] Data source: Stats Report Viewer (nps.gov).
[25] *See id*.
[26] United States Census Bureau, website: https://www.census.gov/quickfacts/moabcityutah (data for July 1, 2019).
[27] Bryce Canyon National Park Foundation Document, website: https://www.nps.gov/brca/learn/management/upload/BRCA_FD_SP.pdf
[28] Data source: Stats Report Viewer (nps.gov).

### 1.B.3 Canyonlands National Park

Canyonlands National Park was originally established on September 12, 1964 with the help of Bates Wilson, the superintendent of Arches National Park. Located near Moab, Utah with 337,598 acres of land and water, Canyonlands is Utah's largest national park. The Green and Colorado rivers split this section of the Colorado Plateau into three main districts: "Island in the Sky," "The Needles," and "The Maze." Since 2007, over 400,000 people visit Canyonlands each year with a record of 776,218 in 2016 alone.[29] Canyonlands features deep canyons, mesas, pinnacles, cliffs, and spires and contains one of the most photographed landforms in the west—the Mesa Arch.

**Figure 6: Canyonlands National Park**

### 1.B.4 Capitol Reef National Park

**Figure 7: Capitol Reef National Park**

Capitol Reef National Park was originally designated a national monument in August 1937 but then turned into a national park in 1971. Spanning 241,904 acres, Capitol Reef is made of a geologic monocline almost 100 miles long. This monocline is called the Waterpocket Fold and is considered a geologic warp in the

[29] Data source: [Stats Report Viewer (nps.gov)](https://irma.nps.gov/Stats/).

Earth's crust spanning from Thousand Lake Mountain to Lake Powell. The tall, seemingly impassible ridges made by the Waterpocket Fold were called "reefs" by early settlers. The white Navajo sandstone dome formations appear like those placed on capitol buildings, giving the park its name. Capitol Reef had 1,226,519 visitors in 2019[30] and offers many hiking and backpacking opportunities, including 71 campsites.

### 1.B.5 Zion National Park

Figure 8: Zion National Park

Established on July 31, 1909, Zion National Park was the first national park in Utah. It is also the fourth most visited National Park in the United States with 4.48 million visitors in 2019.[31] The park's 147,243 acres contain the Zion Canyon which is 15 miles long and 2,640 feet tall.[32] The purpose of Zion National Park is to "preserve the dramatic geology including Zion Canyon and a labyrinth of deep and brilliantly colored Navajo sandstone canyons formed by extraordinary processes of erosion at the margin of the Colorado Plateau."[33] Located in southwestern Utah near St. George, Zion is home to famous hikes including Angel's Landing, The narrows, Observation Point, and the Emerald Pools.

## 1.C Haze Characteristics and Effects

Unimpaired visibility is important to fully enjoy the experience of visiting Utah's national parks and wilderness areas. Visibility is defined as the greatest distance at which an observer can see a black object viewed against the horizon sky. Visibility is impaired by light scattering and absorption caused by PM and gases in the atmosphere that occur from both natural and anthropogenic activities. This diminished clarity is called haze. Haze obscures the color, texture, and form of objects that can be seen at a distance.

Visibility can be impaired by natural sources such as rain, wildland fires, volcanic activity, sea mists, and wind-blown dust from undisturbed desert areas. Visibility also can be impaired by anthropogenic sources of air pollution such as industrial processes, (utilities, smelters,

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[30] Data source: [Stats Report Viewer (nps.gov)](Stats Report Viewer (nps.gov)).
[31] Data source: Stats Report Viewer (nps.gov).
[32] Data Source: https://www.nps.gov/subjects/lwcf/upload/NPS-Acreage-12-31-2012.pdf

[33] Zion National Park Foundation Document, website:
https://www.nps.gov/zion/learn/management/upload/ZION_Foundation_Document_SP-2.pdf

refineries, etc.), mobile sources (cars, trucks, trains, etc.), and area sources (residential wood burning, prescribed burning on wild and agricultural lands, wind-blown dust from disturbed soils, etc.). These sources emit pollutants that, in higher concentrations, can also affect public health.

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

There are different metrics to measure impact on visibility. Visual range is the most intuitive and is defined as the distance at which a given standard object can be seen with the unaided eye. It is measured in miles or kilometers. A deciview is a unit of visibility proportional to the logarithm of the atmospheric light extinction. This unit will be used in many figures and tables within this report. Deciviews measure visibility derived from light extinction so that incremental changes in the haze index correspond to uniform incremental changes in visual perception ranging from pristine to highly impaired conditions.

## 1.D Monitoring Strategy[34]


Figure 9: Monitoring station for Capitol Reef National Park

Interagency Monitoring of Protected Visual Environments (IMPROVE) was designated as the visibility monitoring network representative of the 156 visibility-protected federal CIAs. IMPROVE was developed in 1985 to establish current visibility conditions, track changes in visibility, and help determine the causes and sources of visibility impairment in CIAs. The network is comprised of 110 monitoring sites across the nation[35], four of which are in Utah. IMPROVE monitoring sites in Utah's CIAs include those at Canyonlands National Park (monitoring site for both Arches and Canyonlands national parks), Capitol Reef National Park, Bryce Canyon National Park, and Zion National Park. Figure 10 through Figure 12 show three of Utah's monitoring stations.

[34] 40 CFR 51.308(f)(6) (IMPROVE PROGRAM)
[35] Shown in Figure 13

The IMPROVE monitoring sites contain equipment programmed to automatically collect samples of haze-forming particles from the air continually. Local operators at each field site—in many cases a park ranger, firefighter, or rancher—inspect the samples and exchange filters weekly, shipping all exposed filters back to the Air Quality Research Center (AQRC) at the University of California (UC) Davis every three weeks. Each month, the program's 110 field sites generate about 7,000 filters, which are processed in AQRC's laboratories by staff members and UC Davis students working part-time.[36] The analyses conducted at the AQRC test samples for various pollutants and trace metals and estimate the light scattering effect of each species This estimation results in a light extinction value. For purposes of the RHR, light extinction is estimated for sulfate, nitrate, organic mass by carbon (OMC), light absorbing carbon (LAC), fine soil (FS), sea salt, and coarse material (CM)—all components of particulate emissions. Figure 12 shows the four separate modules used for sampling the different species.

**Figure 11: Monitoring station for Bryce Canyon National Park**

**Figure 10: Monitoring station for Canyonlands and Arches National Park**

[36] For more information see: https://aqrc.ucdavis.edu/improve

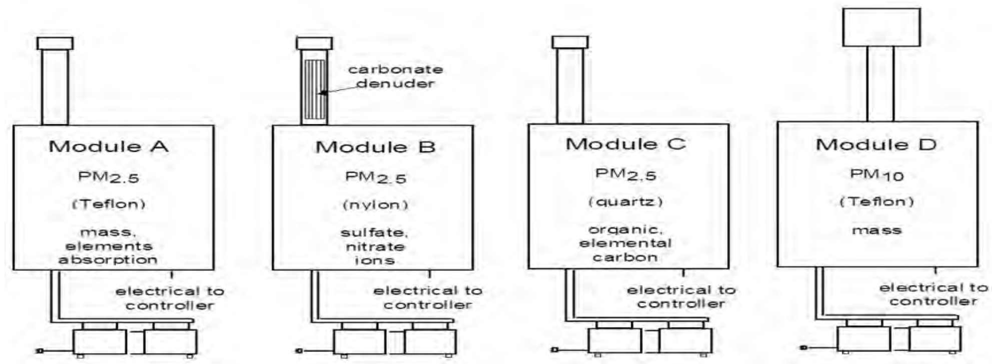


**Figure 12: Monitoring station layout**

## 1.D.1 Participation in the IMPROVE Network

In 1985, the IMPROVE program was established to coordinate the monitoring of air quality in national parks and wilderness areas and to ensure sound and consistent scientific methods were being used. The IMPROVE Steering Committee established monitoring protocols for visibility measurement, PM measurement, and scientific photography of the CIAs. IMPROVE monitoring is designed to establish reference information on visibility conditions and trends to aid in the development of visibility protection programs. Monitoring from the IMPROVE network, shown in Figure 13, demonstrated that visibility in all the CIAs is impaired to some degree by regional haze.


**Figure 13: IMPROVE monitoring sites**

## 1.E History of Regional Haze in Utah

Utah has been at the forefront of haze improvement and prevention since 1991 when the GCVTC was formed. The GCVTC recognized haze as a regional issue prior to the creation of the RHR in 1999 and was the first multi-state collaborative effort to address visual air quality issues. In recognition of the GCVTC, Section 309 of the RHR provided an early regional haze planning opportunity for states within the Colorado Plateau region. Utah is one of the five states to submit a complete Section 309 regional haze plan in 2003.

In amendments to the Clean Air Act (CAA) in 1977, Congress added Section 169A setting the national visibility goal of restoring pristine conditions in national parks and wilderness areas: “Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory CIAs which impairment results from man-made air pollution.”[37]

When the CAA was amended in 1990, Congress added Section 169B,[38] authorizing further research and regular assessments of the progress to improve visibility in the mandatory CIAs.[39]

[37] 42 U.S.C.A. § 7491.
[38] *See id*. § 7492.
[39] Figure 14: Map of 156 Mandatory Federal CIAs shows the location of the CIAs of concern and the Federal Land Managers (FLMs) responsible for each area around the nation.

The RHR specifies that these CIAs should attain “natural conditions” by 2064 and that states should make progress in controlling air pollution to meet this goal. The timeline is broken into

Figure 14: United States map of mandatory CIAs

10-year planning periods, and in each period, states must show reductions in emissions of haze-causing pollutants along a linear path, or glidepath, toward the 2064 end goal.

To meet the RHR planning requirements, states conduct analyses of visibility in each Class I area, identify the available reasonable measures to reduce haze, and implement those measures. The implemented measures establish the required Reasonable Progress Goals (RPG) for each Class I area. The RPGs are the visibility improvement benchmarks on the glidepath toward the long-term goal of natural visibility conditions by 2064.[40] The analysis, measures, and RPGs are the basis of the long-term strategy for the states, and this strategy must be included in the states’ SIPs. States are also required to assess progress halfway through the 10-year implementation period - a process that is intended to keep the states on target to meet the 10-year goals established for each Class I area.

### 1.E.1 Grand Canyon Visibility Transport Commission

The GCVTC was established by EPA in November of 1991, consisting of seven western governors (or their designees), five tribes, and five ex-officio members representing federal land management agencies and EPA.  When establishing the GCVTC, EPA designated a transport region including seven western states: California, Oregon, Nevada, Idaho, Utah, Arizona,

[40] See Figure 15 for an RPG glidepath example of Bryce Canyon National Park, provided by the Western Regional Air Partnership (WRAP) Technical Support System.

Colorado, and New Mexico. Although a part of the Transport Region, the State of Idaho declined the invitation to participate in the GCVTC.

Although Congress required a commission to be established for Grand Canyon National Park, the member states agreed to expand the scope of the GCVTC to address all 16 of the CIAs on


**Figure 15: Regional haze glidepath for Bryce Canyon National Park tracking progress towards natural conditions in 2064**

the Colorado Plateau. The GCVTC elected to use a stakeholder-driven process to accomplish its objectives. Ultimately, the organization included 200+ political, policy and technical stakeholders who staffed a variety of committees and subcommittees to perform policy analysis and technical studies, and to participate in the public debate. The GCVTC was funded by EPA grants and contributions from stakeholders, including substantial in-kind labor. During its four-and-one-half year development, the GCVTC was expanded to include the State of Wyoming and tribal leaders as members. The GCVTC appointed a Public Advisory Committee (PAC) representing broad stakeholder interests to provide input and feedback to the GCVTC. Many Utahns were members of the PAC, with two serving on the PAC Steering Committee, and one serving on the Executive Committee as Vice-Chair of the PAC. The 80+ member Public Advisory Committee developed a consensus report of recommendations for the GCVTC that was ultimately adopted by the GCVTC and submitted to EPA in June 1996.[41]

Recommendations of the GCVTC included the following:

- Policies based on energy conservation, increased energy efficiency, and promotion of the use of renewable resources for energy production;
- Careful tracking of emissions growth that may affect air quality in clean air corridors;

[41] The Grand Canyon Visibility Transport Commission. Recommendations for Improving Western Vistas (June 10, 1996) available at https://www.phoenixvis.net/PDF/GCVTCFinal.pdf

- Regional targets for $SO_2$ emissions with a backstop program, probably including a regional cap and possibly a market-based trading program;
- Cooperatively developed strategies, expanded data collection and improved modeling for reducing or preventing visibility impairment in areas within and adjacent to CIAs, pending further studies of sources adjacent to CIAs;
- Emissions cap for mobile sources at the lowest level (expected to occur in 2005) and establishment of a regional emissions budget, as well as the implementation of national strategies aimed at reducing tailpipe emissions;
- Further study to resolve issues regarding the modeled contribution to visibility impairment of dust from paved and unpaved roads;
- Continued bi-national cooperation to resolve data gaps and jurisdictional issues around emissions from Mexico;
- Programs to minimize emissions and visibility impacts and to educate the public about impacts from prescribed fire and wildfire, because emissions are projected to increase significantly through 2040; and
- Creation of an entity like the GCVTC to promote, support, and oversee the implementation of many of the recommendations in this report.

EPA initially proposed regional haze regulations in 1997.[42] The proposed regulations described a generic program to apply nationally and did not include provisions to address the recommendations of the GCVTC. The Western Governors' Association (WGA) engaged key stakeholders to develop a recommendation on how to transform the GCVTC recommendations into the regional haze regulations. WGA approved the stakeholders' recommendation and transmitted it to EPA in June 1998.[43] Based on this and other public input, EPA issued the final Regional Haze Rule in July 1999 with a national program (Section 308) that could apply to any state or tribe and an optional program (Section 309) relying on the work of the GCVTC that is available to the states and tribes in the nine-state GCVTC transport region.[44]

### 1.E.2 Western Regional Air Partnership

The GCVTC recognized the need for a long-term organization to address the policy and technical studies needed to address regional haze. The Western Regional Air Partnership (WRAP) was formed in September 1997 to fulfill this need. The WRAP's charter allows it to address any air quality issue of interest to WRAP members, though most current work is focused on developing the policy and technical work products needed by states and tribes in writing their regional haze SIPs and tribal implementation plans (TIPs). The WRAP has been co-chaired by the governor of Utah and the governor of the Acoma Pueblo. The WRAP Board is currently composed of representatives from 13 states, 13 tribes, the U.S. Department of Agriculture, the U.S. Department of the Interior, and the EPA. The WRAP operates on a consensus basis and receives financial support from EPA. The WRAP established stakeholder-

[42] Regional Haze Regulations, 62 Fed. Reg. 41138 (July 31, 1997) (proposed rule).
[43] Leavitt, M. O., Governor of Utah, Letter to EPA Administrator Browner on behalf of the Western Governors' Association, June 29, 1998.
[44] Regional Haze Regulations, 64 Fed. Reg. 35714 (July 1, 1999), codified at 40 C.F.R. pt. 51.

based technical and policy oversight committees to assist in managing the development process of regional haze work products. Stakeholder-based working groups and forums were established to focus on the policy and technical work products the states and tribes need to develop their implementation plans.

The WRAP developed and submitted an Annex to the GCVTC recommendations to define a voluntary program of $SO_2$ emission reduction milestones coupled with a backstop market-trading program to assure emission reductions. EPA proposed changes to the Regional Haze Rule to incorporate the GCVTC Annex, and the final revised rule was published on June 5, 2003.[45] The WRAP has completed a suite of products to support states and tribes developing GCVTC-based regional haze implementation plans.[46]

### 1.E.3 2003 Regional Haze SIP

On June 5, 2003, EPA approved the Annex and incorporated the stationary source provisions into the RHR In December 2003 the Utah Air Quality Board adopted Section XX of the SIP to address regional haze. This plan was based on the GCVTC recommendations and the Annex and contained a broad-based strategy to address the many source categories and pollutants that contributed to regional haze in Utah, including clean air corridors, fire, mobile sources, paved and unpaved road dust, pollution prevention and renewable energy programs, and stationary sources.

EPA's approval of the Annex was challenged in court, and on February 18, 2005, the DC Circuit Court of Appeals vacated EPA's 2003 rules.[47] The Court determined that EPA had required a BART demonstration in the Annex that was based on a methodology that had been vacated by the Court in 2002 in *American Corn Growers Association v. E.P.A.*, 291 F.3d 1 (D.C. Cir. 2002), decision. On October 13, 2006, EPA revised the RHR to establish the methodology for states to develop an alternative to BART that was consistent with the DC Circuit's 2005 decision.[48]

### 1.E.4 2008 Regional Haze SIP Revision

While most of the 2003 SIP remained unchanged, in 2008 the Utah Air Quality Board adopted revisions to the stationary source provisions of the SIP to meet the requirements of the revised RHR and to reflect changes in the number of states participating in the program. In addition to these changes, the rule required an update to the SIP in 2008 to address the BART requirement for $NO_x$ and PM as well as an analysis of the impact of sources in Utah on CIAs outside of the Colorado Plateau.

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[45] Revisions to Regional Haze Rule to Incorporate $SO_2$ Milestones and Backstop Emissions Trading Program for Nine Western States and Eligible Indian Tribes Within That Geographic Area, 68 Fed. Reg. 33764 (June 5, 2003), codified at 40 C.F.R. pt. 51.

[46] Additional information about the WRAP can be found on the WRAP website at https://www.wrapair2.org/

[47] *See Ctr. for Energy & Econ. Dev. v. E.P.A.*, 398 F.3d 653 (D.C. Cir. 2005)

[48] *See* Regional Haze Regulations, 71 Fed. Reg. 60,612, 60,631 (Oct. 13, 2006), codified at 40 C.F.R. pt. 51.

### 1.E.5 2011 Regional Haze SIP Revision

The $SO_2$ milestones were updated in 2011 to reflect a reduced number of states participating in the program (Arizona elected to pursue a SIP under Section 308 of the RHR). In addition, the growth estimates for coal-fired utilities and the estimates for emission reductions due to BART were revised.

### 1.E.6 2015 Regional Haze SIP Revision

On June 4, 2015, Utah resubmitted its SIP for PM BART and submitted an alternative to BART for $NO_x$ for PacifiCorp's Electrical Generating Units (EGUs). On January 14, 2016, EPA issued a proposed rule containing a proposal to approve the PM BART and a co-proposal to either approve or disapprove the BART Alternative for $NO_x$ and to impose a Federal Implementation Plan (FIP) requiring BART for $NO_x$ in the event of the disapproval.[49] On July 5, 2016, EPA issued the final rule disapproving the BART alternative for $NO_x$ and approving the BART for the PM portion of the June 4, 2015 SIP.[50] To replace the disapproved BART alternative, EPA promulgated a FIP, requiring installation of Selective Catalytic Reduction (SCR) controls on the subject EGUs by August of 2021.[51]

Utah filed a lawsuit against EPA challenging the July 5, 2016 disapproval of BART Alternative for $NO_x$ in the Tenth Circuit on September 1, 2016.[52] The parties engaged in settlement discussions to resolve the case administratively. As a result of the settlement negotiations, Utah conducted an additional technical analysis using the state-of-the-science model and methodologies to perform air quality model simulations.[53] Utah used the photochemical grid model Comprehensive Air Quality Model with Extensions (CAMx) to estimate and compare the potential visibility impacts at selected CIAs for different emissions scenarios considered for PacifiCorp's EGUs. The CAMx was used because it accounts for complex processes such as the chemistry, transport, and deposition of pollutants responsible for regional haze.

Utah came to the same conclusion employing the CAMx modeling: that its $NO_x$ BART Alternative would provide greater reasonable progress toward natural visibility conditions than BART.[54] Utah revised the disapproved SIP to include this additional technical analysis and, after

[49] *See* Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plans and Federal Implementation Plan; Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze, 81 Fed. Reg. 2004 (Jan. 14, 2016) (proposed rule).
[50] *See* Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plans and Federal Implementation Plan; Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze, 81 Fed. Reg. 43894 (July 5, 2016), codified at 40 C.F.R. pt. 52.
[51] *See id*., 81 Fed. Reg. at 43907.
[52] *See Utah v. E.P.A. et al.*, No. 16-9541 (10th Cir. Sept. 1, 2016).
[53] *See* Section 1.E.7 below for additional details.
[54] Staff Review Recommended Alternative to BART for $NO_x$ at 5-2 (Jan. 14, 2019) ("The model results... indicate that the emissions modeled under the Utah SIP will not degrade visibility conditions relative to the Baseline scenario at any of the analyzed CIAs during either the 20% best or 20% worst visibility days.

public notice and comment, submitted the revised $NO_x$ BART Alternative to EPA on July 3, 2019. Utah submitted a supplement to the July 2019 submission on December 3, 2019 on the issue unrelated to the initial disapproval—the requirement to report all deviations from compliance with the applicable requirements under BART and BART Alternative, including emission limits for PacifiCorp's EGUs. On January 22, 2020, EPA published a proposed rule to approve the July 2019 SIP submittal with December 2019 supplement.[55]

After EPA's public notice and comment, on November 27, 2020, EPA issued a final rule approving Utah's July 2019 SIP submittal and December 2019 supplement.[56] This concluded and resolved the litigation that Utah initiated on September 1, 2016. The Tenth Circuit dismissed the case and issued a mandate on January 11, 2021.[57] EPA's November 27, 2020 final rule is currently challenged in the Tenth Circuit by the conservation organizations (HEAL Utah, National Parks Conservation Association, Sierra Club, and Utah Physicians for a Healthy Environment).[58] The lawsuit was filed on January 19, 2021.[59]

### 1.E.7 2019 Regional Haze SIP Revision

In the 2019 SIP revision, Utah used dispersion modeling and the two-prong test prescribed by the RHR[60] to demonstrate that the proposed alternative to BART does show greater progress than the most stringent $NO_x$ controls (installation of SCR). The two prongs that Utah had to satisfy are (1) that visibility does not decline in any Class I area; and (2) that there is an overall improvement in visibility determined by comparing the average differences between BART and the BART Alternative over all affected CIAs.

The two-prong test was an objective pass-fail test which Utah's BART Alternative met. EPA proposed approval of this latest SIP on January 22, 2020.[61]EPA issued final approval of the 2019 SIP revision on November 27, 2020 with effective date of December 28, 2020.[62] In the final rule EPA concluded "that Utah's $NO_X$ BART Alternative achieves greater reasonable progress under 40 CFR 51.308(e)(2) and (3)."[63] With the final approval, EPA also found that "Utah's SIP fully satisfies the requirements of section 309 of the Regional Haze Rule and

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The modeling results also show that, on average, visibility improvement at the analyzed CIAs is greater under the Utah SIP than the USEPA FIP scenarios during both the 20% best and 20% worst visibility days.").

[55] *See* Approval and Promulgation of Air Quality Implementation Plans; Utah; Regional Haze State and Federal Implementation Plans, 85 Fed. Reg. 3558 (Jan. 22, 2020) (proposed rule).

[56] Approval and Promulgation of Air Quality Implementation Plans; Utah; Regional Haze State and Federal Implementation Plans, 85 Fed. Reg. 75860 (Nov. 27, 2020), codified at 40 C.F.R. pt. 52.

[57] *See* Order, *Utah v. E.P.A. et al.*, No. 16-9541 (10th Cir. Jan. 11, 2021).

[58] *See HEAL Utah et al. v. E.P.A. et al.*, No. 21-9509 (10th Cir. Jan 19, 2021).

[59] *See* Petition for Review, *HEAL Utah et al.*, No. 21-9509 (10th Cir. Jan. 19, 2021).

[60] 40 CFR 51.308€ (3)

[61] *See* 85 Fed. Reg. 3558.

[62] *See* 85 Fed. Reg. 75860.

[63] *Id.*, 85 Fed. Reg. at 75861.

therefore the State has fully complied with the requirements for reasonable progress, including BART, for the first implementation period."[64]

## 1.F General Planning Provisions

### 1.F.1 Regional Haze Program Requirements

The program requirements of the RHR[65] are identified in Subsection 51.308(f) which lists the requirements for haze SIP updates, including a reference to the requirements in Subsection 51.308(d). In addition to re-evaluating all elements required in subsection (d), the states must also do the following:

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

As noted above, the section addressing the requirements for the SIP revisions references the requirements of subsection (d). The subsection (d) requirements are as follows: requirements:

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

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

### 1.F.2 SIP Submission and Planning Commitments

This SIP revision meets the requirements of the EPA's RHR and the CAA. Elements of this SIP address the core elements required by 40 CFR Section 51.308(f)(3)—the establishment of RPGs and measures that Utah will take to meet the RPGs. This SIP revision also addresses 40 CFR 51.308(f)(2) (long-term strategy for regional haze) and 40 CFR 51.308(i)(2) (state

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[64] *Id.*
[65] 40 CFR 51.308

coordination with the FLMs) and commits to develop future plan revisions and adequacy determinations as necessary.

The State of Utah commits to participate in a regional planning process, as a member state through the Western States Air Resource Council (WESTAR) and as a partner in WRAP. WESTAR is a partnership of 15 western states formed to promote the exchange of information, serve as a forum to discuss western regional air quality issues, and share resources for the common benefit of the member states. WRAP is a voluntary partnership of state, tribes, FLMs, local air agencies, and the EPA whose purpose is to understand current and evolving regional air quality issues in the West. The regional planning process describes the process, goals, objectives, management and decision-making structure, and deadlines for completing significant technical analyses of the regional group. To assist in making sound planning decisions, Utah has assisted the regional planning organization to complete regional analyses that include certain methods, inputs, and resources. Utah commits to continue regional participation through future SIPs.

Pursuant to the Tribal Authority Rule[66], any Tribe whose lands are within the boundaries of the State of Utah have the option to develop a regional haze Tribal Implementation Plan (TIP) for their lands to assure reasonable progress in the twelve CIAs in Utah. As such, no provisions of this Implementation Plan shall be construed as being applicable to tribal lands.

### 1.F.3 Utah Statutory Authority

The Utah Air Conservation Act[67] gives the Utah Air Quality Board authority to make rules pertaining to air quality activities.[68]

An administrative rule serves two purposes:

- A properly enacted administrative rule has the binding effect of law. Therefore, a rule affects the regulated entities and citizens as much as a statute passed by the Legislature.
- An administrative rule informs citizens of actions a state government agency will take or how a state agency will conduct its business.

This SIP is a compilation of analyses under Utah's statutory authority that satisfies the requirements of Sections 110 and 169 of the CAA.

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Indian Tribes: Air Quality Planning and Management, 63 Fed. Reg. 7254 (Feb. 12, 1998).

[67] Utah Code Ann. §§ 19-2-101 through 19-2-304 (West 2021).

[68] *See id*. § 19-2-104.

# **Chapter 2:** Utah Regional Haze SIP Development Process

This SIP addresses regulatory requirements of the second planning period by screening facilities with the most impact on Utah's CIAs, conducting and evaluating the four-factor analysis,[69] and making controls determinations based on this analysis. The current visibility conditions in relation to our Uniform Rate of Progress (URP) goals were also analyzed with the modeled data analysis tools provided by the WRAP Technical Support System (TSS).

Utah's SIP development process included consultation with industry stakeholders, environmental advocate stakeholders, regional states, WESTAR, WRAP, FLMs from the National Parks Service and the US Forest Service, and EPA's Region 8 office. Utah also consulted members of other state agencies including the Department of Energy Development and Office of Public Utilities. This chapter outlines Utah's consultation and communications with these entities. For additional details regarding individual consultation, see Chapter 9 Consultation, Public Review, Commitment to further Planning.

After initial consultation, Utah submitted the second planning period RH SIP to the FLMs, EPA, and Tribes of Utah on December, 8, 2021 for their mandatory 60-day comment period. After the comment period, the SIP was submitted to Utah Air Quality Board for the April 6th, 2022 Utah Air Quality Board meeting. The Board then proposed the SIP for public comment on May 1st, 2022 for the required 30 days. Utah then submitted the final SIP to the EPA on August 1, 2022.

## 2.A WRAP Engagement

During this second planning period, the WRAP Regional Haze Planning Work Group (RHPWG)[70] has helped create a framework for regional haze planning for all 15 participating states as well as the City of Albuquerque within the WESTAR and WRAP region. This initiative included regular meetings to discuss regional haze planning, encourage coordination among states, and offer training opportunities. WRAP has also been responsible for the WRAP TSS which is an online portal to the technical and analytical results created from technology development from Colorado State University (CSU) and the Cooperative Institute for Research in the Atmosphere (CIRA). TSS is the source of the key summary analytical results and methods for the required technical elements of the RHR contained within this SIP including:

- Inventories: current and future (growth projections methodologies by source categories)
- Development of a transparent and complete monitoring data metric for planning and model projection purposes
- Database management (including the TSS database)

[69] For purposes of this document, the Four-Factor Analysis is defined as the analysis required by 40 C.F.R. § 51.308(d)(1)(i)(A).
[70] More information on the Regional Haze Planning Work Group can be found at https://www.wrapair2.org/RHPWG.aspx

- Four-Factor Analysis for control measures
- Regional photochemical modeling
- Assessment of “unknowns” and uncertain categories (natural conditions, international emissions, fire, and dust emission, etc.)
- Development of RH SIP package content and progress report template
- Development of control strategies menu for major western state sources

For additional information on the origins of WRAP, see Section 1.E.2.

### 2.A.1 Technical Information and Data: WRAP TSS2.0

The WRAP TSS 2.0 is the data warehouse and online portal used by air quality planners to evaluate the technical data and analytical results to support regional haze implementation plans. The TSS 2.0 is a “system of systems” that integrates capabilities from many systems, including systems focused on: monitoring data analysis efforts, emissions data management systems, fire emissions tracking systems, photochemical aerosol regional modeling analyses, and visualization and summary data analyses.[71] These diverse data sets can be analyzed through the TSS and the resultant outputs can be downloaded for use in SIP reports. This SIP submittal relies on the data stored in and retrieved from the TSS 2.0 system.

## 2.B Consultation with Federal Land Managers

The federal land management 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). FLMs have a critical role in protecting air quality in national parks, wilderness, and other federally protected areas. They have an affirmative responsibility to protect air quality related values, including visibility, in all CIAs.[72] Utah primarily meets with the NPS and USFS for RH planning.

States must provide the FLMs with an opportunity for an early in-person consultation about the state’s long-term strategy to reduce emissions.[73] This consultation should happen early enough in the process so that the information and recommendations provided by the FLMs can meaningfully inform the State’s decisions.[74] The opportunity for consultation is sufficient if the consultation happened at least 120 days prior to any public hearing or other public comment opportunity on SIP or SIP revision.[75] The opportunity for consultation must also be provided no less than 60 days prior to said public hearing or public comment opportunity.[76]

[71] https://views.cira.colostate.edu/tssv2/About/Default.aspx
[72] *See* 40 C.F.R. § 51.166(p)(2).
[73] *See* 40 C.F.R. § 51.308(i)(2).
[74] *See id*.
[75] *See id*.
[76] *See id*.

This consultation must include the opportunity for the affected FLMs to discuss their:

- Assessment of impairment of visibility in any mandatory CIA; and
- Recommendations on the development of the reasonable progress goal and on the development and implementation of strategies to address visibility impairment.[77]

FLM of any mandatory Class I area can submit any recommendations on the implementation of this subpart (40 C.F.R. Part 51, Subpart P: Protection of Visibility) including, but not limited to:

i. Identification of impairment of visibility in any mandatory CIA(s); and
ii. Identification of elements for inclusion in the visibility monitoring strategy required by § 51.305.[78]

Utah has engaged with the FLMs and shared the RH SIP with them on December 8, 2021. See Chapter 9 Consultation, Public Review, Commitment to Further Planning for full documentation of Utah's consultation with the FLMs during this implementation period.

Numerous opportunities were provided through the WRAP for states and FLMs to participate fully in the development of technical documents included in this SIP. This included the ability to review and comment on these analyses, reports, and policies. A summary of the WRAP-sponsored meetings and conference calls is provided on the WRAP website[79].

## 2.C Collaboration with Tribes

Tribal governments are responsible for coordinating with federal and state governments to protect air quality on their sovereign lands and to ensure emission sources on tribal lands meet federal requirements. The 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. For example, The Bonanza power plant, located on "Indian Country" in the Uinta Basin, has a Q/d value large enough to require a Four-Factor Analysis, but is not under the jurisdiction of the Utah Department of Environmental Quality. In order to further the environmental justice initiative in Utah, UDAQ shared its RH SIP draft with the tribes of Utah at the same time it was shared with the FLMs and EPA for a 60-day review on December 8, 2021.

## 2.D Consultation with Other States

States are required to share information with other states that have CIAs that are reasonably anticipated to be impacted by each other's emissions. States are also required to evaluate, though not necessarily implement, control measures requested by other states and document actions taken to resolve disagreements. The TSS 2.0 analyses tools, including emissions tools and source apportionment modeling results, aid states to determine if an in-state source could be impacting an out-of-state Class I area. Utah consulted with neighboring states, both through

[77] *See id*., § 51.308(i)(2)(i) and (ii).
[78] *See id*., § 51.308(i)(1)(i) and (ii).
[79] More information on WRAP-sponsored meetings and conference calls is available at https://www.wrapair2.org/RHPWG.aspx.

webinars and calls organized through the WRAP, and via state-to-state communication, to address the requirements of the RHR for coordinated emissions control strategies between states. Specifically, 40 CFR § 51.308(f)(2)(ii) requires that Utah consult with other states that have emissions that are reasonably anticipated to contribute to visibility impairment in Utah CIAs to develop coordinated emission management strategies containing the emission reductions necessary to make reasonable progress.

WRAP conducted technical analyses to evaluate interstate emissions impacts. These analyses include source apportionment modeling and area of influence/weighted emissions potential (AOI/WEP) analyses. Source apportionment modeling is used to identify states and sectors that are contributing haze. AOI/WEP analyses can identify what significant emission sources are upwind from a Class I area. Utah discussed the results of these analyses with surrounding states. Due to all of Utah's CIAs visibility being at or below their projected glidepath goals towards natural conditions in 2064, UDAQ will not ask for any additional controls from other states that may impact Utah's visibility in CIAs. Refer to sections 6.A.1 and 6.A.2 for a detailed analysis on out of state impacts on Utah's CIA's and Utah's impacts on out of state CIAs.

Utah has met with Colorado, New Mexico, Arizona, and Wyoming directly as well as attended Region 8, WRAP, WESTAR, and Four Corners States meetings as part of the second planning period SIP development. For additional details regarding individual consultation, see Chapter 9 as well as Appendix B or Utah's interstate consultation agreements with surrounding states.

## 2.E Public and Stakeholder Consultation

Many different agencies and interests come together to develop a RH SIP. Prior to formal public review and EPA action, states should communicate regularly with industry and the public. Utah communicated regularly with the regulated industry, including the sources that may be impacted by the Four-Factor Analysis, environmental advocates, as well as members of the public. Utah holds six meetings each for the industry stakeholders and environmental advocates. For additional details regarding stakeholder consultation, see Chapter 9.

# **Chapter 3:** Progress to Date

## 3.A Embedded Progress Report Requirements

Section 51.308(f)(5) of the RHR requires a state to address the requirements of subsections 51.308 (g)(1) through (5) in the plan revision. By fulfilling this requirement, the plan revision due in 2021 will also serve as a progress report for the period since submission of the progress report for the first implementation period. The progress report for the first implementation period included visibility levels, emissions, and implementation status up to a date prior to submittal.[80]

This chapter is meant to inform the public and EPA about implementation activities since the last regional haze SIP submission.

### 3.A.1 Implementation status of all measures in first planning period[81]

The RHR[82] requires certain major stationary sources to evaluate, install, operate and maintain BART technology or an approved BART alternative for $NO_x$ and PM emissions. The State of Utah chose to evaluate BART for PM under the case-by-case provisions of 40 CFR 51.308(e)(1) and BART for $NO_x$ through alternative measures[83]. BART for $SO_2$ is addressed through an alternative program[84] that is described in Part E of the 2019 Regional Haze SIP.

40 CFR 51.308(e)(1)(ii) requires states to determine which BART-eligible sources are also "subject to BART." BART-eligible sources are subject to BART if they emit any air pollutant that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory CIA.

Four BART-eligible electric generating units were identified in the State of Utah: PacifiCorp's Hunter Units 1 and 2 and Huntington Units 1 and 2. The units are located at fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input, one of the 26 specific BART source categories. The units had potential emissions greater than 250 tons per year of visibility impairing pollutants. The units had commenced construction within the BART time frame of August 7, 1962 to August 7, 1977. PacifiCorp Hunter Units 1 and 2 and Huntington Units 1 and 2 replaced first generation low-$NO_x$ burners with Alstom TSF 2000TM low-$NO_x$ firing system and installation of two elevations of separated overfire air with an emission limit of 0.26 lb./MMBtu on a 30-day rolling average.

In addition, PacifiCorp Hunter Unit 3 (not subject-to-BART) replaced first generation low-$NO_x$ burners with improved low-$NO_x$ burners with overfire air with an emission limit of 0.34 lb./MMBtu

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[80] The 2017 Regional Haze Guidance document can be found at https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf
[81] (40 CFR 51.308(g)(1))
[82] 40 CFR 51.308(e) and 40 CFR 51.309(d)(4)(vii)
[83] 40 CFR 51.308(e)(2) and (3)
[84] 40 CFR 51.309

on a 30-day rolling average and PacifiCorp Carbon Units 1 and 2 (not subject-to-BART) were permanently retired by August 15, 2015.

**Table 1: 30-day Rolling Average Emission Limits for the Retrofitted Hunter and Huntington Units**

| Units | Utah Permitted Limits | | |
|---|---|---|---|
| | $SO_2$ (lb./MMBtu) | $NO_x$ (lb./MMBtu) | PM (lb./MMBtu) |
| **Hunter 1** | 0.12 | 0.26 | 0.015 |
| **Hunter 2** | 0.12 | 0.26 | 0.015 |
| **Hunter 3** | | 0.34 | |
| **Huntington 1** | 0.12 | 0.26 | 0.015 |
| **Huntington 2** | 0.12 | 0.26 | 0.015 |

### 3.A.2 Summary of emission reductions achieved by control measure implementation[85]

The enforceable retirement of Carbon Units 1 and 2 resulted in $SO_2$ reductions of 3,388 tons/year from Unit 1 and 4,617 tons per year from Unit 2, resulting in a total of 8,005 tons per year. Utah's emissions reductions are further detailed in Chapter 5.

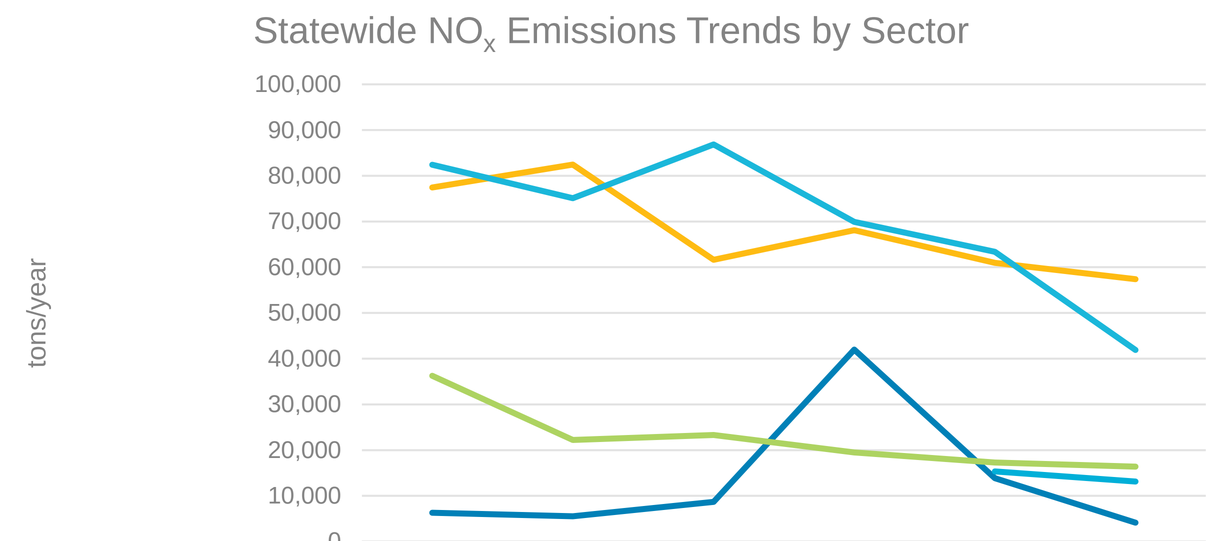
### 3.A.3 Assessment of visibility conditions[86]

Please refer to Chapter 4 for information regarding Utah's visibility analyses.

[85] (40 CFR 51.308(g)(2)(5))
[86] (40 CFR 51.308(g)(3))

### 3.A.4 Analysis of any changes in emissions from all sources and activities within the state[87] ~~[88]~~

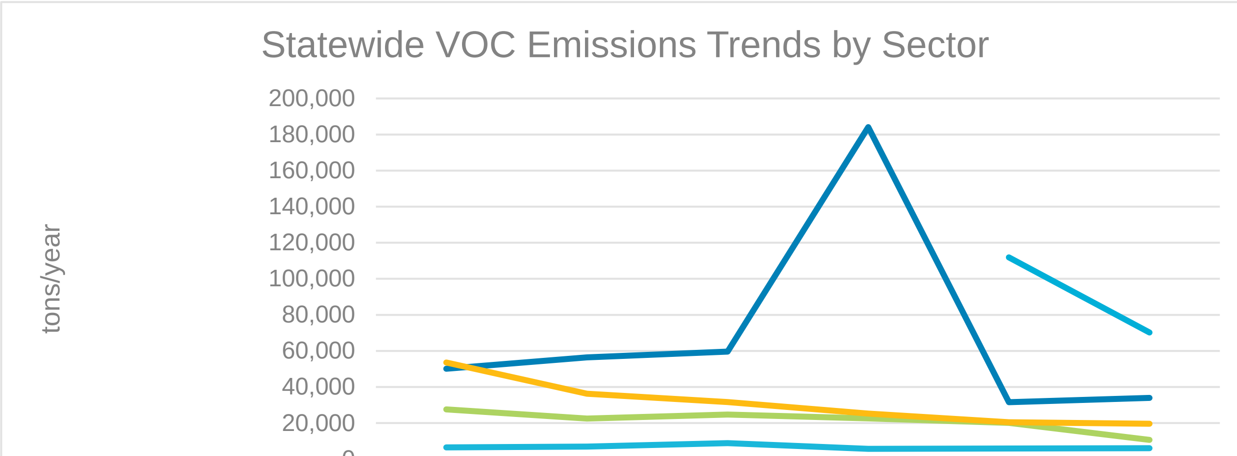
The following figures show Utah’s statewide total emissions trends by sector from 2002 to 2017. This data comes from Utah’s statewide emissions inventories. In 2011, there are certain spikes in emissions for area source emissions due to inventory method changes and an increase in the amount of Source Classification Codes (SCCs) defining area sources. UDAQ notes that inventory methodologies have changed over time and the emissions inventories based on WRAP modeling data in section 5.E may be more useful for comparing historical and recent emissions to future projections for the purposes of satisfying the requirements of 40 CFR 51.308(g)(4).




| | 2002 | 2005 | 2008 | 2011 | 2014 | 2017 |
|---|---|---|---|---|---|---|
| Area Source | 6,294 | 5,536 | 8,664 | 41,987 | 13,848 | 4,134 |
| Area Source - Oil & Gas | | | | | 15,340 | 13,130 |
| Non-Road Mobile | 36,257 | 22,212 | 23,296 | 19,507 | 17,288 | 16,388 |
| On-Road Mobile | 77,437 | 82,449 | 61,634 | 68,109 | 60,952 | 57,387 |
| Point Source | 82,421 | 75,102 | 86,857 | 69,913 | 63,370 | 41,903 |

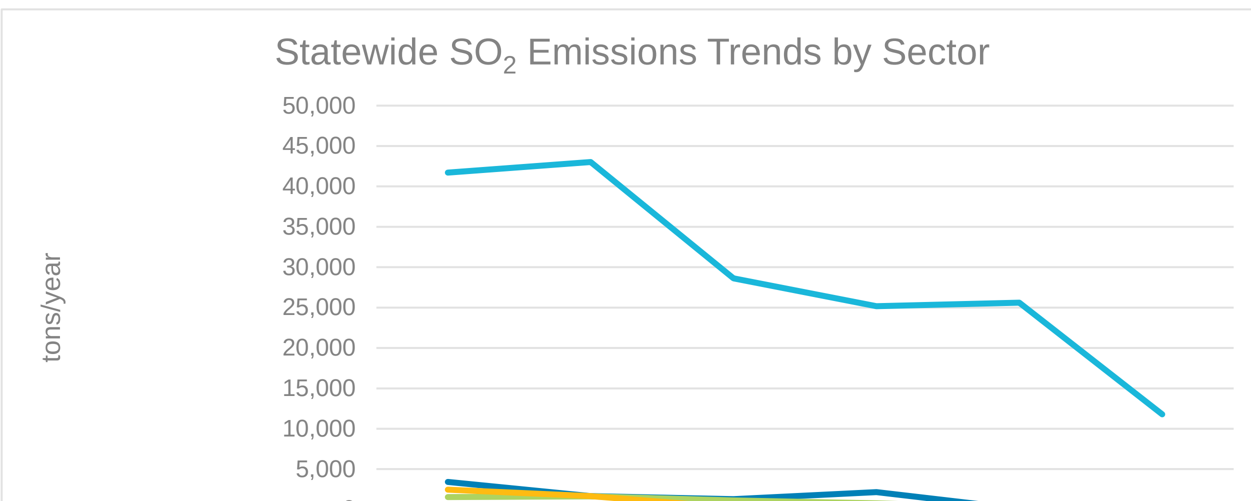
**Figure 16:Statewide $NO_x$ Emissions Trends by Sector**

[87] (40 CFR 51.308(g)(4))



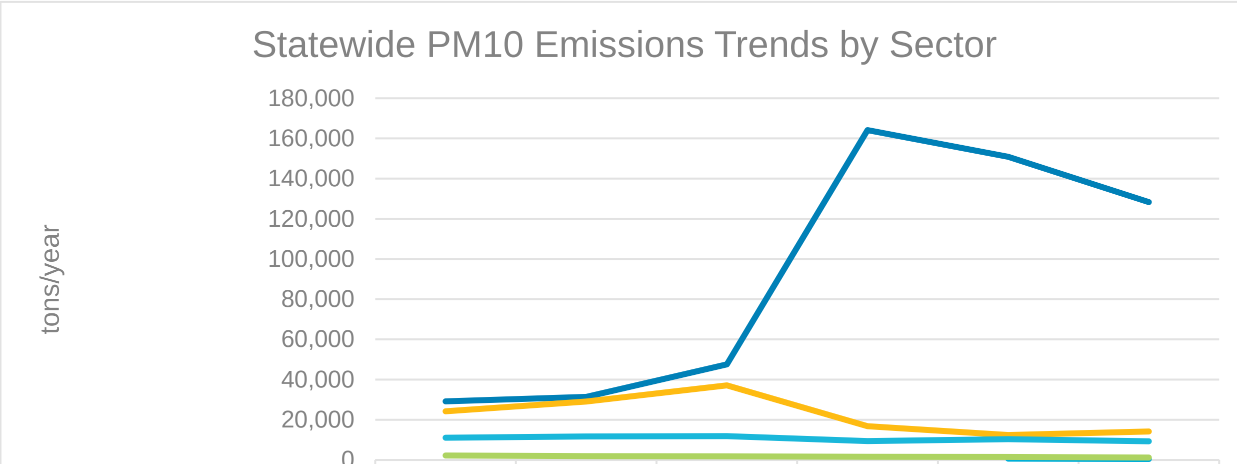

| | 2002 | 2005 | 2008 | 2011 | 2014 | 2017 |
|---|---|---|---|---|---|---|
| Area Source | 50,152 | 56,416 | 59,587 | 184,099 | 31,574 | 33,935 |
| Area Source - Oil & Gas | | | | | 111,880 | 70,217 |
| Non-Road Mobile | 27,584 | 22,479 | 24,677 | 22,629 | 20,066 | 10,671 |
| On-Road Mobile | 53,582 | 36,278 | 31,673 | 25,282 | 20,487 | 19,619 |
| Point Source | 6,555 | 6,963 | 8,872 | 5,707 | 5,899 | 6,104 |

**Figure 17: Statewide VOC Emissions Trends by Sector**



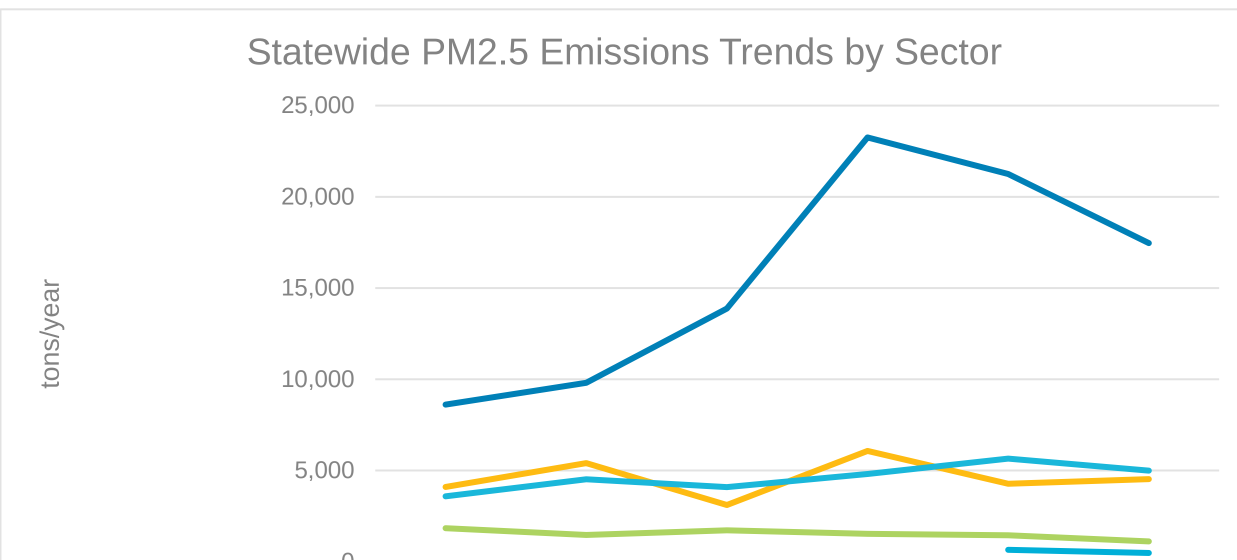

| | 2002 | 2005 | 2008 | 2011 | 2014 | 2017 |
|---|---|---|---|---|---|---|
| Area Source | 3,416 | 1,660 | 1,284 | 2,156 | 89 | 117 |
| Area Source - Oil & Gas | | | | | 92 | 74 |
| Non-Road Mobile | 1,536 | 1,627 | 1,132 | 759 | 214 | 220 |
| On-Road Mobile | 2,458 | 1,667 | 247 | 333 | 295 | 327 |
| Point Source | 41,704 | 43,019 | 28,621 | 25,170 | 25,600 | 11,786 |

**Figure 18: Statewide SO2 Emissions Trends by Sector**



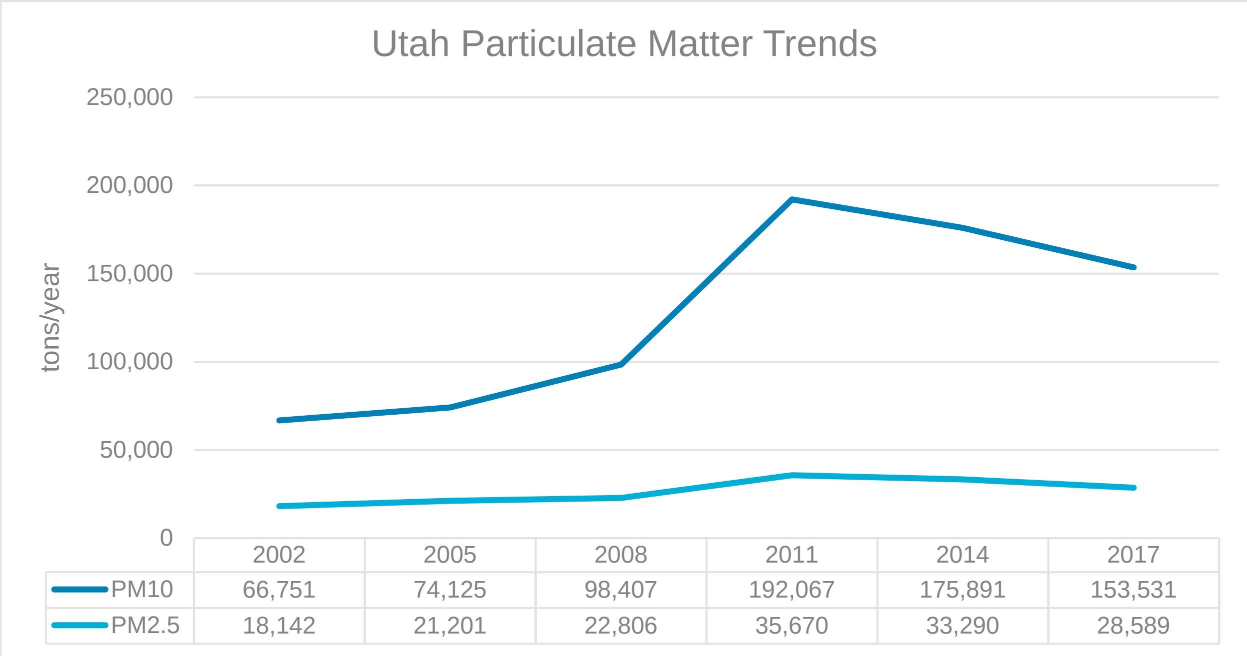

| | 2002 | 2005 | 2008 | 2011 | 2014 | 2017 |
|---|---|---|---|---|---|---|
| Area Source | 29,181 | 31,416 | 47,552 | 164,142 | 150,865 | 128,303 |
| Area Source - Oil & Gas | | | | | 675 | 483 |
| Non-Road Mobile | 2,243 | 1,892 | 1,841 | 1,627 | 1,528 | 1,230 |
| On-Road Mobile | 24,246 | 29,077 | 37,137 | 16,856 | 12,426 | 14,212 |
| Point Source | 11,080 | 11,739 | 11,877 | 9,443 | 10,397 | 9,303 |

**Figure 19: Statewide $PM_{10}$ Emissions Trends by Sector**



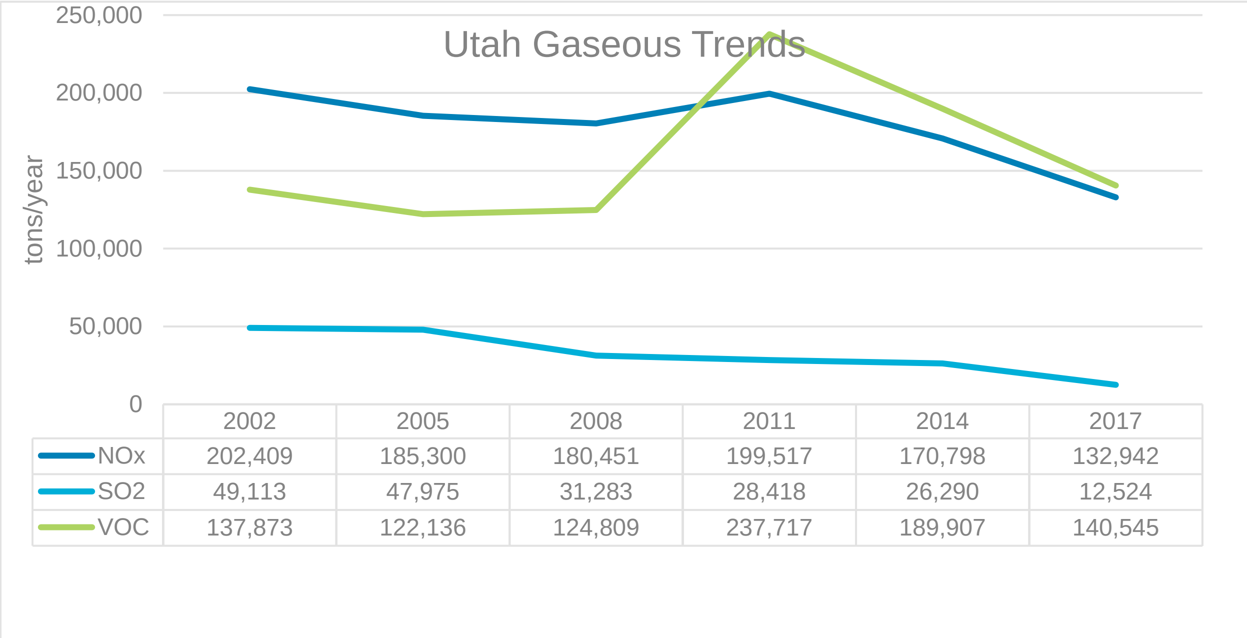

| | 2002 | 2005 | 2008 | 2011 | 2014 | 2017 |
|---|---|---|---|---|---|---|
| Area Source | 8,613 | 9,806 | 13,878 | 23,254 | 21,254 | 17,460 |
| Area Source - Oil & Gas | | | | | 656 | 483 |
| Non-Road Mobile | 1,840 | 1,473 | 1,727 | 1,533 | 1,449 | 1,117 |
| On-Road Mobile | 4,101 | 5,404 | 3,111 | 6,074 | 4,278 | 4,532 |
| Point Source | 3,587 | 4,518 | 4,089 | 4,809 | 5,653 | 4,998 |

**Figure 20: Statewide $PM_{2.5}$ Emissions Trends by Sector**




| | 2002 | 2005 | 2008 | 2011 | 2014 | 2017 |
|---|---|---|---|---|---|---|
| PM10 | 66,751 | 74,125 | 98,407 | 192,067 | 175,891 | 153,531 |
| PM2.5 | 18,142 | 21,201 | 22,806 | 35,670 | 33,290 | 28,589 |

**Figure 21: Utah Particulate Matter Trends**




| | 2002 | 2005 | 2008 | 2011 | 2014 | 2017 |
|---|---|---|---|---|---|---|
| NOx | 202,409 | 185,300 | 180,451 | 199,517 | 170,798 | 132,942 |
| SO2 | 49,113 | 47,975 | 31,283 | 28,418 | 26,290 | 12,524 |
| VOC | 137,873 | 122,136 | 124,809 | 237,717 | 189,907 | 140,545 |

**Figure 22: Utah Gaseous Trends**

### 3.A.5 Assessment of any changes in emissions from within or outside the state.[89]

The Center for the New Energy Economy (CNEE) at Colorado State University conducted an analysis of current and future emissions of $NO_x$ and $SO_2$ from fossil-fueled EGUs in 13-Western states1 for WESTAR and WRAP.[90] WRAP state air quality staff and representatives of Western electric utilities actively participated in the project and helped develop the study parameters, including information needed for Western regional air quality analyses and planning under the federal Clean Air Act.

$SO_2$ and $NO_x$ emissions from the Western power sector have decreased dramatically over the last 20 years. As shown in Figure 23, 2018 EGU emissions of $SO_2$ were 84% below 1998 levels and $NO_x$ emissions were 71% below 1998.

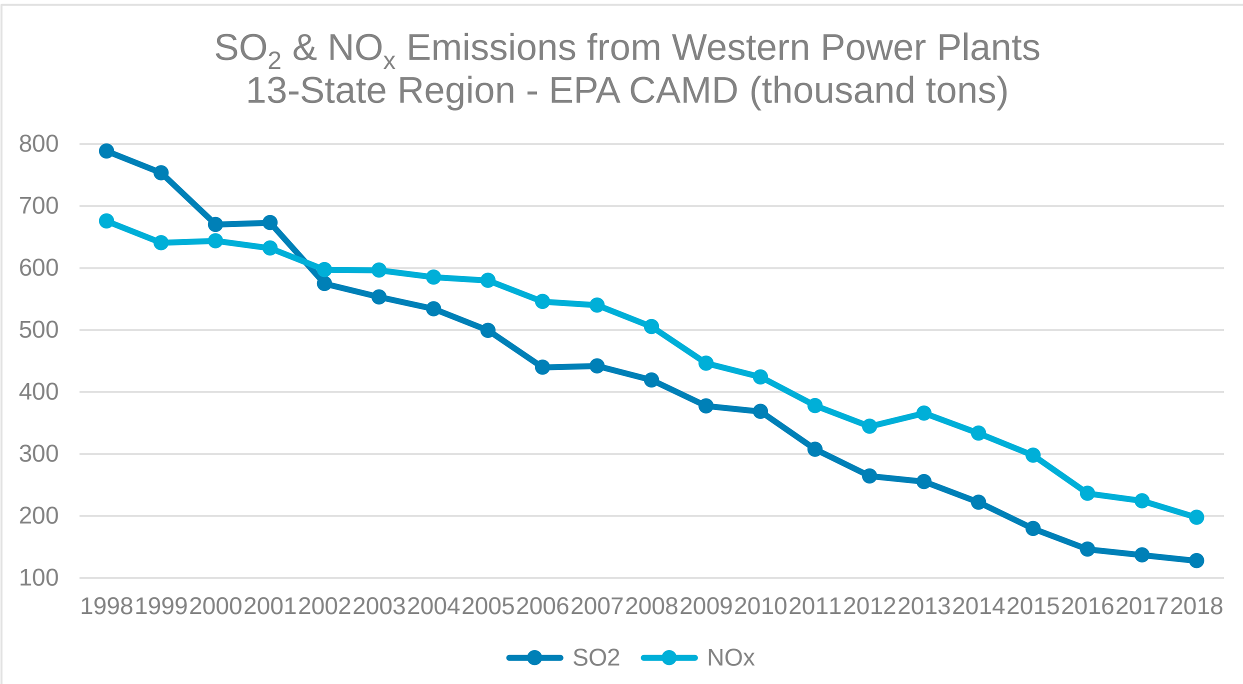



**Figure 23: $SO_2$ and $NO_x$ Emissions Trends for Western Power Plants[1]**

Table 2 below shows that 29 of the 84 coal units operating in the West in 2018 have plans (not all federally enforceable) to retire by 2028. Emissions from these units were omitted from the 2028 projections produced by the CNEE, though some states opted to include emissions for some of the listed EGUs in the final WRAP 2028OTBa2 projections due to uncertainties about firm closures (e.g., North Valmy, San Juan Generating Station, etc.).

[89] (40 CFR 51.308(g)(5))
[90] The Analysis of EGU Emissions for Regional Haze Planning by the CNEE can be found at http://www.wrapair2.org/%5C/pdf/Final%20EGU%20Emissions%20Analysis%20Report.pdf

**Table 2: Western Coal Unit Retirement and Control Summary**

| State | Facility Name | Unit ID | Operating Year | Retirement Year | Notes |
|---|---|---|---|---|---|
| **PLANNED RETIREMENTS - NO POST-COMBUSTION CONTROL FOR NO=x** | | | | | |
| **AZ** | Cholla | 1 | 1962 | 2025 | APS IRP |
| **AZ** | Cholla | 3 | 1980 | 2025 | APS IRP |
| **AZ** | Cholla | 4 | 1981 | 2025 | PAC IRP |
| **AZ** | Navajo Generating Station | 1 | 1974 | 2019 | SRP IRP |
| **AZ** | Navajo Generating Station | 2 | 1975 | 2019 | SRP IRP |
| **AZ** | Navajo Generating Station | 3 | 1976 | 2019 | SRP IRP |
| **CO** | Comanche (470) | 1 | 1973 | 2022 | Xcel Colorado Energy Plan |
| **CO** | Comanche (470) | 2 | 1975 | 2025 | Xcel Colorado Energy Plan |
| **CO** | Craig | C1 | 1980 | 2025 | Legal/Regulatory |
| **CO** | Nucla | 1 | 1991 | 2022 | Legal/Regulatory |
| **CO** | Valmont | 5 | 1964 | 2017 | Retired |
| **MT** | Colstrip | 1 | 1975 | 2022 | Legal/Regulatory |
| **MT** | Colstrip | 2 | 1976 | 2022 | Legal/Regulatory |
| **NM** | San Juan | 1 | 1976 | 2022 | PNM IRP (SNCR) |
| **NM** | San Juan | 2 | 1973 | 2017 | Retired |
| **NM** | San Juan | 3 | 1979 | 2017 | Retired |
| **NM** | San Juan | 4 | 1982 | 2022 | PNM IRP |
| **NV** | North Valmy | 1 | 1981 | 2025 | NV IRP (2019 per ID Power?) |
| **NV** | North Valmy | 2 | 1985 | 2025 | NV IRP |
| **NV** | Reid Gardner | 4 | 1983 | 2017 | Retired |
| **OR** | Boardman | 1SG | 1980 | 2021 | Legal/Regulatory |
| **UT** | Intermountain | 1SGA | 1986 | 2025 | Planned (new gas?) |
| **UT** | Intermountain | 2SGA | 1987 | 2025 | Planned (new gas?) |
| **WA** | Centralia | BW21 | 1972 | 2021 | Legal/Regulatory (12/31/2020) |
| **WA** | Centralia | BW22 | 1973 | 2026 | Legal/Regulatory (12/31/2025) |
| **WY** | Naughton | 3 | 1971 | 2018 | PAC IRP - gas in 2019? |
| **MT** | Hardin | | | 2017 | |
| **POTENTIAL RETIREMENTS - NO POST-COMBUSTION CONTROL FOR $NO_x$** | | | | | |
| **AZ** | Coronado Generating Station | U1B | 1979 | | Retire or install SCR in 2025 |
| **UT** | Bonanza | 1-Jan | 1986 | 2030 | Coal consumption cap |
| **WY** | Dave Johnston | BW41 | 1959 | 2027 | PAC IRP |
| **WY** | Dave Johnston | BW42 | 1961 | 2027 | PAC IRP |
| **WY** | Dave Johnston | BW43 | 1964 | 2027 | PAC IRP |

| State | Facility Name | Unit ID | Operating Year | Retirement Year | Notes |
|---|---|---|---|---|---|
| WY | Dave Johnston | BW44 | 1972 | 2027 | PAC IRP |
| WY | Jim Bridger | BW71 | 1974 | 2028 | PAC IRP (SCR req'd 2022) |
| WY | Naughton | 1 | 1963 | 2029 | PAC IRP |
| WY | Naughton | 2 | 1968 | 2029 | PAC IRP |
| POST 2028 RETIREMENT DATE - SCR INSTALLED | | | | | |
| AZ | Coronado Generating Station | U2B | 1980 | | SCR 2014 |
| AZ | Springerville Generating Station | 4 | 2009 | | SCR |
| AZ | Springerville Generating Station | TS3 | 2006 | | SCR |
| CO | Comanche (470) | 3 | 2010 | | SCR |
| CO | Craig | C2 | 1979 | | SCR 2017 |
| CO | Hayden | H1 | 1965 | 2030 | Xcel IRP - SCR in 2015 |
| CO | Hayden | H2 | 1976 | 2036 | Xcel IRP - SCR 2016 |
| CO | Pawnee | 1 | 1981 | 2034 | Xcel IRP - SCR 2014 |
| NM | Four Corners Steam Elec Station | 4 | 1969 | | 2031 per TEP&PNM - SCR 2017 |
| NM | Four Corners Steam Elec Station | 5 | 1970 | | 2031 per TEP&PNM - SCR 2017 |
| NV | TS Power Plant | 1 | 2008 | | SCR |
| WY | Dry Fork Station | 1 | 2011 | | SCR |
| WY | Jim Bridger | BW73 | 1976 | 2037 | PAC IRP - SCR 2015 |
| WY | Jim Bridger | BW74 | 1979 | 2037 | PAC IRP - SCR 2016 |
| WY | Laramie River | 1 | 1981 | | SCR 2019 |
| WY | Wygen I | 1 | 2003 | | SCR |
| WY | Wygen II | 1 | 2008 | | SCR |
| WY | Wygen III | 1 | 2010 | | SCR |
| AZ | Apache Station | 3 | 1979 | | SNCR 2017 |
| CO | Craig | C3 | 1984 | | SNCR 2017 |
| WY | Laramie River | 2 | 1981 | | SNCR 2018 |
| WY | Laramie River | 3 | 1982 | | SNCR 2018 |
| POST 2028 RETIREMENT DATE - NO POST COMBUSTION CONTROLS FOR $NO_x$ | | | | | |
| AZ | Springerville Generating Station | 1 | 1985 | | |
| AZ | Springerville Generating Station | 2 | 1990 | | |
| CO | Martin Drake | 6 | 1968 | | |
| CO | Martin Drake | 7 | 1974 | | |
| CO | Rawhide Energy Station | 101 | 1984 | | |

| State | Facility Name | Unit ID | Operating Year | Retirement Year | Notes |
|---|---|---|---|---|---|
| **CO** | Ray D Nixon | 1 | 1980 | | |
| **MT** | Colstrip | 3 | 1984 | | |
| **MT** | Colstrip | 4 | 1986 | | |
| **MT** | Lewis & Clark | B1 | 1958 | | |
| **NM** | Escalante | 1 | 1984 | | |
| **UT** | Hunter | 1 | 1978 | 2042 | PAC IRP - Haze Lawsuit |
| **UT** | Hunter | 2 | 1980 | 2042 | PAC IRP - Haze Lawsuit |
| **UT** | Hunter | 3 | 1983 | 2042 | PAC IRP |
| **UT** | Huntington | 1 | 1977 | 2036 | PAC IRP - Haze Lawsuit |
| **UT** | Huntington | 2 | 1974 | 2036 | PAC IRP - Haze Lawsuit |
| **WY** | Jim Bridger | BW72 | 1975 | 2032 | PAC IRP (SCR Req'd 2021) |
| **WY** | Neil Simpson II | 1 | 1995 | | |
| **WY** | Wyodak | BW91 | 1978 | 2039 | PAC IRP - Haze Lawsuit |

Emissions from coal units that will retire by 2028 comprised 27% of the $SO_2$ and 34% of the $NO_x$ emitted in 2018 by all EGUs (coal and gas) in the 13-state Western region.[91] Figure 24 below shows the portion of EGU emissions represented by remaining fossil units and retiring coal units. Table 3 below contains data compiled by WESTAR-WRAP showing the changes in emissions from 1996-2018 and percent change throughout the GCVTC states.

[91] The Analysis of EGU Emissions for Regional Haze Planning by the CNEE can be found at http://www.wrapair2.org/%5C/pdf/Final%20EGU%20Emissions%20Analysis%20Report.pdf

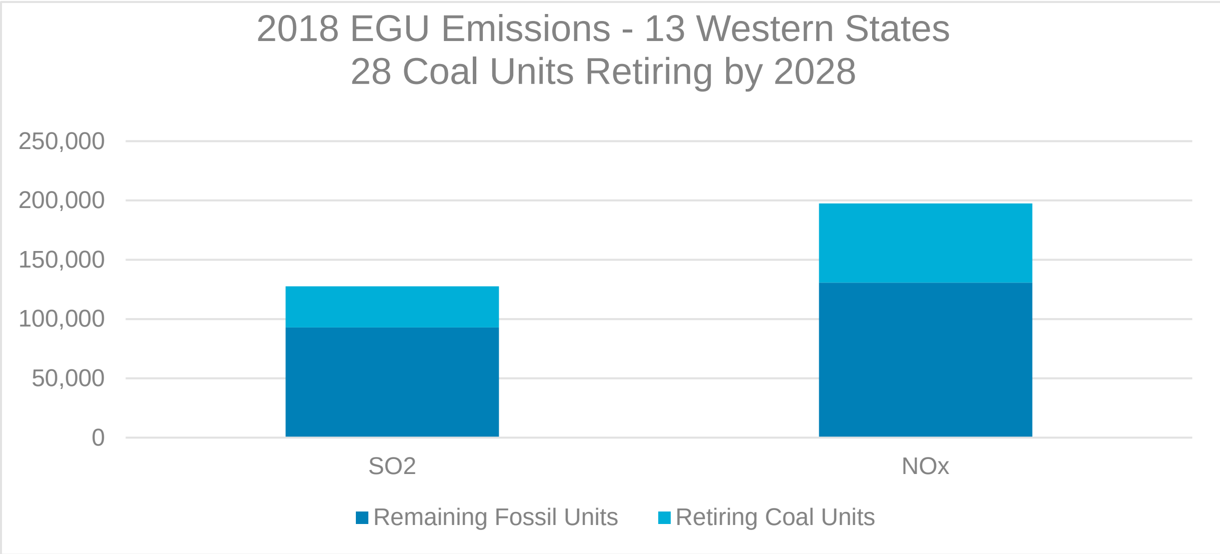



**Figure 24: Remaining and Retiring EGU Emissions Apportionment**

**Table 3: Changes in Emissions from 1996 - 2018 for 9 GCVTC States**

| Year | VOC | $NO_x$ | $SO_2$ | $PM_{2.5}$* | CM |
|---|---|---|---|---|---|
| **1996** | 3325 | 3952 | 1063 | 1197 | 1171 |
| **2002** | 2449 | 2241 | 675 | 832 | 1886 |
| **2018** | 2760 | 1683 | 503 | 832 | 2104 |
| **% Change** | -17 | -57 | -53 | -30 | 80 |

# **Chapter 4:** Utah Visibility Analysis[92]

The rule adopted in 1999 defined "visibility impairment" as "any humanly perceptible change" (i.e., difference) "in visibility (light extinction, visual range, contract, or coloration) from that which would have existed under natural conditions."[93] The 1999 rule directed states to track visibility impairment on the 20% "most impaired days" and 20% "least impaired days" in order to determine progress towards natural visibility conditions.[94] This iteration of the rule did not define "most impaired days" or "least impaired days" or clearly indicate whether they were the days with the highest and lowest values for both natural and anthropogenic impairment or for anthropogenic impairment only. However, the preamble to the 1999 final rule stated that the least and most impaired days were to be selected as the monitored days with the lowest and highest actual deciview levels, respectively, which encompass both natural and anthropogenic contributions to reduced visibility.[95] In 2003, the EPA issued a guidance detailing the steps for selecting and calculating light extinction on the "worst" and "best" visibility days, which also indicated that it is preferable for states to determine the least and most impaired days based on monitoring data rather than determining and selecting the days with the highest and lowest anthropogenic impacts.[96] For the assessment purposes in the first planning period, the GCVTC considered the average of the days representing the 20% best visibility conditions to be the least impaired days.

The "worst" visibility days for some CIAs are impacted by natural emissions (e.g., wildfires and dust storms). These natural contributions to haze vary in magnitude and duration. WRAP used regional photochemical grid models to project visibility improvement between the 2002 baseline and the 2018 future year and to set RPGs for the RHR state implementation plans. Despite western states projecting large emission reductions from EGUs, mobile sources and smoke management programs, the results of the 2018 visibility RPGs indicated many western CIAs were projected to achieve less progress than the glidepath.

As a result, EPA modified the way in which certain days during each year are to be selected for purposes of tracking progress towards natural visibility conditions in order to focus attention on days when anthropogenic emissions impair visibility and away from days when wildfires and natural dust storms are the greatest contributors to visibility impairment.[97] These changes will

[92] 40 CFR 51.308(F)(1)
[93] "64 Fed. Reg. 35714, 35764."
[94] "40 CFR 51.308(d)(2)(i)-(iv)."
[95] The 2019 EPA Guidance can be found at: https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf
[96] The EPA Guidance for Tracking Progress Under the Regional Haze Rule can be found at https://www.epa.gov/visibility/guidance-tracking-progress-under-regional-haze-rule
[97] The 2019 EPA Guidance can be found at: https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

provide the public and public officials with more meaningful information on how emission reduction contribute to a decline in anthropogenic visibility impairment by reasonably reducing the distorting effects of wildfires and natural dust storms on estimates of reasonable progress.

The EPA method defined a threshold for the episodic portion of natural haze for the carbonaceous species (organic mass carbon (OMC), elemental carbon (EC)) and crustal material (fine soil plus coarse mass), components that are indicators of wildfires and dust storms, respectively.[98] EPA recommended nominal thresholds for each episodic species' combinations as the minimums of the yearly 95$^{th}$ percentile for the 15-year period from 2000 to 2014. The daily fraction of species extinction values greater than the 95$^{th}$ percentile threshold are assigned to the natural episodic bin. Smaller, routine natural contributions from biogenic or geogenic emissions are assumed to be a constant fraction of the measured IMPROVE species concentrations on each day, with the fraction calculated as the ratio of a previously estimated annual average natural concentration[99] (Natural Conditions II, NC-II) divided by the non-episodic annual average IMPROVE concentrations measured for each species. The metric calculates the

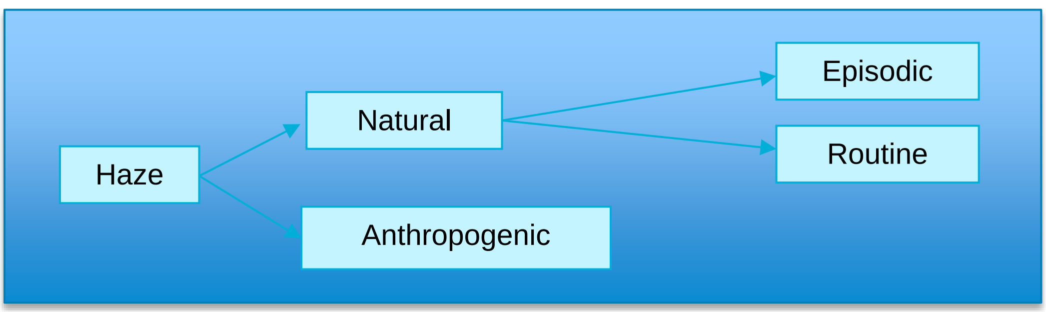



**Figure 25: Light extinction for Utah Class I Areas: natural and anthropogenic sources**

natural routine portion, such that its annual average (excluding episodic events) is equal to the site and species-specific NC-II concentrations.

Daily anthropogenic impairment is calculated as:

$$\Delta\ \mathbf{dv}_{\text{anthropogenic visibility impairment}} = \mathbf{dv}_{\text{total}} - \mathbf{dv}_{\text{natural}}$$

Daily anthropogenic impairment values are ranked from high to low impairment in order to select the 20% most impaired days (MIDs) each year. States must now determine the baseline (2000-2004) visibility condition for the 20% most anthropogenically impaired days. This approach differs from the previous round in which the 20% most impaired days were selected from days with the highest total impairment, not separating anthropogenic versus natural impairment. Once the most impaired days are selected, states must calculate the rate of visibility improvement over time that is required to reach natural conditions by 2064 for the 20% most impaired days. Using the metric described above for separating natural (episodic and routine)

[98] Figure 25 shows how haze is separated into natural and anthropogenic causes
[99] IMPROVE. 2007. Natural Haze Levels II: Application of the New IMPROVE Algorithm to Natural Species Concentrations Estimates. Interagency Monitoring of Protected Visual Environments. http://vista.cira.colostate.edu/Improve/gray-literature/ (accessed October 2021)

and anthropogenic, natural conditions are calculated as the average of the daily natural contributions on the 20% most impaired days, in the period 2000-2014. The figures below display the clearest and most impaired days calculated as described in EPA guidance. The line drawn from the baseline to the endpoint is termed the glidepath, or the "uniform rate of progress (URP)," and is calculated for each Class I area, and is used as a tracking metric for the path to natural conditions. The URP is calculated with the following formula:

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

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

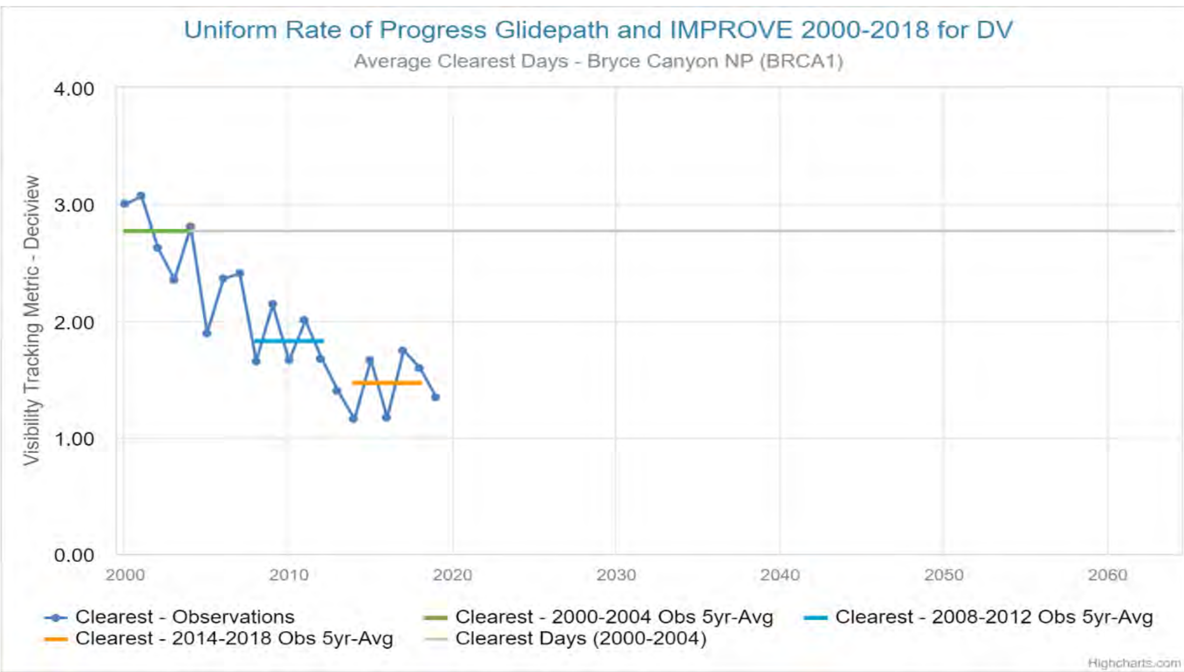



**Figure 26: URP Glidepath for Clearest Days, Bryce Canyon NP**

No changes were made from the previous implementation period in how the 20% clearest days are calculated. The 20% clearest days are calculated from the days with the lowest total impairment. As stated previously, the RHR requires states to demonstrate that there is no degradation in the 20% clearest days from the baseline period.[100]

[100] "64 Fed. Reg. 35714, 35764."

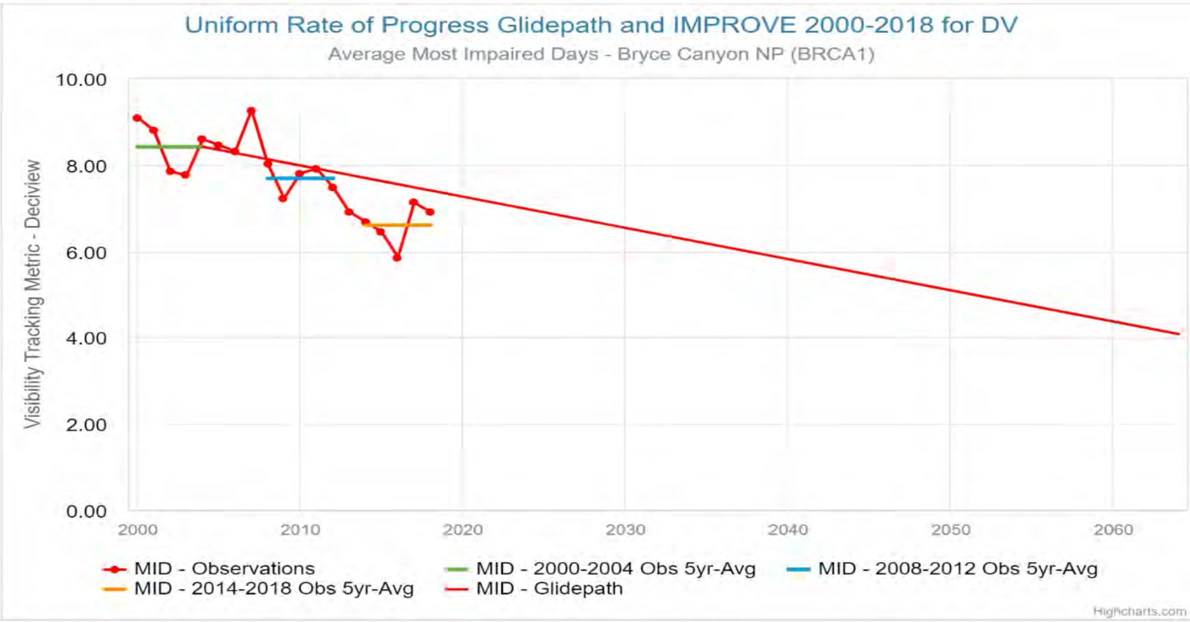



**Figure 27: URP Glidepath for most impaired days, Bryce Canyon NP**

## 4.A Baseline, Current Conditions and Natural Visibility Conditions

Section 51.308(f)(1) of the RHR requires Utah to calculate the baseline, current, and natural visibility conditions as well as to determine the visibility progress to date and the uniform rate of progress (URP) for each of its five CIAs. According to the RHR, baseline period visibility conditions, current visibility conditions, natural conditions, and the URP should be expressed in deciviews and calculated based on total light extinction.[101] Baseline visibility conditions are based on available monitoring data of the most impaired and clearest days during the period of 2000 to 2004. Current visibility conditions are to be calculated based upon the most recent five years of data by calculating the average of the annual deciview index values for the most impaired days and clearest days in this period, and averaging these respective annual values. Natural visibility conditions are to be calculated by estimating the average deciview index on most impaired and clearest days under natural conditions. Calculations were made in accordance with 40 CFR 51.308(d)(2) and EPA's Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program.[102]

[101] The 2019 EPA Guidance can be found at: https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf
[102] Table 4 and Table 5 describe the IMPROVE site information for Utah's CIAs

**Table 4: Representative IMPROVE Monitoring Sites**

| Class I Area Name | Representative IMPROVE Site | Site ID |
|---|---|---|
| Arches National Park | Canyonlands NP | CANY1 |
| Bryce Canyon National Park | Bryce Canyon NP | BRCA1 |
| Canyonlands National Park | Canyonlands NP | CANY1 |
| Capitol Reef National Park | Capitol Reef NP | CAPI1 |
| Zion National Park | Zion NP | ZICA1 |

**Table 5: IMPROVE site information for CIAs**

| Site ID | Class I Area Name(s) | Latitude | Longitude | State | AQS Code |
|---|---|---|---|---|---|
| BRCA1 | Bryce Canyon National Park | 37.6184 | -112.1736 | UT | 49-017-0101 |
| CANY1 | Arches National Park, Canyonlands National Park | 38.4587 | -109.821 | UT | 49-037-0101 |
| CAPI1 | Capitol Reef National Park | 38.3022 | -111.2926 | UT | 49-055-9000 |
| ZICA1 | Zion National Park | 37.1983 | -113.1507 | UT | 49-053-0130 |

### 4.A.1 Baseline (2000-2004) visibility for the most impaired and clearest days[103]

Baseline visibility conditions are based on the available IMPROVE monitoring data of the 20% most impaired and clearest days during the period of 2000 to 2004. Table 6 shows the baseline visibility calculated for clearest days and most impaired days for each of Utah's CIAs.

**Table 6: Baseline Visibility for the 20% Most Impaired Days and 20% Clearest Days**

| Site ID | Class I Area Name(s) | Clearest Days (dv) | Most Impaired Days (dv) |
|---|---|---|---|
| BRCA1 | Bryce Canyon National Park | 2.77 | 8.42 |
| CANY1 | Arches National Park, Canyonlands National Park | 3.75 | 8.79 |
| CAPI1 | Capitol Reef National Park | 4.10 | 8.78 |
| ZICA1 | Zion National Park | 4.48 | 10.40 |

### 4.A.2 Natural visibility for the most impaired and clearest days[104]

Natural visibility conditions are to be calculated by estimating the average deciview index on most impaired and clearest days under natural conditions. Table 7 summarizes the natural visibility values calculated for the clearest and most impaired days in each of Utah's CIAs.

[103] (40 CFR 51.308(f)(1)(i))

[104] (40 CFR 51.308(f)(1)(ii))

**Table 7: Natural Visibility values for Utah CIAs**

| Site ID | Class I Area Name(s) | Clearest Days (dv) | Most Impaired Days (dv) |
|---|---|---|---|
| BRCA1 | Bryce Canyon National Park | 0.57 | 4.08 |
| CANY1 | Arches National Park, Canyonlands National Park | 1.05 | 4.13 |
| CAPI1 | Capitol Reef National Park | 1.28 | 4.00 |
| ZICA1 | Zion National Park | 1.83 | 5.26 |

### 4.A.3 Current (2014-2018) visibility for the most impaired and clearest days[105]

Current visibility conditions are to be calculated based upon the most recent five years of data by calculating the average of the annual deciview index values for the most impaired days and clearest days in this period, and averaging these respective annual values. Table 8 below shows the current visibility values calculated for the clearest and most impaired days in each of Utah's CIAs.

**Table 8: Current Visibility (2014-2018) conditions in Utah CIAs**

| Site ID | Class I Area Name(s) | Clearest Days (dv) | Most Impaired Days (dv) |
|---|---|---|---|
| BRCA1 | Bryce Canyon National Park | 1.46 | 6.60 |
| CANY1 | Arches National Park, Canyonlands National Park | 2.20 | 6.76 |
| CAPI1 | Capitol Reef National Park | 2.38 | 7.18 |
| ZICA1 | Zion National Park | 3.86 | 8.75 |

[105] (40 CFR 51.308(f)(1)(iii))

### 4.A.4 Progress to date: most impaired and clearest days[106]

Actual progress towards the natural visibility conditions goal has been calculated in relation to the baseline period for each of Utah's CIAs. This is exhibited by the difference between the average visibility condition during the 5-year baseline, previous implementation period, and each subsequent 5-year period up to and including the current period. Table 9 displays the progress in Utah's CIAs comparing the baseline values for clearest and most impaired days with the first implementation period and 2014-2018 values.

**Table 9: Progress to date for the most impaired and clearest days**

| Site ID | 2000-2004 Baseline (dv) | | 2008-2012 Previous implementation period (dv) | | 2014-2018 Current (dv) | |
|---|---|---|---|---|---|---|
| | 20% Clearest | 20% Most Impaired | 20% Clearest | 20% Most Impaired | 20% Clearest | 20% Most Impaired |
| BRCA1 | 2.77 | 8.42 | 1.82 | 7.69 | 1.46 | 6.60 |
| CANY1 | 3.75 | 8.79 | 2.93 | 8.12 | 2.20 | 6.76 |
| CAPI1 | 4.10 | 8.78 | 2.53 | 8.16 | 2.38 | 7.18 |
| ZICA1 | 4.48 | 10.40 | 4.22 | 9.17 | 3.86 | 8.75 |

### 4.A.5 Differences between current and natural for the most impaired and clearest days[107]

Table 10 compares the difference between the current deciview values for each CIA to the estimated natural visibility for the 20% most impaired days and clearest days.

**Table 10: Current visibility compared to natural visibility**

| Site ID | 2014-2018 Current (dv) | | Natural Visibility (dv) | | Difference (dv) | |
|---|---|---|---|---|---|---|
| | 20% Clearest | 20% Most Impaired | 20% Clearest | 20% Most Impaired | 20% Clearest | 20% Most Impaired |
| BRCA1 | 1.46 | 6.60 | 0.57 | 4.08 | 0.89 | 2.52 |
| CANY1 | 2.20 | 6.76 | 1.05 | 4.13 | 1.15 | 2.63 |
| CAPI1 | 2.38 | 7.18 | 1.28 | 4.00 | 1.1 | 3.18 |
| ZICA1 | 3.86 | 8.75 | 1.83 | 5.26 | 2.03 | 3.49 |

[106] (40 CFR 51.308(f)(1)(iv))
[107] (40 CFR 51.308(f)(1)(v))

## 4.B Uniform Rate of Progress[108]

Utah analyzed and determined the uniform rate of progress (URP) over time for each of its five CIAs, starting at the baseline period of 2000-2004, that would be needed to attain the natural visibility condition on the 20% most anthropogenically impaired days by the year 2064. Table 11 shows the URP for each IMPROVE site.

**Table 11: Uniform Rates of Progress**

| CIA IMPROVE Site | Baseline Conditions (Most Impaired Days) (dv) | 2064 Natural Conditions (Most Impaired Days) (dv) | Years to Reach Natural Conditions | Uniform Rate of Progress (URP) (dv/year) |
|---|---|---|---|---|
| BRCA1 | 8.42 | 4.08 | 60 | -0.072 |
| CANY1 | 8.79 | 4.13 | 60 | -0.078 |
| CAPI1 | 8.78 | 4.00 | 60 | -0.080 |
| ZICA1 | 10.40 | 5.26 | 60 | -0.086 |

Utah then used the URP to establish the level of visibility change needed from baseline conditions by 2028 as shown in Table 12. The 2028 URP level is used for comparison to WRAP photochemical modeling projections for 2028 shown in sections 6.A.10 and 8.C.

**Table 12: Calculation of 2028 Uniform Rate of Progress Level**

| CIA IMPROVE Site | Baseline Conditions (Most Impaired Days) (dv) | Visibility Change by 2028 (URPX24 years) (dv) | 2028 URP Level (dv) |
|---|---|---|---|
| BRCA1 | 8.42 | -1.74 | 6.68 |
| CANY1 | 8.79 | -1.87 | 6.92 |
| CAPI1 | 8.78 | -1.91 | 6.87 |
| ZICA1 | 10.40 | -2.06 | 8.35 |

## 4.C Adjustments to URP: International impacts and/or prescribed fire[109]

EPA added a provision in the 2019 guidance that allows EPA to approve adjustments to the URP to reflect the impacts of international and wildland prescribed fire sources of visibility impairment if an adjustment has been developed through scientifically valid data and methods. These adjustments would be developed and applied separately, although they would both be accomplished by adding an estimate of the impact of the relevant source type or types to the value of the natural visibility condition for the 20% most anthropogenically impaired days, for the purposes of calculating the URP.[110] The wildland prescribed fires that are eligible under the

[108] (40 CFR 51.308(f)(1)(vi))
[109] (40 CFR 51.308(f)(1)(vi)(B)(1) and (2))
[110] The 2019 EPA Guidance can be found at: https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

RHR to be included in this adjustment are those conducted with the objective to establish, restore, and/or maintain sustainable and resilient wildland ecosystems, to reduce the risk of catastrophic wildfires, and/or to preserve endangered or threatened species during which appropriate basic smoke management practices were applied.[111]

Consistent with the methods evaluated in the EPA Technical Support Document[112], WRAP calculated the international and wildland prescribed fire glidepath adjustments for Utah using 2028OTBa2 source apportionment modeling results normalized to the IMPROVE monitoring data and added to EPA estimated natural conditions.[113]

Modeling done by both EPA and WRAP shows that Utah is significantly impacted by international and wildland prescribed fire emissions (as shown by Figures 28-31). Further detail on emission source apportionment can be found in Chapter 5: Utah Sources of Visibility Impairment.

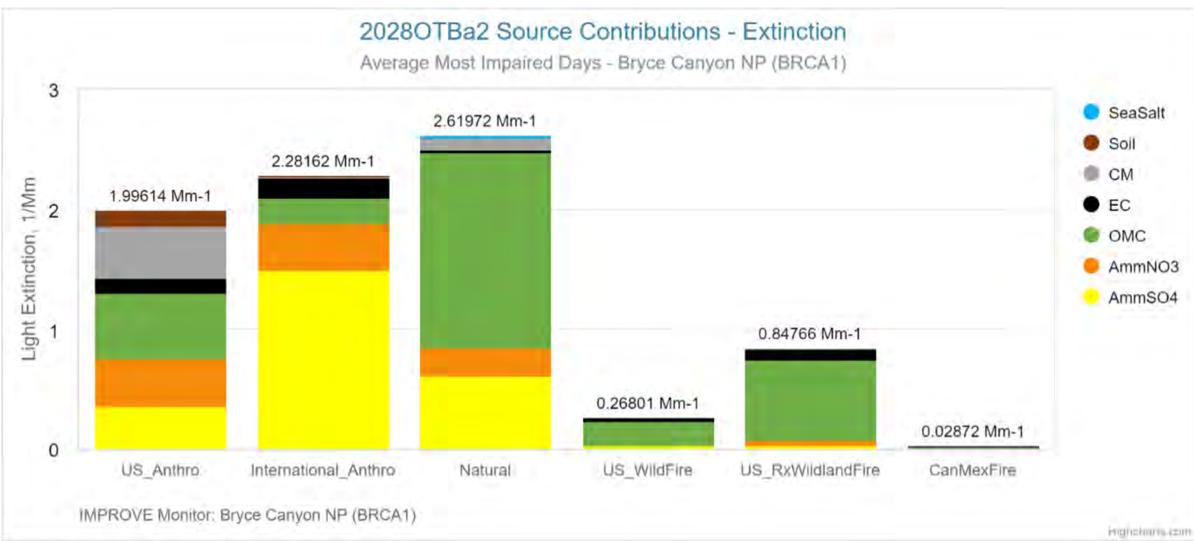



**Figure 28: Projected Source Contributions to Light Extinction in Bryce Canyon NP**

[111] "64 Fed. Reg. 35714, 35764."

[112] Technical Support Document (TSD) Revised Recommendations for Visibility Progress Tracking Metrics for the Regional Haze Program https://www.epa.gov/sites/default/files/2016-07/documents/technical_support_document_for_draft_guidance_on_regional_haze.pdf

[113] WRAP Technical Support System for Regional Haze Planning: Modeling Methods, Results, and References https://views.cira.colostate.edu/tssv2/Docs/WRAP_TSS_modeling_reference_final_20210930.pdf

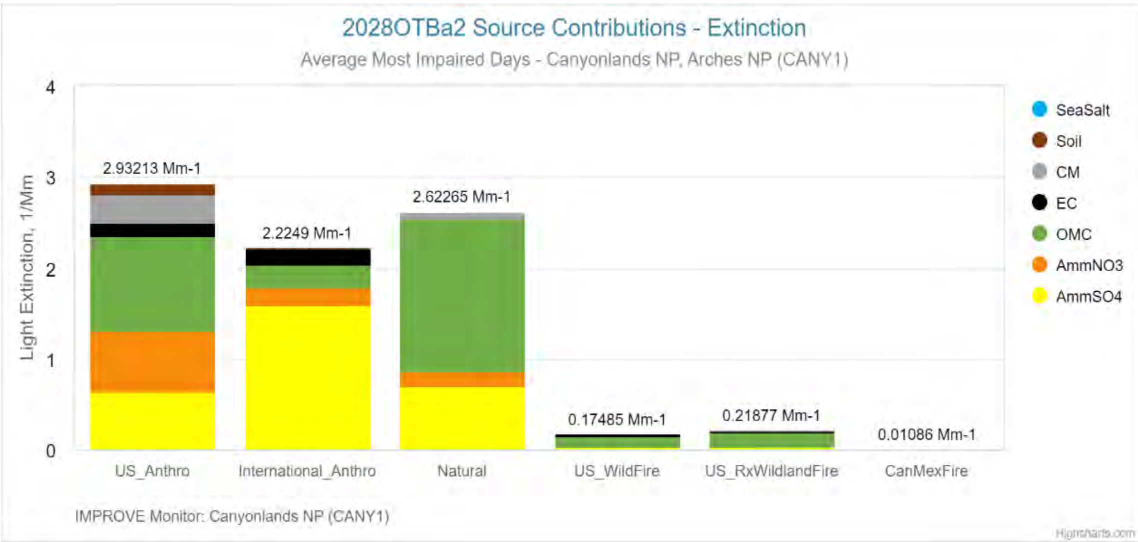



**Figure 29: Projected Source Contributions to Light Extinction in Canyonlands and Arches NP**

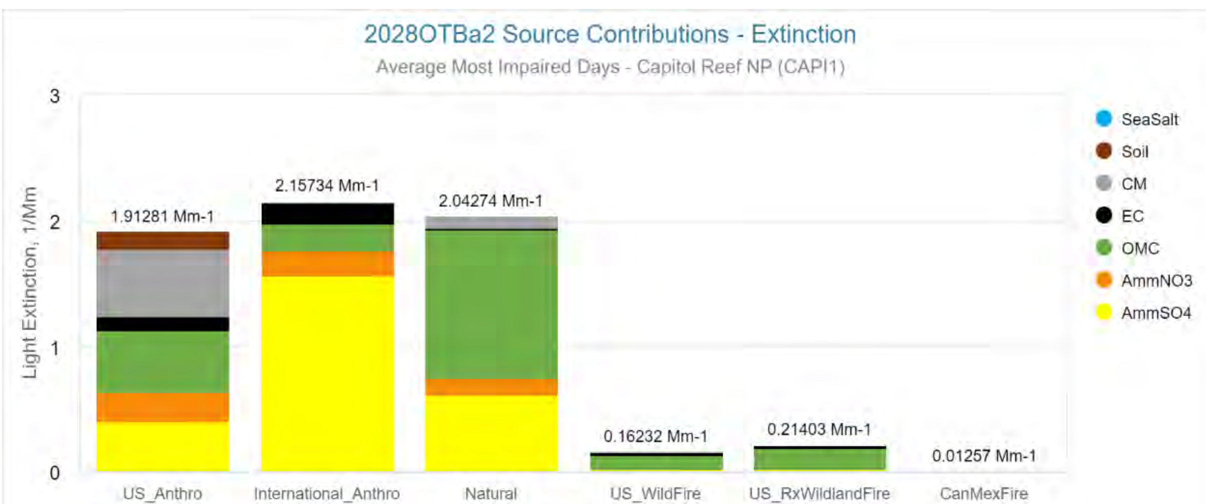



**Figure 30: Projected Source Contributions to Light Extinction in Capitol Reef NP**

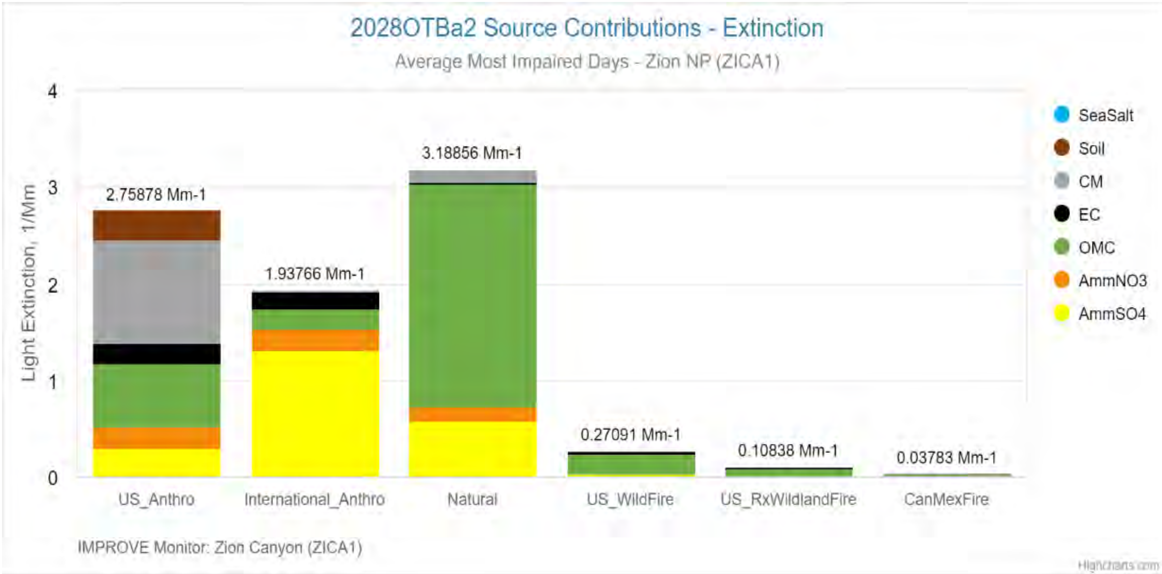



**Figure 31: Projected Source Contributions to Light Extinction in Zion NP**

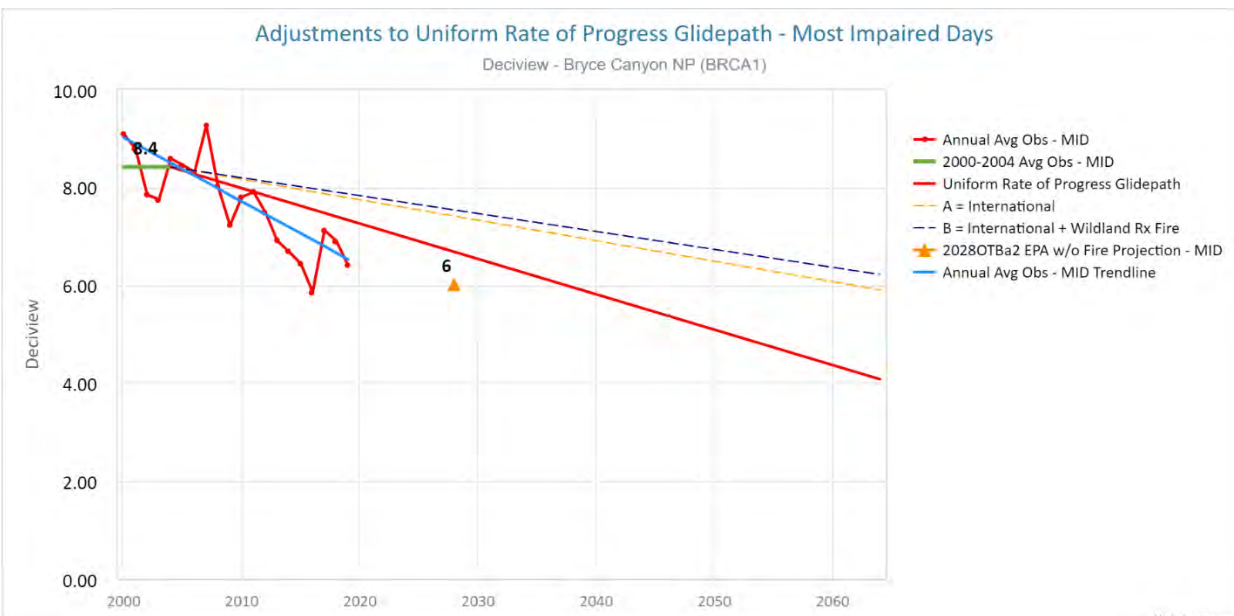



**Figure 32: Example URP Glidepath for Bryce Canyon National Park Showing Adjustment Options**

Figure 32 shows an example of Bryce Canyon's URP glidepath with the international and wildland prescribed fire adjustments. It should be noted that the prescribed fire adjustments for Utah's CIAs are small relative to those in other states. The international source adjustments, on the other hand, can be sizable. While the international and wildland prescribed fire adjustments are available for Utah's CIA glidepaths, UDAQ is choosing to remain conservative for the purposes of this implementation period by not using them. However, this choice does not preclude the use of glidepath adjustments in future planning periods, since international and wildland prescribed fire emissions do impact Utah CIAs and are largely beyond the control of individual states and since prescribed fires are seen to be an increasingly important tool for land managers in the future.

# **Chapter 5:** Utah Sources of Visibility Impairment

## 5.A Natural Sources of Impairment

Natural impairment sources include any non-anthropogenically caused visibility-reducing emissions and are often seasonally attributed to natural events such as rain, sea mists, windblown dust, wildfire, volcanic activity, and biogenic emissions. Natural sources of impairment are often caused by seasonal conditions and lead to high concentrations of visibility-impairing emissions that are short-term. Natural contributions to impairment are categorized into the “episodic” and “routine” types. Episodic contributions, such as large wildfires or dust storms, occur infrequently and vary yearly in number and size. Routine contributions include biogenic sources, sea salt, and incorporate the site-specific value for Rayleigh scattering, a term which refers to the scattering of light off of particles in the air. These contributions occur often and are more consistent on a yearly basis.

## 5.B Anthropogenic Sources of Impairment

Anthropogenic impairment sources include any visibility-decreasing emissions directly related to human-caused activities. These activities include industrial processes (utilities, smelters, refineries, etc.), mobile sources (cars, trucks, trains, etc.) and area sources (residential wood burning, prescribed burning on wild and agricultural lands, wind-blown dust from disturbed soils, etc.). Anthropogenic sources of emissions include those originating within Utah as well as neighboring states, Mexico, Canada, and maritime shipping emissions from across the Pacific Ocean. While Utah can consult with regional states about their anthropogenic emission contributions to impairment in Utah’s CIAs, those international contributions cannot be controlled at the state level. Table 13 details the data sources used by WRAP for determining anthropogenic source emissions contributions.

**Table 13: Data sources for WRAP emissions sectors[114]**

| Source Sector | 2014v2 | RepBase2 | 2028OTBa2 |
|---|---|---|---|
| **California All Sectors 12WUS2** | CARB-2014v2 | CARB-2014v2 | CARB-2028 |
| **WRAP Fossil EGU w/ CEM** | WRAP-2014v2 | WRAP-RB-EGU [1] | WRAP-2028-EGU [1] |
| **WRAP Fossil EGU w/o CEM** | EPA-2014v2 | WRAP-RB-EGU [1] | WRAP-2028-EGU [1] |
| **WRAP Non-Fossil EGU** | EPA-2014v2 | EPA-2016v1 | EPA-2028v1 |
| **Non-WRAP EGU** | EPA-2014v2 | EPA-2016v1 | EPA-2028v1 |
| **O&G WRAP O&G States** | WRAP-2014v2 | WRAP-RB-O&G [2] | WRAP-2028-O&G [2] |
| **O&G WRAP Other States** | EPA-2014v2 | EPA-2016v1 | EPA-2016v1 [3] |
| **O&G non-WRAP States** | EPA-2014v2 | EPA-2016v1 | EPA-2016v1 [3] |
| **WRAP Non-EGU Point** | WRAP-2014v2 | WRAP-2014v2 [4] | WRAP-2014v2 [4] |
| **Non-WRAP non-EGU Point** | EPA-2014v2 | EPA-2016v1 | EPA-2016v1 |
| **On-Road Mobile 12WUS2** | WRAP-2014v2 | WRAP-2014v2 | WRAP-2028-Mobile [5] |
| **On-Road Mobile 36US** | EPA-2014v2 | EPA-2016v1 | EPA-2028v1 |
| **Non-Road 12WUS2** | EPA-2014v2 | EPA-2016v1 | WRAP-2028-Mobile [5] |
| **Non-Road non-WRAP 36US** | EPA-2014v2 | EPA-2016v1 [6] | EPA-2028v1 [6] |

[114] This table’s data comes from the 2021 WRAP Technical Support System Emissions and Modeling Report and References document.

| | | | |
|---|---|---|---|
| **Other (Non-Point) 12WUS2** | EPA-2014v2 | EPA-2014v2 [7] | EPA-2014v2 [7] |
| **Other (Non-Point) 36US** | EPA-2014v2 | EPA-2016v1 | EPA-2016v1 |
| **Can/Mex/Offshore 12WUS2** | EPA-2014v2 | EPA-2016v1 | EPA-2016v1 |
| **Fires (WF, Rx, Ag)** | WRAP-2014-Fires | WRAP-RB-Fires [8] | WRAP-RB-Fires [8] |
| **Natural (Bio, etc.)** | WRAP-2014v2 | WRAP-2014v2 | WRAP-2014v2 |
| **Boundary Conditions (BCs)** | WRAP-2014-GEOS | WRAP-2014-GEOS | WRAP-2014-GEOS |

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

## 5.C Overview of Emission Inventory System - TSS

The WRAP 2014v2 inventory was based on the National Emissions Inventory (NEI) and updates provided by states through their Emissions and Modeling Protocol subcommittee. Specific data sources for each emissions sector are detailed below:

The CAMx Particle Source Apportionment tool (PSAT) is a photochemical model that tracks gaseous and particle air emissions from sources through atmospheric dispersion, photochemical reactions, and transport to receptors where IMPROVE monitors are located. These PSAT runs include aerosol concentrations of:

- $AmmNO_3$
- $AmmSO_4$
- Primary Organic Mass from Carbon (OMC)
- Primary Elemental Carbon (EC)
- Primary Fine Soil
- Primary Coarse Mass
- Sea salt
- Secondary Organic Aerosols
    - Anthropogenic (SOAA)
    - Biogenic (SOAB)

These particles are direct products of primary gaseous and particle emissions and secondary aerosol formation. Secondary organic aerosols (SOA) tracers are not used in these PSAT runs, rather SOAs at the receptor are assigned to anthropogenic (SOAA) or biogenic (SOAB) contributions based on the chemical signatures (e.g., isoprene is assigned as biogenic in origin; benzene is assigned as anthropogenic in origin).

WRAP modeled values for six source categories and 15 component source groups[115]:

- U.S. Anthropogenic (USAnthro)
    - U.S. anthropogenic (AntUS)
    - U.S. agricultural fire (AgfireUS)
    - Secondary Organic Aerosol-Anthropogenic (SOAA)
    - Commercial Marine Vessels (CMVUS)
    - U.S. anthropogenic contributions from outside the CAMx 36-km domain boundary as defined by the GEOS-Chem global model. (BC-US)
- U.S. Wildfire (WFUS)
- U.S. Wildland Prescribed fire (RxUS)
- Canadian and Mexican fires (OthFr)
- Natural
    - Natural (Nat)
    - Secondary Organic Aerosol -Biogenic (SOAB)
    - Natural contributions from outside the CAMx 36-km domain boundary as defined by the GEOS-Chem global model. (BC-Nat)
- International Anthropogenic (IntlAnthro)
    - International Anthropogenic contributions from outside the CAMx 36-km domain boundary as defined by the GEOS-Chem global model. (BC-Int)
    - Canadian Anthropogenic (AntCAN)
    - Mexican Anthropogenic (AntMEX)
    - Commercial Marine vessels – International (beyond 200km from U.S. coast) (CMV_nonUS)

Summaries of Utah's emissions data are located in Table 15 to Table 20.

## 5.D Wildland Prescribed Fires

Most forest ecosystems in the West have a general pattern in which fires naturally occur, otherwise called a fire regime. These regimes serve the purpose of helping a forest get rid of excess wood fuel and cause opportunities for regrowth and regeneration. Many forest ecosystems in the West depend on fire to create their optimal conditions. As human populations increase in the West, the Wildland-Urban Interface (WUI) has led to fire suppression which impedes natural fire regimes for the safety of residential areas. This causes an increase in fuel (burnable wood) in the forests of Utah that increases their chances of unintentionally catching fire. Further contributing to the dangers of uncontrolled fire is the increase in climate change every year. To better control the location and degree at which forest fires occur, fire can be prescribed for an area under certain weather conditions and with the appropriate permits. Utilizing prescribed fires and returning fire to an ecosystem in a controlled manner helps restore its health and reduce potentially catastrophic wildfires. Healthy ecosystems with restored natural fire regimes are more resistant to severe fire, disease, and insect infestations. The United States Forest Service (USFS) and other land management agencies in Utah closely monitor

[115] Information on the TSS source apportionment data is located at http://views.cira.colostate.edu/tssv2/Reports2/Modeling/Src-App-DB-Avg-Bext-By-Source.aspx

local precipitation, wind, fuel, moisture, and other elements to determine the best conditions to carry out prescribed burning.

The State of Utah and the USFS have developed mutual commitments to advance the strategy of "Shared Stewardship" in Utah. In August 2018, the Forest Service released a document outlining a new strategy for land management called "Toward Shared Stewardship Across Landscapes: An Outcome-Based Investment Strategy." This strategy responds to the growing challenges faced by land managers including catastrophic wildfires. Of particular concern are longer fire seasons and the increasing size and severity of wildfires, along with the expanding risk to communities, water sources, wildlife habitat, air quality, and the safety of firefighters. Through Shared Stewardship, the State and Forest Service can work together and set landscape-scale priorities, implement projects at the appropriate scale, co-manage risks, share resources, and learn from each other while building long-term capacity to live with wildfire. Due to these initiatives, more frequent wildfires in the West, and thus increasing importance of prescribed fires, Utah does not consider reducing prescribed fires as a reasonable method to reduce visibility impairment.

## 5.E Utah Emissions

Federal visibility regulations[116] require a statewide emissions inventory of pollutants anticipated to contribute to visibility impairment in Utah's CIAs. WRAP inventoried pollutants in Utah including $SO_2$, $NO_x$, VOCs, $PM_{2.5}$, $PM_{10}$, and $NH_3$. The WRAP 2014v2 inventory was based on the 2014v2 National Emissions Inventory (NEI) as well as updates provided by western states (including Utah). RepBase2, the representative baseline emissions scenario, updated the 2014v2 inventory originally used to account for changes and variations in emissions from 2014 to 2018.[117] This version also accounted for duplicate records found and revised some EGU, non-EGU point, oil, and gas emissions. The 2028 On the Books Inventory (2028OTBa2) projection follows the methods presented by the EPA in their 2019 Technical Support Document. WRAP states updated projections for all anthropogenic source sectors. Oil and gas area emissions were also updated by Ramboll, Inc. and the WRAP Oil and Gas Workgroup and separated into Tribal and non-Tribal mineral ownership. Table 14 contains data compiled by WRAP with information on the status of EGU retirements in Utah that were used in the RepBase2 and 2028OTBa2 inventories.

**Table 14: Status of Utah EGU Retirements in RepBase2 and 2028OTBa2 Inventories**

| Facility Name | Unit ID | In-Service Year | Retirement Year | Notes | Operator | Unit Type |
|---|---|---|---|---|---|---|
| **Intermountain** | 1SGA | 1986 | 2025 | Announced retirement | Intermountain Power Service Corporation | Dry bottom wall-fired boiler |
| **Intermountain** | 2SGA | 1987 | 2025 | Announced retirement | Intermountain Power Service Corporation | Dry bottom wall-fired boiler |

[116] 40 C.F.R. § 51.308(d)(4)(v).
[117] UDAQ notes that these projections include emission not under state jurisdiction (i.e. Tribal)

| Facility Name | Unit ID | In-Service Year | Retirement Year | Notes | Operator | Unit Type |
|---|---|---|---|---|---|---|
| **Bonanza** | 1-Jan | 1986 | 2030 | Coal consumption cap | Deseret Generation & Transmission | Dry bottom wall-fired boiler |
| **Hunter** | 1 | 1978 | 2042 | PAC IRP; Round 1 RH FIP in Litigation | PacifiCorp Energy Generation | Tangentially-fired |
| **Hunter** | 2 | 1980 | 2042 | PAC IRP; Round 1 RH FIP in Litigation | PacifiCorp Energy Generation | Tangentially-fired |
| **Hunter** | 3 | 1983 | 2042 | PAC IRP | PacifiCorp Energy Generation | Dry bottom wall-fired boiler |
| **Huntington** | 1 | 1977 | 2036 | PAC IRP; Round 1 RH FIP in Litigation | PacifiCorp Energy Generation | Tangentially-fired |
| **Huntington** | 2 | 1974 | 2036 | PAC IRP; Round 1 RH FIP in Litigation | PacifiCorp Energy Generation | Tangentially-fired |

The resulting inventories were then used by WRAP to model future visibility in Utah's CIAs.[118]

State and federal law require Utah to conduct a statewide emissions inventory program every three years. This inventory accounts for point, area, and mobile sources and accounts for the following criteria pollutants:

- Ammonia ($NH_3$)
- Carbon Monoxide (CO)
- Lead and Lead Compounds
- Nitrogen Oxides (NO)
- Particulate Matter ($PM_{10}$ and $PM_{2.5}$)
- Sulfur Oxides ($SO_2$)
- Volatile Organic Compounds (VOCs)

The following tables contain Utah's projected emissions inventories by species resulting from the RepBase2 and 2018OTBa2 modeling projections.

[118] The complete methodology used to develop the WRAP emissions inventory can be found in "WRAP Technical Support System for Regional Haze Planning: Emissions and Modeling Methods, Results, and References" released on August 19, 2021.

Table 15: Utah $SO_2$ Emission Inventory – RepBase2 (2014-2018) and 2028OTBa2

| Utah – Statewide $SO_2$ Emissions (TPY) | | | | |
|---|---|---|---|---|
| Type | **Source Category** | **2014v2 Actual** | **Representative Baseline 2** | **2028 OTB a2** |
| **Anthropogenic** | Electric Generating Units (EGU) | 24,011 | 11,357 | 9,866 |
| **Anthropogenic** | Oil and Gas – Point | 664 | 545 | 570 |
| **Anthropogenic** | Industrial and Non-EGU Point | 2,400 | 2,402 | 2,402 |
| **Anthropogenic** | Oil and Gas – Non-point | 41 | 41 | 31 |
| **Anthropogenic** | Residential Wood Combustion | 24 | 24 | 24 |
| **Anthropogenic** | Fugitive dust | 0 | 0 | 0 |
| **Anthropogenic** | Agriculture | 0 | 0 | 0 |
| **Anthropogenic** | Remaining Non-point | 61 | 61 | 61 |
| **Anthropogenic** | On-Road Mobile | 275 | 275 | 185 |
| **Anthropogenic** | Non-road Mobile | 25 | 16 | 13 |
| **Anthropogenic** | Rail | 3 | 3 | 3 |
| **Anthropogenic** | Commercial Marine | 0 | 0 | 0 |
| **Anthropogenic** | Agricultural Fire | 5 | 5 | 5 |
| **Anthropogenic** | Wildland Prescribed Fire | 320 | 524 | 524 |
| | **Total Anthropogenic** | **27,829** | **15,253** | **13,684** |
| **Natural** | Wildfire | 375 | 1,295 | 1,295 |
| **Natural** | Biogenic | 0 | 0 | 0 |
| | **Total Natural** | **375** | **1,295** | **1,295** |
| | **Grand Total** | **28,204** | **16,548** | **14,979** |

The largest source of $SO_2$ emissions is fossil fuel combustion (mainly coal) at power plants and other industrial facilities. In Utah, the largest source of $SO_2$ emissions are EGUs. Smaller sources include metal extraction, mobile vehicles, and wood burning. Wildfires are the second largest source of $SO_2$ emissions in both the RepBase and 2028 scenarios. $SO_2$ emissions that lead to high concentrations of $SO_2$ in the air generally also lead to the formation of other sulfur oxides ($SO_x$). $SO_x$ can react with other compounds in the atmosphere to form small particles. These particles contribute to PM pollution. Ammonium sulfate particles can have a great impact on visibility due to their greater light scattering effects. According to the 2028OTBa2 modeling, $SO_2$ emissions are projected to decline to 14,979 tons per year in 2028.

Table 16: Utah $NO_x$ Emission Inventory – RepBase2 (2014-2018) and 2028OTBa2

| Utah – Statewide $NO_x$ Emissions (TPY) | | | | |
|---|---|---|---|---|
| Type | **Source** | **2014v2** | **Representative** | **2028 OTB a2** |

| Utah – Statewide $NO_x$ Emissions (TPY) | | | | |
|---|---|---|---|---|
| | **Category** | **Actual** | **Baseline 2** | |
| **Anthropogenic** | Electric Generating Units (EGU) | 54,497 | 31,882 | 23,848 |
| **Anthropogenic** | Oil and Gas – Point | 14,636 | 14,589 | 9,140 |
| **Anthropogenic** | Industrial and Non-EGU Point | 13,086 | 13,107 | 13,107 |
| **Anthropogenic** | Oil and Gas – Non-point | 1,811 | 1,806 | 1,428 |
| **Anthropogenic** | Residential Wood Combustion | 189 | 189 | 189 |
| **Anthropogenic** | Fugitive dust | 0 | 0 | 0 |
| **Anthropogenic** | Agriculture | 0 | 0 | 0 |
| **Anthropogenic** | Remaining Non-point | 4,846 | 4,846 | 4,846 |
| **Anthropogenic** | On-Road Mobile | 74,643 | 74,643 | 25,539 |
| **Anthropogenic** | Non-road Mobile | 9,669 | 7,029 | 4,741 |
| **Anthropogenic** | Rail | 5,646 | 5,646 | 4,164 |
| **Anthropogenic** | Commercial Marine | 1 | 0 | 0 |
| **Anthropogenic** | Agricultural Fire | 19 | 19 | 19 |
| **Anthropogenic** | Wildland Prescribed Fire | 596 | 572 | 572 |
| | **Total Anthropogenic** | **179,639** | **154,328** | **87,593** |
| **Natural** | Wildfire | 704 | 2,063 | 2,063 |
| **Natural** | Biogenic | 12,602 | 12,602 | 12,602 |
| | **Total Natural** | **13,306** | **14,665** | **14,665** |
| | **Grand Total** | **192,945** | **168,993** | **102,258** |

$NO_x$ is a group of highly reactive gases formed in high-temperature combustion processes. This group includes $NO_2$, nitrous acid, and nitric acid. $NO_2$ emissions are primarily caused by fuel combustion from cars, trucks, buses, power plants, and off-road equipment. These substances are toxic by themselves and can react to form ozone or $PM_{10}$ in the form of nitrates. Large nitrate particles have a greater light-scattering effect than large sulfate particles or dust particles. Most $NO_x$ emissions in Utah are from EGUs. $NO_x$ emissions are projected to decline to 102,258 tons per year, according to the 2028OTBa2 modeling.

**Table 17: Utah VOC Emission Inventory – RebBase2 (2014-2018) and 2028OTBa2**

| Utah - Statewide VOC Emissions (TPY) | | | | |
|---|---|---|---|---|
| Type | **Source Category** | **2014v2 Actual** | **Representative Baseline 2** | **2028 OTB a2** |
| **Anthropogenic** | Electric Generating Units (EGU) | 391 | 285 | 276 |
| **Anthropogenic** | Oil and Gas - Point | 111,225 | 110,906 | 71,207 |
| **Anthropogenic** | Industrial and Non-EGU Point | 3,146 | 3,152 | 3,152 |
| **Anthropogenic** | Oil and Gas - Non-point | 37,069 | 35,252 | 21,513 |
| **Anthropogenic** | Residential Wood Combustion | 1,589 | 1,589 | 1,589 |
| **Anthropogenic** | Fugitive dust | 0 | 0 | 0 |
| **Anthropogenic** | Agriculture | 2,120 | 2,120 | 2,120 |

| Utah - Statewide VOC Emissions (TPY) | | | | |
|---|---|---|---|---|
| **Anthropogenic** | Remaining Non-point | 29,913 | 29,913 | 29,913 |
| **Anthropogenic** | On-Road Mobile | 28,356 | 28,356 | 11,589 |
| **Anthropogenic** | Non-road Mobile | 17,694 | 8,966 | 6,314 |
| **Anthropogenic** | Rail | 287 | 287 | 179 |
| **Anthropogenic** | Commercial Marine | 0 | 0 | 0 |
| **Anthropogenic** | Agricultural Fire | 31 | 31 | 31 |
| **Anthropogenic** | Wildland Prescribed Fire | 8,675 | 23,415 | 23,415 |
| | **Total Anthropogenic** | **240,496** | **244,272** | **171,298** |
| **Natural** | Wildfire | 10,062 | 54,614 | 54,614 |
| **Natural** | Biogenic | 717,742 | 717,742 | 717,742 |
| | **Total Natural** | **727,804** | **772,356** | **772,356** |
| | **Grand Total** | **968,300** | **1,016,628** | **943,654** |

VOCs are volatile organic compounds that have high vapor pressure at room temperature. Many VOCs are human-made compounds that are used and produced in the manufacturing of paints, pharmaceuticals, and refrigerants. Companies in Utah must report all reactive VOC emissions (including fugitive emissions). Different VOCs have differing levels of reactivity that convert them to ozone. Therefore, changes in their emissions have limited effects on local or regional ozone pollution. VOCs also play a role in the formation of secondary particulates that can impact regional haze. The largest source of VOC emissions in Utah is oil and gas point sources. VOC emissions are expected to decline to 943,654 tons per year according to the 2028OTBa2 projections.

**Table 18: Utah $PM_{2.5}$ Emission Inventory – RepBase2 (2014-2018) and 2028OTBa2**

| Utah - Statewide $PM_{2.5}$ Emissions (TPY) | | | | |
|---|---|---|---|---|
| Type | **Source Category** | **2014v2 Actual** | **Representative Baseline 2** | **2028 OTB a2** |
| **Anthropogenic** | Electric Generating Units (EGU) | 2,799 | 2,195 | 1,310 |
| **Anthropogenic** | Oil and Gas - Point | 631 | 621 | 476 |
| **Anthropogenic** | Industrial and Non-EGU Point | 2,618 | 2,620 | 2,620 |
| **Anthropogenic** | Oil and Gas - Non-point | 81 | 81 | 61 |
| **Anthropogenic** | Residential Wood Combustion | 1,403 | 1,403 | 1,403 |
| **Anthropogenic** | Fugitive dust | 12,177 | 12,177 | 12,177 |
| **Anthropogenic** | Agriculture | 0 | 0 | 0 |
| **Anthropogenic** | Remaining Non-point | 1,181 | 1,181 | 1,181 |
| **Anthropogenic** | On-Road Mobile | 2,726 | 2,726 | 1,081 |
| **Anthropogenic** | Non-road Mobile | 1,103 | 706 | 447 |
| **Anthropogenic** | Rail | 165 | 165 | 108 |
| **Anthropogenic** | Commercial Marine | 0 | 0 | 0 |
| **Anthropogenic** | Agricultural Fire | 83 | 83 | 83 |

| | | | | |
|---|---|---|---|---|
| **Anthropogenic** | Wildland Prescribed Fire | 3,580 | 7,092 | 7,092 |
| | **Total Anthropogenic** | **28,547** | **31,050** | **28,039** |
| **Natural** | Wildfire | 4,161 | 17,381 | 17,381 |
| **Natural** | Biogenic | 0 | 0 | 0 |
| | **Total Natural** | **4,161** | **17,381** | **17,381** |
| | **Grand Total** | **32,708** | **48,431** | **45,420** |

$PM_{2.5}$ particulates are fine, inhalable particles or droplets with a diameter of 2.5 microns or smaller. Within two years after the EPA revises NAAQS for criteria pollutants, it must designate areas according to their attainment status. These designations are based on the most recent three years of monitoring data, state recommendations, and other technical information. If an area is not meeting the standard, Utah must write a $PM_{2.5}$ SIP that includes necessary control measures to ensure future attainment. The sector with the largest contribution of $PM_{2.5}$ emissions in Utah is fugitive dust. $PM_{2.5}$ emissions are expected to decline somewhat according to the 2028OTBa2 modeling.

**Table 19: Utah $PM_{10}$ Emission Inventory – RepBase2 (2014-2018) and 2028OTBa2**

| Utah - Statewide $PM_{10}$ Emissions (TPY) | | | | |
|---|---|---|---|---|
| Type | **Source Category** | **2014v2 Actual** | **Representative Baseline 2** | **2028 OTB a2** |
| **Anthropogenic** | Electric Generating Units (EGU) | 3,671 | 2,534 | 1,607 |
| **Anthropogenic** | Oil and Gas - Point | 632 | 621 | 476 |
| **Anthropogenic** | Industrial and Non-EGU Point | 5,385 | 5,387 | 5,387 |
| **Anthropogenic** | Oil and Gas - Non-point | 81 | 81 | 61 |
| **Anthropogenic** | Residential Wood Combustion | 1,410 | 1,410 | 1,410 |
| **Anthropogenic** | Fugitive dust | 95,505 | 95,505 | 95,505 |
| **Anthropogenic** | Agriculture | 0 | 0 | 0 |
| **Anthropogenic** | Remaining Non-point | 1,317 | 1,317 | 1,317 |
| **Anthropogenic** | On-Road Mobile | 4,547 | 4,547 | 3,550 |
| **Anthropogenic** | Non-road Mobile | 1,165 | 745 | 477 |
| **Anthropogenic** | Rail | 179 | 179 | 111 |
| **Anthropogenic** | Commercial Marine | 0 | 0 | 0 |
| **Anthropogenic** | Agricultural Fire | 119 | 119 | 119 |
| **Anthropogenic** | Wildland Prescribed Fire | 4,224 | 8,097 | 8,097 |
| | **Total Anthropogenic** | **118,235** | **120,542** | **118,117** |
| **Natural** | Wildfire | 4,910 | 20,318 | 20,318 |
| **Natural** | Biogenic | 0 | 0 | 0 |
| | **Total Natural** | **4,910** | **20,318** | **20,318** |
| | **Grand Total** | **123,145** | **140,860** | **138,435** |

$PM_{10}$ is inhalable particulate matter that is 10 microns or smaller in diameter. Sources of $PM_{10}$ include:

- Vehicles
- Wood-burning
- Wildfires or open burns
- Industry
- Dust from construction sites, landfills, gravels pits, agriculture, and open lands

The NAAQS for PM specifies the maximum amount of PM present in outdoor air. PM concentration is measured in micrograms per cubic meter, or µg/m$^3$. For $PM_{10}$, most high values tend to occur during wintertime inversions. In the summertime, high wind events can also lead to unusually high $PM_{10}$ values. According to the 2028OTBa2 projections, $PM_{10}$ emissions are expected to decrease to 138,435 tons per year in 2028. This is lower than the representative baseline from 2014 to 2017, but higher than the recalculated 2014 emissions.

**Table 20: Utah $NH_3$ Emission Inventory – RepBase2 (2014-2018) and 2028OTBa2**

| Utah - Statewide $NH_3$ Emissions | | | | |
|---|---|---|---|---|
| Type | **Source Category** | **2014v2 Actual** | **Representative Baseline 2** | **2028 OTB a2** |
| **Anthropogenic** | Electric Generating Units (EGU) | 273 | 262 | 261 |
| **Anthropogenic** | Oil and Gas - Point | 0 | 0 | 0 |
| **Anthropogenic** | Industrial and Non-EGU Point | 400 | 400 | 400 |
| **Anthropogenic** | Oil and Gas - Non-point | 0 | 0 | 0 |
| **Anthropogenic** | Residential Wood Combustion | 63 | 63 | 63 |
| **Anthropogenic** | Fugitive dust | 0 | 0 | 0 |
| **Anthropogenic** | Agriculture | 12,982 | 12,982 | 12,982 |
| **Anthropogenic** | Remaining Non-point | 5,012 | 5,012 | 5,012 |
| **Anthropogenic** | On-Road Mobile | 1,025 | 1,025 | 1,039 |
| **Anthropogenic** | Non-road Mobile | 17 | 14 | 17 |
| **Anthropogenic** | Rail | 3 | 3 | 3 |
| **Anthropogenic** | Commercial Marine | 0 | 0 | 0 |
| **Anthropogenic** | Agricultural Fire | 70 | 70 | 70 |
| **Anthropogenic** | Wildland Prescribed Fire | 678 | 1,164 | 1,164 |
| | **Total Anthropogenic** | **20,523** | **20,995** | **21,011** |
| **Natural** | Wildfire | 787 | 2,702 | 2,702 |
| **Natural** | Biogenic | 0 | 0 | 0 |
| | **Total Natural** | **787** | **2,702** | **2,702** |
| | **Grand Total** | **21,310** | **23,697** | **23,713** |

$NH_3$ plays a role in light extinction since it is involved in the formation of ammonium nitrate and ammonium sulfate. The various industries that emit $NH_3$ include:

- Fertilizer manufacturing
- Fossil fuel combustion
- Livestock management
- Refrigeration methods

Currently, there is limited federal regulation of $NH_3$ emissions, although the CAA provides federal authority to regulate this pollutant. $NH_3$ emissions levels are consistent in each of the three WRAP projections for 2014, 2014-2017, and 2028.

# **Chapter 6:** Long-Term Strategy for Second Planning Period[119]

## 6.A LTS Requirements [120]

The Long-Term Strategy requirements under Subsections 51.308(d)(3) and (f)(2) include the following:

- Submit an initial LTS and 5-year progress review per 40 CFR 51.308(g) that addresses regional haze visibility impairment.
- Consult with other states to develop coordinated emission management strategies for CIAs outside Utah where Utah emissions cause or contribute to visibility impairment, or for CIAs in Utah where emissions from other states cause or contribute to visibility impairment.
- Enforceable emissions limitations, compliance schedules, and other measures necessary to achieve the reasonable progress goals established by Utah for its CIAs.
- Document the technical basis on which the state is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each CIA it affects.
- Identify all anthropogenic sources of visibility impairing emissions (major and minor stationary sources, mobile sources, and area sources).
- Consider the following factors when developing the LTS:
    - Emission reductions due to ongoing air pollution control programs, including measures to address Reasonably Attributable Visibility Impairment (RAVI);
    - Measures to mitigate the impacts of construction activities;
    - Emission limitations and schedules for compliance to achieve the reasonable progress goal;
    - Source retirement and replacement schedules;
    - Smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for this purpose;
    - Enforceability of emission limitations and control measures; and
    - The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

Sections 6.A.1 through 6.A.8 detail how Utah addressed the above LTS factors.

[119] 40 CFR 51.308(f)(2)
[120] 40 CFR 51.308(d)(3) and (f)(2)

### 6.A.1 States reasonably anticipated to contribute to visibility impairment in the Utah CIAs[121]

*Bryce Canyon National Park*

In Bryce Canyon National Park, California contributes the highest portion of U.S. anthropogenic ammonium nitrate-caused light extinction on most impaired days at 35%, followed by Utah at 23%. California also contributes the highest amount of U.S. anthropogenic ammonium sulfate light extinction in Bryce Canyon at 19% followed by non-WRAP states at 14%, Utah at 14%, Arizona at 12%, Wyoming at 12%, and New Mexico at 11%.

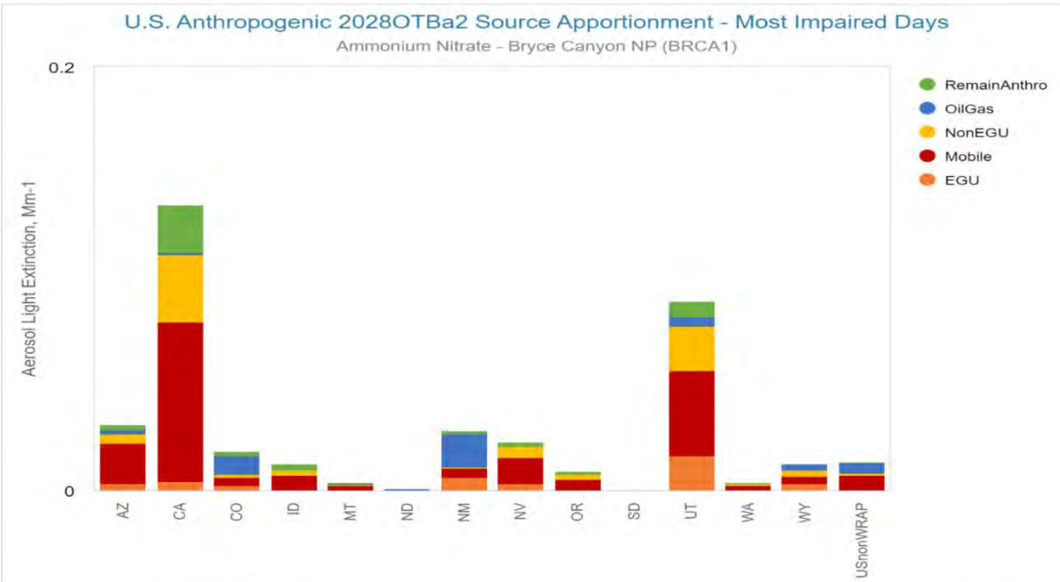



**Figure 33: WRAP States Ammonium Nitrate Source Apportionment for Most Impaired Days at Bryce Canyon National Park**

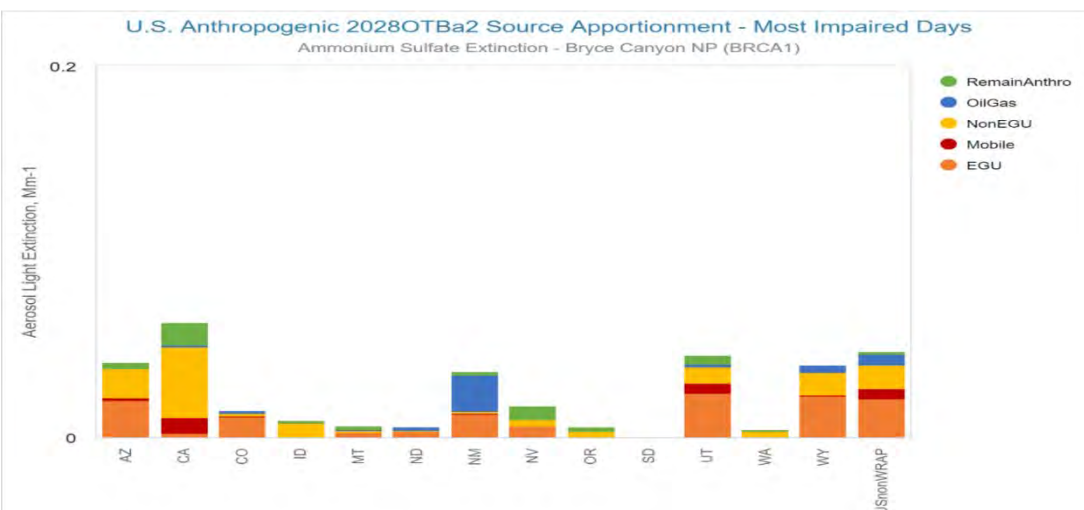



**Figure 34: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Bryce Canyon National Park**

[121] 40 CFR 51.308 (f)(2)(ii)

### *Canyonlands and Arches National Park*

In Canyonlands and Arches National Park, Utah contributes the largest portion of U.S. ammonium nitrate light extinction (60%) followed by Colorado (14%). Utah also contributes the most U.S. ammonium sulfate light extinction (40%) on the park's most impaired days followed by New Mexico (13%) and non-WRAP US states (12%).

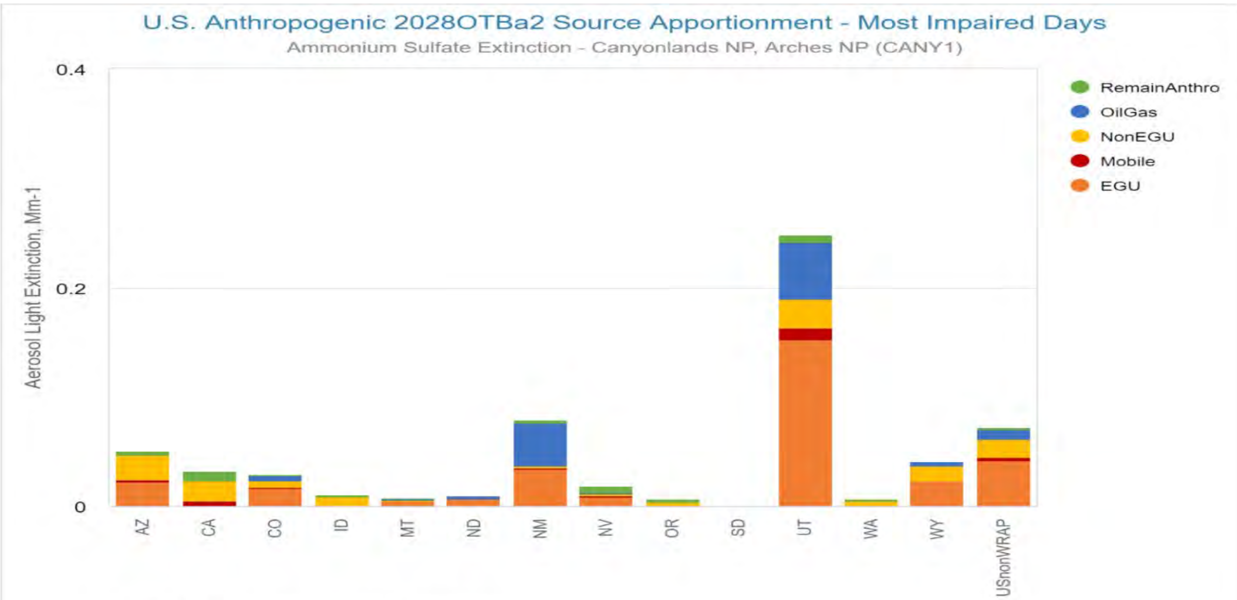



**Figure 35: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Canyonlands and Arches National Park**

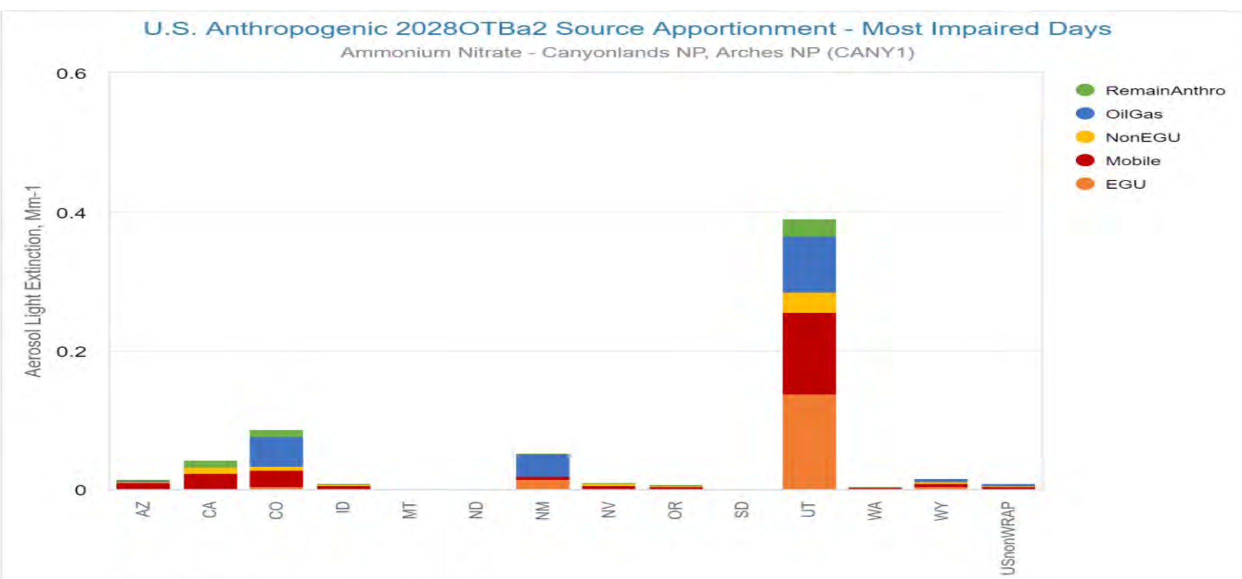



**Figure 36: WRAP States Ammonium Nitrate Source Apportionment for Most Impaired Days at Canyonlands and Arches National Park**

*Capitol Reef National Park*

Utah contributes the highest portion of U.S. anthropogenic ammonium nitrate light extinction on Capitol Reef's most impaired days at 35%. California contributes the second-highest amount at 21%. Utah also contributes the highest portion of U.S. anthropogenic ammonium sulfate light extinction at 20%, closely followed by non-WRAP states (15%), California (13%), and Wyoming (13%).

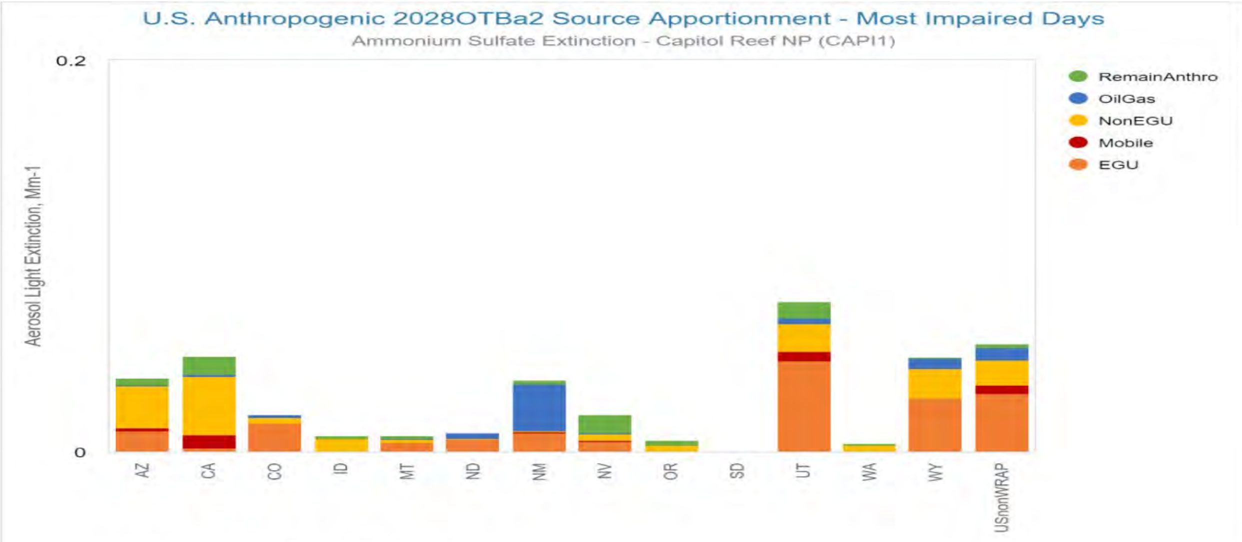



**Figure 37: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Capitol Reef National Park**

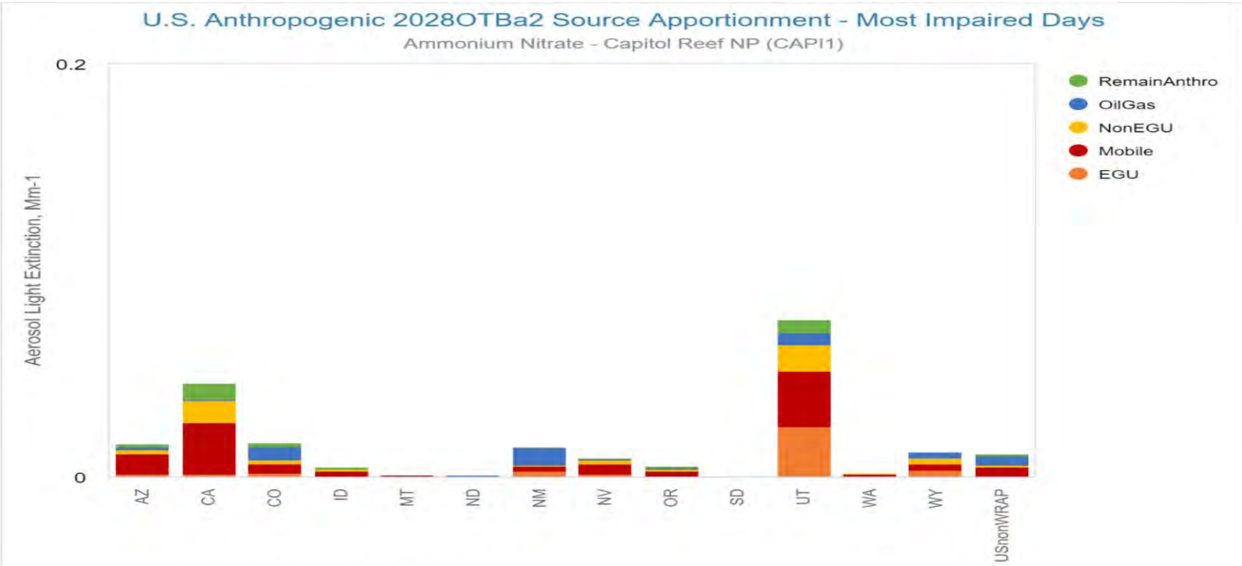



**Figure 38: WRAP States Ammonium Nitrate Source Apportionment for Most Impaired Days at Capitol Reef National Park**

*Zion National Park*

For Zion National Park's most impaired days, California contributes the highest portion of U.S. anthropogenic ammonium nitrate light extinction (49%) with mobile emissions comprising the majority of their impact (27%). California also contributes to the majority of U.S. anthropogenic ammonium sulfate light extinction (37%), most of which are from non-EGU sources (23%).

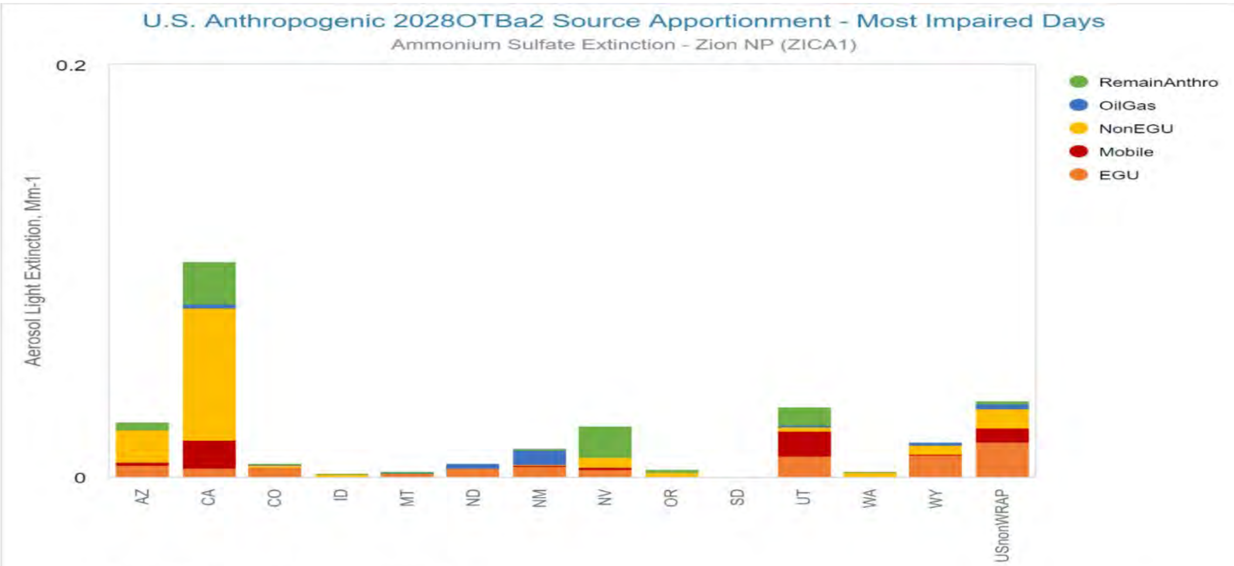



**Figure 39: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Zion National Park**

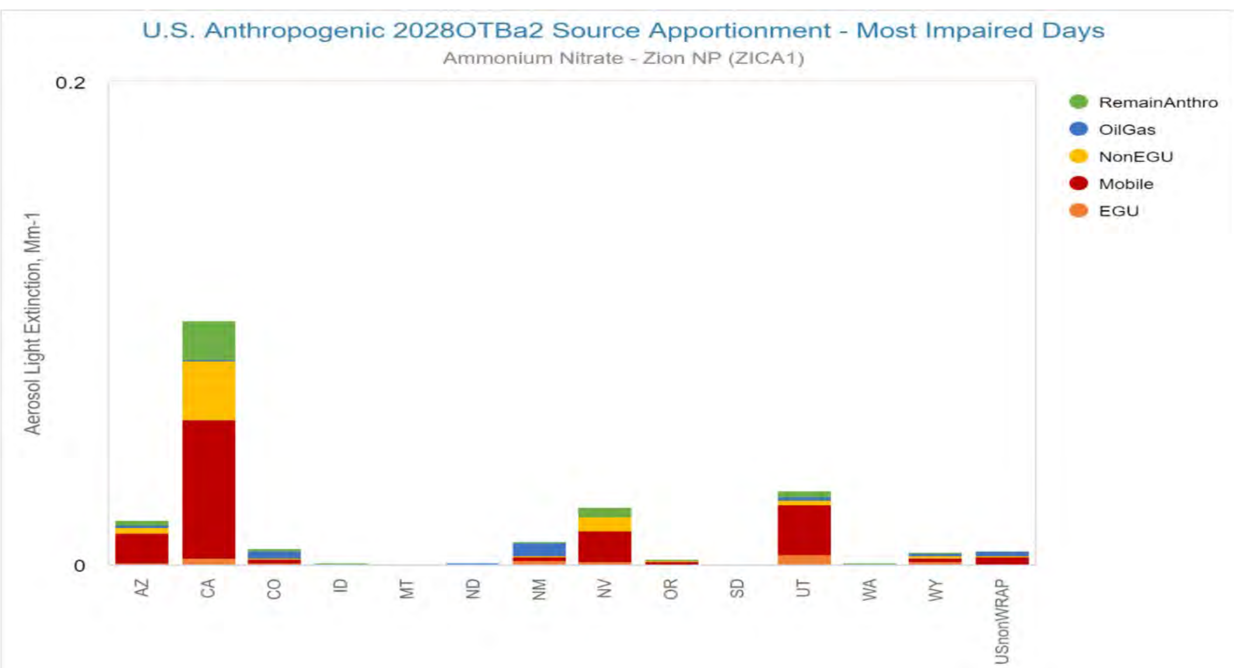



**Figure 40: WRAP States Ammonium Nitrate Source Apportionment for Most Impaired Days at Zion National Park**

### 6.A.2 Utah sources identified by downwind states that are reasonably anticipated to impact CIAs[122]

Utah has analyzed the WRAP photochemical modeling for OTB 2028 and found that emissions from Utah can impact visibility at CIAs in other states. Table 21 and Table 22 below summarize Utah's percent contribution to total U.S. anthropogenic nitrate and sulfate light extinction at CIAs in neighboring states. As can be seen, Utah's highest nitrate impacts occur in Colorado, Idaho, and Wyoming CIAs and mostly stem from mobile source emissions. Utah's highest sulfate impacts also occur in Colorado, Idaho, and Wyoming (namely at MOZI1, WHRI1, CRMO1, and BRID1) and predominantly stem from EGU emissions and some non-EGU emissions in the case of CRMO1. It should be noted that the WRAP source apportionment results for Utah EGUs include impacts from the Bonanza power plant, which is located in Indian Country and which is not, therefore, a source regulated by UDAQ. A review of the weighted emissions potential (WEP) values for sulfate at the latter CIAs identified one Utah EGU, Kennecott Power Plant, with a top-ten sulfate WEP value for BRID1 (rank 2, 7.4% of total WEP). However, this facility was officially closed in 2020. The facilities with the two highest ranking non-EGU WEP sulfate values at CRMO1 were the Tesoro (now Marathon) refinery (rank 6, 6.8% of total WEP) and the Kennecott Smelter and Refinery (rank 10, 2.2% of total WEP), both of which recently underwent BACT analysis for the Salt Lake $PM_{2.5}$ serious area SIP and are well-controlled for $SO_2$.

As one might expect, when Utah anthropogenic impacts are compared to total nitrate and sulfate light extinction at the same CIAs, Utah's shares drop markedly, as shown in Table 23 and Table 24, respectively. And nitrate and sulfate are only two of several contributors to total visibility impairment. As such, Utah's shares of nitrate and sulfate impacts should be considered in this broader context. That said, the aforementioned source apportionment results were not used to screen out any sources from a requirement to conduct a four-factor analysis. Rather, UDAQ relied upon a preliminary Q/d analysis to identify sources with a Q/d of >=6. UDAQ then conducted a secondary screening to review the initial pool of Q/d-qualifying sources to account for factors such as recent emissions controls required by other air quality programs, facility closures, federal preemptions on state controls, etc. Finally, UDAQ reviewed WEP results for nitrate and sulfate to ensure that the remaining Q/d pool reasonably captured sources with impacts at Utah and non-Utah CIAs. This screening analysis is detailed in section 7.A.

**Table 21: Utah Share of U.S. Anthropogenic Nitrate Impacts on Neighboring State CIAs**

| State | Site | EGU | Mobile | Non-EGU | Oil & Gas | Remaining Anthro | Utah Total |
|---|---|---|---|---|---|---|---|
| **AZ** | BALD1 | 0.19% | 0.22% | 0.10% | 0.02% | 0.03% | 0.55% |
| **AZ** | CHIR1 | 0.76% | 0.68% | 0.29% | 0.19% | 0.13% | 2.05% |
| **AZ** | GRCA2 | 0.64% | 0.63% | 0.13% | 0.22% | 0.09% | 1.71% |
| **AZ** | IKBA1 | 0.21% | 0.29% | 0.10% | 0.05% | 0.07% | 0.73% |
| **AZ** | PEFO1 | 2.89% | 1.95% | 0.75% | 0.57% | 0.56% | 6.73% |
| **AZ** | SAGU1 | 0.35% | 0.32% | 0.10% | 0.08% | 0.07% | 0.93% |
| **AZ** | SIAN1 | 0.19% | 0.19% | 0.11% | 0.02% | 0.03% | 0.53% |

[122] 40 CFR 51.308 (f)(2)(ii)(A)

| State | Site | EGU | Mobile | Non-EGU | Oil & Gas | Remaining Anthro | Utah Total |
|---|---|---|---|---|---|---|---|
| **AZ** | SYCA_RHTS | 1.12% | 1.45% | 0.57% | 0.23% | 0.26% | 3.62% |
| **AZ** | TONT1 | 0.22% | 0.30% | 0.09% | 0.05% | 0.07% | 0.74% |
| **CO** | GRSA1 | 2.39% | 1.35% | 0.44% | 0.59% | 0.32% | 5.08% |
| **CO** | MEVE1 | 4.33% | 2.76% | 0.81% | 0.91% | 0.68% | 9.49% |
| **CO** | MOZI1 | 4.14% | 7.23% | 3.00% | 3.00% | 1.44% | 18.81% |
| **CO** | ROMO1 | 1.95% | 3.53% | 1.47% | 1.27% | 0.72% | 8.94% |
| **CO** | WEMI1 | 2.43% | 2.20% | 0.72% | 0.99% | 0.25% | 6.59% |
| **CO** | WHRI1 | 5.14% | 6.75% | 2.23% | 2.64% | 0.98% | 17.74% |
| **ID** | CRMO1 | 0.62% | 6.88% | 3.42% | 0.03% | 2.02% | 12.97% |
| **ID** | SAWT1 | 0.05% | 0.38% | 0.22% | 0.01% | 0.09% | 0.74% |
| **ID** | SULA1 | 0.09% | 0.96% | 0.45% | 0.01% | 0.13% | 1.63% |
| **NM** | BAND1 | 0.58% | 0.43% | 0.14% | 0.14% | 0.08% | 1.37% |
| **NM** | BOAP1 | 0.50% | 0.47% | 0.19% | 0.12% | 0.12% | 1.41% |
| **NM** | GICL1 | 0.27% | 0.38% | 0.15% | 0.07% | 0.06% | 0.93% |
| **NM** | GUMO1 | 0.17% | 0.27% | 0.09% | 0.06% | 0.02% | 0.60% |
| **NM** | SACR1 | 0.06% | 0.06% | 0.02% | 0.02% | 0.01% | 0.17% |
| **NM** | SAPE1 | 0.84% | 0.60% | 0.24% | 0.24% | 0.14% | 2.05% |
| **NM** | WHIT1 | 0.12% | 0.14% | 0.05% | 0.04% | 0.03% | 0.38% |
| **NM** | WHPE1 | 0.96% | 0.84% | 0.29% | 0.23% | 0.16% | 2.48% |
| **NV** | JARB1 | 0.43% | 1.32% | 0.54% | 0.10% | 0.23% | 2.63% |
| **WY** | BRID1 | 2.98% | 12.91% | 6.56% | 1.53% | 2.41% | 26.39% |
| **WY** | NOAB1 | 0.49% | 3.11% | 1.60% | 0.07% | 0.72% | 5.98% |
| **WY** | YELL2 | 0.63% | 5.90% | 2.94% | 0.07% | 1.43% | 10.97% |

**Table 22: Utah Share of U.S. Anthropogenic Sulfate Impacts on Neighboring State CIAs**

| State | Site | EGU | Mobile | Non-EGU | Oil & Gas | Remaining Anthro | Utah Total |
|---|---|---|---|---|---|---|---|
| **AZ** | BALD1 | 0.60% | 0.03% | 0.23% | 0.02% | 0.02% | 0.91% |
| **AZ** | CHIR1 | 1.26% | 0.04% | 0.33% | 0.08% | 0.03% | 1.74% |
| **AZ** | GRCA2 | 2.18% | 0.08% | 0.19% | 0.28% | 0.08% | 2.81% |
| **AZ** | IKBA1 | 1.29% | 0.07% | 0.29% | 0.10% | 0.06% | 1.81% |
| **AZ** | PEFO1 | 2.30% | 0.11% | 0.51% | 0.14% | 0.07% | 3.12% |
| **AZ** | SAGU1 | 1.36% | 0.06% | 0.34% | 0.06% | 0.04% | 1.86% |
| **AZ** | SIAN1 | 0.62% | 0.03% | 0.18% | 0.03% | 0.03% | 0.89% |
| **AZ** | SYCA_RHTS | 4.21% | 0.22% | 1.45% | 0.09% | 0.15% | 6.13% |
| **AZ** | TONT1 | 1.31% | 0.06% | 0.33% | 0.09% | 0.04% | 1.84% |
| **CO** | GRSA1 | 4.85% | 0.09% | 0.38% | 0.52% | 0.07% | 5.91% |
| **CO** | MEVE1 | 7.97% | 0.17% | 0.84% | 1.57% | 0.14% | 10.69% |
| **CO** | MOZI1 | 10.25% | 0.27% | 1.48% | 0.67% | 0.18% | 12.85% |
| **CO** | ROMO1 | 5.89% | 0.28% | 2.12% | 0.49% | 0.17% | 8.96% |
| **CO** | WEMI1 | 6.79% | 0.19% | 0.96% | 1.41% | 0.14% | 9.49% |
| **CO** | WHRI1 | 22.85% | 0.45% | 1.91% | 2.12% | 0.30% | 27.62% |

| State | Site | EGU | Mobile | Non-EGU | Oil & Gas | Remaining Anthro | Utah Total |
|---|---|---|---|---|---|---|---|
| **ID** | CRMO1 | 4.17% | 0.48% | 4.08% | 0.01% | 0.35% | 9.10% |
| **ID** | SAWT1 | 1.23% | 0.06% | 0.82% | 0.01% | 0.04% | 2.15% |
| **ID** | SULA1 | 0.79% | 0.11% | 0.70% | 0.01% | 0.08% | 1.70% |
| **NM** | BAND1 | 1.25% | 0.04% | 0.18% | 0.22% | 0.02% | 1.70% |
| **NM** | BOAP1 | 0.68% | 0.03% | 0.14% | 0.04% | 0.02% | 0.91% |
| **NM** | GICL1 | 0.89% | 0.04% | 0.26% | 0.04% | 0.03% | 1.25% |
| **NM** | GUMO1 | 0.49% | 0.02% | 0.12% | 0.03% | 0.01% | 0.66% |
| **NM** | SACR1 | 0.21% | 0.01% | 0.04% | 0.01% | 0.00% | 0.27% |
| **NM** | SAPE1 | 2.07% | 0.06% | 0.31% | 0.25% | 0.05% | 2.74% |
| **NM** | WHIT1 | 0.29% | 0.01% | 0.06% | 0.02% | 0.01% | 0.38% |
| **NM** | WHPE1 | 1.55% | 0.05% | 0.28% | 0.13% | 0.03% | 2.04% |
| **NV** | JARB1 | 2.05% | 0.12% | 0.85% | 0.03% | 0.07% | 3.13% |
| **WY** | BRID1 | 12.26% | 0.63% | 5.98% | 0.30% | 0.42% | 19.59% |
| **WY** | NOAB1 | 4.01% | 0.15% | 1.12% | 0.17% | 0.12% | 5.57% |
| **WY** | YELL2 | 5.29% | 0.35% | 3.22% | 0.05% | 0.24% | 9.15% |

**Table 23: Utah Share of Total Nitrate Impacts on Neighboring State CIAs**

| State | Site | EGU | Mobile | Non-EGU | Oil & Gas | Remaining Anthro | Utah Total |
|---|---|---|---|---|---|---|---|
| **AZ** | BALD1 | 0.06% | 0.07% | 0.03% | 0.01% | 0.01% | 0.17% |
| **AZ** | CHIR1 | 0.17% | 0.15% | 0.06% | 0.04% | 0.03% | 0.45% |
| **AZ** | GRCA2 | 0.07% | 0.07% | 0.01% | 0.03% | 0.01% | 0.20% |
| **AZ** | IKBA1 | 0.12% | 0.16% | 0.06% | 0.03% | 0.04% | 0.41% |
| **AZ** | PEFO1 | 1.34% | 0.90% | 0.35% | 0.26% | 0.26% | 3.11% |
| **AZ** | SAGU1 | 0.18% | 0.17% | 0.05% | 0.04% | 0.04% | 0.48% |
| **AZ** | SIAN1 | 0.10% | 0.09% | 0.06% | 0.01% | 0.01% | 0.27% |
| **AZ** | SYCA_RHTS | 0.38% | 0.50% | 0.19% | 0.08% | 0.09% | 1.24% |
| **AZ** | TONT1 | 0.13% | 0.18% | 0.06% | 0.03% | 0.04% | 0.44% |
| **CO** | GRSA1 | 1.19% | 0.68% | 0.22% | 0.29% | 0.16% | 2.54% |
| **CO** | MEVE1 | 2.38% | 1.52% | 0.45% | 0.50% | 0.37% | 5.21% |
| **CO** | MOZI1 | 1.77% | 3.09% | 1.28% | 1.28% | 0.61% | 8.03% |
| **CO** | ROMO1 | 1.19% | 2.16% | 0.90% | 0.77% | 0.44% | 5.45% |
| **CO** | WEMI1 | 0.94% | 0.85% | 0.28% | 0.38% | 0.10% | 2.54% |
| **CO** | WHRI1 | 1.81% | 2.39% | 0.79% | 0.93% | 0.35% | 6.27% |
| **ID** | CRMO1 | 0.26% | 2.94% | 1.46% | 0.01% | 0.86% | 5.54% |
| **ID** | SAWT1 | 0.01% | 0.08% | 0.05% | 0.00% | 0.02% | 0.16% |
| **ID** | SULA1 | 0.02% | 0.18% | 0.08% | 0.00% | 0.02% | 0.31% |
| **NM** | BAND1 | 0.32% | 0.24% | 0.08% | 0.08% | 0.05% | 0.75% |
| **NM** | BOAP1 | 0.24% | 0.22% | 0.09% | 0.06% | 0.06% | 0.67% |
| **NM** | GICL1 | 0.01% | 0.01% | 0.00% | 0.00% | 0.00% | 0.03% |
| **NM** | GUMO1 | 0.06% | 0.09% | 0.03% | 0.02% | 0.01% | 0.20% |

| State | Site | EGU | Mobile | Non-EGU | Oil & Gas | Remaining Anthro | Utah Total |
|---|---|---|---|---|---|---|---|
| **NM** | SACR1 | 0.04% | 0.04% | 0.01% | 0.01% | 0.01% | 0.12% |
| **NM** | SAPE1 | 0.44% | 0.31% | 0.13% | 0.12% | 0.07% | 1.07% |
| **NM** | WHIT1 | 0.05% | 0.06% | 0.02% | 0.02% | 0.01% | 0.17% |
| **NM** | WHPE1 | 0.42% | 0.37% | 0.13% | 0.10% | 0.07% | 1.09% |
| **NV** | JARB1 | 0.11% | 0.33% | 0.13% | 0.03% | 0.06% | 0.65% |
| **WY** | BRID1 | 0.97% | 4.20% | 2.13% | 0.50% | 0.78% | 8.57% |
| **WY** | NOAB1 | 0.08% | 0.49% | 0.25% | 0.01% | 0.11% | 0.95% |
| **WY** | YELL2 | 0.18% | 1.69% | 0.84% | 0.02% | 0.41% | 3.14% |

**Table 24: Utah Share of Total Sulfate Impacts on Neighboring State CIAs**

| State | Site | EGU | Mobile | Non-EGU | Oil & Gas | Remaining Anthro | Utah Total |
|---|---|---|---|---|---|---|---|
| **AZ** | BALD1 | 0.06% | 0.00% | 0.02% | 0.00% | 0.00% | 0.10% |
| **AZ** | CHIR1 | 0.13% | 0.00% | 0.03% | 0.01% | 0.00% | 0.17% |
| **AZ** | GRCA2 | 0.93% | 0.03% | 0.08% | 0.12% | 0.03% | 1.19% |
| **AZ** | IKBA1 | 0.14% | 0.01% | 0.03% | 0.01% | 0.01% | 0.20% |
| **AZ** | PEFO1 | 0.46% | 0.02% | 0.10% | 0.03% | 0.01% | 0.63% |
| **AZ** | SAGU1 | 0.20% | 0.01% | 0.05% | 0.01% | 0.01% | 0.27% |
| **AZ** | SIAN1 | 0.06% | 0.00% | 0.02% | 0.00% | 0.00% | 0.09% |
| **AZ** | SYCA_RHTS | 0.50% | 0.03% | 0.17% | 0.01% | 0.02% | 0.72% |
| **AZ** | TONT1 | 0.15% | 0.01% | 0.04% | 0.01% | 0.00% | 0.21% |
| **CO** | GRSA1 | 1.31% | 0.02% | 0.10% | 0.14% | 0.02% | 1.60% |
| **CO** | MEVE1 | 1.98% | 0.04% | 0.21% | 0.39% | 0.03% | 2.66% |
| **CO** | MOZI1 | 2.68% | 0.07% | 0.39% | 0.18% | 0.05% | 3.36% |
| **CO** | ROMO1 | 1.64% | 0.08% | 0.59% | 0.14% | 0.05% | 2.50% |
| **CO** | WEMI1 | 1.45% | 0.04% | 0.20% | 0.30% | 0.03% | 2.02% |
| **CO** | WHRI1 | 4.16% | 0.08% | 0.35% | 0.39% | 0.05% | 5.02% |
| **ID** | CRMO1 | 0.46% | 0.05% | 0.45% | 0.00% | 0.04% | 1.01% |
| **ID** | SAWT1 | 0.08% | 0.00% | 0.05% | 0.00% | 0.00% | 0.13% |
| **ID** | SULA1 | 0.05% | 0.01% | 0.05% | 0.00% | 0.01% | 0.11% |
| **NM** | BAND1 | 0.41% | 0.01% | 0.06% | 0.07% | 0.01% | 0.55% |
| **NM** | BOAP1 | 0.19% | 0.01% | 0.04% | 0.01% | 0.00% | 0.25% |
| **NM** | GICL1 | 0.12% | 0.01% | 0.03% | 0.00% | 0.00% | 0.17% |
| **NM** | GUMO1 | 0.11% | 0.00% | 0.03% | 0.01% | 0.00% | 0.15% |
| **NM** | SACR1 | 0.06% | 0.00% | 0.01% | 0.00% | 0.00% | 0.08% |
| **NM** | SAPE1 | 0.54% | 0.01% | 0.08% | 0.07% | 0.01% | 0.71% |
| **NM** | WHIT1 | 0.07% | 0.00% | 0.01% | 0.00% | 0.00% | 0.10% |
| **NM** | WHPE1 | 0.44% | 0.01% | 0.08% | 0.04% | 0.01% | 0.58% |
| **NV** | JARB1 | 0.13% | 0.01% | 0.05% | 0.00% | 0.00% | 0.20% |
| **WY** | BRID1 | 2.01% | 0.10% | 0.98% | 0.05% | 0.07% | 3.21% |
| **WY** | NOAB1 | 0.35% | 0.01% | 0.10% | 0.02% | 0.01% | 0.49% |

| State | Site | EGU | Mobile | Non-EGU | Oil & Gas | Remaining Anthro | Utah Total |
|---|---|---|---|---|---|---|---|
| **WY** | YELL2 | 0.68% | 0.05% | 0.41% | 0.01% | 0.03% | 1.17% |

### 6.A.3 Technical Basis of Reasonable Progress Goals

Please refer to sections 4.A.4 and 4.A.5 to view visibility progress to date and natural baseline comparisons for Utah's CIAs as well as section 6.A.10 to review UDAQ's Long-Term Strategy along with its technical basis.

### 6.A.4 Identify Anthropogenic Sources

Please refer to sections 5.C and 5.E for Utah's detailed emissions inventory by sector. Please refer to sections 7.A and 7.A.1 for Utah's source screening processes and Q/d analysis for determining which sources have the highest potential impact on Utah's CIAs.

### 6.A.5 Emissions Reductions Due to Ongoing Pollution Control Programs[123]

*RAVI*

RAVI refers to a process to identify and control visibility impairment that is caused by the emissions of air pollutants from one, or a small number of sources directly impacting a CIA. The three primary steps in this process are:[124]

- FLM certification of impairment
- State identification of existing sources causing or contributing to the impairment
- BART analysis to determine what controls, if any, are required on any existing source that meets BART criteria and has been identified as contributing to impairment

In the case that a FLM certifies impairment for any of Utah's CIAs, RAVI[125] will be addressed by the state through the following actions:

- Submittal of an initial RAVI LTS along with periodic revisions every three years
- Submittal of an LTS revision within three years of an FLM certification of impairment
- Consultation with FLMs
- Submittal of a report to the EPA and public on Utah's progress towards the national goal

UDAQ consulted with NPS who confirmed that none of Utah's CIAs have been certified as impaired by any FLMs.

*National Ambient Air Quality Standards*

The CAA requires the EPA to set NAAQS for pollutants considered harmful to public health and the environment. The CAA establishes two types of air quality standards: primary and

[123] 51.308(d)(3) and (f)(2)

[124] The Recommendations for Making Attribution Determinations in the Context of Reasonably Attributable BART can be found at: http://www.westar.org/RA%20BART/final%20RA%20BART%20Report.pdf

[125] 40 CFR 51.302

secondary. Primary standards are set to protect public health, including the health of sensitive populations such as asthmatics, children, and the elderly. Secondary standards are set to protect public welfare, including protection from decreased visibility and damage to animals, crops, vegetation, and buildings.

The EPA has established health-based NAAQS for the six criteria pollutants including CO, $NO_2$, $O_3$, PM, $SO_2$, and lead. The EPA establishes the primary health standards after considering both the concentration level and the duration of exposure that can cause adverse health effects. Pollutant concentrations that exceed the NAAQS are considered unhealthy for some portion of the population. At concentrations between 1.0 and 1.5 times the standard, while the general public is not expected to be adversely affected by the pollutant, the most sensitive portion of the population may be. However, at levels above 1.5 times the standard, even healthy people may see adverse effects. The UDAQ monitors these criteria pollutants, as well as meteorological conditions and several non-criteria pollutants for special studies at various monitoring sites throughout the state.

The CAA has three different designations for areas based on whether they meet the NAAQS for each pollutant. Areas in compliance with the NAAQS are designated as attainment areas. Areas where there is no monitoring data showing compliance or noncompliance with the NAAQS are designated as unclassifiable areas. Areas that are not in compliance with the NAAQS are designated as nonattainment areas. A maintenance area is an attainment area that was once designated as nonattainment for one of the NAAQS and has since been demonstrated as attaining and continuing to attain that standard for a period of a minimum of 10 years. Most of the State of Utah has been designated as either Attainment or Unclassifiable for all the NAAQS.

Utah has never been out of compliance with any $NO_2$ standard, and has not exceeded the lead standard since the 1970s. Three cities in Utah (Salt Lake City, Ogden, and Provo) were at one time designated as nonattainment areas for carbon monoxide. Due primarily to improvements in motor vehicle technology, Utah has complied with the carbon monoxide standards since 1994. Salt Lake City, Ogden, and Provo were successfully redesignated to attainment status in 1999, 2001, and 2006, respectively.

### *Ozone ($O_3$)*

In October of 2015, the EPA strengthened the ozone NAAQS from 75 ppb to 70 ppb, based on a three-year average of the annual 4th highest daily eight-hour average concentration. The standard was reviewed again in 2020 and the EPA chose to retain the standard at 70 ppb. Ozone monitors operated by the UDAQ along the Wasatch Front show exceedances of the current standard in Weber, Davis, and Salt Lake counties. There were also exceedances in Uinta County and Duchesne County during the winter. In 2016, the Governor recommended that portions of the Wasatch Front and Uinta Basin be designated non-attainment and that the rest of the State be designated attainment/unclassifiable. The current status of attainment for ozone in the Uintah basin is marginal non-attainment.

The unique wintertime ozone issue in the Uinta Basin is caused by oil and gas extraction. UDAQ is working on rule amendments and potentially new rules for the oil and gas industry to stay in compliance with the ozone NAAQS.

### *$PM_{10}$*

The EPA established the 24-hour NAAQS for $PM_{10}$ in July 1987 as 150 µg/m3. The standard is met when the probability of exceeding the standard is no greater than once per year for a three-year averaging period. Salt Lake County and Utah County had been designated nonattainment for $PM_{10}$ shortly after the standard was promulgated. Ogden City was also designated as a nonattainment area due to one year of high concentrations (1992) but was determined to be attaining the standard in January 2013. State Implementation Plans (SIP) were written and promulgated in 1991 and included control strategies that resulted in the marked decrease in $PM_{10}$ concentrations observed in the early 1990s. Ogden City, and Salt Lake and Utah Counties were officially designated as attainment for $PM_{10}$ effective March 27, 2020. These three former nonattainment areas are now subject to the maintenance plans that were approved by EPA and the areas must continue to attain the standard for the first maintenance period of ten years. High values of monitored $PM_{10}$ sometimes result from exceptional events, such as dust storms and wildfires.

### *$PM_{2.5}$*

The EPA first established standards for $PM_{2.5}$ in 1997. In 2006, the EPA lowered the 24-hour $PM_{2.5}$ standard from 65µg/m3 to 35 µg/m3. The $PM_{2.5}$ NAAQS underwent a review in 2020 and the standards were retained. In 2009, three areas in Utah were designated nonattainment for $PM_{2.5}$. UDAQ wrote a moderate SIP for the Logan, UT-ID nonattainment area, including a vehicle emissions inspection program. Logan attained the standard, and has since been redesignated to attainment status. The Provo and Salt Lake $PM_{2.5}$ nonattainment areas were unable to attain by the moderate attainment date and were reclassified to serious nonattainment. A serious SIP was submitted to EPA for the Salt Lake nonattainment area, and the Provo nonattainment area attained the standard prior to a serious SIP due date. Best Available Control Measures and Technologies were still required in both nonattainment areas, significantly reducing VOCs, $NO_x$, and both primary and secondary $PM_{2.5}$ in the airsheds. Both areas have now attained the standard, and EPA is reviewing SIP elements and maintenance plans for official redesignation to attainment/maintenance.

### *Sulfur Dioxide ($SO_2$)*

In 1971, EPA established a 24-hour average $SO_2$ standard of 0.14 ppm, and an annual arithmetic average standard of 0.030 ppm. In 2010, EPA revised the primary standard for $SO_2$, setting it at 75 ppb for a three-year average of the $99^{th}$percentile of the annual distribution of daily maximum one-hour average concentrations for $SO_2$. Throughout the 1970s, the Magna monitor routinely measured violations of the 1971 24-hour standard. Consequently, all of Salt Lake County and parts of eastern Tooele County above 5,600 feet were designated as nonattainment for that standard. Two significant technological upgrades at the Kennecott smelter costing the company nearly one billion dollars resulted in continued compliance with the $SO_2$ standard since 1981. In the mid-1990s, Kennecott, Geneva Steel, the five refineries in Salt

Lake City, and several other large sources of $SO_2$ made dramatic reductions in emissions as part of an effort to curb concentrations of secondary particulates (sulfates) that were contributing to $PM_{10}$ violations. More recently, Kennecott closed Units 1, 2, and 3 of its coal-fired power plants in 2016 and Unit 4 in 2019, resulting in further $SO_2$ emissions reductions.

Utah submitted an $SO_2$ Maintenance Plan and redesignation request for Salt Lake and Tooele Counties to the EPA in April of 2005, but EPA never took formal action on the request. Because of changes in the emissions in subsequent years, and changes in the modeling used to demonstrate attainment of the standard, in November 2019, the State of Utah withdrew its 2005 Maintenance Plan and redesignation request. UDAQ is currently working very closely with EPA to develop a new maintenance plan and redesignation request to address the 1971 standard. UDAQ will conduct modeling and other analyses in 2021 with the goal of submitting an approvable maintenance plan and redesignation request to EPA by the end of that year. On November 1, 2016, Governor Herbert submitted a recommendation to EPA that all areas of the state be designated as attainment for the 2010 $SO_2$ NAAQS based on monitoring and air quality modeling data. On January 9, 2018, EPA formally concurred with this recommendation and designated all areas of the state as attainment/unclassifiable.

The NAAQS program and Utah's work to stay in compliance with all NAAQS has significantly decreased VOC, $NO_x$, $PM_{2.5}$, $PM_{10}$, and $SO_2$ emissions over time, benefiting the regional haze program.

#### *Air Quality Incentive Programs*

In addition to the NAAQS program, UDAQ administers multiple incentive programs created to encourage individuals and businesses to voluntarily reduce emissions. Funding for these programs comes from various sources, including settlement agreements, legislative appropriations, and federal grant programs. The emissions reductions from incentive programs are not included as part of any SIP, but the reductions do make an impact on monitored ambient values.

#### *Targeted Airshed Grants*

UDAQ has been a recipient of EPA targeted airshed grants in the past for $PM_{2.5}$ and ozone in Logan, Salt Lake, Provo, and the Uinta Basin nonattainment areas. Programs include woodstove/fireplace conversions, school bus replacements, vehicle repair and replacement assistance programs, and an oil and gas engine replacement program. UDAQ applied for the competitive grants and was awarded a total of $14.5 million for these projects that are still in process.

#### *Utah Clean Diesel Program*

The Utah Clean Diesel Program aims to cut emissions from heavy- duty diesel vehicles and equipment that operate in the State's nonattainment areas. Fleet owners receive a 25% incentive toward the purchase of new vehicles and equipment that meet the cleanest emissions standards. Retiring engine model years 2006 and older diesel trucks that are currently operational and have a minimum of three years remaining in their useful life and replacing them with current model years can achieve approximately 71 to 90% reductions in $NO_x$, 97 to 98%

reductions in $PM_{2.5}$, and 89 to 91% reductions in VOCs, according to the EPA Emissions Standards for Heavy-Duty Highway Engines and Vehicles. Nearly $24 million in federal grants have been awarded through the Utah Clean Diesel Program since 2008, resulting in thousands of tons reduced from diesel emissions.

### *Legislative Appropriations for Incentive Programs*

The woodstove and fireplace conversion funded by the targeted airshed grant was wildly successful, and the Utah State Legislature appropriated UDAQ an additional $9 million to convert wood burning appliance to gas or electric along Utah's Wasatch Front. This program is currently being administered. During the 2019 General Legislative Session, the State Legislature appropriated $4.9 million to be used as an incentive for the installation of electric vehicle supply equipment (EVSE) throughout the State. The EVSE Incentive Program allows businesses, non-profit organizations, and other governmental entities (excluding State Executive Branch agencies) to apply for a grant for reimbursement of up to 50% of the purchase and installation costs for a pre-approved EVSE project. Funds can be used for the purchase and installation of both Level 2 or DC fast charging EVSE. This program continues to be administered. During the 2019 Legislative Session, the Legislature appropriated $500,000 to the UDAQ to administer a Trip Reduction Program. A primary component of the Trip Reduction Program is a Free-Fare Day Pilot Project. The UDAQ has worked closely with the Utah Transit Authority (UTA) to provide free fares during inversion periods when air quality levels are increasing and projected to reach levels that are harmful to human health.

### *Clean Air Violation Settlement Dollars for Emissions Reduction Incentives*

The State of Utah is a beneficiary of over $35 million from the Volkswagen (VW) Environmental Mitigation Trust, part of a settlement with VW for violations of the CAA. UDAQ has developed an environmental mitigation plan to offset the $NO_x$ emissions from the vehicles in the State affected by the automaker's violations. The plan directs the $35 million settlement funds towards upgrades to government-owned diesel truck and bus fleets as well as the expansion of electric-vehicle (EV) charging equipment. Funding allocations are as follows:

- Class 4-8 Local Freight Trucks and School Bus, Shuttle Bus, and Transit Bus: 73.5%
- Light-Duty, Zero Emissions Vehicle Supply Equipment: 11%
- Administrative Costs: 8.5%
- Diesel Emission Reduction Act (DERA) options: 7%

Projects were prioritized and selected based on their reduction of $NO_x$, cost-per-ton of $NO_x$ reduced, value to the nonattainment areas, and community benefits. Awardees will have three years to complete their projects.

Using settlement money from General Motors, UDAQ runs an electric lawn equipment exchange each year. Participants receive a higher incentive dollar amount if they scrap an old gas-powered piece of equipment.

### 6.A.6 Measures to Mitigate the Impacts of Construction Activities

Fugitive dust is particles of soil, ash, coal, minerals, etc., which become airborne because of wind or mechanical disturbance. Fugitive dust can be generated from natural causes such as wind or from manmade causes such as unpaved haul roads and operational areas, storage, hauling and handling of aggregate materials, construction activities and demolition activities. Fugitive dust contributes particulate matter (PM) emissions to the atmosphere. PM emissions must be minimized to meet NAAQS. Fugitive dust is limited to an opacity of 20% or less on site, and 10% or less at the property boundary. Opacity is a measurement of how much visibility is obscured by a plume of dust. For example, if a plume of dust obscures 20% of the view in the background, the visible emissions from the dust plume is 20% opacity. The regulations described in this Subsection apply to the following areas of the state:

- all regions of Salt Lake and Davis counties
- all portions of the Cache Valley
- all regions in Weber and Utah counties west of the Wasatch Mountain range
- in Box Elder County, from the Wasatch Mountain range west to the Promontory Mountain range and south of Portage
- in Tooele County, from the northernmost part of the Oquirrh mountain range to the northern most part of the Stansbury Mountain range and north of Route 199.

In addition to opacity limits, any source 0.25 acre or greater in size is required to submit a Fugitive Dust Control Plan (FDCP) to the UDAQ. The FDCP is required to help sources minimize the amount of fugitive dust generated onsite. A source is required to submit a FDCP prior to initial construction or operation and prior to any modifications made on site that effect fugitive dust emissions. Sources are required to maintain records indicating compliance with the conditions of a FDCP. For high wind events (winds over 25 miles per hour) additional records are required. The sources must make these records available for review by the UDAQ upon request.

There are also regulations regarding possible fugitive dust from roadways:

- Any person whose activities result in fugitive dust from a road shall minimize fugitive dust to the maximum extent possible.
- Any person who deposits materials that may create fugitive dust on a public or private paved road shall clean the road promptly.
- Any person responsible for construction or maintenance of any existing road or having a right-of-way easement or possessing the right to use a road shall minimize fugitive dust to the maximum extent possible.
- Any person responsible for construction or maintenance of any new or existing unpaved road shall prevent, to the maximum extent possible, the deposit of material from the unpaved road onto any intersecting paved road during construction or maintenance. This includes site entrances and exits for vehicles.
- Demolition activities including razing homes, buildings, or other structures.

### 6.A.7 Basic smoke management practices

Subsection 51.309(d)(6) of Title 40 Code of Federal Regulations includes the following requirements for state implementation plans regarding programs related to fire: (1) documentation that all federal, state and private prescribed fire programs in the state evaluate and address the degree of visibility impairment from smoke in their planning and application; (2) a statewide inventory and emissions tracking system for VOCs, $NO_x$, elemental and organic carbon, and fine particle emissions from fire; (3) identification and removal of any administrative barriers to the use of alternatives to burning where possible; (4) inclusion of enhanced smoke management programs considering visibility as well as health and nuisance objectives based on specific criteria; (5) and establishment of annual emission goals for fire in cooperation with states, tribes, federal land managers and private entities to minimize emissions increases from fire to the maximum extent feasible.

Utah implements an EPA-approved Smoke Management Plan (SMP) to regulate open burning and prescribed fire activities. Utah has developed a smoke management regulation (found in Utah Administrative Code r. R307-204) that implements the Western Regional Air Partnership (WRAP) Enhanced Smoke Management Programs for Visibility Policy. The SMP considers smoke management techniques and the visibility impacts of smoke when developing, issuing or conditioning permits, and when making dispersion forecast recommendations. Pursuant to 40 CFR § 51.309(d)(6)(i), the State of Utah has evaluated all federal, state, and private prescribed fire programs in the state, based on the potential to contribute to visibility impairment in the 16 CIAs of the Colorado Plateau, and how visibility protection from smoke is addressed in planning and operation. The State of Utah relied upon the WRAP report Assessing Status of Incorporating Smoke Effects into fire Planning and Operation as a guide for making this evaluation. The State of Utah has also evaluated whether these prescribed fire programs contain the following elements: actions to minimize emissions; evaluation of smoke dispersion; alternatives to fire; public notification; air quality monitoring; surveillance and enforcement; and program evaluation.

The Utah Smoke Management Plan (SMP), revised March 23, 2000, provides operating procedures for federal and state agencies that use prescribed fire, wildfire, and wildland fire on federal, state, and private wildlands in Utah. The SMP includes the program elements listed in 40 CFR § 51.309(d)(6)(i), except for alternatives to fire. In a letter dated November 8, 1999, the EPA certified the Utah SMP under EPA's April 1998 Interim Air Quality Policy on Wildland and Prescribed Fires (Policy). EPA's Policy also includes the elements that are listed in 40 CFR § 51.309(d)(6)(i).

In 2001, the Utah SMP requirements were codified through rulemaking and comprise R307-204 of the Utah Administrative Code. R307-204 applies to all persons using prescribed fire or wildland fire on land they own or manage, including federal, state, and private wildlands. The Utah TSD Supplement includes copies of the Utah SMP.

Under R307-204, Land Managers are required to submit pre-burn information including the location of any CIAs within 15 miles of the burn, a map depicting the potential impact of the smoke from the burn on any CIAs, a description of fuels and acres to be burned, emission reduction techniques to be applied, and monitoring of smoke effects to be conducted. In addition, Land Managers are required to submit a more detailed burn plan that includes, at a minimum, information on the fire prescription or conditions under which a prescribed fire may be ignited.

Under R307-204, prescribed fires requiring a burn plan cannot be ignited and wildland fire used for resource benefits cannot be managed before the UDAQ Director approves the burn request. The burn approval requirement provides for the scheduling of burns to reduce impacts on visibility in CIAs.

After the burn is completed, the Land Manager is required to submit post-burn information (daily emission report) to evaluate the effectiveness of the burn and provide a record of acres treated by the burn, emissions information, public interest, daytime and nighttime smoke behavior, any emission reduction techniques applied, and evaluation of those techniques. The procedures listed above serve as an evaluation of the degree of visibility impairment from smoke from prescribed fires that are conducted on federal, state, and private wildlands.

Information on the types of management alternatives to fire considered by Land Managers are included in programmatic or long-term management plans. These programmatic plans are developed in accordance with the National Environmental Policy Act (NEPA) and are reviewed by the UDAQ on an individual basis. Typically, the Land Manager does not evaluate alternatives to fire once the decision has been made to use fire and the subsequent burn plan developed.

### 6.A.8 Emissions Limitations and Schedules for Compliance to Achieve the RPG

The 2028OTBa2 modeled visibility projections from WRAP for Utah are based on recent actual emissions and activities of in-state sources. These projections are compared to the URP glidepaths in section 8.C. As shown in Table 26 (section 6.A.10), Utah is making reasonable progress in each of its parks and is projected to continue that progress through 2028 on the assumption that Utah sources continue operating within the confines of these “on-the-books” emissions trends. Section 8.D contains Utah’s reasonable progress determinations detailing emissions limits and controls UDAQ has deemed necessary for Utah to achieve reasonable progress in its CIAs. Emissions limitations and schedules for compliance for the second planning period may be found in SIP Subsection IX.H.23.[126]

### 6.A.9 Source retirement and replacement schedules

Table 25 details the planned EGU retirement and replacement schedules for Utah sources used in WRAP’s RepBase2 and 2028OTBa2 modeling projections. Of all of the planned retirements, only the announced retirement of the Intermountain Generation Station in 2025 occurs within the second planning period. Though the IGS coal-fired units are expected to cease operation by mid-2025, Utah is establishing a firm closure date of no later than December 31, 2027, to

[126] See Appendix A

ensure that these units will not continue to operate beyond the end of the second planning period. This date allows flexibility for closing the plant and the rescinding of the permit and approval order.

**Table 25: Status of Utah EGU Retirements in RepBase2 and 2028OTBa2 Inventories**

| Facility Name | Unit ID | In-Service Year | Retirement Year | Notes | Operator | Unit Type |
|---|---|---|---|---|---|---|
| **Intermountain** | 1SGA | 1986 | 2025 | Announced retirement | Intermountain Power Service Corporation | Dry bottom wall-fired boiler |
| **Intermountain** | 2SGA | 1987 | 2025 | Announced retirement | Intermountain Power Service Corporation | Dry bottom wall-fired boiler |
| **Bonanza** | 1-Jan | 1986 | 2030 | Coal consumption cap from settlement agreement | Deseret Generation & Transmission | Dry bottom wall-fired boiler |
| **Hunter** | 1 | 1978 | 2042 | PAC IRP; Round 1 RH FIP in Litigation | PacifiCorp Energy Generation | Tangentially-fired |
| **Hunter** | 2 | 1980 | 2042 | PAC IRP; Round 1 RH FIP in Litigation | PacifiCorp Energy Generation | Tangentially-fired |
| **Hunter** | 3 | 1983 | 2042 | PAC IRP | PacifiCorp Energy Generation | Dry bottom wall-fired boiler |
| **Huntington** | 1 | 1977 | 2036 | PAC IRP; Round 1 RH FIP in Litigation | PacifiCorp Energy Generation | Tangentially-fired |
| **Huntington** | 2 | 1974 | 2036 | PAC IRP; Round 1 RH FIP in Litigation | PacifiCorp Energy Generation | Tangentially-fired |

## 6.A.10 Anticipated net effect on visibility from projected changes in emissions during this planning period

According to the RHR, the 2028 RPG for the 20 percent most anthropogenically impaired days is to be compared to the 2000-2004 baseline period visibility condition for the same set of days and must provide for visibility improvement since the baseline period.[127] UDAQ has used modeling data from WRAP's TSS to project the anticipated net effect on visibility progress that will occur in the second planning period based on already adopted controls and "on-the-books" activities and emissions rates. UDAQ has chosen the "2028OTBa2 w/o fire" projection that excludes wildfire to more accurately represent future emissions from sources UDAQ is better able to control. This projection reduces the impact of elemental carbon and organic carbon from

[127] 40 CFR 51.308(f)(3)(i)

fires from the original 2028 EPA projection to remove additional fire impacts that were not fully eliminated by the move from haziest days metric (used during the first planning period) to most impaired days metric (used during the second planning period). These projections result from in-state emission reductions due to ongoing air pollution control programs, including source measures the state has already adopted to meet RHR requirements and CAA requirements other than for visibility protection.

### *Long Term Strategy Summary*

UDAQ's long term strategy (LTS) includes an array of existing and new measures as detailed below.

#### Existing Measures

UDAQ relied upon several existing measures in the development of its LTS, including federal on-road and non-road vehicle and equipment standards and BACM measures and BACT controls included in the recently completed Serious Area PM2.5 SIP for the Salt Lake Nonattainment Area. Utah also relied upon the following existing round 1 regional haze controls:

- Existing $NO_x$ control rate-based limits and Hunter power plant
- Existing $NO_x$ control rate-based limits and Huntington power plant
- Existing $SO_2$ limits for Hunter power plant (Section 309 control added to SIP in round 2)
- Existing $SO_2$ limits for Huntington power plant (Section 309 control added to SIP in round 2)
- Closure of the Carbon power plant

UDAQ also added existing controls/limits on haze-forming pollutants at screened-in facilities to the round 2 SIP to ensure ongoing enforceability in the regional haze context:

- Graymont
- Ash Grove
- Sunnyside
- US Magnesium
- Intermountain Generation Station

Most of the above measures are already accounted for in the WRAP 2028OTBa2 scenario, which was based on the emission inventories and data sources listed in Section 5.B of this SIP revision. However, two existing measures led to additional emissions reductions that were not accounted for in the WRAP 2028OTBa2 projections:

- $PM_{2.5}$ SIP BACT SCR level $NO_x$ rate-based limit and subsequent closure of the Kennecott Utah Copper power plant
- $PM_{2.5}$ SIP BACT annual mass-based $SO_2$ limit at the Tesoro Refinery

#### New Measures

As stated previously UDAQ required four-factor analyses on six sources with Q/d values >=6 that met additional screening criteria. These analyses informed the reasonable progress determinations for these sources and led to the inclusion of the following new measures in the LTS:

- A plantwide enforceable mass-based $NO_x$ limit on Hunter power plant
- A plantwide enforceable mass-based $NO_x$ limit on Huntington power plant
- Installation of FGR on the US Magnesium Rowley Plant Riley Boiler
- An enforceable closure date for Units 1 and 2 of the Intermountain Generation Station

Emissions reductions for one of these new measures, the closure of IGS Units 1 and 2, were already accounted for in the WRAP 2028OTBa2 projections based upon closure plans that had been announced at the time the scenario was developed.

Table 26 below summarizes estimated net changes to the 2028 projection based upon the inclusion of both new and existing measures in the LTS. The emission reductions from the KUC power plant were estimated based on the elimination of the EGU emissions from that facility from the 2028OTBa2 scenario. The $SO_2$ emission reductions for the Tesoro Refinery were estimated by reducing the 2028OTBa2 $SO_2$ emissions for that facility (708 tons) to the SIP Section IX.H source-wide $SO_2$ annual limit of 300 tons per year, resulting in a reduction of 408 tons. The remaining emission reductions stem from the four-factor analyses and reasonable progress determinations for the sources listed.

**Table 26: Net Changes in Emissions from New and Existing Measures Relative to 2028OTBa2**

| Source/Facility | New or Existing Measure | Reduction Included in 2028OTBa2 | $NO_X$ | $SO_2$ | $PM_{10}$-PRI | $PM_{2.5}$-PRI | VOC | $NH_3$ |
|---|---|---|---|---|---|---|---|---|
| **PacifiCorp- Hunter Power Plant** | New | No | -158 | 0 | 0 | 0 | 0 | 0 |
| **PacifiCorp- Huntington Power Plant** | New | No | 149 | 0 | 0 | 0 | 0 | 0 |
| **US Magnesium Riley Boiler** | New | No | -23 | 0 | 0 | 0 | 0 | 0 |
| **Tesoro Refining & Marketing Company LLC** | Existing | No | 0 | -408 | 0 | 0 | 0 | 0 |
| **Kennecott Utah Copper LLC- Power Plant** | Existing | No | -1,152 | -2,152 | -135 | -99 | -6 | 0 |
| **Total** | | | -1,184 | -2,560 | -135 | -99 | -6 | 0 |

Based upon these changes, UDAQ revised the original 2028OTBa2 projection as summarized in Table 27. The resulting 2028LTS scenario results in emissions reductions of 44% (NOx), 27% (SO2), 2% (PM10), 10% (PM2.5) and 30% (VOC) relative to RepBase2.

**Table 27: Statewide Anthropogenic Scenario Totals and LTS Emission Reductions (tpy)**

| Source Category | 2014v2 | RepBase2 | 2028OTBa2 | Change Due to New and Existing Measures | 2028LTS | 2028LTS-RepBase2 | 2028LTS-RepBase2 (% Change) |
|---|---|---|---|---|---|---|---|
| $NO_X$ | 179,639 | 154,328 | 87,593 | -1,184 | 86,409 | -67,919 | -44% |
| $SO_2$ | 27,829 | 15,253 | 13,684 | -2,560 | 11,124 | -4,129 | -27% |
| $PM_{10}$ | 118,235 | 120,542 | 118,117 | -135 | 117,982 | -2,560 | -2% |
| $PM_{2.5}$ | 28,547 | 31,050 | 28,039 | -99 | 27,940 | -3,110 | -10% |
| VOC | 240,496 | 244,272 | 171,298 | -6 | 171,292 | -72,980 | -30% |
| $NH_3$ | 20,523 | 20,995 | 21,011 | 0 | 21,011 | 16 | 0% |

Because the LTS was developed after the completion of the WRAP photochemical modeling, the additional reductions from the LTS relative to 2028OTBa2 are not expressly accounted for in the modeled reasonable progress goal. The omission of these emissions reductions in the 2028OTBa2 projection make our glidepath comparisons conservative, as actual 2028 visibility can be expected to improve due to additional emission reductions associated with the LTS.

### *Visibility Comparison*

Table 28 compares the baseline visibility data for each of Utah's CIAs with the 2028 point along the URP glidepath and the 2028 modeled projections and calculates the resulting percentage of progress towards the 2028 URP made in each.

**Table 28: Comparison of baseline, 2028 URP, 2028 EPA w/o fire projection for worst and clearest days**

| CIA IMPROVE Site | WORST DAYS | | | | | CLEAREST DAYS | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Baseline (dv) | 2028 URP (dv) | 2028 EPA w/o Fire Projection (dv) | % Progress to 2028 URP | 2028 Below URP Glidepath? (Y/N) | Baseline (dv) | 2028 EPA Projection (dv) | 2028 EPA w/o Fire Projection (dv) | 2028 Below No Degradation Line? (Y/N) |
| BRCA1 | 8.42 | 6.68 | 6.03 | 137.60% | YES | 2.77 | 1.22 | 1.20 | YES |
| CANY1 | 8.79 | 6.92 | 6.19 | 139.10% | YES | 3.75 | 1.94 | 1.92 | YES |
| CAPI1 | 8.78 | 6.87 | 6.63 | 112.28% | YES | 4.10 | 2.17 | 2.10 | YES |
| ZICA1 | 10.40 | 8.35 | 8.27 | 103.73% | YES | 4.48 | 3.65 | 3.54 | YES |

The following figures compare the modeled 2002, representative baseline, and 2028 projections with source apportionment for most impaired days to show the visibility progress made in Utah's CIAs.

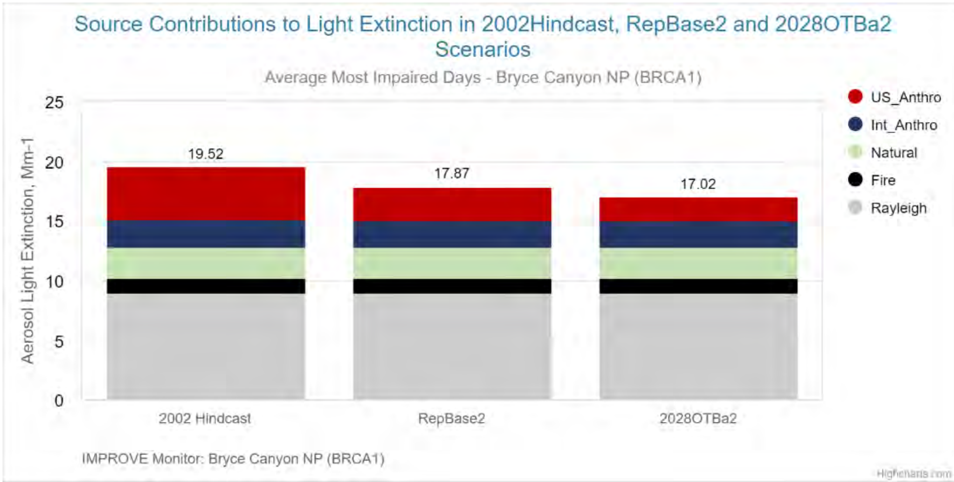



**Figure 41: Modeled Visibility Progress for MID at Bryce Canyon National Park**

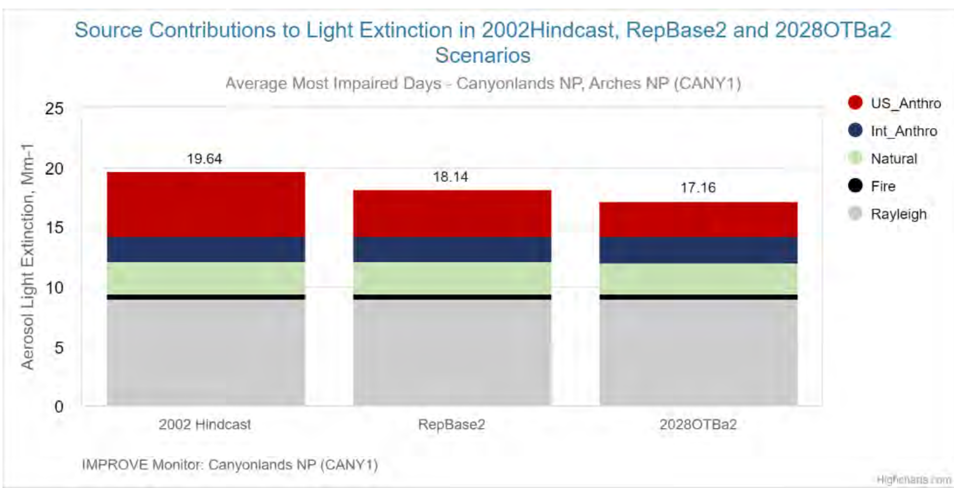



**Figure 42: Modeled Visibility Progress for MID at Canyonlands and Arches National Park**

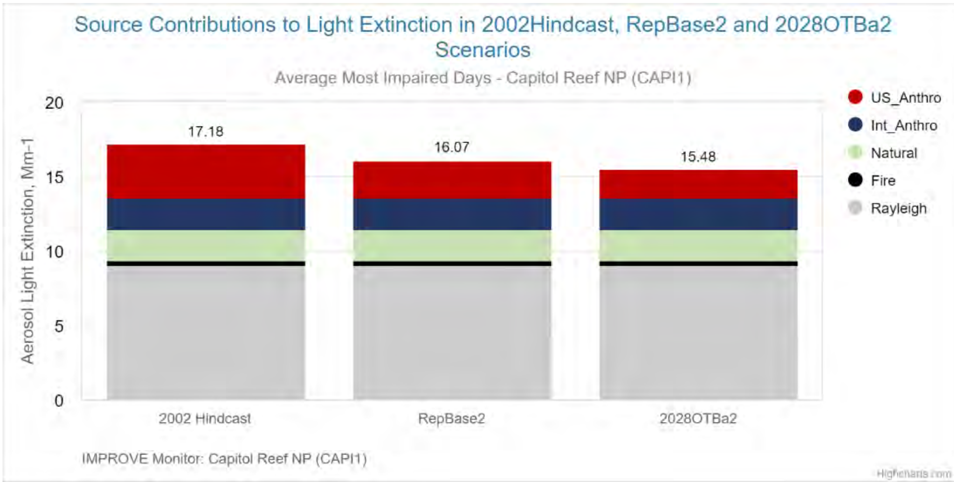



**Figure 43: Modeled Visibility Progress for MID at Capitol Reef National Park**

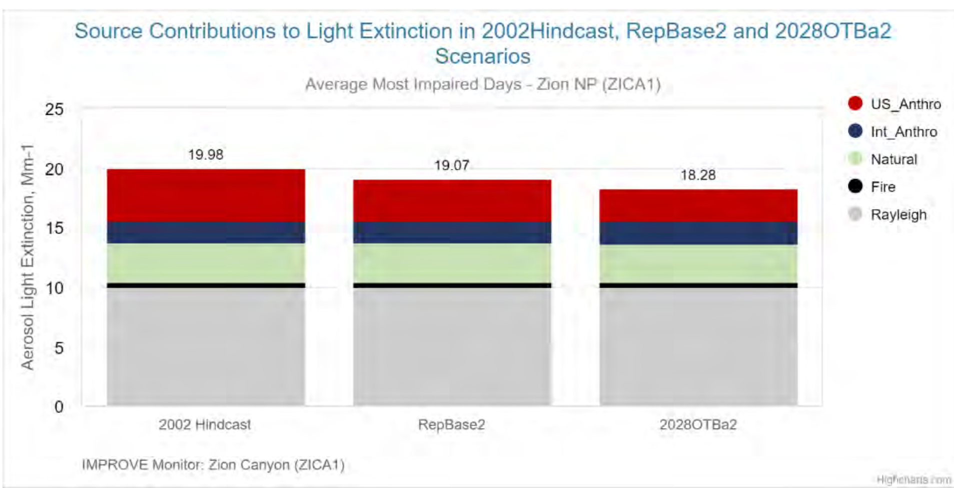



**Figure 44: Modeled Visibility Progress for MID at Zion National**

The following figures represent the visibility progress made in each CIA based on only US anthropogenic contribution with the same modeling projections for most impaired days.

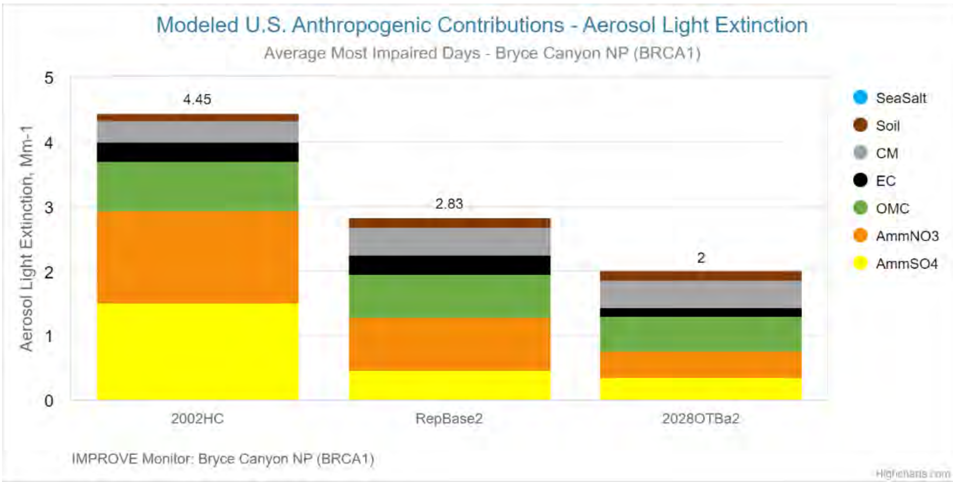



**Figure 45: Modeled Visibility Progress for US Anthropogenic Contributions to MIDs at Bryce Canyon National Park**

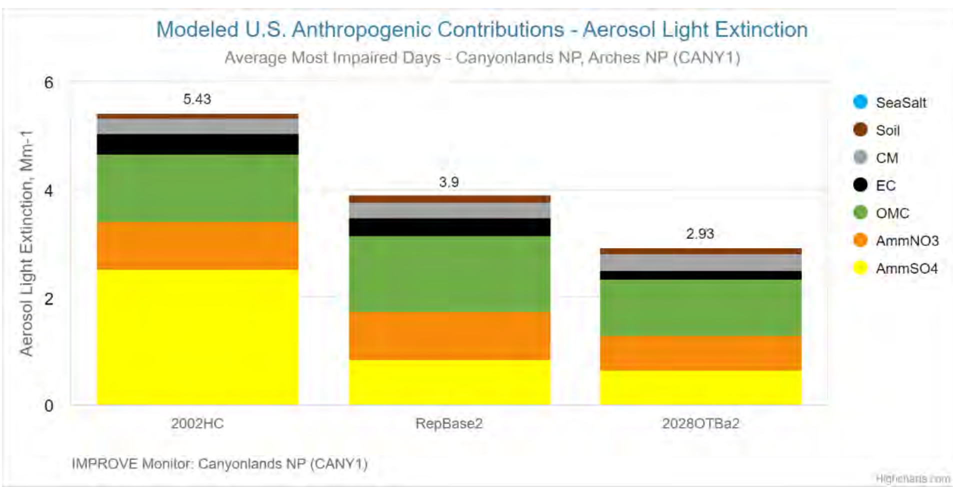



**Figure 46: Modeled Visibility Progress for US Anthropogenic Contributions to MIDs at Canyonlands and Arches National Park**

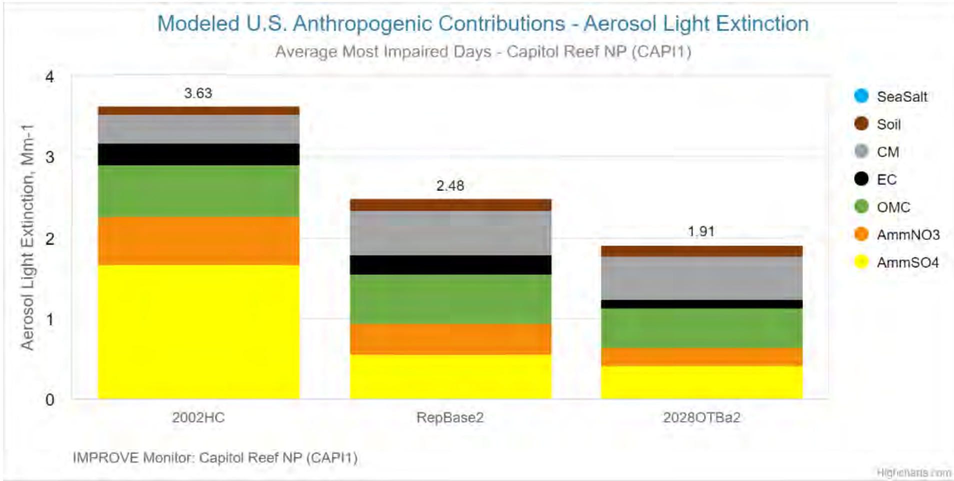



**Figure 47: Modeled Visibility Progress for US Anthropogenic Contributions to MIDs at Capitol Reef National Park**

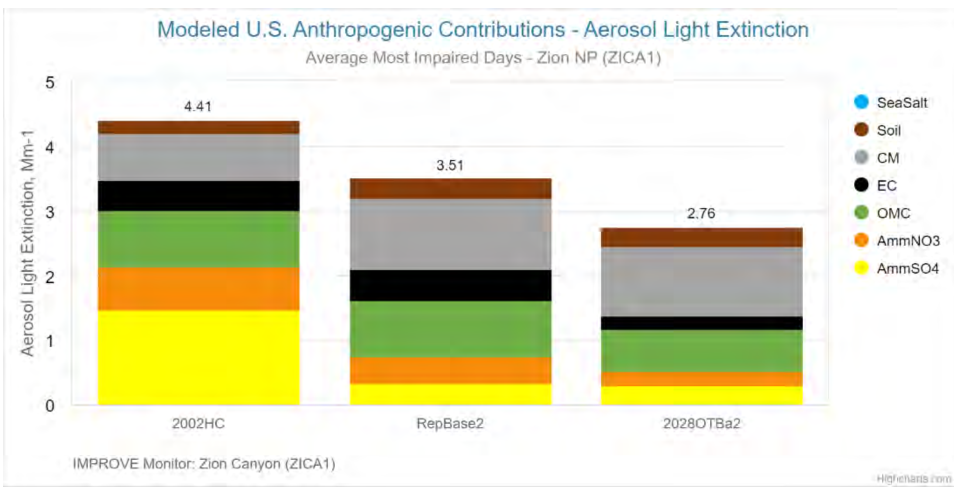



**Figure 48: Modeled Visibility Progress for US Anthropogenic Contributions to MIDs at Zion National Park**

### 6.A.11 Enforceability of Emissions Limitations

Any emissions limits and operating procedures identified for the implementation of the RHR are listed in SIP Subsection IX.H.21, 22, and 23, which are made enforceable through EPA approval and incorporation into the Utah Air Quality Rules. The proposed IX.H language can be found in Appendix A. Existing control measures from UDAQ's $PM_{2.5}$ and $PM_{10}$ SIP revisions deemed necessary for reasonable progress can be found in IX.H.2, 4, and 12.

# **Chapter 7:** Emission Control Analysis[128]

## 7.A Source Screening

Through modeling done by WRAP with data collected at the IMPROVE sites in Utah's CIAs, UDAQ was able to assess the source apportionment for the most impaired days in Utah's National Parks. Figure 49 shows that, on most impaired days, US anthropogenic, international, and biogenic pollution are the most significant sources of light extinction. Figure 50 and Figure 51 further apportion species contributing to each pollution source. US anthropogenic impairment consists primarily of organic mass carbon, coarse mass, ammonium nitrate, and ammonium sulfate. For this implementation period, Utah has focused on visibility impairing pollutants attributed to anthropogenic sources which can be controlled including ammonium nitrate and ammonium sulfate.

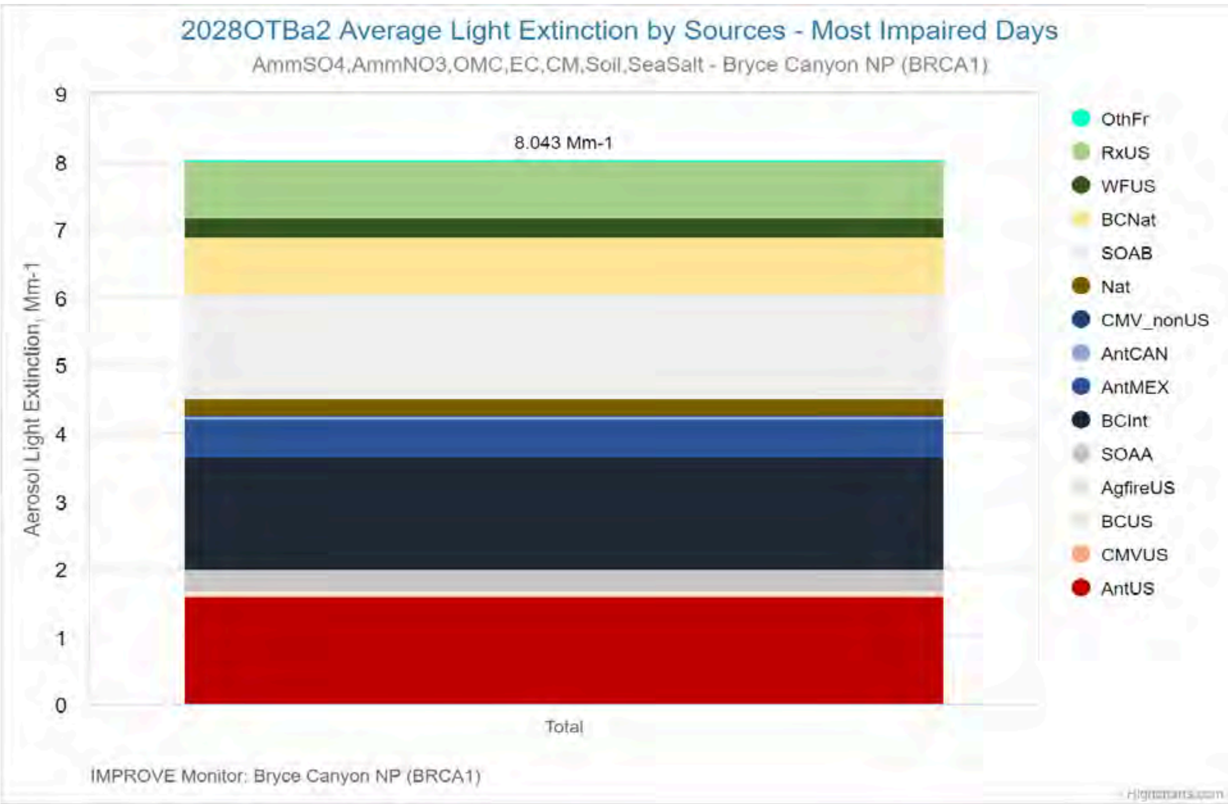



**Figure 49: Average Light Extinction by Sources in Bryce Canyon National Park**

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[128] 40 CFR 51.308(f)(2)(i)

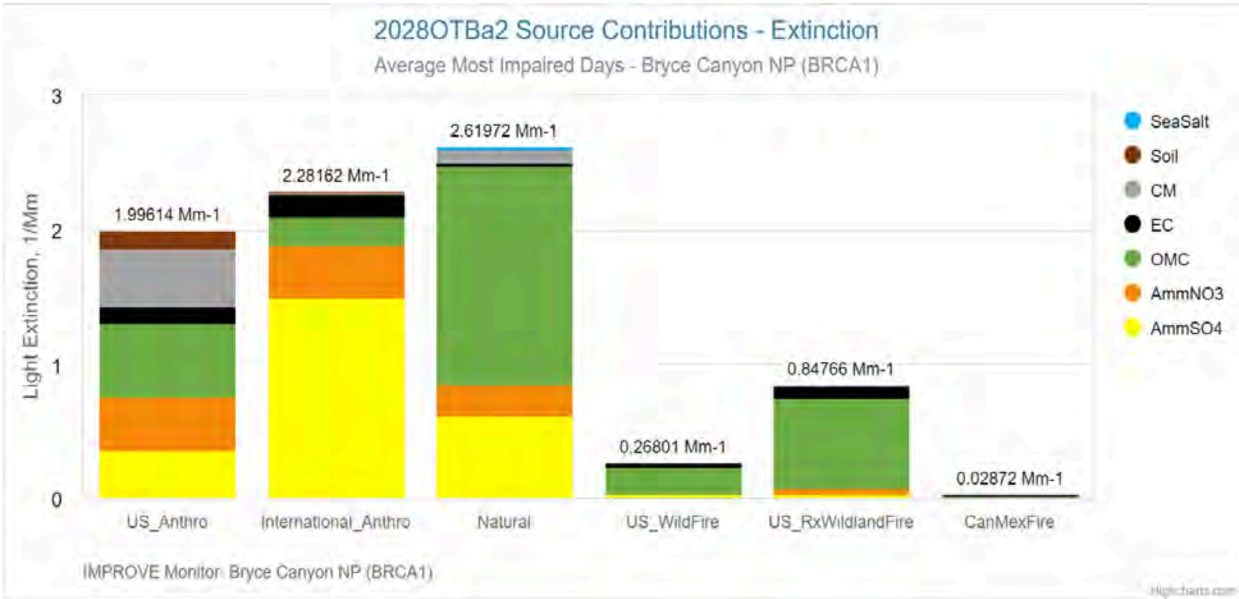


**Figure 50: Source Contributions on Average Most Impaired Days in Bryce Canyon National Park**

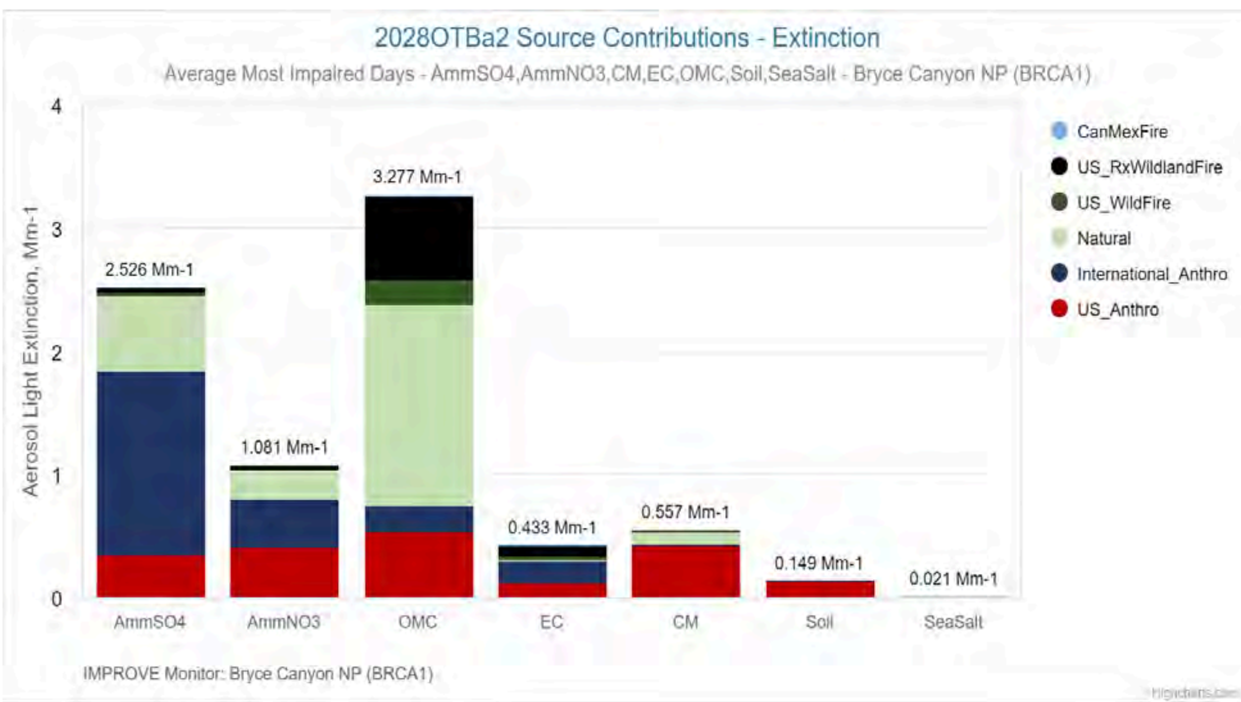


**Figure 51: WRAP States Ammonium Sulfate Source Apportionment for Most Impaired Days at Bryce Canyon National Park**

The regulated sources included in the map below consist of point sources and oil and gas wells within Utah. There are 37 sources emitting pollutants greater than 100 TPY (major sources) and

511 other point sources emitting less than 100 TPY. There are 13,853 oil and gas wells in Utah, including all “shut-in” wells which are not currently in use, but could resume production at any time, which would be documented by reports from the Utah Division of Oil, Gas, and Mining (UDOGM).

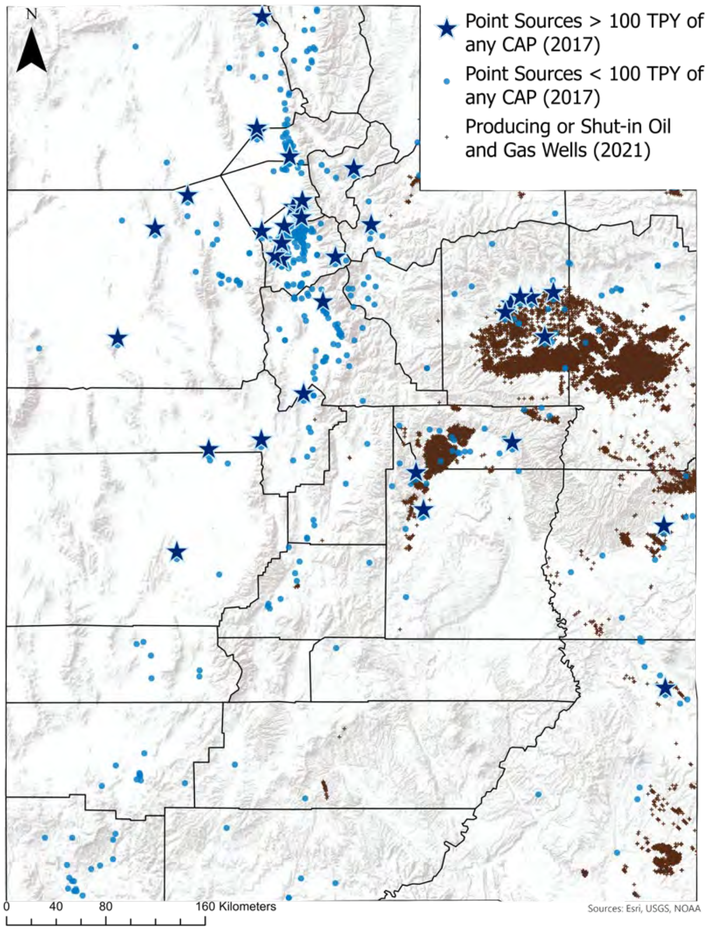


**Figure 52: Map of Utah Regulated Sources with Emissions >100 TPY**

## 7.A.1 Q/d Analysis

The RHR[129] requires states to consider anthropogenic sources of visibility impairment and should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. Sources in Utah were selected based on a Q/d analysis. The analysis is a ratio of a source’s emissions in tons per year (Q) in 2014 divided by the distance (d) in kilometers to any Class I area. Emissions in tons per year of $SO_2$, $NO_x$, and PM were

[129] 40 C.F.R. § 51.308(f)(2).

included in the analysis. WRAP's analysis suggested using a Q/d value of 10 as the threshold for sources with the most potential to impact CIAs. However, UDAQ used a more conservative threshold of six.[130]

**Table 29: Sources initially selected to perform a Four-Factor analysis**

| Facility Name | Combined Q/d | Total Q tpy* | Distance to Nearest Class I area in km (D) | Class I Area | Q/d $NO_x$ | Q/D $SO_2$ | Q/D $PM_{10}$ | $NO_x$ tons per year (Q) | $SO_2$ tons per year (Q) | $PM_{10}$ tons per year (Q) |
|---|---|---|---|---|---|---|---|---|---|---|
| **Ash Grove Cement Company- Leamington Cement Plant** | 6.9 | 930.5 | 134.0 | Capitol Reef | 6.3 | 0.04 | 0.6 | 845.5 | 5.9 | 79.1 |
| **CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant†** | 20.9 | 747.1 | 35.8 | Canyonlands | 5.3 | 14.0 | 1.6 | 188.6 | 499.6 | 59.0 |
| **Graymont Western Us Incorporated- Cricket Mountain Plant** | 9.0 | 1,180.7 | 130.8 | Capitol Reef | 7.0 | 0.3 | 1.7 | 916.5 | 40.8 | 223.4 |
| **Intermountain Power Service Corporation- Intermountain Generation Station†** | 193.6 | 28,945.7 | 149.5 | Capitol Reef | 153.3 | 29.2 | 11.1 | 22,909.2 | 4,371.5 | 1,665.0 |
| **Kennecott Utah Copper LLC- Mine & Copperton Concentrator†** | 22.1 | 5,234.5 | 237.2 | Capitol Reef | 17.7 | 0.01 | 4.4 | 4,199.6 | 2.0 | 1,032.9 |
| **Kennecott Utah Copper LLC- Power Plant, Lab, and Tailings Impoundment†** | 11.8 | 2,949.7 | 250.4 | Capitol Reef | 5.3 | 6.0 | 0.5 | 1,322.5 | 1,500.3 | 126.8 |
| **PacifiCorp- Hunter Power Plant** | 216.1 | 16,177.9 | 74.9 | Capitol Reef | 153.5 | 52.6 | 10.0 | 11,491.2 | 3,939.3 | 747.4 |
| **PacifiCorp- Huntington Power Plant** | 105.5 | 10,106.2 | 95.8 | Capitol Reef | 71.7 | 25.9 | 7.9 | 6,871.6 | 2,479.2 | 755.4 |
| **Sunnyside Cogeneration Associates- Sunnyside Cogeneration Facility** | 15.2 | 1,477.1 | 97.0 | Arches | 3.6 | 10.9 | 0.8 | 348.9 | 1,054.8 | 73.4 |
| **US Magnesium LLC- Rowley Plant** | 7.4 | 2,124.2 | 288.7 | Capitol Reef | 3.6 | 0.1 | 3.7 | 1,052.1 | 17.9 | 1,054.2 |
| | *Tons per year: Data is from version 2 of the 2014 National Emissions Inventory<br>† Additional data from these sources, including recent emissions, projected 2028 emissions, and planned closure, allowed them to be exempt from a 4-factor analysis | | | | | | | | | |
| | | | | | | | | | | |

Because the original Q/d analysis used 2014 NEI data, UDAQ also conducted a follow-up Q/d screen using more recently available 2017 NEI data to ensure that the source selection results

[130] See Table 27

remained consistent and that no sources with potential impacts were missed. No additional sources were identified with Q/d >=6. One source, CCI Paradox Lisbon Natural Gas Plant, was not selected as the plant was not in operation that year and had no emissions. Also, the 2017 NEI does not include haul truck emissions from the KUC Mine & Copperton Concentrator, resulting in a Q/d of 3.9 for that source. UDAQ elaborates on this source in Section 7.A.2 below.

**Table 30: 2017 NEI Q/d Screen**

| Facility Name | Combined Q/d | Total Q tpy* | Distance to Nearest Class I area in km (D) | Class I Area | Q/d $NO_x$ | Q/D $SO_2$ | Q/D $PM_{10}$ | $NO_x$ tons per year (Q) | $SO_2$ tons per year (Q) | $PM_{10}$ tons per year (Q) |
|---|---|---|---|---|---|---|---|---|---|---|
| **Ash Grove Cement Company- Leamington Cement Plant** | 9.8 | 1,319.3 | 134.0 | Capitol Reef | 8.8 | 0.14 | 0.9 | 1,183.8 | 19.0 | 116.5 |
| **CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant†** | NA | NA | 35.8 | Canyonlands | NA | NA | NA | NA | NA | NA |
| **Graymont Western Us Incorporated- Cricket Mountain Plant** | 6.3 | 823.8 | 130.8 | Capitol Reef | 4.07 | 0.13 | 2.1 | 532.7 | 17.5 | 273.6 |
| **Intermountain Power Service Corporation- Intermountain Generation Station†** | 85.5 | 12,785.0 | 149.5 | Capitol Reef | 62.3 | 16.6 | 6.6 | 9,318.8 | 2,483.6 | 982.6 |
| **Kennecott Utah Copper LLC- Mine & Copperton Concentrator††** | 3.9 | 931.6 | 237.2 | Capitol Reef | 0.02 | 0.00 | 3.9 | 5.2 | 0.0 | 926.4 |
| **Kennecott Utah Copper LLC- Power Plant, Lab, and Tailings Impoundment†** | 6.3 | 1,570.1 | 250.4 | Capitol Reef | 1.8 | 4.1 | 0.3 | 460.8 | 1,036.4 | 73.0 |
| **PacifiCorp- Hunter Power Plant** | 184.2 | 13,789.1 | 74.9 | Capitol Reef | 130.6 | 46.9 | 6.7 | 9,773.8 | 3,511.6 | 503.8 |
| **PacifiCorp- Huntington Power Plant** | 90.7 | 8,686.0 | 95.8 | Capitol Reef | 61.9 | 23.8 | 5.0 | 5,931.2 | 2,281.0 | 473.8 |
| **Sunnyside Cogeneration Associates- Sunnyside Cogeneration Facility** | 10.0 | 965.4 | 97.0 | Arches | 4.4 | 4.9 | 0.6 | 428.0 | 477.0 | 60.3 |
| **US Magnesium LLC- Rowley Plant** | 6.4 | 1,832.5 | 288.7 | Capitol Reef | 3.5 | 0.02 | 2.8 | 1,004.9 | 6.7 | 820.9 |

| | |
|---|---|
| | *Tons per year: Data is from the 2017 National Emissions Inventory<br>† Additional data from these sources, including recent emissions, projected 2028 emissions, and planned closure, allowed them to be exempt from a 4-factor analysis<br>††The 2017 NEI does not include the KUC Mine haul truck emissions. UDAQ elaborates on this in section 7.A.2 below |

### 7.A.2 Secondary Screening of Sources

After performing Q/d analysis, UDAQ further narrowed down the list of sources required to undergo the four-factor analysis based on current emissions, projected emissions in 2028, closure and controls put in place after the 2014 base year inventory. As a result of this secondary screening, the following sources were not required to provide a four-factor analysis:

The CCI Paradox Midstream, LLC - Lisbon Natural Gas Processing Plant

The CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant has a complicated regulatory and ownership history which has impacted its emissions performance over the recent past.[131] The combined Q/d (for $NO_x$, $SO_2$, and $PM_{10}$) for the facility was 13.68 for Arches and 20.87 for Canyonlands, both of which are above the Q/d threshold of 6 used to select significant sources of haze impairing pollutants to Utah's CIAs. These high Q/d values largely stemmed from anomalously high $SO_2$ emissions in 2014 (and 2015) due to issues with the disposal well at the plant. DAQ reviewed Lisbon's most recent five years of data (2017-2021) and re-calculated the Q/d values shown in Table 31 below, all of which fall below UDAQ's Q/d threshold of 6. Of note, recent actual $SO_2$ emissions have dropped dramatically to between 0.01 and 0.13 percent of the 2014 levels used in the original screening. For this reason, this source was ultimately not required to provide a four-factor analysis. However, UDAQ is continuing to work with this source to evaluate whether reductions in permitted emission limits may be appropriate, particularly for $SO_2$, given recent actual emissions levels.

[131] In 2009 the plant received a permit modification to lower the $SO_2$ emissions from 1,593 tons down to 111 tons. The plant requested a reduction in emissions as it had installed both primary and secondary control systems to limit emissions of $SO_2$. Unfortunately, in 2010 the plant requested a new modification and mistakenly restored the original 1,593 tons of $SO_2$ emissions without explanation. While that PTE value has been carried forward in more recent permitting actions, actual emissions have never reached the 1,593-ton value. The plant changed ownership in early-2017, which resulted in changes in the operation of the facility and addition of a helium plant in early-2020.

**Table 31: Paradox Lisbon Plant Q/d Analysis for nearest CIAs**

| Year | $PM_{10}$-PRI | $SO_2$ | $NO_x$ | CIA | Distance (km) | $PM_{10}$-PRI | $SO_2$ | $NO_x$ | Total Q/d |
|---|---|---|---|---|---|---|---|---|---|
| **2017** | Plant was not in operation | | | | | | | | |
| **2018** | 45.1 | 0.1 | 111.6 | Canyonlands | 35.8 | 1.3 | 0.0 | 3.1 | 4.4 |
| **2018** | 45.1 | 0.1 | 111.6 | Arches | 54.6 | 0.8 | 0.0 | 2.0 | 2.9 |
| **2019** | Plant was not in operation | | | | | | | | |
| **2020** | 61.9 | 0.6 | 126.0 | Canyonlands | 35.8 | 1.7 | 0.0 | 3.5 | 5.3 |
| **2020** | 61.9 | 0.6 | 126.0 | Arches | 54.6 | 1.1 | 0.0 | 2.3 | 3.5 |
| **2021** | 27.8 | 0.1 | 181.4 | Canyonlands | 35.8 | 0.8 | 0.0 | 5.1 | 5.8 |
| **2021** | 27.8 | 0.1 | 181.4 | Arches | 54.6 | 0.5 | 0.0 | 3.3 | 3.8 |

Intermountain Power Service Corporation- Intermountain Generation Station

On September 29, 2006, the Governor of California approved California Senate Bill (SB) 1368, which directed the California Energy Commission to establish a greenhouse gas (GHG) emission performance standard (EPS) for electricity generation and which disallowed load-serving entities in California from entering into long-term financial commitments with electrical corporations unless the generation supplied under the financial commitment complies with that standard. Because approximately 98% of the power generated at the Intermountain Generation Station (IGS) is consumed by customers of California utilities and because the power generated by the IGS's two coal-fired units exceeds California's GHG EPS, the current contract for coal-fired generation, which expires in 2025, will not be renewed for power from those units. Instead, the permittee, Intermountain Power Service Corporation (IPSC), plans to replace the coal-fired units with an EPS-compliant combined-cycle natural gas plant, which will be highly thermally efficient and which will include state-of-the-art emissions controls such as SCR. As a result, regional haze-related pollutants (PM, $SO_2$, and $NO_x$) from the IGS are expected to decrease dramatically. Though the coal-fired units are expected to cease operation by mid-2025, Utah is establishing a firm closure date of no later than December 31, 2027, to ensure that the coal-fired units at IGS will not continue to operate beyond the end of the second planning period. This date allows flexibility for closing the plant and the rescinding of the permit and approval order. UDAQ did approach IPSC about the feasibility of improving the efficiency of existing controls, particularly $SO_2$ scrubbing, at the facility in the three years between mid-2022 and mid-2025, but the company indicated that such improvements are logistically and economically infeasible over such a short time period. Furthermore, the operator's engineering and environmental staff and resources are fully engaged in the process of bringing the replacement gas-fired units online, the successful completion of which will bring about dramatic emissions reductions.

Kennecott Utah Copper LLC- Mine & Copperton Concentrator

The predominant visibility impairing pollutant from the Kennecott Mine and Copperton Concentrator is $NO_x$, the vast majority of which comes from mine haul trucks and other non-road equipment as shown in Table 32 below. Specifically, this equipment was responsible for 4,376.7

tons (82.5%) of the 5,308.3 tons of combined $PM_{10}$, $SO_2$, and $NO_x$ emissions from this facility. Section 209 of the Clean Air Act preempts the State from setting standards for non-road vehicles or engines, leaving UDAQ with few options to control NOx emissions from haul trucks.[132] When non-road emissions are removed from the 2017 inventory for this source, the Q/d drops to 3.9 – i.e., below UDAQ's threshold value of 6. That said, as identified by EPA,[133] the anticipated $NO_x$+NMHC emissions reduction from replacing a Tier 1 haul truck with a Tier 4 truck is 65.9%, and the $NO_x$+NMHC emissions reduction from replacing a Tier 2 haul truck with a Tier 4 truck is 42.3%. This gives UDAQ a degree of comfort that emissions from this source will continue to improve over time as older vehicles are replaced.

Additionally, this source recently underwent a thorough BACT analysis as part of the Salt Lake Serious Nonattainment Area PM $_{2.5}$ SIP. As a result, there are no additional controls that can be applied at this time beyond those already included in the SIP as identified in Table 33 in Section 7.A.2 below.

**Table 32: 2017 Kennecott Utah Copper LLC – Mine & Concentrator Emissions and Revised Q/d**

| Source/Distance/Q/d | $PM_{10}$ | $SO_2$ | $NO_X$ | $PM_{10}+SO_2+NO_X$ |
|---|---|---|---|---|
| **Non-Truck Emissions** | 926.4 | 0.0 | 5.2 | 931.6 |
| **Haul Truck (non-road) Emissions** | 170.0 | 2.7 | 4,204.0 | 4,376.7 |
| **Total Emissions** | 1,096.4 | 2.7 | 4,209.2 | 5,308.3 |
| **Distance to nearest CIA (km)** | 237.2 | 237.2 | 237.2 | 237.2 |
| **Revised Q/d without haul truck emissions** | 3.9 | 0.0 | 0.0 | 3.9 |

Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment

The coal-fired boilers at the Power Plant Lab Tailings impoundment were decommissioned, and the Approval Order (AO) reflecting this change was updated on February 4, 2020.[134] The February 2020 AO removed any ability for Kennecott to operate coal fired boilers as all the coal-fired boilers were removed from the approved equipment list. The AO summarizes the updates in the project description. Units 1-3 were prohibited to operate under the recently approved $PM_{2.5}$ SIP, and a specific SIP condition set their closure date. Thus, due to that applicable condition, Units 1 – 3 were removed from the permit. Kennecott proposed the removal of Unit 4 from the permit because they planned to decommission the unit. The AO project summarizes that Kennecott made that decision voluntarily, and – based on that decision – Unit 4 was removed from the permit. The AO only lists remaining ancillary equipment. It does not list Units 1-3 or Unit 4 as equipment for the facility and – for this reason – Kennecott does not have

[132] *See* 42 U.S.C. § 7543(e).
[133] Source: https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100OA05.pdf

[134] This Approval Order can be found at: https://daqpermitting.utah.gov/DocViewer?IntDocID=117327&contentType=application/pdf

approval to operate any coal-fired boilers. Based on this equipment change, UDAQ also rescinded the Title V permit for the facility on February 12, 2020.[135] The vast majority of emissions from this facility were associated with the boilers, and emissions from the remaining equipment (a diesel emergency generator engine, cooling tower, degreasers and two natural gas-fired emergency generators to support the KUC electricity distribution control room) are low enough that this source is below the Q/d threshold for the four-factor analysis. Finally, even if had not been decommissioned, this source recently underwent a thorough BACT analysis for the $PM_{2.5}$ SIP, which resulted in the inclusion of fuel-switching to natural gas and an SCR-derived $NO_x$ rate-based emission limit for Unit 4 in SIP Section IX.H as summarized in Table 33 below. For these reasons, this source was not required to provide a four-factor analysis for the round 2 regional haze SIP.

**Table 33: Existing Controls in Utah's SIP for Screened Sources**

| Company | Facility | Applicable Units | Control Type | Limits | Implementation Date | SIP Reference | Last Revision | EPA Approval | Part H reference |
|---|---|---|---|---|---|---|---|---|---|
| **PacifiCorp** | Hunter | 1 and 2 | PM | Emissions of particulate (PM) shall not exceed 0.015 lb/MMBtu heat input from each boiler based on a 3-run test average. | No later than January 1, 2019 | Regional Haze | June 24, 2019 | Pending | H.22 Source Specific Emission Limitations: Regional Haze Requirements, Best Available Retrofit Technology |
| **PacifiCorp** | Hunter | 1 and 2 | $NO_x$ | Emissions of $NO_x$ from each boiler shall not exceed 0.26 lb/MMBtu heat input for a 30-day rolling average. | No later than January 1, 2019 | Regional Haze | June 24, 2019 | Pending | H.22 Source Specific Emission Limitations: Regional Haze Requirements, Best Available Retrofit Technology |
| **PacifiCorp** | Hunter | 3 | $NO_x$ | Emissions of $NO_x$ shall not exceed 0.34 lb/MMBtu heat input for a 30- day rolling average. | No later than January 1, 2019 | Regional Haze | June 24, 2019 | Pending | H.22 Source Specific Emission Limitations: Regional Haze Requirements, Best Available Retrofit Technology |
| **PacifiCorp** | Huntington | 1 and 2 | PM | Emissions of particulate (PM) shall not exceed 0.015 lb/MMBtu heat input from each boiler based on a 3-run test average. | No later than January 1, 2019 | Regional Haze | June 24, 2019 | Pending | H.22 Source Specific Emission Limitations: Regional Haze Requirements, Best Available Retrofit Technology |
| **PacifiCorp** | Huntington | 1 and 2 | $NO_x$ | Emissions of $NO_x$ from each boiler shall not exceed 0.26 lb/MMBtu heat input for a 30-day rolling average. | No later than January 1, 2019 | Regional Haze | June 24, 2019 | Pending | H.22 Source Specific Emission Limitations: Regional Haze Requirements, Best Available Retrofit Technology |
| **Kennecott Utah Copper LLC** | Bingham Canyon Mine | Diesel-powered ore and waste haul trucks | Mileage | Maximum total mileage per calendar day for diesel-powered ore and waste haul trucks shall not exceed 30,000 miles. | No later than January 1, 2019 | PM2.5 | December 2, 2020 | Pending | H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area |

[135] See Appendix G for UDAQ's letter rescinding the Title V permit.

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|---|---|---|---|---|---|---|---|---|---|
| **Kennecott Utah Copper LLC** | Bingham Canyon Mine | In-pit crusher baghouse | $PM_{2.5}$ | The In-pit crusher baghouse shall not exceed a $PM_{2.5}$ emission limit of 0.78 lbs/hr(0.007 gr/dscf) $PM_{2.5}$ monitoring shall be performed by stack testing every three years. | No later than January 1, 2019 | PM2.5 | December 2, 2020 | Pending | H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area |
| **Kennecott Utah Copper LLC** | Copperton Concentrator | Dryers | | Control emissions from the Product Molybdenite Dryers with a scrubber during operation of the dryers. | No later than January 1, 2019 | $PM_{2.5}$ | December 2, 2020 | Pending | H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area |
| **Kennecott Utah Copper LLC** | Copperton Concentrator | Heaters | $NO_x$ | The remaining heaters shall not operate more than 300 hours per rolling 12-month period unless upgraded so the $NO_x$ emission rate is no greater than 30 ppm. | No later than January 1, 2019 | $PM_{2.5}$ | December 2, 2020 | Pending | H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area |
| **Kennecott Utah Copper LLC** | Utah Power Plant | 4 | Fuel | Only natural gas shall only be used as a fuel, unless the supplier or transporter of natural gas imposes a curtailment. Unit #4 may then burn coal, only for the duration of the curtailment plus sufficient time to empty the coal bins following the curtailment. | No later than January 1, 2019 | $PM_{2.5}$ | December 2, 2020 | Pending | H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area |
| **Kennecott Utah Copper LLC** | Utah Power Plant | 4 | $PM_{2.5}$ | Filterable $PM_{2.5}$ emissions to the atmosphere when burning natural gas shall not exceed 0.004 grains/dscf. Filterable+condensible $PM_{2.5}$ emissions to the atmosphere when burning natural gas shall not exceed 0.03 grains/dscf. | No later than January 1, 2019 | $PM_{2.5}$ | December 2, 2020 | Pending | H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area |
| **Kennecott Utah Copper LLC** | Utah Power Plant | 4 | $NO_x$ | $NO_x$ emissions to the atmosphere when burning natural gas shall not exceed 32 lbs/hr or 0.04 lbs/MMBtu | No later than January 1, 2019 | $PM_{2.5}$ | December 2, 2020 | Pending | H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area |
| **Kennecott Utah Copper LLC** | Utah Power Plant | 5 | $PM_{2.5}$ | $PM_{2.5}$ with duct burning emissions to the atmosphere when burning natural gas shall not exceed 18.8 lbs/hr (filterable + condensible) | No later than January 1, 2019 | $PM_{2.5}$ | December 2, 2020 | Pending | H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Kennecott Utah Copper LLC** | Utah Power Plant | 5 | VOC | VOC emissions to the atmosphere shall not exceed 2.0 ppmdv | No later than January 1, 2019 | $PM_{2.5}$ | December 2, 2020 | Pending | H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area |
| **Chevron Products Co.** | Salt Lake Refinery | Source-wide | $PM_{10}$ | Combined emissions of $PM_{10}$ shall not exceed 0.715 tons per day (tpd). | No later than January 1, 2019 | $PM_{10}$ | December 2, 2020 | Pending | H.2 Source Specific Emission Limitations in Salt Lake County $PM_{10}$ Nonattainment/ Maintenance Area |
| **Chevron Products Co.** | Salt Lake Refinery | Source-wide | $NO_x$ | Combined emissions of $NO_x$ shall not exceed 2.1 tons per day (tpd) and 766.5 tons per rolling 12-month period. | No later than January 1, 2019 | $PM_{10}$ | December 2, 2020 | Pending | H.2 Source Specific Emission Limitations in Salt Lake County $PM_{10}$ Nonattainment/ Maintenance Area |
| **Chevron Products Co.** | Salt Lake Refinery | Source-wide | $SO_2$ | Combined emissions of $SO_2$ shall not exceed 1.05 tons per day (tpd) and 383.3 tons per rolling 12-month period. | No later than January 1, 2019 | $PM_{10}$ | December 2, 2020 | Pending | H.2 Source Specific Emission Limitations in Salt Lake County $PM_{10}$ Nonattainment/ Maintenance Area |
| **Chevron Products Co.** | Salt Lake Refinery | Source-wide | $PM_{2.5}$ | Combined emissions of $PM_{2.5}$ (filterable+condensable) shall not exceed 0.305 tons per day (tpd) and 110 tons per rolling 12-month period. | No later than January 1, 2019 | $PM_{2.5}$ | December 2, 2020 | Pending | H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area |
| **Chevron Products Co.** | Salt Lake Refinery | Source-wide | $NO_x$ | Combined emissions of $NO_x$ shall not exceed 2.1 tons per day (tpd) and 766.5 tons per rolling 12-month period. | No later than January 1, 2019 | $PM_{2.5}$ | December 2, 2020 | Pending | H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area |
| **Chevron Products Co.** | Salt Lake Refinery | Source-wide | $SO_2$ | Combined emissions of $SO_2$ shall not exceed 1.05 tons per day (tpd) and 383.3 tons per rolling 12-month period. | No later than January 1, 2019 | $PM_{2.5}$ | December 2, 2020 | Pending | H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area |
| **Chevron Products Co.** | Salt Lake Refinery | Engine K35001 | $NO_x$ | Emissions of $NO_x$ from each rich-burn compressor engine shall not exceed 236 $NO_x$ in ppmvd @ 0% $O_2$ | No later than January 1, 2019 | $PM_{2.5}$ | December 2, 2020 | Pending | H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area |
| **Chevron Products Co.** | Salt Lake Refinery | Engine K35002 | $NO_x$ | Emissions of $NO_x$ from each rich-burn compressor engine shall not exceed 208 $NO_x$ in ppmvd @ 0% $O_2$ | No later than January 1, 2019 | $PM_{2.5}$ | December 2, 2020 | Pending | H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area |
| **Chevron Products Co.** | Salt Lake Refinery | Engine K35003 | $NO_x$ | Emissions of $NO_x$ from each rich-burn compressor engine shall not exceed 230 $NO_x$ in ppmvd @ 0% $O_2$ | No later than January 1, 2019 | $PM_{2.5}$ | December 2, 2020 | Pending | H.12. Source-Specific Emission Limitations in Salt Lake City – UT $PM_{2.5}$ Nonattainment Area |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Chevron Products Co.** | Salt Lake Refinery | External combustion process equipment | $PM_{10}$ | Combined emissions of filterable $PM_{10}$ from all external combustion process equipment shall be no greater than 0.234 tons per day. | No later than January 1, 2019 | $PM_{10}$ | December 2, 2020 | Pending | H.4 Interim Emission Limits and Operating Practices |

### 7.A.3 Weighted Emissions Potential Analysis of Sources in Utah and Neighboring States

WRAP released a Weighted Emissions Potential (WEP) analysis after UDAQ chose sources to submit a four-factor analysis. The WEP is obtained by overlaying extinction weighted residence time (EWRT) results with 2028OTBa2 emissions of light extinction precursors and shows which sources have the highest potential to impact visibility in CIAs. Table 34 and Table 35 list the point sources with the top ten WEP values for Utah CIAs for nitrate and sulfate, respectively, and summarize whether those sources were captured by Utah's initial Q/d screen and whether they were ultimately required to submit a four-factor analysis. As can be seen, UDAQ's initial Q/d screen captured most of the point sources with the highest-ranking WEP values at Utah CIAs. For those sources that were ultimately excluded from submitting a four-factor analysis, the tables provide notes as to the rationale for the exclusion, including plant closures, recent BACT analysis/controls, revised emission inventories, and the predominance of emissions from sources that states are largely preempted from controlling (e.g., non-road). The tables also include information regarding the status of non-Utah point sources with high-ranking WEP values, where available.

Tables 36 and 37 list Utah point sources that were among the top ten WEP values in the CIAs of neighboring states for nitrate and sulfate, respectively. Again, the tables show that UDAQ's initial and secondary screening largely succeeded in identifying the sources with the potential to impact CIAs, while excluding some sources that were already well-controlled, closed/closing, or that have few options for state-level controls.

<u>Tesoro and Chevron Refineries</u>

UDAQ's original Q/d screening using 2014 NEI data yielded values below 6 for the Chevron and Tesoro facilities. At EPA's request, UDAQ re-calculated the Q/d thresholds of its major sources using 2017 NEI data to ensure that additional sources did not exceed a Q/d of 6 and confirmed that no additional sources would be screened-in using the newer data. Specifically, neither the Chevron or Tesoro refineries had a revised Q/d of 6 or greater. Here it should be noted that UDAQ chose a more stringent Q/d threshold of 6 rather than the Q/d value of 10 recommended by WRAP.

However, both sources had high-ranking weighted emissions potential values for sulfate or nitrate and various in-state and out-of-state CIAs, Specifically, Chevron ranked 9th for nitrate at BRCA1 with a % of total point WEP of 1.4%. Chevron had no high-ranking sulfate impacts. Tesoro ranked 10th at BRCA1 for nitrate at BRCA1 (0.9%) and had the following rankings and % values for sulfate:

- BRCA1: Rank 8 (2.6%)
- CAPI1: Rank 8 (1.6%)
- BRID1: Rank 8 (3.9%)
- YELL2: Rank 8 (3.4%)
- CRMO1: Rank 6 (2.7%)
- SAWT1: Rank 8 (2.7%)

Though “Top 10” ranked, these WEP values represented a relatively small percentage of total point WEP at each CIA, as indicated above.

In addition, the 2019 Guidance states that it "may be reasonable for a state not to select an effectively controlled source" (page 22) and that "the statutory considerations for selection of BACT and LAER are also similar to, if not more stringent than, the four statutory factors for reasonable progress" (See 2019 EPA Guidance at 23). Both Chevron and Tesoro recently underwent a thorough BACT analysis for the Serious Area $PM_{2.5}$ Salt Lake Nonattainment Area SIP that resulted in additional controls and limits being added to SIP Section IX.H. Specifically, Tesoro installed a wet gas scrubber unit to control $SO_2$ emissions and is now subject to a source-wide annual $SO_2$ limit of 300 tons per year. For comparison, WRAP’s WEP analyses used a 2028OTBa2 projection of 708.3 tons. Tesoro’s actual $SO_2$ emissions for 2019-2021 since the installation of new controls ranged between 22 and 23 tons per year. As a result, the sulfate WEP values for this source – which were already a tiny fraction of total point source sulfate WEP – are not representative of either the enforceable limits or the recent actuals for this facility. Please refer to section 7.A.2 to review the existing controls resulting from the recent $PM_{2.5}$ and $PM_{10}$ SIP revisions for Chevron and Tesoro which include both source-wide and equipment limits for $NO_x$, $SO_2$, $PM_{10}$, and $PM_{2.5}$. Please refer to section 6.A.10 to review the projected emissions reductions resulting from Tesoro's existing controls.

**Table 34: Nitrate Point Source WEP Rank for Utah CIAs**

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB $NO_x$ (tons) | Distance (meters) | $NO_x$ Q/d | WEP_$NO_3$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | UT Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **BRCA1** | 1 | PacifiCorp-Hunter Power Plant | UT | 10,001.2 | 198,466.7 | 50.4 | 109,484.1 (18.6%) | YES | YES | |
| **BRCA1** | 2 | PacifiCorp-Huntington Power Plant | UT | 6,091.4 | 216,464.4 | 28.1 | 61,138.6 (10.4%) | YES | YES | |
| **BRCA1** | 3 | Kennecott Utah Copper LLC- Mine & Copperton Concentrator | UT | 4,199.6 | 329,072.0 | 12.8 | 52,048.8 (8.8%) | YES | NO | BACT for $PM_{2.5}$ Serious SIP; majority of $NO_x$ emissions from non-road sources |

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB $NO_x$ (tons) | Distance (meters) | $NO_x$ Q/d | WEP_$NO_3$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | UT Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **BRCA1** | 4 | Graymont Western US Incorporated-Cricket Mountain Plant | UT | 916.5 | 155,620.0 | 5.9 | 34,304.4 (5.8%) | YES | YES | |
| **BRCA1** | 5 | Ash Grove Cement Company-Leamington Cement Plant | UT | 845.5 | 214,929.5 | 3.9 | 30,091.0 (5.1%) | YES | YES | |
| **BRCA1** | 6 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 1,157.5 | 342,148.6 | 3.4 | 20,954.3 (3.6%) | YES | NO | Power plant closed in 2020 |
| **BRCA1** | 7 | Salt Lake City Intl | UT | 784.0 | 350,666.3 | 2.2 | 17,677.6 (3.0%) | NO | NO | Q/d <6; majority of $NO_x$ emissions from non-road sources (aircraft take-offs and landings) |
| **BRCA1** | 8 | US Magnesium LLC- Rowley Plant | UT | 1,052.1 | 367,453.2 | 2.9 | 10,062.0 (1.7%) | YES | YES | |
| **BRCA1** | 9 | Chevron Products Co - Salt Lake Refinery | UT | 375.6 | 355,251.0 | 1.1 | 8,359.5 (1.4%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **BRCA1** | 10 | Tesoro Refining & Marketing Company LLC | UT | 358.1 | 351,572.8 | 1.0 | 8,053.0 (0.9%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **CANY1** | 1 | PacifiCorp-Hunter Power Plant | UT | 10,001.2 | 130,681.1 | 76.5 | 128,112.8 (13.9%) | YES | YES | |
| **CANY1** | 2 | PacifiCorp-Huntington Power Plant | UT | 6,091.4 | 148,607.2 | 41.0 | 68,616.5 (7.4%) | YES | YES | |
| **CANY1** | 3 | Bonanza | TR | 5,721.7 | 185,722.9 | 30.8 | 59,301.8 (6.4%) | NA | NA | Likely closure in 2030 due to settlement |
| **CANY1** | 4 | PNM - San Juan Generating Station | NM | 7,390.8 | 219,591.9 | 33.7 | 47,113.4 (5.1%) | NA | NA | Subject to four-factor analysis in NM's draft SIP. PNM has announced plant closure in 2022 |

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB $NO_x$ (tons) | Distance (meters) | $NO_x$ Q/d | WEP_$NO_3$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | UT Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **CANY1** | 5 | Kennecott Utah Copper LLC- Mine & Copperton Concentrator | UT | 4,199.6 | 307,168.4 | 13.7 | 45,956.2 (5.0%) | YES | NO | BACT for $PM_{2.5}$ Serious SIP; majority of $NO_x$ emissions from non-road sources |
| **CANY1** | 6 | Four Corners Power Plant | TR | 4,060.4 | 228,638.6 | 17.8 | 24,859.3 (2.7%) | NA | NA | APS has announced plant closure in 2031 |
| **CANY1** | 7 | Sunnyside Cogeneration Associates-Sunnyside Cogeneration Facility | UT | 442.2 | 129,762.3 | 3.4 | 22,940.9 (2.5%) | YES | YES | |
| **CANY1** | 8 | Chaco Gas Plant | NM | 2,053.4 | 264,690.7 | 7.8 | 14,056.2 (1.5%) | NA | NA | Not subject to four-factor analysis in NM's proposed SIP |
| **CANY1** | 9 | CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant | UT | 201.9 | 57,532.7 | 3.5 | 12,076.0 (1.3%) | YES | NO | 2018 emissions Q/d <6 |
| **CANY1** | 10 | RED ROCK GATHERING-PREMIER BAR X C.S. | CO | 73.3 | 118,289.1 | 0.6 | 11,567.0 (1.3%) | NA | NA | Not subject to four-factor analysis in CO's proposed SIP due to low $NO_x$ Q/d |
| **CAPI1** | 1 | PacifiCorp-Hunter Power Plant | UT | 10,001.2 | 98,938.2 | 101.1 | 334,329.1 (37.2%) | YES | YES | |
| **CAPI1** | 2 | PacifiCorp-Huntington Power Plant | UT | 6,091.4 | 120,459.7 | 50.6 | 167,247.5 (18.6%) | YES | YES | |
| **CAPI1** | 3 | Kennecott Utah Copper LLC- Mine & Copperton Concentrator | UT | 4,199.6 | 263,195.8 | 16.0 | 42,259.0 (4.7%) | YES | NO | BACT for $PM_{2.5}$ Serious SIP; majority of $NO_x$ emissions from non-road sources |
| **CAPI1** | 4 | Graymont Western US Incorporated-Cricket Mountain Plant | UT | 916.5 | 148,543.7 | 6.2 | 26,049.6 (2.9%) | YES | YES | |

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB $NO_x$ (tons) | Distance (meters) | $NO_x$ Q/d | WEP_$NO_3$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | UT Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **CAPI1** | 5 | Ash Grove Cement Company- Leamington Cement Plant | UT | 845.5 | 159,501.2 | 5.3 | 24,633.4 (2.7%) | YES | YES | |
| **CAPI1** | 6 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 1,157.5 | 275,718.8 | 4.2 | 13,860.1 (1.5%) | YES | NO | Power plant closed in 2020 |
| **CAPI1** | 7 | US Magnesium LLC- Rowley Plant | UT | 1,052.1 | 313,659.3 | 3.4 | 10,218.3 (1.1%) | YES | YES | |
| **CAPI1** | 8 | Bonanza | TR | 5,721.7 | 261,713.3 | 21.9 | 9,450.1 (1.1%) | NA | NA | Likely closure in 2030 due to settlement |
| **CAPI1** | 9 | Sunnyside Cogeneration Associates- Sunnyside Cogeneration Facility | UT | 442.2 | 158,414.3 | 2.8 | 8,764.7 (1.0%) | YES | YES | |
| **CAPI1** | 10 | Salt Lake City Intl | UT | 784.0 | 280,646.7 | 2.8 | 7,264.8 (0.8%) | NO | NO | Q/d <6; majority of $NO_x$ emissions from non-road sources (aircraft take-offs and landings) |
| **ZICA1** | 1 | St. George City Power- Red Rock Power Generation Station | UT | 34.3 | 38,429.0 | 0.9 | 13,108.2 (5.3%) | NO | NO | Q/d <6 |
| **ZICA1** | 2 | PacifiCorp- Hunter Power Plant | UT | 10,001.2 | 285,805.3 | 35.0 | 12,364.2 (5.0%) | YES | YES | |
| **ZICA1** | 3 | McCarran Intl | NV | 2,430.2 | 218,239.9 | 11.1 | 9,235.4 (3.7%) | NA | NA | Majority of $NO_x$ emissions from non-road sources (aircraft take-offs and landings) |
| **ZICA1** | 4 | Kern River Gas Transmission Company- Veyo Compressor Station | UT | 72.7 | 56,439.3 | 1.3 | 9,185.2 (3.7%) | NO | NO | Q/d <6 |

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB $NO_x$ (tons) | Distance (meters) | $NO_x$ Q/d | WEP_$NO_3$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | UT Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **ZICA1** | 5 | Kennecott Utah Copper LLC- Mine & Copperton Concentrator | UT | 4,199.6 | 385,739.6 | 10.9 | 7,998.7 (3.2%) | YES | NO | BACT for $PM_{2.5}$ Serious SIP; majority of $NO_x$ emissions from non-road sources |
| **ZICA1** | 6 | Pg&E Topock Compressor Station | CA | 968.8 | 300,092.2 | 3.2 | 7,620.0 (3.1%) | NA | NA | Not subject to four-factor analysis in CA's proposed SIP due to low NOx Q/d |
| **ZICA1** | 7 | Millcreek Power | UT | 19.4 | 38,438.7 | 0.5 | 7,402.2 (3.0%) | NO | NO | Q/d <6 |
| **ZICA1** | 8 | PacifiCorp- Huntington Power Plant | UT | 6,091.4 | 300,744.4 | 20.3 | 7,156.5 (2.9%) | YES | YES | |
| **ZICA1** | 9 | Lhoist North America and Granite Const. (Apex) | NV | 1,361.8 | 181,728.8 | 7.5 | 7,041.9 (2.8%) | NA | NA | NV's proposed SIP requires SNCR on Kilns 1, 3, & 4 as well as LNB on Kiln 1. Kilns 3 & 4 have existing LNBs. |
| **ZICA1** | 10 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 1,157.5 | 398,524.3 | 2.9 | 6,609.7 (2.7%) | YES | NO | Power plant closed in 2020 |

## Table 35: Sulfate Point Source WEP Rank for Utah CIAs

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB SO2 (tons) | Distance (meters) | SO2 Q/d | WEP_$SO_4$ (% of Total) | Selected in Utah Q/d Screen? (Y/N) | UT Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **BRCA1** | 1 | CHEMICAL LIME NELSON PLANT | AZ | 2,040.6 | 253,654.7 | 8.0 | 43,684.7 (21.8%) | NA | NA | Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls |
| **BRCA1** | 2 | PacifiCorp- Hunter Power Plant | UT | 3,498.2 | 198,466.7 | 17.6 | 22,430.8 (11.2%) | YES | YES | |

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB SO2 (tons) | Distance (meters) | SO2 Q/d | WEP_SO$_4$ (% of Total) | Selected in Utah Q/d Screen? (Y/N) | UT Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **BRCA1** | 3 | Kennecott Utah Copper LLC-Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 342,148.6 | 6.3 | 17,191.7 (8.6%) | YES | NO | Power plant closed in 2020 |
| **BRCA1** | 4 | PacifiCorp-Huntington Power Plant | UT | 2,449.0 | 216,464.4 | 11.3 | 14,397.6 (7.2%) | YES | YES | |
| **BRCA1** | 5 | ASARCO LLC - HAYDEN SMELTER | AZ | 3,062.1 | 527,077.3 | 5.8 | 14,391.7 (7.2%) | NA | NA | Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls |
| **BRCA1** | 6 | Kennecott Utah Copper LLC-Smelter & Refinery | UT | 704.4 | 342,656.1 | 2.1 | 5,618.9 (2.8%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **BRCA1** | 7 | Four Corners Power Plant | TR | 2,537.7 | 341,751.7 | 7.4 | 5,413.2 (2.7%) | NA | NA | APS has announced plant closure in 2031 |
| **BRCA1** | 8 | Tesoro Refining & Marketing Company LLC | UT | 708.3 | 351,572.8 | 2.0 | 5,158.3 (2.6%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **BRCA1** | 9 | TUCSON ELECTRIC POWER CO - SPRINGERVILLE | AZ | 6,991.9 | 455,128.8 | 15.4 | 3,654.7 (1.8%) | NA | NA | New SO2 limits for units 1 & 2 included in AZ's proposed SIP |
| **BRCA1** | 10 | Phoenix Sky Harbor Intl | AZ | 275.1 | 463,195.4 | 0.6 | 3,615.9 (1.8%) | NA | NA | Majority of $NO_X$ emissions from non-road sources (aircraft take-offs and landings) |
| **CANY1** | 1 | PacifiCorp-Hunter Power Plant | UT | 3,498.2 | 130,681.1 | 26.8 | 78,098.2 (19.1%) | YES | YES | |
| **CANY1** | 2 | PacifiCorp-Huntington Power Plant | UT | 2,449.0 | 148,607.2 | 16.5 | 48,079.5 (11.8%) | YES | YES | |
| **CANY1** | 3 | CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant | UT | 534.9 | 57,532.7 | 9.3 | 39,468.2 (9.7%) | YES | NO | 2018 emissions Q/d <6 |
| **CANY1** | 4 | Four Corners Power Plant | TR | 2,537.7 | 228,638.6 | 11.1 | 32,557.0 (8.0%) | NA | NA | APS has announced plant closure in 2031 |

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB SO2 (tons) | Distance (meters) | SO2 Q/d | WEP_$SO_4$ (% of Total) | Selected in Utah Q/d Screen? (Y/N) | UT Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **CANY1** | 5 | Sunnyside Cogeneration Associates-Sunnyside Cogeneration Facility | UT | 460.8 | 129,762.3 | 3.6 | 25,602.8 (6.3%) | YES | YES | |
| **CANY1** | 6 | Kennecott Utah Copper LLC-Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 317,050.4 | 6.8 | 21,266.8 (5.2%) | YES | NO | Power plant closed in 2020 |
| **CANY1** | 7 | TUCSON ELECTRIC POWER CO - SPRINGERVILLE | AZ | 6,991.9 | 463,072.9 | 15.1 | 13,923.7 (3.4%) | NA | NA | New $SO_2$ limits for units 1 & 2 included in AZ's proposed SIP |
| **CANY1** | 8 | CHEMICAL LIME NELSON PLANT | AZ | 2,040.6 | 448,519.3 | 4.6 | 13,409.0 (3.3%) | NA | NA | Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls |
| **CANY1** | 9 | Bonanza | TR | 1,281.3 | 185,722.9 | 6.9 | 11,908.4 (2.9%) | NA | NA | Likely closure in 2030 due to settlement |
| **CANY1** | 10 | PNM - San Juan Generating Station | NM | 823.1 | 219,591.9 | 3.7 | 10,995.1 (2.7%) | NA | NA | Subject to four-factor analysis in NM's draft SIP. PNM has announced plant closure in 2022 |
| **CAPI1** | 1 | PacifiCorp-Hunter Power Plant | UT | 3,498.2 | 98,938.2 | 35.4 | 138,922.3 (34.7%) | YES | YES | |
| **CAPI1** | 2 | PacifiCorp-Huntington Power Plant | UT | 2,449.0 | 120,459.7 | 20.3 | 79,880.4 (20.0%) | YES | YES | |
| **CAPI1** | 3 | Kennecott Utah Copper LLC-Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 275,718.8 | 7.8 | 31,599.4 (7.9%) | YES | NO | Power plant closed in 2020 |
| **CAPI1** | 4 | CHEMICAL LIME NELSON PLANT | AZ | 2,040.6 | 356,269.4 | 5.7 | 25,448.1 (6.4%) | NA | NA | Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls |

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB SO2 (tons) | Distance (meters) | SO2 Q/d | WEP_$SO_4$ (% of Total) | Selected in Utah Q/d Screen? (Y/N) | UT Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **CAPI1** | 5 | Sunnyside Cogeneration Associates-Sunnyside Cogeneration Facility | UT | 460.8 | 158,414.3 | 2.9 | 10,823.1 (2.7%) | YES | YES | |
| **CAPI1** | 6 | ASARCO LLC - HAYDEN SMELTER | AZ | 3,062.1 | 589,323.9 | 5.2 | 10,351.8 (2.6%) | NA | NA | Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls |
| **CAPI1** | 7 | Kennecott Utah Copper LLC-Smelter & Refinery | UT | 704.4 | 277,921.4 | 2.5 | 10,261.2 (2.6%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **CAPI1** | 8 | Tesoro Refining & Marketing Company LLC | UT | 708.3 | 280,166.8 | 2.5 | 6,278.1 (1.6%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **CAPI1** | 9 | NORTH VALMY GENERATING STATION | NV | 2,277.3 | 574,890.7 | 4.0 | 5,620.2 (1.4%) | NA | NA | NV's proposed SIP includes a federally enforceable closure date of 12/31/28 |
| **CAPI1** | 10 | Bonanza | TR | 1,281.3 | 261,713.3 | 4.9 | 4,809.0 (1.2%) | NA | NA | Likely closure in 2030 due to settlement |
| **ZICA1** | 1 | CHEMICAL LIME NELSON PLANT | AZ | 2,040.6 | 186,619.3 | 10.9 | 38,687.4 (24.8%) | NA | NA | Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls |
| **ZICA1** | 2 | Kennecott Utah Copper LLC-Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 398,524.3 | 5.4 | 9,186.4 (5.9%) | YES | NO | Power plant closed in 2020 |
| **ZICA1** | 3 | ASARCO LLC - HAYDEN SMELTER | AZ | 3,062.1 | 512,466.4 | 6.0 | 6,672.2 (4.3%) | NA | NA | Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls |

| Utah CIA | Rank | Facility Name | Source State | 2028 OTB SO2 (tons) | Distance (meters) | SO2 Q/d | WEP_$SO_4$ (% of Total) | Selected in Utah Q/d Screen? (Y/N) | UT Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| **ZICA1** | 4 | McCarran Intl | NV | 265.3 | 218,239.9 | 1.2 | 4,713.6 (3.0%) | NA | NA | Majority of $NO_x$ emissions from non-road sources (aircraft take-offs and landings) |
| **ZICA1** | 5 | PacifiCorp-Hunter Power Plant | UT | 3,498.2 | 285,805.3 | 12.2 | 4,557.8 (2.9%) | YES | YES | |
| **ZICA1** | 6 | Phoenix Sky Harbor Intl | AZ | 275.1 | 428,694.4 | 0.6 | 4,554.6 (2.9%) | NA | NA | Majority of $NO_x$ emissions from non-road sources (aircraft take-offs and landings) |
| **ZICA1** | 7 | California Portland Cement Co. | CA | 1,445.5 | 520,498.4 | 2.8 | 4,038.8 (2.6%) | NA | NA | Not subject to four-factor analysis in CA's proposed SIP due to AB 617 |
| **ZICA1** | 8 | Republic Services Sunrise | NV | 209.5 | 201,737.4 | 1.0 | 4,025.8 (2.6%) | NA | NA | Not subject to four-factor analysis in NV's proposed SIP due to low Q/d |
| **ZICA1** | 9 | TUCSON ELECTRIC POWER CO - SPRINGERVILLE | AZ | 6,991.9 | 480,561.1 | 14.5 | 3,447.7 (2.2%) | NA | NA | New SO2 limits for units 1 & 2 included in AZ's proposed SIP |
| **ZICA1** | 10 | PacifiCorp-Huntington Power Plant | UT | 2,449.0 | 300,744.4 | 8.1 | 3,032.3 (1.9%) | YES | YES | |

### Table 36: Nitrate Utah Point Source WEP Rank for Non-Utah CIAs

| CIA State | CIA | Rank | Facility Name | Source State | 2028 OTB $NO_x$ (tons) | Distance (meters) | $NO_x$ Q/d | WEP_$NO_3$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **WY** | BRID1 | 5 | Kennecott Utah Copper LLC- Mine & Copperton Concentrator | UT | 4,199.6 | 328,062.1 | 12.8 | 23,190.1 (3.9%) | YES | NO | BACT for $PM_{2.5}$ Serious SIP; majority of $NO_x$ emissions from non-road sources |

| CIA State | CIA | Rank | Facility Name | Source State | 2028 OTB $NO_x$ (tons) | Distance (meters) | $NO_x$ Q/d | WEP_$NO_3$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **WY** | YELL2 | 9 | Kennecott Utah Copper LLC- Mine & Copperton Concentrator | UT | 4,199.6 | 461,954.1 | 9.1 | 4,042.4 (1.8%) | YES | NO | BACT for $PM_{2.5}$ Serious SIP; majority of $NO_x$ emissions from non-road sources |
| **WY** | YELL2 | 10 | Salt Lake City Intl | UT | 784.0 | 437,939.4 | 1.8 | 3,887.0 (1.7%) | NO | NO | Q/d <6; majority of $NO_x$ emissions from non-road sources (aircraft take-offs and landings) |
| **ID** | CRMO1 | 10 | Kennecott Utah Copper LLC- Mine & Copperton Concentrator | UT | 4,199.6 | 338,486.4 | 12.4 | 22,912.5 (2.5%) | YES | NO | BACT for $PM_{2.5}$ Serious SIP; majority of $NO_x$ emissions from non-road sources |

## Table 37: Sulfate Utah Point Source WEP Rank for Non-Utah CIAs

| CIA State | CIA | Rank | Facility Name | Source State | 2028 OTB $SO_2$ (tons) | Distance (meters) | $SO_2$ Q/d | WEP_$SO_4$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **CO** | MEVE1 | 6 | CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant | UT | 534.9 | 126,687.8 | 4.2 | 22,144.4 (1.3%) | YES | NO | 2018 emissions Q/d <6 |
| **CO** | MEVE1 | 9 | PacifiCorp-Hunter Power Plant | UT | 3,498.2 | 310,434.6 | 11.3 | 11,845.4 (0.7%) | YES | YES | |
| **CO** | WEMI1 | 3 | CCI Paradox Midstream, LLC: Lisbon Natural Gas Processing Plant | UT | 534.9 | 140,388.0 | 3.8 | 24,308.8 (3.8%) | YES | NO | 2018 emissions Q/d <6 |
| **CO** | WEMI1 | 6 | PacifiCorp-Hunter Power Plant | UT | 3,498.2 | 326,019.1 | 10.7 | 12,361.1 (1.9%) | YES | YES | |

| CIA State | CIA | Rank | Facility Name | Source State | 2028 OTB $SO_2$ (tons) | Distance (meters) | $SO_2$ Q/d | WEP_$SO_4$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **WY** | BRID1 | 5 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 317,383.8 | 6.8 | 53,003.7 (6.3%) | YES | NO | Power plant closed in 2020 |
| **WY** | BRID1 | 8 | Tesoro Refining & Marketing Company LLC | UT | 708.3 | 299,746.7 | 2.4 | 32,334.3 (3.9%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **WY** | NOAB1 | 8 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 499,395.1 | 4.3 | 15,792.1 (2.2%) | YES | NO | Power plant closed in 2020 |
| **WY** | YELL2 | 2 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 449,396.5 | 4.8 | 23,791.3 (7.4%) | YES | NO | Power plant closed in 2020 |
| **WY** | YELL2 | 8 | Tesoro Refining & Marketing Company LLC | UT | 708.3 | 435,882.7 | 1.6 | 10,963.7 (3.4%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **ID** | CRMO1 | 4 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 326,319.5 | 6.6 | 18,525.9 (6.8%) | YES | NO | Power plant closed in 2020 |
| **ID** | CRMO1 | 6 | Tesoro Refining & Marketing Company LLC | UT | 708.3 | 325,079.4 | 2.2 | 7,431.8 (2.7%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **ID** | CRMO1 | 10 | Kennecott Utah Copper LLC- Smelter & Refinery | UT | 704.4 | 323,667.2 | 2.2 | 6,113.6 (2.2%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **ID** | SAWT1 | 4 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 446,448.0 | 4.8 | 6,827.9 (5.4%) | YES | NO | Power plant closed in 2020 |
| **ID** | SAWT1 | 8 | Tesoro Refining & Marketing Company LLC | UT | 708.3 | 448,276.9 | 1.6 | 3,373.8 (2.7%) | NO | NO | Q/d <6; BACT for +$PM_{2.5}$ Serious SIP |

| CIA State | CIA | Rank | Facility Name | Source State | 2028 OTB $SO_2$ (tons) | Distance (meters) | $SO_2$ Q/d | WEP_$SO_4$ (% of total) | Selected in Utah Q/d Screen? (Y/N) | Included in Four-Factor Analysis? (Y/N) | Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **ID** | SAWT1 | 10 | Kennecott Utah Copper LLC- Smelter & Refinery | UT | 704.4 | 442,899.3 | 1.6 | 2,252.8 (1.8%) | NO | NO | Q/d <6; BACT for $PM_{2.5}$ Serious SIP |
| **NV** | JARB1 | 10 | Kennecott Utah Copper LLC- Power Plant Lab Tailings Impoundment | UT | 2,151.9 | 304,126.8 | 7.1 | 5,105.3 (1.4%) | YES | NO | Power plant closed in 2020 |
| **AZ** | GRCA2 | 10 | PacifiCorp- Hunter Power Plant | UT | 3,498.2 | 363,743.3 | 9.6 | 2,321.3 (0.6%) | YES | YES | |

## 7.A.4 Other Sources

The foregoing Q/d analysis, secondary screening, and WEP analysis sections were used to help identify point sources with potential impacts at Utah and non-Utah CIAs. However, the emissions inventories detailed in section 5.A and the WRAP photochemical source apportionment results provided in section 6.A suggest that non-point sources in Utah may also impact visibility in CIAs. This section discusses the potential impacts of and state of emissions controls for non-point sources in Utah.

### *Oil and Gas*

Utah oil and gas sources are spread over a very large area making a traditional Q/d analysis problematic. Furthermore, in light of updated inventory findings discussed below, UDAQ does not consider the WRAP oil and gas inventories to be adequate for any type of Q/d emissions analysis, derived or otherwise. That said, UDAQ acknowledges that oil and gas sector emissions may affect visibility in CIAs.

Most of Utah's oil and gas sector emissions occur in the Uinta Basin (UB), where considerable work has already been done to address this sector's contribution to wintertime ozone pollution. The UB, located in northeast Utah, contains the majority of oil and gas extraction in Utah. The UB has been found to have high levels of ozone during the winter months. This phenomenon is associated with the geological basin, cold temperature inversion, and snow cover albedo in the presence of VOCs and $NO_x$. The majority of emissions for the ozone precursors of VOC and $NO_x$ come primarily from the oil and gas exploration and production in the area, not other urban or mobile sources. Since the discovery of these high ozone emissions, Utah has acted to control the oil and gas sources in the UB and the rest of the state. However, the jurisdictional complexity of the UB has led to inconsistency between state-controlled sources and EPA-controlled sources on Indian Country. Emission inventories show that about 80% of the emissions are under EPA regulatory control. The 2017 oil and gas emission inventory compared to the total emission inventory for the UB accounts for about 97% of the total VOC emissions and 68% of the total $NO_x$ emissions. The 2017 oil and gas emission inventory showed that 80% of emissions in the UB result from areas under EPA control. Therefore, the state of Utah can only address about 20% of the ozone-forming precursors VOC and $NO_x$ and cannot address air quality issues on their own in the UB. Over the past several years, UDAQ has proposed and adopted a series of statewide rules specific to oil and gas operations found in Utah's state administrative rules R301-500 to 511. Though these rules have been focused on controlling VOC emissions, there is also a state-specific rule for natural gas-powered engines associated with oil and gas production. Since the rule was put in place in 2018, several sources have provided engine stack test data that have led UDAQ, EPA, and the Tribes to initiate further research and compliance studies on engines in the Basin, with a focus on two-stroke smaller horsepower engines that power pump jacks associated with oil-producing wells. The data collected have indicated lower values for $NO_x$ emissions than what was reported in the 2017 oil and gas emission inventory for these engines, yet much higher emissions of VOCs. UDAQ will be evaluating this data and will be evaluating future rulemaking for engines associated with oil and gas operations that would be statewide. EPA did follow UDAQ's lead and has proposed the Uintah and Ouray Federal Implementation Plan that is similar to Utah's oil and gas rules, and will bring some regulatory consistency to the area. The UDAQ will continue to coordinate with EPA and the Tribe to encourage that rules are consistent across all regulatory jurisdictions, but ultimately any controls under EPA regulatory jurisdiction will be determined by EPA and the Tribe[136].

### *Mobile*

As identified in section 6.A above, mobile source emissions are a leading Utah source for nitrate impacts at all Utah CIAs and in some neighboring states, namely Colorado, Idaho, and Wyoming. Under Section 209 of the Clean Air Act, states are largely preempted from setting standards for on-road and non-road mobile sources. Fortunately, federal emission standards for on-road vehicles and engines as well as non-road equipment are projected to result in dramatic reductions in $NO_x$ and PM emissions in Utah over the second planning period for regional haze. To help guarantee these emissions reductions, the State of Utah has worked with the petroleum refiners that supply the Utah market to ensure that suppliers produce gasoline that meets the Tier 3 sulfur requirement of 30 ppm and not just comply using credits. In addition, Utah has taken measures as part of other air quality programs to ensure that mobile source emissions are well-controlled. For example, Utah has vehicle inspection and maintenance programs in place in Utah, Salt Lake, Davis, Weber, and Cache counties, which accounted for 79.3% of the state's population in 2021[i] and 60.1% of total statewide on-road mobile source OTB2028a2 emissions. These programs also include diesel vehicle inspections which, while not creditable in Utah's various SIP revisions, help reduce $NO_x$ emissions that contribute to nitrate formation and CIA impacts.

[136] Please refer to sections 5.B and 9.C.2, response 24 for additional information concerning Utah's area sources.

*Remaining Anthropogenic*

The remaining anthropogenic category of the WRAP photochemical analysis represents non-oil and gas area source emissions, and specifically includes fugitive dust, agriculture, agricultural fire, residential wood combustion, and all remaining nonpoint sources (e.g., residential and commercial stationary source fuel combustion). As shown in section 6.A, the remaining anthropogenic impacts are relatively small for Utah and non-Utah CIAs. That said, these sources are relatively well-controlled as a result of rulemaking associated with other air quality programs in Utah (e.g., the $PM_{2.5}$ SIP BACM review and resulting controls). For example, Utah restricts residential wood burning on so-called mandatory action days when conditions are ripe for secondary formation of particulates. Utah has also adopted an ultra-low $NO_x$ water heater rule that applies statewide and, when fully implemented, will result in a 75% reduction in $NO_x$ emissions from residential and commercial water heating-related natural gas stationary source fuel combustion. Additional Utah area source rules to reduce $NO_x$ and/or PM emissions include those governing hydronic heaters, fugitive dust, and pilot lights.

## 7.A.5 Environmental Justice Considerations

Environmental Justice (EJ) is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies[137]. Absent further guidance from EPA, UDAQ believes the consideration of EJ is best used in the screening process to ensure sources within disproportionately affected areas are included in the four-factor analysis process. UDAQ has used the EJScreen (version 2.0) tool developed by EPA to analyze the environmental justice indices surrounding the sources selected to conduct four-factor analyses. EJScreen[138]. For the 10 sources originally screened in this implementation period, UDAQ reviewed all pollution and sources as well as socioeconomic indicators (a total of 19 indices) as percentiles calculated by comparing data from census blocks within the state of Utah. UDAQ notes that the RH program does not have the authority to control the following indexes included in this analysis: lead paint, superfund sites, wastewater discharge, RMP facilities, hazardous waste, or underground storage tanks. Percentiles for all indexes were generated for each source's location centered within a 20-mile buffer radius. UDAQ recorded all indexes in the 80th percentiles and above at the state level for the screened sources and offers the following information used to consider the co-benefits of the reasonable progress determinations included in this implementation period. UDAQ was not able to draw significant conclusions from this analysis affecting the reasonable progress determinations made in this SIP revision.

**Table 38: Ash Grove Leamington Cement Plant EJScreen Findings**

| Selected Variables | Value | State | |
|---|---|---|---|
| | | Avg. | %tile |

[137] More information on EJ can be found at: https://www.epa.gov/environmentaljustice
[138] Technical information on EJScreen can be found at: https://www.epa.gov/sites/default/files/2021-04/documents/ejscreen_technical_document.pdf

| | | | |
|---|---|---|---|
| **Pollution and Sources** | | | |
| **No percentiles above 80.** | | | |
| **Socioeconomic Indicators** | | | |
| **Under Age 5** | 12% | 8% | 85 |

**Table 39: Graymont Western Cricket Mountain Plant EJScreen Findings**

| Selected Variables | Value | State | |
|---|---|---|---|
| | | Avg. | %tile |
| **Pollution and Sources** | | | |
| **Lead Paint (% Pre-1960 Housing)** | 0.3 | 0.17 | 81 |
| **Socioeconomic Indicators** | | | |
| **No percentiles above 80.** | | | |

**Table 40: PacifiCorp Hunter Power Plant EJScreen Findings**

| Selected Variables | Value | State | |
|---|---|---|---|
| | | Avg. | %tile |
| **Pollution and Sources** | | | |
| **No percentiles above 80.** | | | |
| **Socioeconomic Indicators** | | | |
| **Over Age 64** | 16% | 11% | 81 |

**Table 41: PacifiCorp Huntington Power Plant EJScreen Findings**

| Selected Variables | Value | State | |
|---|---|---|---|
| | | Avg. | %tile |
| **Pollution and Sources** | | | |
| **No percentiles above 80.** | | | |
| **Socioeconomic Indicators** | | | |
| **Unemployment Rate** | 6% | 4% | 84 |
| **Over Age 64** | 16% | 11% | 80 |

Table 42: Sunnyside Cogeneration Power Plant EJScreen Findings

| Selected Variables | Value | State | |
|---|---|---|---|
| | | Avg. | %tile |
| **Pollution and Sources** | | | |
| **Lead Paint (% Pre-1960 Housing)** | 0.48 | 0.17 | 89 |
| **Socioeconomic Indicators** | | | |
| **Low Income** | 41% | 27% | 80 |
| **Unemployment Rate** | 8% | 4% | 89 |
| **Over Age 64** | 17% | 11% | 83 |

Table 43: US Magnesium Rowley Plant EJScreen Findings

| Selected Variables | Value | State | |
|---|---|---|---|
| | | Avg. | %tile |
| **Pollution and Sources** | | | |
| **2017 Air Toxics Respiratory HI** | 0.62 | 0.3 | 98 |
| **Wastewater Discharge (toxicity-weighted concentration/m distance)** | 11 | 13 | 88 |
| **Socioeconomic Indicators** | | | |
| **No percentiles above 80.** | | | |

Table 44: Intermountain Generation Station EJScreen Findings

| Selected Variables | Value | State | |
|---|---|---|---|
| | | Avg. | %tile |
| **Pollution and Sources** | | | |
| **Lead Paint (% Pre-1960 Housing)** | 0.29 | 0.17 | 81 |
| **Socioeconomic Indicators** | | | |
| **No percentiles above 80.** | | | |

Table 45: Kennecott Power Plant EJScreen Findings

| Selected Variables | Value | State | |
|---|---|---|---|
| | | Avg. | %tile |
| **Pollution and Sources** | | | |
| **2017 Air Toxics Cancer Risk* (lifetime risk per million)** | 24 | 21 | 89 |
| **2017 Air Toxics Respiratory HI*** | 0.37 | 0.3 | 89 |
| **Superfund Proximity (site count/km distance)** | 0.34 | 0.18 | 88 |
| **Hazardous Waste Proximity (facility count/km distance)** | 1.5 | 0.89 | 80 |
| **Socioeconomic Indicators** | | | |
| **No percentiles above 80.** | | | |

Table 46: Kennecott Mine and Copperton Concentrator EJScreen Findings

| Selected Variables | Value | State | |
|---|---|---|---|
| | | Avg. | %tile |
| **Pollution and Sources** | | | |
| **2017 Air Toxics Cancer Risk* (lifetime risk per million)** | 24 | 21 | 88 |
| **2017 Air Toxics Respiratory HI*** | 0.36 | 0.3 | 89 |
| **Superfund Proximity (site count/km distance)** | 0.24 | 0.18 | 83 |
| **Socioeconomic Indicators** | | | |
| **No percentiles above 80.** | | | |

Table 47: Paradox Lisbon Plant EJScreen Findings

| Selected Variables | Value | State | |
|---|---|---|---|
| | | Avg. | %tile |
| **Pollution and Sources** | | | |
| **Superfund Proximity (site count/km distance)** | 0.36 | 0.18 | 88 |
| **Socioeconomic Indicators** | | | |
| **Over Age 64** | 18% | 11% | 86 |

## 7.B Four-Factor Analyses for Utah Sources[139]

Each source subject to submitting a four-factor analysis in this second planning period submitted a report on the available control technologies for $SO_2$ and $NO_x$ emission reductions and the application of each technology to that facility. UDAQ notes that none of the sources selected to complete a four-factor analysis are within any nonattainment areas under the NAAQS. The information on available controls should include the analysis of the following four factors when determining the possible emission reductions:

1. Factor 1 – The Costs of Compliance
2. Factor 2 – Time Necessary for Compliance
3. Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance
4. Factor 4 – Remaining Useful Life of the Source[140]

Although not specifically required, the recommended approach was to follow a step-by-step review of possible emission reduction options in a “top-down” fashion similar to EPA’s guidelines for reviewing BART or Best Available Retrofit Technology (as found in 70 Fed. Reg. 39,104, 39,108-09 (July 6, 2005)). The steps involved are as follows:

1. Identify all available retrofit control technologies
2. Eliminate technically infeasible control technologies
3. Evaluate the control effectiveness of remaining control technologies
4. Evaluate impacts and document results

The process is inherently similar to that used in selecting BACT (Best Available Control Technology) under the NSR/PSD (Title I) permitting program. UDAQ evaluated the submissions from each source following the methodology outlined above. Where a particular submission may

[139] 40 CFR 51.308(f)(2)(i)
[140] *See* 40 C.F.R. § 51.308(f)(2)(i).

have differed from the recommended process, UDAQ makes a note, and provides additional explanation as necessary.

### 7.B.1 Control Equipment Descriptions

*Available $NO_x$ Reduction Strategies and Technologies*[141]
The sources selected to provide additional analyses consistent with the four factors listed above-evaluated controls primarily for $NO_x$ emissions reductions. The following represents proven, available $NO_x$ reduction strategies and technologies for four-factor sources. The sources selected to provide additional analyses consistent with the four factors listed above evaluated controls primarily for $NO_x$ emissions reductions.

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

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

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

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

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

*Staged combustion.* Either air or fuel injection can be staged, creating either a fuel-rich zone followed by an air-rich zone or an air-rich zone followed by a fuel-rich zone. Staged combustion can be achieved by installing a low-$NO_x$ staged combustion burner, or the furnace can be

[141] More information on emission control strategies can be found at: https://www.epa.gov/sites/default/files/2015-07/documents/chapter_5_emission_control_technologies.pdf

retrofitted for staged combustion. $NO_x$ reductions of more than 40% have been demonstrated with staged combustion.

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

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

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

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

### *Available $SO_2$ Reduction Strategies and Technologies*[142]

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

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

*Sorbent Injection.* Sorbent injection involves adding an alkali compound to the combustion gases for reaction with the $SO_2$. Typical calcium sorbents include lime and variants of lime. Sodium-based compounds are also used. Dry sorbent injection systems are simple systems, and generally require a sorbent storage tank, feeding mechanism, transfer line and blower, and injection device. Sorbent injection processes remove 30–60% of sulfur oxide emissions; however, if the sorbent is hydrated lime, then 80% or greater removal can be achieved. These systems are commonly called lime spray dryers.

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

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

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

*Spray Dry Absorber.* The typical spray dry absorber (SDA) uses lime slurry and water injected into a tower to remove $SO_2$ from the combustion gases. The towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry to

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[142] More information on emission control strategies can be found at: https://www.epa.gov/sites/default/files/2015-07/documents/chapter_5_emission_control_technologies.pdf

produce a relatively dry by-product. The process equipment associated with an SDA typically includes an alkaline storage tank, mixing and feed tanks, atomizer, spray chamber, particulate control device, and recycle system. The recycle system collects solid reaction products and recycles them back to the spray dryer feed system to reduce alkaline sorbent use. SDAs are the commonly used dry scrubbing method in large industrial and utility boiler applications. SDAs have demonstrated the ability to achieve greater than 95% $SO_2$ reduction.

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

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

### 7.B.2 Existing Controls on Active EGUs

The following tables summarize existing controls on all active coal and gas facilities in Utah. For more detailed information on control compliance schedules from the first implementation period and retirement dates, refer to section 3.A.1.

**Table 48: Existing controls on active coal units in Utah**

| Facility | Unit | Operator | $SO_2$ Control(s) | $NO_X$ Control(s) |
|---|---|---|---|---|
| Bonanza | 43101 | Deseret Generation & Transmission | Wet Limestone | Low $NO_X$ Burner Technology (Dry Bottom only) |
| Hunter | 1 | PacifiCorp Energy Generation | Wet Lime FGD | Low $NO_X$ Burner Technology w/ Closed-coupled OFA |
| Hunter | 2 | PacifiCorp Energy Generation | Wet Lime FGD | Low $NO_X$ Burner Technology w/ Separated OFA |
| Hunter | 3 | PacifiCorp Energy Generation | Wet Lime FGD | Low $NO_X$ Burner Technology w/ Overfire Air |
| Huntington | 1 | PacifiCorp Energy Generation | Wet Lime FGD | Low $NO_X$ Burner Technology w/ Closed-coupled OFA |
| Huntington | 2 | PacifiCorp Energy Generation | Wet Lime FGD | Low $NO_X$ Burner Technology w/ Separated OFA |

**Table 49: Existing controls on active gas units in Utah**

| Facility Name | Unit ID | Owner | $NO_x$ Control(s) |
|---|---|---|---|
| Lake Side Power Plant | CT03 | PacifiCorp Energy Generation | Selective Catalytic Reduction |
| Lake Side Power Plant | CT04 | PacifiCorp Energy Generation | Selective Catalytic Reduction |
| Lake Side Power Plant | CT02 | PacifiCorp Energy Generation | Selective Catalytic Reduction |
| Currant Creek Power Project | CTG1B | PacifiCorp Energy Generation | Selective Catalytic Reduction |
| Currant Creek Power Project | CTG1A | PacifiCorp Energy Generation | Selective Catalytic Reduction |
| Nebo Power Station | U1 | Utah Associated Municipal Power Systems | Dry Low $NO_x$ Burners<br>Selective Catalytic Reduction |
| Millcreek Power | MC-1 | City of St. George | Dry Low $NO_x$ Burners |
| Millcreek Power | MC-2 | City of St. George | Dry Low $NO_x$ Burners<br>Selective Catalytic Reduction |
| Gadsby | 4 | PacifiCorp Energy Generation | Water Injection<br>Selective Catalytic Reduction |
| West Valley Power Plant | U4 | Utah Municipal Power Agency | Water Injection<br>Selective Catalytic Reduction |
| West Valley Power Plant | U2 | Utah Municipal Power Agency | Water Injection<br>Selective Catalytic Reduction |
| West Valley Power Plant | U3 | Utah Municipal Power Agency | Water Injection<br>Selective Catalytic Reduction |
| Gadsby | 5 | PacifiCorp Energy Generation | Water Injection<br>Selective Catalytic Reduction |
| West Valley Power Plant | U5 | Utah Municipal Power Agency | Water Injection<br>Selective Catalytic Reduction |
| Gadsby | 6 | PacifiCorp Energy Generation | Water Injection<br>Selective Catalytic Reduction |
| West Valley Power Plant | U1 | Utah Municipal Power Agency | Water Injection<br>Selective Catalytic Reduction |
| Gadsby | 2 | PacifiCorp Energy Generation | Low $NO_x$ Burner Technology (Dry Bottom only) |
| Gadsby | 1 | PacifiCorp Energy Generation | Low $NO_x$ Burner Technology (Dry Bottom only) |

## 7.C Source Consultation

UDAQ has kept regular contact with the sources selected to perform four-factor analyses on their units and offered guidance on developing control cost estimates using EPA's Air Pollution

Control Cost Manual[143] and facility-specific data representing current emissions, projected future emissions, and potential control scenarios. UDAQ received and reviewed each source's initial four-factor analysis and sent an evaluation to each source with recommendations, requests for additional information, and explanations of any issues with calculations or assumptions made by sources in calculations. Refer to Chapter 9 to review detailed information on UDAQ's meetings with the sources. The following sections contain each source's four-factor analysis, UDAQ's evaluation of their initial submittal, and the sources resulting responses and corrections.[144]

## 7.C.1 Ash Grove Cement Company- Leamington Cement Plant Four-Factor Analysis Summary and Evaluation[145]

### *Facility Identification*

**Name:** Ash Grove Cement Company
**Address:** Hwy. 132, Leamington, Utah 84638
**Owner/Operator:** Ash Grove Cement Company
**UTM coordinates:** 4,379,850 m Northing, 397,000 m Easting, Zone 12

### *Facility Process Summary*

Ash Grove Cement Company (Ash Grove) operates the Leamington Cement Plant. This plant has been in operation since 1981. At the Leamington cement plant, cement is produced when inorganic raw materials, primarily limestone (quarried on site), are correctly proportioned, ground and mixed, and then fed into a rotating kiln. The kiln alters the materials and recombines them into small stones called cement clinker. The clinker is cooled and ground with gypsum and additional limestone into a fine powdered cement. The final product is stored on site for later shipping. The major sources of air emissions are from the combustion of fuels for the kiln operation, from the kiln, and from the clinker cooling process.

### *Facility Criteria Air Pollutant Emissions Sources*

This source consists of the following emission unit:

- Unit Designation: Kiln 1
  Kiln 1 has the following emission controls installed:
  SNCR for $NO_x$ control; $NO_x$, CO, Total Hydrocarbons (VOC), and Oxygen ($O_2$) CEMS on main stack; Mercury (Hg) CEMS or integrated sorbent trap monitoring system on main stack; TSP (PM) Continuous Parametric Monitoring System (CPMS) on main kiln and clinker cooler stack.

143 The EPA Air Pollution Control Cost Manual can be found in at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual
144 Each source's full four-factor analysis submittals, UDAQ's four-factor analysis evaluations, and evaluation responses sent by sources can be found at https://deq.utah.gov/air-quality/regional-haze-in-utah in the "Current Regional Haze Planning" section.
145 Ash Grove's full four-factor analysis submittal can be found in appendix C.1.A or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008930.pdf

*Facility Current Potential to Emit*

The current PTE values for Ash Grove, as established by the most recent NSR permit issued to the source (DAQE-AN103030029-19) are as follows:

**Table 50: Ash Grove Leamington Cement Plant Current Potential to Emit**

| Pollutant | Potential to Emit (tons/year) |
|---|---|
| **$SO_2$** | 192.50 |
| **$NO_x$** | 1347.20 |

## Ash Grove's Four-Factor Analysis Conclusion

Ash Grove believes that reasonable progress compliant controls are already in place. Ash Grove's actual $NO_x$ emission level of 1198 tpy is adequate and the Leamington facility does not propose any change to their current limit of 2.8 lbs./ton clinker on a 30-day rolling average basis.

## UDAQ Four-Factor Analysis Evaluation[146]

Although some additional information should be supplied by the source regarding SNCR efficiency, the Leamington Cement Plant appears to be adequately controlled at this time for purposes of Second Planning Period.

## Ash Grove's Evaluation Response[147]

AGC provided the actual $SO_2$ emissions rates for the Leamington Plant's main kiln which are lower than their PTE. Lowering $SO_2$ emissions further would require the addition of aluminum and iron which are not readily available to Ash Grove. The efficiency of the Leamington Plant's SNCR system was designed to be able to achieve 2.8 lb. $NO_x$/ton clinker on a 30-day rolling average basis, and the plant typically operates in the 2.5-2.6 lb. $NO_x$/ton clinker range. The system uses an Aqua $NH_3$ solution as a chemical reagent. Adding additional solution is not feasible as the plant already requires reagent delivery by truck every two days and additional reagent would require the installation of larger nozzles and/or larger storage tanks. The system is also near solution saturation as it currently runs, and additional solution may not increase control efficiency, but rather cause $NH_3$ to slip from the system and be emitted from the stack. Thus, Ash Grove believes that the current and $NO_x$ limits reflect a reasonable level of safety margin relative to actual emission rates.

[146] UDAQs full evaluation of Ash Grove's four-factor analysis submittal can be found in appendix C.1.A or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2021-009636.pdf
[147] Ash Grove's full evaluation response can be found in appendix C.1.B or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2021-011724.pdf

### UDAQ Response Conclusion

UDAQ accepts the additional information provided by Ash Grove on their emission rate efficiency and agrees that their units are well controlled. Refer to section 8.D.1. for UDAQ's reasonable progress determination for Ash Grove.

## 7.C.2 Graymont Western US Incorporated- Cricket Mountain Plant Four-Factor Analysis Summary and Evaluation[148]

*Facility Identification*

**Name:** Cricket Mountain Plant
**Address**: 32 Miles Southwest of Delta, Utah; Highway 257
**Owner/Operator:** Graymont Western US Incorporated
**UTM coordinates:** 4,311,010 m Northing, 343,100 m Easting, Zone 12

*Facility Process Summary*

Graymont Western US Inc. (Graymont) operates the Cricket Mountain Lime Plant in Millard County. The Cricket Mountain Lime Plant consists of quarries and a lime processing plant, which includes five (5) rotary lime kilns (Kilns 1 through 5). The rotary kilns are used to convert crushed limestone ore into quicklime. The products produced for resale are lime, limestone, and kiln dust. The kilns operate on pet coke and coal. Sources of emissions at this source include mining, limestone processing, rotary lime kilns, post-kiln lime handling, and truck & loadout facilities.

*Facility Criteria Air Pollutant Emissions Sources*

The source consists of the following emission units:

- Rotary Lime Kiln #1 rated at 600 tons of lime per 24-hour period with a preheater and baghouse emissions control system (D-85) rated at an exhaust gas flow rate 54,000 scfm and an Air to Cloth (A/C) ratio of 3.26:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA
- Rotary Lime Kiln #2 rated at 600 tons of lime per 24-hour period with a preheater, cyclone and baghouse emissions control system (D-275) rated at an exhaust gas flow rate of 48,000 scfm and an A/C ratio of 2.9:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA
- Rotary Lime Kiln #3 rated at 840 tons of lime per 24-hour period with a preheater, cyclone and baghouse emissions control system (D-375) rated at an exhaust gas flow rate of 55,000 scfm and a A/C ratio of 2.49:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA
- Rotary Lime Kiln #4 rated at 1266 tons of lime per 24-hour period with a preheater, cyclone and baghouse emissions control system (D-485) rated at an exhaust gas flow

[148] Graymont's full four-factor analysis submittal for the Cricket Mountain Plant can be found in appendix C.2.A or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008924.pdf

rate of 100,000 scfm and an A/C ratio of 5:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA

- Rotary Lime Kiln #5 rated at 1400 tons of lime per 24-hour period with a preheater and baghouse emissions control system (D-585) rated at an exhaust gas flow rate of 103,000 scfm and an A/C ratio of 3.5:1. NESHAP Applicability: 40 CFR 63 Subpart AAAAA

#### *Facility Current Potential to Emit*

The current PTE values for Source, as established by the most recent NSR permit issued to the source (DAQE-AN103130044-21) are as follows:

**Table 51: Current Potential to Emit - Graymont**

| Pollutant | Potential to Emit (tons/year) |
|---|---|
| **$SO_2$** | 760.29 |
| **$NO_x$** | 3,883.85 |

### Graymont Four-Factor Analysis Conclusion

The facility currently uses low $NO_x$ burners in its five kilns to minimize $NO_x$ emissions. The use of low $NO_x$ burners is a commonly applied technology in current BACT determinations for new rotary preheater lime kilns today. The application of SCR has never been attempted on a lime kiln. SNCR has only one RBLC entry documenting implementation on a lime kiln. The use of these controls does not represent a cost-effective control technology given the limited expected improvements to $NO_x$ emission rates, high uncertainty of successful implementation, high capital investment, and high cost per ton $NO_x$ removed. Therefore, the emissions for the 2028 on-the-books modeling scenario are expected to be the same as those used in the “control scenario” for the Graymont Cricket Mountain facility.

### UDAQ Four-Factor Analysis Evaluation[149]

UDAQ disagrees with several points of Graymont’s analysis. Aside from the lack of $SO_2$ analysis, UDAQ found several errors in the Graymont $NO_x$ analysis which must be corrected.

1. Two additional control technologies were identified by DAQ as potential ways of reducing $NO_x$ emissions: fuel switching and alternative production techniques. The Graymont Cricket Mountain Plant is fueled by coal – alternative fuels should be investigated. Secondly, the kilns at this facility are long horizontal rotary preheater/precalciner style kilns. Other types of kiln such as vertical lime kilns should also be investigated.
2. Graymont has claimed that SNCR is not technically feasible for installation on rotary preheater kilns. However, that is not accurate as there have been other SNCR retrofits

[149] UDAQ’s full evaluation of Graymont’s four-factor analysis submittal can be found in appendix C.2.A or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2021-009634.pdf

done at preheater rotary lime kilns. Those lime kilns include the Lhoist North America O'Neal Plant in Alabama, the Unimin Corporation lime plant in Calera, Alabama, and the rotary lime kilns of the Lhoist North America Nelson Lime Plant in Arizona, as well as the Mississippi Lime Company plant in Illinois (specifically mentioned by Graymont as the only source listed on the RBLC).

3. A $NO_x$ reduction of 20% for SNCR is too low for use in the analysis, given that Graymont itself quoted the average $NO_x$ removal at cement kilns with SNCR was 40%, with the range of $NO_x$ removal efficiency between 35%-58%. At a minimum, Graymont should have evaluated the use of SNCR at 35% removal efficiency rather than merely 20%.
4. The current bank prime rate is 3.25% and not 4.75% as stated by Graymont. The economic analysis must be recalculated using the correct interest rate.
5. The cost of an air preheater was included – which appears to be a mistake based on an error (a typographical misprint) found in EPA's SNCR control cost spreadsheets. In one place the spreadsheet uses a value of 3.0 lb. $SO_2$/ton coal while in another the value is erroneously listed as 0.3 lb. $SO_2$/ton coal. Graymont apparently included the cost of the air preheater when burning coal which does not require such equipment as part of an SNCR installation.

Although DAQ has not fully evaluated these deficiencies, it has analyzed how Graymont's cost evaluation would change if the correct bank prime interest rate were used, if the cost of the air preheater were not included, and if the removal efficiency of the SNCR were increased to a minimum of 35%. To reflect the increased cost of a more efficient SNCR than that proposed by Graymont, the direct annual costs (energy, cost of ammonia, etc.) were doubled as a conservative estimate. The results of these changes are as follows:

**Table 52: Estimated Direct Annual Costs (doubled) Graymont**

| Kiln | Capital Costs ($) | Direct Annual Costs ($) | Total Annual Costs ($) | $NO_x$ Removed (tons) | cost-effectivenes s ($/ton) |
|---|---|---|---|---|---|
| **1** | $3,616,821 | $180,574 | $328,281 | 30 | $10,943 |
| **2** | $3,878,230 | $186,204 | $343,367 | 22 | $15,608 |
| **3** | $4,321,811 | $208,776 | $377,952 | 18 | $20,997 |
| **4** | $5,285,030 | $258,458 | $461,703 | 38 | $12,150 |
| **5** | $5,031,753 | $289,720 | $485,174 | 122 | $ 3,977 |

Based on these revised results, the application of SNCR may appear to be feasible, at least for Kiln #5. Additional analysis should be provided by the source to further detail these deficiencies.

### Graymont's Evaluation Response[150]

In order to obtain a more accurate capital and operating cost estimate, Graymont commissioned a Class 4 engineering cost estimate to ascertain capital and operating costs associated with installing and operating Selective Non-Catalytic Reduction (SNCR) Nitrogen Oxides ($NO_x$) abatement systems on Cricket Mountain kilns. The cost estimations performed by a third-party engineer indicate that the total capital cost for installation of SNCR systems at Cricket Mountain exceeds $6.9 MMUSD and operating costs exceed $1.4 MMUSD annually, resulting in a cost of $17,561 per ton of $NO_x$ removed based upon a 20% removal efficiency. A factor of 20% was utilized based on the temperature and residence time limitations of the SNCR reaction zone for each Cricket Mountain kiln combined with the Low $NO_x$ baseline concentration already achieved through the use of Low $NO_x$ Burners (LNB)[151].

Graymont also compared the current $NO_x$ emissions from Cricket Mountain to publicly available information for the Lhoist North America (LNA) rotary preheater kilns which utilize SCNR. Graymont offered the following observations:

- The existing LNBs at Cricket Mountain have effectively reduced the $NO_x$ emission intensity to a level more than three times less than the pre-control $NO_x$ intensity of LNA's Nelson Plant which utilizes SNCR.
- Any additive efficiency that might be gained from Cricket Mountain's use of SNCR would be marginal, at best, as SNCR $NO_x$ removal efficiency is highly dependent upon the inlet $NO_x$ concentration, reaction zone temperature and residence time, all of these factors reduce the anticipated efficiency that can reasonably be assumed for the Cricket Mountain Kilns.
- The LNA SNCR technology for rotary lime kilns is proprietary and not unconditionally commercially available to Graymont. The technology appears to be patented, adding to its cost and the uncertainty as to its technical feasibility.
- SNCR addition at Cricket Mountain would have unintended negative environmental impacts and visibility disbenefits, including the generation of condensable particulate, an identified regional haze primary pollutant.
- The Cricket Mountain facility operates 5 rotary preheat lime kilns, each of which are substantially different technology than mid-fired cement kilns (more conducive reaction zone temperatures, higher $NO_x$ concentrations, and longer residence times). As such, it is not appropriate to draw direct comparisons with application of SNCR between cement kilns and lime kilns as referenced in your letter.

Based on Graymont's findings, requiring the installation of SNCR at Cricket Mountain would be unreasonable because it would be infeasible, unnecessary and counterproductive to making

[150] Graymont's full evaluation response can be found in appendix C.2.C or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2021-011722.pdf

[151] Lhoist North America indicated in a November 2020 4-factor analysis that Kilns 1, 2 & 3 would be capable of a maximum $NO_x$ control of 20%.

reasonable progress towards the goal of preventing future, and remedying any existing, anthropogenic impairment of visibility in mandatory Class I Federal areas in the context of Utah's pending Round 2 Regional Haze State Implementation Plan (RH SIP). Cricket Mountain's successful implementation of LNBs effectively controls $NO_x$ at the point of generation in kilns.

These $NO_x$ rates are sufficient for inclusion in the UDAQ RH SIP since they are already some of the lowest achieved in the industry and far exceed what has been deemed BART at other kilns (such as the SNCR controlled kilns at the LNA Nelson Facility).

### UDAQ Response Conclusion

UDAQ accepts Graymont's four-factor analysis amendments and additional justification on the unfeasibility of additional controls on the Cricket Mountain Facility's kilns. Refer to section 8.D.2 for UDAQ's controls for reasonable progress determination.

## 7.C.3 PacifiCorp's Hunter and Huntington Power Plants Four-Factor Analysis Summary and Evaluation[152]

#### *Facility Identification*

**Name:** Hunter Power Plant
**Address:** P.O. Box 569, Castle Dale, UT 84513
**Owner/Operator:** PacifiCorp
**UTM coordinates:** 497,800 m Easting, 4,335,800 m Northing, UTM Zone 12

#### *Facility Process Summary*

The Hunter Power Plant is located near Castle Dale in Emery County. The plant is classified as a PSD source and is a Phase II Acid Rain source. The source is PSD major for $SO_2$, $NO_x$, $PM_{10}$, and CO and also major for VOC and HAPs. The source is subject to the provisions of 40 CFR 52.21(aa); 40 CFR 60 Subparts A, D, Da, Y, and HHHH; and 40 CFR 63 Subparts A, ZZZZ, and UUUUU.

#### *Facility Criteria Air Pollutant Emissions Sources*

The source consists of the following emission units:

- Steam Generating Unit #1 - Nominal 480 MW gross capacity dry bottom, tangentially-fired boiler fired on subbituminous and bituminous coal using distillate fuel oil during start-up and flame stabilization. System is equipped with a low-$NO_x$ burner/overfire air system (OFA), baghouse, and $SO_2$ Wet FGD (WFGD) scrubber with no scrubber bypass.
- Steam Generating Unit #2 - Nominal 480 MW gross capacity dry bottom, tangentially-fired boiler fired on subbituminous and bituminous coal using distillate fuel oil during

[152] PacifiCorp's full four-factor analysis submittal for the Hunter and Huntington power plants can be found in appendix C.3.A or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008926.pdf

start-up and flame stabilization. System is equipped with a low-$NO_x$ burner/OFA, baghouse, and $SO_2$ WFGD scrubber with no scrubber bypass.

- Steam Generating Unit #3 - Nominal 495 MW gross capacity dry bottom, wall-fired boiler fired on subbituminous and bituminous coal using distillate fuel oil during start-up and flame stabilization. System is equipped with baghouse, a low $NO_x$ burner/OFA, and $SO_2$ FGD scrubber.

### *Facility Current Potential to Emit*

The current PTE values for the Hunter Power Plant, as established by the most recent NSR permit issued to the source (DAQE-AN102370028-18) are as follows:

**Table 53: Hunter Current Potential to Emit**

| Pollutant | Potential to Emit (Tons/Year) |
|---|---|
| **$SO_2$** | 5,537.5 |
| **$NO_x$** | 15,095 |

## PacifiCorp Four Factor Analysis Conclusion

When balanced for Hunter Units 1, 2, and 3 the four factors demonstrate that the RPEL is the best option for making reasonable progress during the second planning period. First, installation of SNCR or SCR are not cost effective (even with the skewed depreciable life assumptions) and would result in hundreds of millions of dollars in costs for PacifiCorp customers, and tens of millions in additional operating costs for PacifiCorp. Implementation of the Hunter RPEL would not result in any significant additional costs for customers and would result in minimal additional operating costs. Second, installation of SNCR or SCR would involve long-lead times for permitting, design, procurement, and installation before reductions and compliance can be achieved. The Hunter RPEL requires negligible time for compliance, and could be implemented as soon as the State's implementation plan is finalized and achieves federal approval. Third, SCR requires more energy to implement, and SNCR and SCR result in additional non-air environmental impacts over the Hunter RPEL. As documented, the Hunter RPEL has less potential consumption of natural resources, less GHG emissions, and less generation of CCR.

Fourth and finally, a requirement to install SCR or SNCR on Hunter Units 1, 2, and 3 would create uncertainty about the facility's remaining useful life. Many coal-fired power plants across the country have been forced to shut down due to the increased costs associated with SNCR and SCR. Implementing the Hunter RPEL would not be expected to either increase or decrease the remaining useful life of the facility. Based on this analysis, Utah should determine that the Hunter RPEL is the best option for achieving reasonable progress during the second planning period.

The Utah Division of Air Quality has indicated that photochemical grid modeling and analysis of visibility impacts will be performed by WRAP as part of the state's second planning period analysis. PacifiCorp anticipates that visibility modeling which incorporates the Hunter RPEL (and is compared to modeling of Hunter's current, permitted potential to emit) would assist the state in demonstrating reasonable progress at the CIAs impacted by emissions from the Hunter plant, supporting a conclusion that no additional installation of retrofit pollution control equipment is required at Hunter. However, if the State were to determine that the Hunter RPEL, as proposed, would not contribute to reasonable progress, PacifiCorp respectfully requests that the State propose an alternative RPEL ($NO_x$ +$SO_2$ limit) for Hunter (allowing time for PacifiCorp to analyze the feasibility of the alternative RPEL proposal) as opposed to pursuing a requirement to install SNCR or SCR retrofits. This reasonable progress analysis demonstrates that implementing a RPEL is a better option than installing SNCR or SCR retrofits under each of the four statutory factors.

### UDAQ Four-Factor Analysis Evaluation[153]

At this time, UDAQ is unable to proceed with its review and requests additional information as follows:

1. The source needs to resubmit the Four-factor analysis correcting the errors mentioned above.
2. Additional information must be provided regarding the infeasibility of SCR.
    a. This information can include additional details on economics as well as technical limitations.
3. Additional information must be provided regarding the infeasibility of SNCR.
    a. As with SCR, this information can include additional details on economics as well as technical limitations.
4. Supplemental details regarding the RPEL approach, including the selection of allowable limits should be provided. The methodology used for setting the allowable limits should be discussed in detail.
5. Any other pertinent information PacifiCorp feels is warranted should also be provided in order to assist UDAQ in the review process.

### Huntington Power Plant

#### *Facility Identification*

**Name:** Huntington Power Plant

**Address:** P.O. Box 680, Huntington, UT 84528

**Owner/Operator:** PacifiCorp

**UTM coordinates:** 493,130 Easting 4,358,840 Northing, UTM Zone 12

#### *Facility Process Summary*

The PacifiCorp Huntington Power Plant is a coal-fired steam electric generating facility consisting of two (2) boilers. Unit #1 is a 480 MW unit constructed in October 1973; Unit #2 is a 480 MW unit that commenced construction in April 1970. Bituminous and sub-bituminous coal is the primary fuel source for the dry bottom, tangentially-fired boilers. Fuel oil is used to start up the boilers from a cold start and for boiler flame stabilization. The Huntington Power Plant uses

[153] UDAQ's full four-factor analysis evaluation for the Hunter and Huntington power plants can be found in appendix C.3.B or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008926.pdf

low-$NO_x$ burners, separated overfire air system, $SO_2$ FGD scrubber system, and pulse jet fabric filters for both units.

### *Facility Criteria Air Pollutant Emissions Sources*

The source consists of the following emission units:

- Boiler Unit #1 – Nominal 480 MW gross capacity dry bottom, tangentially-fired utility boiler fired on subbituminous and bituminous coal using fuel oil during startup and flame stabilization. Equipped with a fabric filter baghouse, low $NO_x$ burners with overfire air system, and a $SO_2$ FGD scrubber. NSPS Subpart D.
- Boiler Unit #2 – Nominal 480 MW gross capacity dry bottom tangentially-fired utility boiler fired on subbituminous and bituminous coal using fuel oil during startup and flame stabilization. Equipped with a fabric filter baghouse, low-$NO_x$ burners with overfire air system, and a $SO_2$ FGD scrubber.

### *Facility Current Potential to Emit*

The current PTE values for the Huntington Power Plant, as established by the most recent NSR permit issued to the source (DAQE-AN102370028-18) are as follows:

**Table 54: Current Potential to Emit: Huntington**

| Pollutant | Potential to Emit (Tons/Year) |
|---|---|
| **$SO_2$** | 3,105 |
| **$NO_x$** | 7,971 |

## PacifiCorp Four Factor Analysis Conclusion

When balanced for Huntington Units 1 and 2, the four factors demonstrate that the RPEL is the best option for making reasonable progress during the second planning period. First, installation of SNCR or SCR are not cost effective (even with the skewed depreciable life assumptions) and would result in hundreds of millions of dollars in costs for PacifiCorp customers, and tens of millions in additional operating costs for PacifiCorp. Implementation of the Huntington RPEL would not result in any significant additional costs for customers and would result in minimal additional operating costs. Second, installation of SNCR or SCR would involve long-lead times for permitting, design, procurement, and installation before reductions and compliance can be achieved. The Huntington RPEL requires negligible time for compliance, and could be implemented as soon as the State's implementation plan is finalized and achieves federal approval. Third, SCR requires more energy to implement, and SNCR and SCR result in additional non-air environmental impacts over the Huntington RPEL. As documented, the Huntington RPEL has less potential consumption of natural resources, less GHG emissions, and less generation of CCR. Fourth and finally, a requirement to install SCR or SNCR on Huntington Units 1 and 2 would create uncertainty about the facility's remaining useful life. Many coal-fired power plants across the country have been forced to shut down due to the increased costs associated with SNCR and SCR. Implementing the Huntington RPEL would not be expected to either increase or decrease the remaining useful life of the facility. Based on this analysis, Utah should determine that the Huntington RPEL is the best option for achieving reasonable progress during the second planning period.

The Utah Division of Air Quality has indicated that photochemical grid modeling and analysis of visibility impacts will be performed by the Western Regional Air Partnership ("WRAP") as part of the state's second planning period analysis. PacifiCorp anticipates that visibility modeling which incorporates the Huntington RPEL (and is compared to modeling of Huntington's current, permitted potential to emit) would assist the state in demonstrating reasonable progress at the CIAs impacted by emissions from the Huntington plant, supporting a conclusion that no additional installation of retrofit pollution control equipment is required at Huntington. However, if the State were to determine that the Huntington RPEL, as proposed, would not contribute to reasonable progress, PacifiCorp respectfully requests that the State propose an alternative RPEL ($NO_x$ +$SO_2$ limit) for Huntington (allowing time for PacifiCorp to analyze the feasibility of the alternative RPEL proposal) as opposed to pursuing a requirement to install SNCR or SCR retrofits. This reasonable progress analysis demonstrates that implementing a RPEL is a better option than installing SNCR or SCR retrofits under each of the four statutory factors.

### UDAQ's Four Factor Analysis Conclusion

At this time, UDAQ is unable to proceed with its review and requests additional information as follows:

1. The source needs to resubmit the Four-factor analysis correcting the errors mentioned above.
2. Additional information must be provided regarding the infeasibility of SCR.
    a. This information can include additional details on economics as well as technical limitations.
3. Additional information must be provided regarding the infeasibility of SNCR.
    a. As with SCR, this information can include additional details on economics as well as technical limitations.
4. Supplemental details regarding the RPEL approach, including the selection of allowable limits should be provided. The methodology used for setting the allowable limits should be discussed in detail.
5. Any other pertinent information PacifiCorp feels is warranted should also be provided in order to assist UDAQ in the review process.

### PacifiCorp's Four-Factor Analysis Evaluation Response for Hunter and Huntington[154]

PacifiCorp proposed that UDAQ make the following adjustments to obtain a more representative cost effectiveness value for the installation of SNCR at the Hunter and Huntington plants:

• Utilize an SNCR NOx control efficiency of 20% for the Hunter and Huntington boilers, which is expected to be achievable based on unit size and firing configuration;

[154] PacifiCorp's full evaluation response for the Hunter and Huntington Power Plants can be found in appendix C.3.C or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2021-011726.pdf

• Utilize capital and O&M costs provided by S&L which are site specific and more accurate than the generalized costs provided by the CCM model;

• Utilize PacifiCorp's actual weighted average cost of capital of 7.303% as the interest rate in the model instead of the 3.25% rate originally used by UDAQ;

• Utilize the current and accurate net MW generation rates and net unit heat rate provided in Table 1[155] to calculate boiler heat input; and lastly;

• Utilize the actual 2015-2019 average annual capacity factors in Table 3[156] instead of the rates included in Table 2, which are inaccurate.

PacifiCorp believed that use of the S&L capital and O&M cost data when combined with an SNCR 20% control efficiency and 7.303% interest rate will provide an accurate representation of unit-specific cost effectiveness. This is demonstrated by UDAQ's and PacifiCorp's SCR cost effectiveness determinations which provide essentially equivalent dollar-per-ton values. The following tables provide a summary of PacifiCorp's revised SNCR cost effectiveness values for the Hunter and Huntington plants applying these adjustments. The estimates are based on a systemwide SNCR control efficiency of 20% and an interest rate of 7.303%. Note that the provided values do not incorporate minor changes in annualized capital and O&M costs which will occur when the April 9, 2020, S&L studies are updated to incorporate the current 7.303% interest rate and use of the 20% SNCR $NO_x$ control efficiency versus the studies' original use of a 7% interest rate and anticipated SNCR-controlled permit limit emission rates.

**Table 55: PacifiCorp Updated Hunter SNCR Cost Effectiveness**

| Cost Effectiveness | Hunter 1 | Hunter 2 | Hunter 3 |
|---|---|---|---|
| **Baseline**<br>**Heat Input (MMBtu/year)**<br>**NOx Emissions Rate (lb/MMBtu)**<br>**NOx Emissions (tons/year)** | 28,482,643<br>0.200<br>2,842 | 30,101,030<br>0.193<br>2,902 | 31,182,279<br>0.280<br>4,359 |
| **NOx Emissions w/ SNCR (20% efficiency)**<br>**Controlled NOx Emissions Rate (lb/MMBtu)**<br>**Controlled NOx Emissions (tons/year)** | 0.160<br>2,273 | 0.154<br>2,322 | 0.224<br>3,487 |
| **SNCR Annual NOx Removal (tons/year)** | **568** | **580** | **872** |
| **SNCR Cost Effectiveness (7.303% interest rate)**<br>**Annualized Capitalized Costs (20-yr life)**<br>**Total Annualized O&M Costs** | $1,546,424<br>$2,168,400 | $1,546,424<br>$2,208,800 | $1,546,424<br>$3,176,600 |
| **Total Annual Cost ($/year)** | **$3,714,824** | **$3,755,224** | **$4,723,024** |
| **Cost effectiveness ($/ton)** | **$6,536** | **$6,469** | **$5,417** |

155 Located on page 4 of appendix C in PacifiCorp's Four Factor Analysis Evaluation Response
156 Located on page 5 of appendix C in PacifiCorp's Four Factor Analysis Evaluation Response

**Table 56: PacifiCorp Updated Huntington SNCR Cost Effectiveness**

| Cost Effectiveness | Huntington 1 | Huntington 2 |
|---|---|---|
| **Baseline**<br>**Heat Input (MMBtu/year)**<br>**NOx Emissions Rate (lb/MMBtu)**<br>**NOx Emissions (tons/year)** | 28,063,728<br>0.212<br>2,968 | 27,150,145<br>0.208<br>2,825 |
| **NOx Emissions w/ SNCR (20% efficiency)**<br>**Controlled NOx Emissions Rate (lb/MMBtu)**<br>**Controlled NOx Emissions (tons/year)** | 0.169<br>2,374 | 0.166<br>2,260 |
| **SNCR Annual NOx Removal (tons/year)** | **594** | **565** |
| **SNCR Cost Effectiveness (7.303% interest rate)**<br>**Annualized Capitalized Costs (20-yr life)**<br>**Total Annualized O&M Costs** | $1,560,724<br>$2,256,200 | $1,560,724<br>$2,156,000 |
| **Total Annual Cost ($/year)** | **$3,816,924** | **$3,716,724** |
| **Cost effectiveness ($/ton)** | **$6,431** | **$6,579** |

In conclusion, PacifiCorp submitted that the above table's use of accurate annualized capital and O&M costs when combined with an appropriate SNCR $NO_x$ control efficiency of 20% provide reasonable SNCR cost effectiveness determinations for the Hunter and Huntington units. PacifiCorp has requested that S&L update their April 9, 2020, studies to utilize the current interest rate of 7.303% and the more conservative SNCR NOx control efficiency of 20% for all Hunter and Huntington units. These updates are currently being finalized and are not anticipated to materially impact the data provided here. PacifiCorp will notify UDAQ if any material changes occur.

## UDAQ Response Conclusion

### *Interest Rate*

Upon consulting with the Control Cost Manual and EPA staff,[157] UDAQ has found that it is preferable for a source's four-factor analysis to use a source-specific interest rate. After further discussion with the Utah Department of Public Utilities, UDAQ has confirmed that 7.34% is PacifiCorp's most recently approved interest rate in Utah.[158] However, as noted in the company's Four-Factor Analysis Evaluation Response for Hunter and Huntington above, "The actual weighted average cost of capital is calculated using the rates approved by the six state regulatory authorities where PacifiCorp conducts business and the percentage of energy delivered by PacifiCorp to each of those states." UDAQ accepts the resulting 7.303% interest rate as an appropriate source-specific rate across the company's service territory and notes that this rate is more conservative than the Utah Public Service Commission approved 7.34% with regard to control-cost assessment.

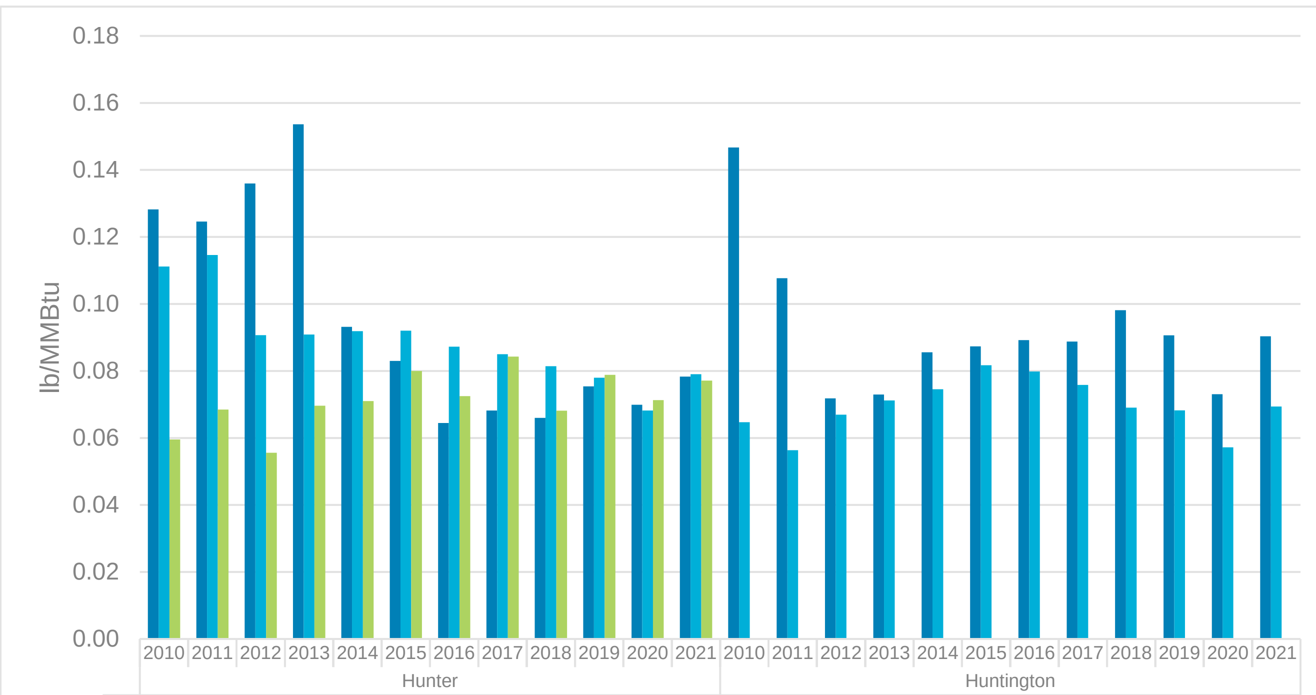
157 See email correspondence with Larry Sorrels (EPA) in Appendix D.2.H.
158 Source: https://pscdocs.utah.gov/electric/20docs/2003504/3168662003504ro12-30-2020.pdf

### *$SO_2$*

As noted above, all five units at both plants have FGD in place to control $SO_2$ emissions, and all units have $SO_2$ emission limits (generally 0.12 lb/MMBtu 30-day rolling average) that correspond to these controls as included in the approval orders for both plants. Since controls were installed/upgraded, all five units at both plants have operated at levels below the 0.12 lb/MMBtu $SO_2$ emission limits, ranging between approximately 0.6 and 0.10 lb/MMBtu as shown in Figure 53 below. UDAQ does not believe it is possible for the Hunter and Huntington units to scrub to the $SO_2$ emissions level of 0.03 lb/MMBtu specified in the original four-factor submittal RPEL proposal with the existing FGD controls. As PacifiCorp states in their comments[159]:

> *The Utah Units' $SO_2$ pollution control equipment (scrubbers) have design rates from 0.08 to 0.10 lb/MMBtu, and the costs indicated in the 2020 RP Analysis are to optimize these rates. The design parameters were necessary to ensure compliance with the Units' 0.12 lb/MMBtu emission limits. The existing Utah Units' scrubbers cannot control to lower $SO_2$ emission rates. To achieve a 0.03 lb/MMBtu $SO_2$ rate, new scrubbers would have to be constructed at an estimated capital cost of $180 million for each unit.*

UDAQ views the 0.03 lb/MMBtu rate as an artifact of the way the RPELs were calculated, and – as discussed in the $NO_x$ section below – UDAQ does not concur with this methodology or the RPELs that result from it.




| Hunter | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0.13 | 0.12 | 0.14 | 0.15 | 0.09 | 0.08 | 0.06 | 0.07 | 0.07 | 0.08 | 0.07 | 0.08 |
| 2 | 0.11 | 0.11 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.08 | 0.08 | 0.08 | 0.07 | 0.08 |
| 3 | 0.06 | 0.07 | 0.06 | 0.07 | 0.07 | 0.08 | 0.07 | 0.08 | 0.07 | 0.08 | 0.07 | 0.08 |

| Huntington | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0.15 | 0.11 | 0.07 | 0.07 | 0.09 | 0.09 | 0.09 | 0.09 | 0.10 | 0.09 | 0.07 | 0.09 |
| 2 | 0.06 | 0.06 | 0.07 | 0.07 | 0.07 | 0.08 | 0.08 | 0.08 | 0.07 | 0.07 | 0.06 | 0.07 |
| 3 | | | | | | | | | | | | |

**Figure 53: Hunter and Huntington $SO_2$ Rate**

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[159] See appendix C.3.D to view PacifiCorp's response to comments regarding $SO_2$ scrubbing

The 2019 Guidance states that it "may be reasonable for a state not to select an effectively controlled source. A source may already have effective controls in place as a result of a previous regional haze SIP or to meet another CAA requirement." The guidance goes on to provide "scenarios in which EPA believes it may be reasonable for a state not to select a particular source for further analysis," including the following example:

> *For the purpose of $SO_2$ control measures, an EGU that has add-on flue gas desulfurization (FGD) and that meets the applicable alternative $SO_2$ emission limit of the 2012 Mercury Air Toxics Standards (MATS) rule47 for power plants. The two limits in the rule (0.2 lb/MMBtu for coal-fired EGUs or 0.3 lb/MMBtu for EGUs fired with oil-derived solid fuel) are low enough that it is unlikely that an analysis of control measures for a source already equipped with a scrubber and meeting one of these limits would conclude that even more stringent control of $SO_2$ is necessary to make reasonable progress.*

As previously stated, all of PacifiCorp's Utah units have permitted $SO_2$ limits of 0.12 lb/MMBtu, which is well below the 0.2 lb/MMBtu limit provided in the 2019 Guidance.

For the foregoing reasons, UDAQ concludes that $SO_2$ emissions are well-controlled at all five Hunter and Huntington units. These units have operated at rates between 0.06 and 0.10 lb/MMBtu in recent years, and this range is consistent with the design parameters of the existing scrubbers. UDAQ also acknowledges that potential variations in the sulfur content of coal impact the ability of the existing controls to consistently scrub to lower levels in rejecting lower limits for these units.

Because Utah participated in the Section 309 compliance pathway for $SO_2$ in its round one SIP, the existing $SO_2$ emission limits were not included among the Section IX.H controls for regional haze. Since the continued operation of these controls is essential to making reasonable progress as demonstrated by the WRAP photochemical modeling and helps eliminate the possibility of backsliding on past emissions reductions, UDAQ is adding the existing $SO_2$ emission limits for all five units to SIP Section IX.H.23 to ensure federal enforceability in the regional haze context. However, UDAQ is eliminating the startup, shutdown, maintenance/planned outage or malfunction exemptions found in the approval order for Huntington Units 1 and 2 to ensure that the limits are applicable to these sources continuously to be consistent with CAA requirements.

### *$NO_x$*

### Four-factor Analyses

For $NO_x$ controls, specifically SNCR and SCR, UDAQ concurs with PacifiCorp's calculations supporting their four-factor analyses (as amended or further justified in the company's follow-up submittals). However, UDAQ does not concur with the company's four-factor analysis calculations for the proposed RPELs. First, the emissions reductions ascribed to the RPELs were based upon the application of SNCR controls – a technology the company claimed not to be cost-effective – to each plant's plantwide applicability limit (PAL). Furthermore, the control costs associated with the RPELs were estimated based solely on the cost of additional scrubbing of $SO_2$, while the estimated emissions reductions included both $NO_x$ and $SO_2$, and the RPEL cost-effectiveness analysis used an unrealistic baseline emissions scenario (i.e., 100% of the PAL). As a result, the RPEL cost-effectiveness estimates cannot be meaningfully compared to those for physical controls. For these reasons, UDAQ rejects the proposed RPELs.

Regarding SNCR and SCR cost-effectiveness, the company's analysis was based upon applying recent (2015-2019 average) heat inputs (in MMBtu/year) and emissions rates (in lb/MMBtu) to calculate emissions (MMBtu/year X lb/MMBtu = lb/year) compared to using the same heat inputs at the control emissions rates for SNCR and SCR. The delta between the recent actual emissions versus emissions with new controls represented the emissions reductions associated with each control. The total annual cost of each control was then divided by tons reduced per year to establish a cost-effectiveness metric of dollars per ton ($/ton) of emissions reduced.

PacifiCorp's analysis yielded cost-effectiveness values ranging from $5,417/ton to $6,579/ton for SNCR and $4,401/ton to $6,533/ton for SCR, as summarized in Table 57 below.

**Table 57: Cost-effectiveness of SNCR and SCR and Hunter and Huntington Power Plants**

| Unit | SNCR $/ton | SCR $/ton |
|---|---|---|
| **Hunter 1** | $6,536 | $6,533 |
| **Hunter 2** | $6,469 | $6,488 |
| **Hunter 3** | $5,417 | $4,401 |
| **Huntington 1** | $6,431 | $5,979 |
| **Huntington 2** | $6,579 | $6,294 |

As noted above, PacifiCorp's cost-effectiveness estimates were calculated using a baseline of recent actual emission levels. However, as EPA notes in its 2019 Guidance:

> *A state may choose a different emission control scenario as the analytical baseline scenario. Generally, the estimate of a source's 2028 emissions is based at least in part on information on the source's operation and emissions during a representative historical period. However, there may be circumstances under which it is reasonable to project that 2028 operations will differ significantly from historical emissions. Enforceable requirements are one reasonable basis for projecting a change in operating parameters and thus emissions; energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and a verifiable basis for quantifying any change in future emissions due to operational changes may be another.*[160]

[160] *See* Guidance on Regional Haze Implementation Plans for the Second Implementation Period (Aug. 20, 2019) (2019 Regional Haze Guidance) at 29, available at https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

In its July 2021 clarifications memo, EPA adds that there may be instances in which state projections of changes in future utilization are unenforceable, leading to the need to establish utilization or production limits to ensure reasonable progress at existing emission rates:

> *. . . in some cases, states may have projected significantly lower total emissions due to unenforceable utilization or production assumptions and those projections are dispositive of the four-factor analysis. For example, a state that rejected new controls solely based on cost effectiveness values that were higher due to low utilization assumptions. In this circumstance, an emission limit that requires compliance with only an emission rate may not be able to reasonably ensure that the source's future emissions will be consistent with the assumptions relied upon for the reasonable progress determination. EPA anticipates these circumstances will be rare. One option a state may consider in this case is to incorporate a utilization or production limit corresponding to the assumption in the four-factor analysis into the SIP. Although not required, this approach is one way for states to address circumstances in which a specific emission rate does not, by itself, represent the reasonable progress determination.*[161]

Furthermore, EPA recognized that in instances in which control costs are dominated by a relatively high proportion of fixed capital costs, actual cost-effectiveness will be highly dependent on the future utilization levels of the facility. In instances where utilization is lower than initially projected, controls will be less cost-effective, while higher future utilization will result in improved cost-effectiveness, since there will be more tons reduced by a given control but for the same fixed costs when utilization increases. In such instances, EPA notes that a mass-based emission limit may be appropriate to demonstrate reasonable progress:

> *. . . if the annualized cost for a measure is dominated by fixed capital costs, the state may have determined that the measure is necessary to make reasonable progress if the operating level is high (making cost/ton and cost/Mm-1 relatively low) but not if the operating level is low (making cost/ton and cost/Mm-1 relatively high). In this case, a mass-based emission limit may be reasonable because it could relieve the source of the requirement to install the control if it manages its operating level strategically.*
>
> *. . . in addition to considering technology-based emission control measures, a state may consider restrictions on hours of operation, fuel input, or product output. Such restrictions could be implemented directly or by a time-based limit on mass emissions.*[162]

To further assess the appropriateness of installing physical controls at these facilities, UDAQ developed a plant utilization sensitivity analysis for installing SCR at all five units at both plants. In this analysis, UDAQ assumed a baseline emission scenario using historical utilization levels

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[161] *See* Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021) (2021 Regional Haze Clarifications) at 12, available at https://www.epa.gov/system/files/documents/2021-07/clarifications-regarding-regional-haze-state-implementation-plans-for-the-second-implementation-period.pdf.

[162] *See* 2019 Regional Haze Guidance at 45, available at https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

(based on 2015-2019 actual emissions), and then varied potential future utilization relative to that baseline to create four alternative emissions scenarios:

- 125% of baseline utilization
- 75% of baseline utilization
- 50% of baseline utilization

UDAQ also scaled O&M costs by the same factors in an attempt to account for changes in variable costs but kept fixed capital costs constant. Figure 54 below summarizes this sensitivity analysis.

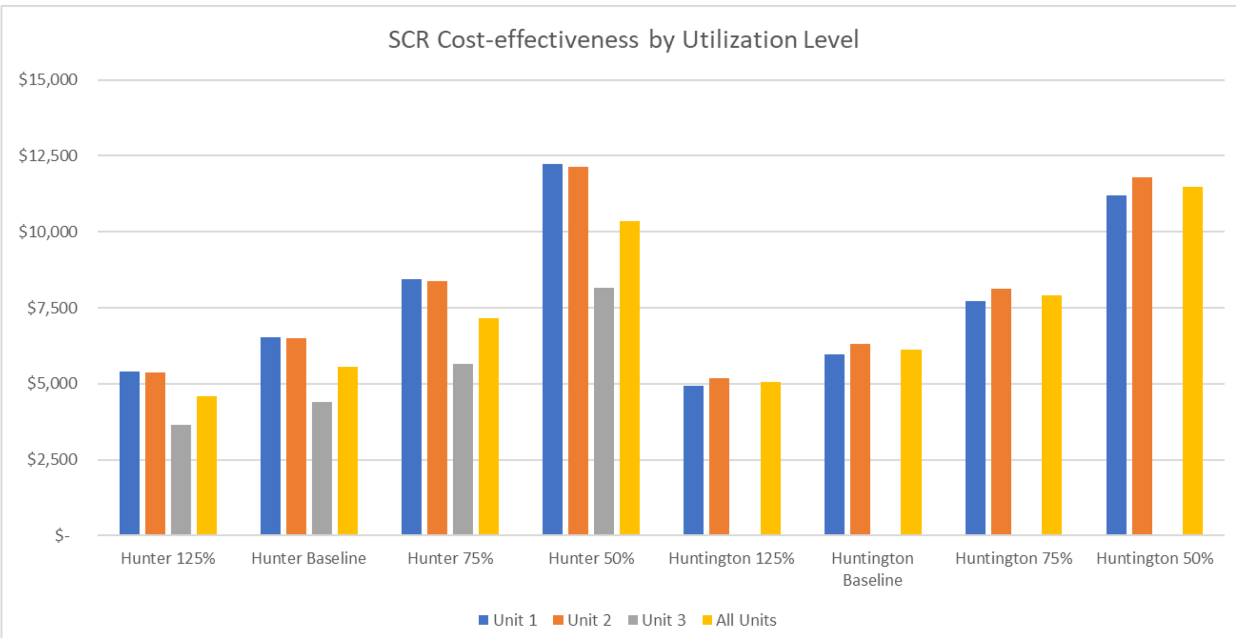


**Figure 54: SCR Cost-effectiveness by utilization level at Hunter and Huntington Power Plants**

As can be seen, higher unit and plant utilization yields lower $/ton estimates (more cost-effective), while lower utilization yields higher $/ton estimates (less cost-effective).

This sensitivity analysis raises the question of how the units at both plants are likely to be utilized throughout the second regional haze planning period. In its attempt to address this question, WRAP relied on the Center for the New Energy Economy (CNEE) at Colorado State University to project 2028 emissions for coal- and gas-fired EGUs throughout the West for use in modeling to support WRAP states in their SIP development.[163] For coal-fired units, these estimates were based on 2016-2018 utilization (i.e., gross load), heat rates, and emissions rates, but were adjusted for certain known or "on-the-books" (OTB) changes in emissions

[163] *See* http://www.wrapair2.org/pdf/Final%20EGU%20Emissions%20Analysis%20Report.pdf.

controls, fuel switching, and unit closures. For example, in Utah, CNEE accounted for the previously announced closure of Intermountain Power Plant (IPP) Units 1 and 2 in 2025 by reducing emissions accordingly.

Using this OTB methodology, WRAP projected 2028 $NO_x$ emissions of 10,001 tons/year for Hunter and 6,091 tons/year for Huntington.[164] These emissions estimates are similar though not identical to PacifiCorp's recent actual emissions used in its four-factor analyses, with the differences stemming from the use of different averaging periods and methodologies.

### Anticipated Changes in Utilization

The electricity generation industry is experiencing significant change with the introduction of cheap natural gas and renewable sources such as wind and solar altering previous operating practices. Other factors affecting change include increased grid coordination (e.g., the Energy Imbalance Market (EIM), the potential establishment of a new Western regional transmission organization (RTO), new transmission capacity, etc.), dramatic improvements in lighting and other equipment efficiency, uncertainty regarding the future of climate regulation, and increased customer preference for cleaner energy resources. Low-cost renewable electricity in particular has forced operators to switch "baseload" EGUs, such as Utah's coal-fired plants, to "follow" load between periods when renewables are available and unavailable. This trend is reflected in the utilization[165] of the Hunter and Huntington power plants as shown in Figure 55 and Figure 56 below.

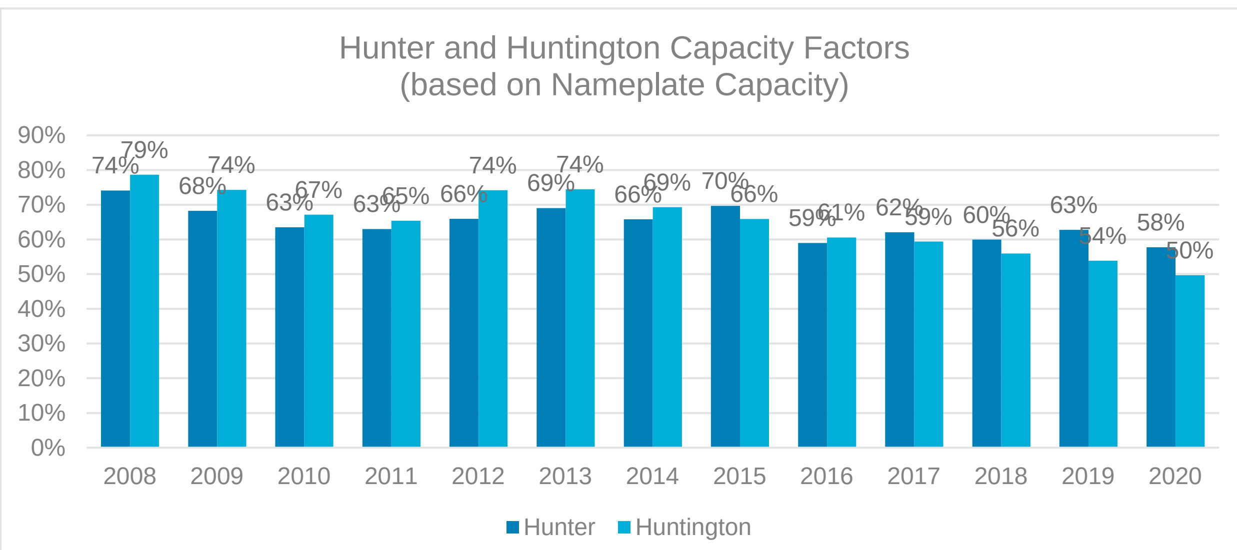


**Figure 55: Hunter and Huntington Capacity Factors**

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[164] CNEE originally estimated 9,992 tons/year for Hunter and 6,083 for Huntington, but the final WRAP projections included additional non-EGU sources at each plant to arrive at the values above.
[165] From Utah Geological Survey Energy *Utah Energy and Mineral Statistics,* Table 5.1 (https://geology.utah.gov/docs/statistics/electricity5.0/pdf/T5.1.pdf) and Table 5.15a (https://geology.utah.gov/docs/statistics/electricity5.0/pdf/T5.15.pdf).

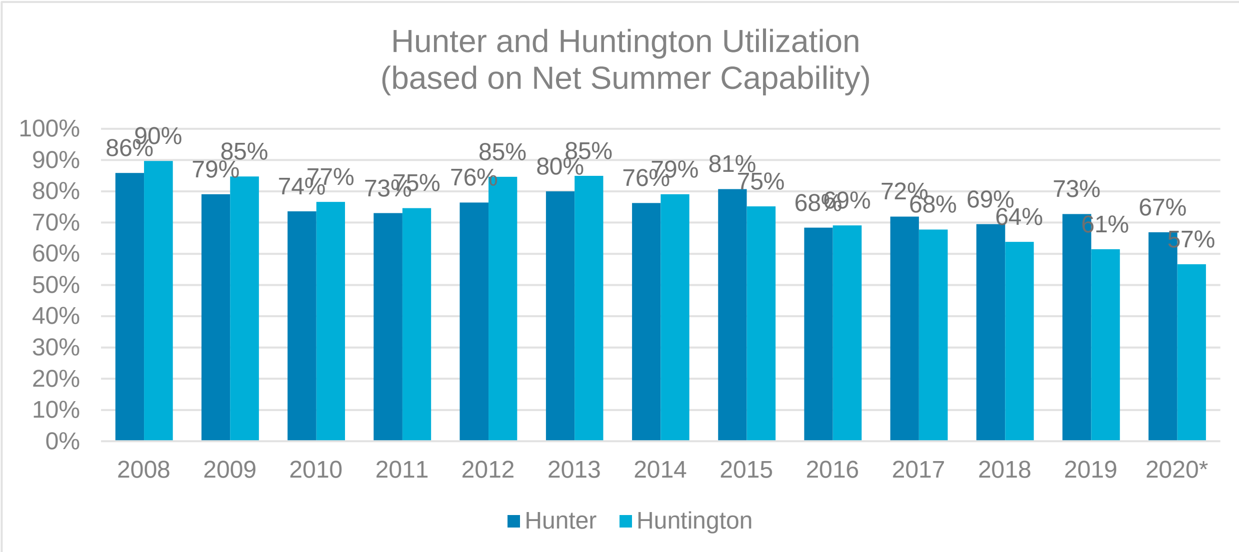


Figure 56: Hunter and Huntington Utilization (based on Net Summer Capability)

These changes in utilization, coupled with existing emission reduction controls, have led to decreases in $NO_x$ emissions from Utah's coal-fueled EGUs, as shown in Figure 57.

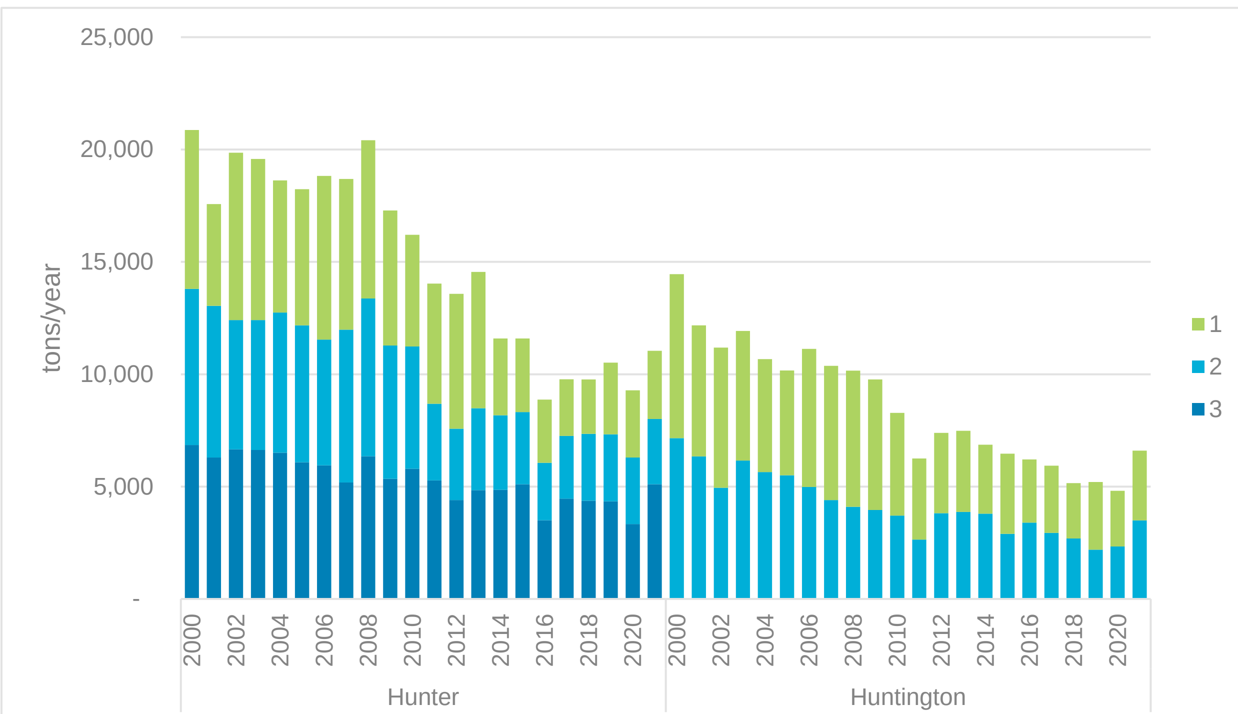


Figure 57: Hunter and Huntington $NO_x$ Emissions by Unit

While there is always uncertainty regarding the future utilization of a facility, PacifiCorp's 2021 Integrated Resource Plan (IRP)[166] helps shed light on the likely future operation of Hunter and Huntington Power Plants. Indeed, it provides the company's most recent and robust assessment of the projected future resource utilization.

As shown in Figure 58 (2021 IRP Figures 1.4-1.7), the 2021 IRP preferred portfolio includes approximately 6,000 MW of new solar capacity, over 3,500 MW of new wind capacity, over 6,000 MW of new storage capacity, and over 2,500 MW of new non-emitting resources (e.g., hydrogen, nuclear, etc.) through 2040. Over the same period, it anticipates over 4,000 MW of coal retirements or conversion of coal units to natural gas, as shown in Figure 59 (2021 IRP Figure 1.12) below.

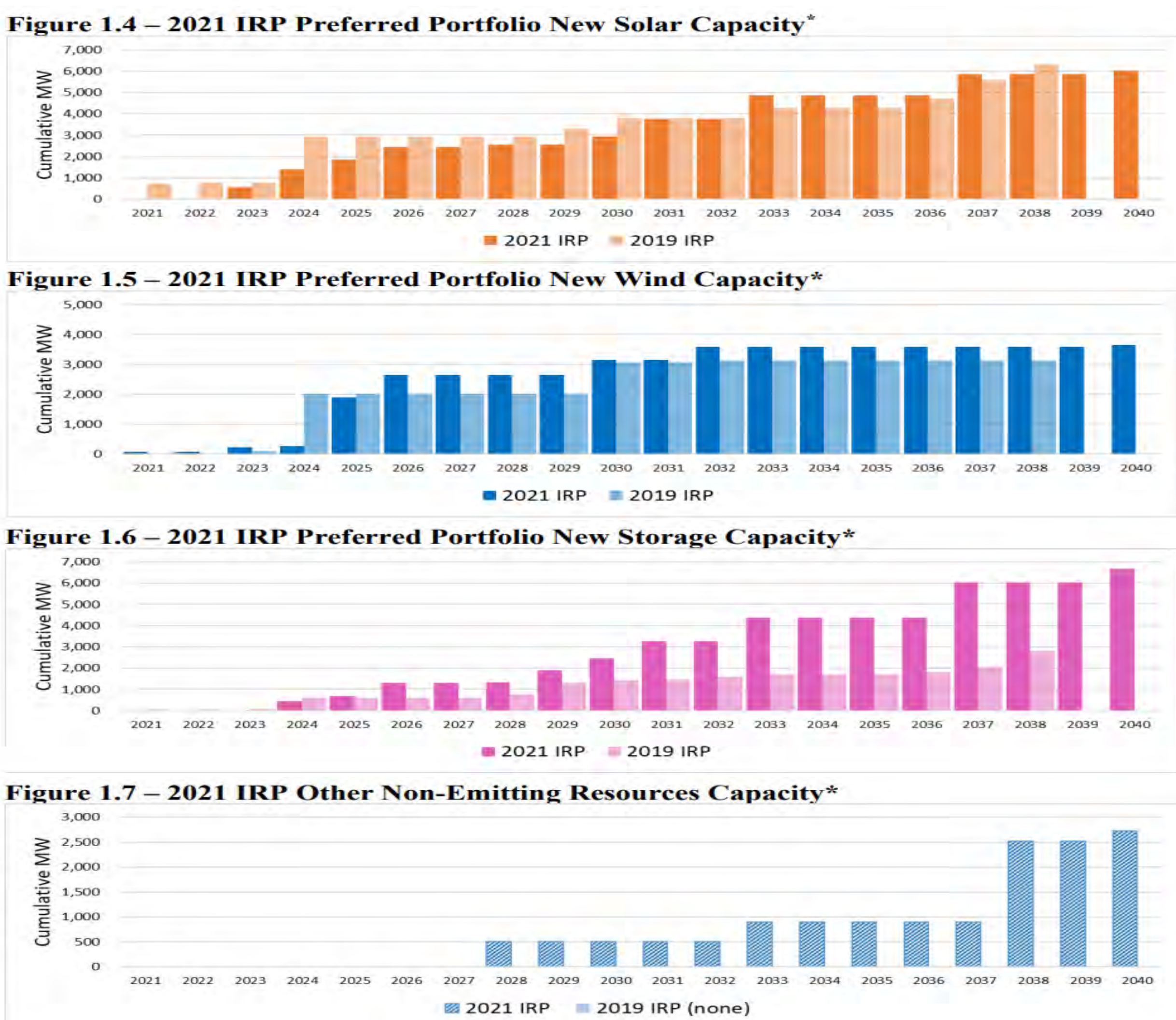


**Figure 58: PacifiCorp 2021 IRP Cumulative Resource Additions**

[166] https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf

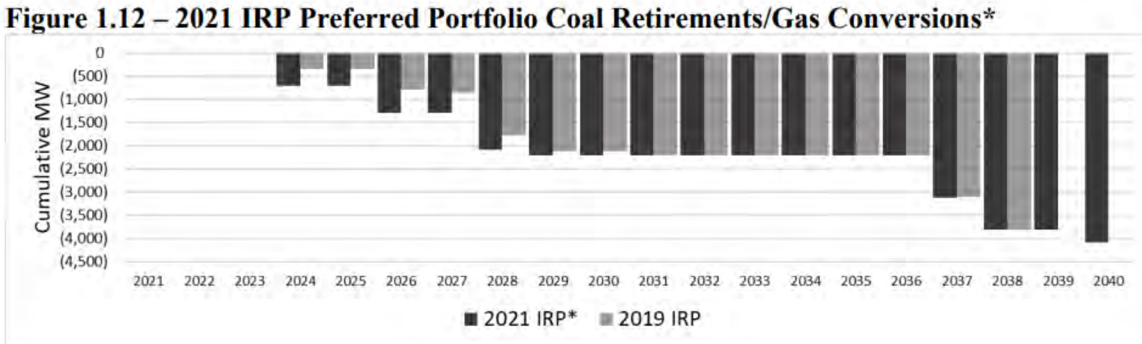


**Figure 59: PacifiCorp 2021 IRP Cumulative Coal Retirements/Gas Conversions**

Figure 60 compares PacifiCorp's remaining coal capacity (MW) to both the coal share of total energy (% of total MWh) and total capacity (% of total MW) over the 2021 IRP planning window. In 2021, coal-fired units are responsible for 49% of total energy, but only 31% of total capacity. Over time the coal energy share declines at a steeper rate than the coal capacity share as renewables and non-emitting resources enter PacifiCorp's system, with the metrics crossing each other in 2031 at 11%. By the end of the IRP planning window in 2040 when the Hunter

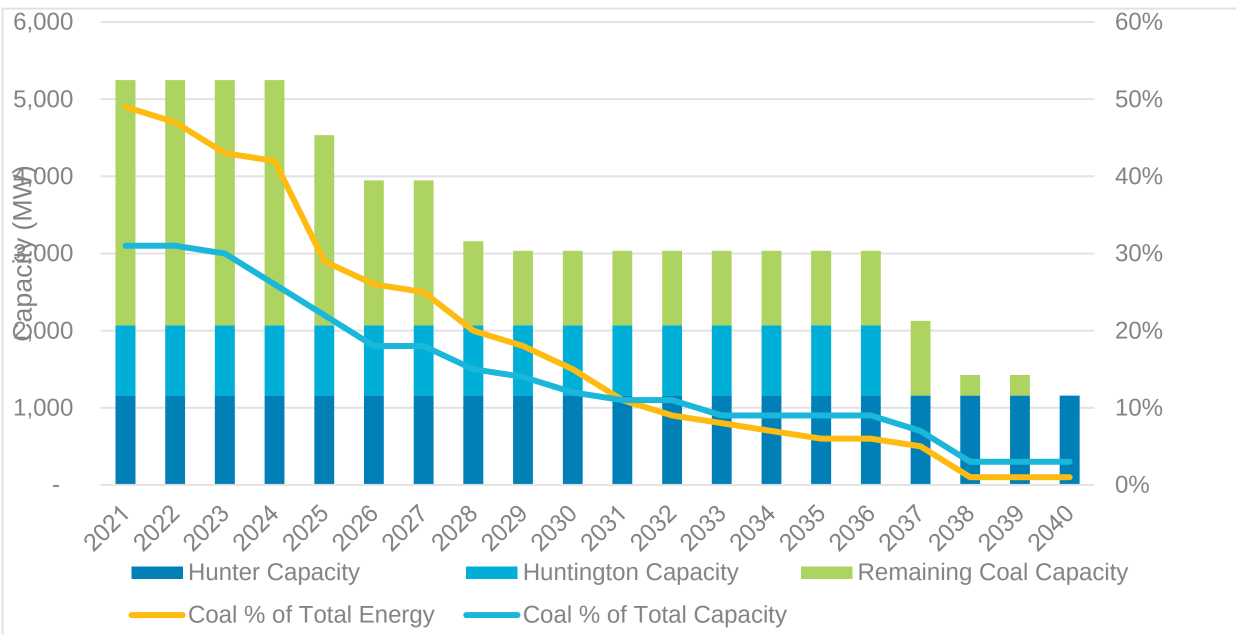


**Figure 60: PacifiCorp 2021 IRP Coal Capacity (MW) vs. Coal % of Total Energy and % of Total Capacity**

power plant is the only coal-fired unit remaining in PacifiCorp's system, the coal capacity share is only 3% and the coal energy share is only 1% of the total system. Importantly, it is energy generation, not capacity, that correlates with emissions levels for a given emission rate. Of particular interest is the period from 2029 through 2036 during which both in- and out-of-state coal capacity remains flat. Yet over the same period, the coal-fired share of total energy declines from 18% to just 6%. This chart helps illustrate that PacifiCorp's coal-fired units switch from being energy resource to capacity resources over time, as they transition to their new role of supporting zero-emission resources.

While the 2021 IRP projected plant-level and unit-level capacity factors for Hunter and Huntington are confidential and, therefore, not available to include in the SIP, the redacted comments of interveners before the Utah Public Service Commission (PSC) who have been granted access to these projections provide an additional degree of confidence that the utilization of these plants is likely to change. For example, excerpts from the redacted comments by Western Resource Advocates (WRA)[167] shed light on the projected future utilization of PacifiCorp's coal-fired plants:

> *With the planned new resources in PacifiCorp's Preferred Portfolio, the transformation of PacifiCorp's coal fleet is projected to accelerate significantly over the coming decade from the provision of round-the-clock energy to seasonal dispatch with limited annual hours of operation. (page 10)*
>
> *Confidential Exhibit 4 is comprised of six pages, and displays monthly capacity factors for PacifiCorp's long-lived coal plants: Jim Bridger, Wyodak, Hunter, and Huntington. A review of the exhibit makes clear that once take-or-pay contracts expire, the units at Hunter and Huntington operate only seasonally… (pages 15-16)*

### Affordability

In addition to concerns that reduced future plant utilization will erode the cost-effectiveness of physical controls at Hunter and Huntington, it is important to note that PacifiCorp believes that these controls are unaffordable under the current constraints the company faces as a regulated public utility and in the face of post-pandemic supply chain issues and rising inflation. As PacifiCorp states[168]:

> *…the dollar-per-ton cost-effectiveness value for SCR does not represent all of the considerations necessary to determine whether SCR is a reasonable control that should be required at the Utah Units. As the Affordability Analysis shows, a demonstration that SCR is the least-cost, least-risk option for PacifiCorp's customers faces likely insurmountable obstacles. In addition, over the past decade, the requirement to install SCR has led to early retirement or refueling of numerous other coal-fueled generating plants in the region and across the country. External factors including increased regulatory scrutiny of investments in coal-fueled resources, state laws limiting the market for coal-fueled power and increasing competition from renewable and storage resources add to the pressures making SCR unaffordable, especially for a regulated utility. The decision to retire a coal-fueled unit rather than install SCR is not merely "a voluntary business decision[ ] that the benefits of continuing to generate electricity at the affected units were outweighed" by other factors. Instead, an early retirement decision is a*

[167] See https://pscdocs.utah.gov/electric/21docs/2103509/322689RdctdWRACmnts3-4-2022.pdf.

[168] PacifiCorp's public comment period submission can be found at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2022-007454.pdf

> *regulatory necessity as continued plant operation becomes unfeasible because "the costs of [SCR] . . . [are] so onerous that the source[ ] simply could not afford them" making "the sources' decisions to cease operations . . . in essence involuntary."*

In the Wyodak Facility SCR Affordability Analysis (August 25, 2020) supplied with their public comments on the proposed SIP, PacifiCorp identifies several coal units across the country that have either been retired or repowered rather than installing SCR to meet regulatory requirements, including:

- Cholla Plant, Arizona
- Craig Unit 1, Colorado
- San Juan Generating Station (retirement of two of four units), New Mexico
- Progress Energy and Duke have shut down 22 units subject to BART instead of installing controls, North Carolina
- Boardman Plant elected to cease burning coal instead of installing SCR, Oregon
- Dave Johnson Plan will retire Unit 3 by 2027 rather than installing SCR, Wyoming

More recently, PacifiCorp has announced that it will convert Jim Bridger 1 and 2 to natural gas rather than installing SCR.

Affordability concerns have led some 2021 IRP commenters to opine that SCR might be considered an imprudent investment relative to unit closures in the economic regulatory arena, including parties who in their round two proposed SIP comments to UDAQ claim SCR to be a cost-effective control. For example, in redacted comments before the Utah PSC, the Sierra Club states, "SCR requirements will at some point be required under the Clean Air Act. At that time, the early retirement case becomes roughly equivalent from an economic standpoint to the current preferred case, depending on the price-policy scenario."[169] Here it is important to note that EPA has historically held that it does not have the authority to force the retirement of a unit under the regional haze rule: "Generally, EPA does not interpret the regional haze rule to provide us with authority to make a BART determination that requires the shutdown of a source."[170]

Additional affordability concerns were raised in public comments from Deseret Power, which owns an undivided 25.108% of Hunter Unit 2. Deseret states[171]:

> *For over 20 years, Deseret has operated as a financially distressed company under the terms of a troubled debt forbearance (the "Debt Forbearance") with its principal creditor. Under the terms of the Debt Forbearance, Deseret essentially pledged all of its available net cashflow toward partial payment of long-term indebtedness which Deseret has been unable to pay in full. A key provision of the Debt Forbearance is that Deseret cannot*

[169] See https://pscdocs.utah.gov/electric/21docs/2103509/322718RdctdSierraClubCmnts3-4-2022.pdf

[170] 79 FR 5032, 5045 (Jan. 30, 2014).

[171] The public comments submitted by Deseret Power can be found at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2022-007475.pdf

*incur any added indebtedness without prior express consent of the existing creditor. The creditor understandably does not allow Deseret to take on new debt without first scrutinizing whether and to what extent the new debt would result in increased net cashflows to help repay the outstanding arrearage on existing debt held by the creditor.*

*In its present condition, Deseret is not certain it would be able to raise capital necessary to finance its portion of costs to install any additional and costly post-combustion controls at Hunter II. It would be left to the decision of Deseret's creditor to refuse to allow Deseret to solicit or draw on any new source of financing for such controls.*

These affordability concerns and the potential for forced unit closures weigh in favor of considering reasonable alternatives to requiring the installation of physical controls.

### Balancing the Four Statutory Factors

Given the likely reduction in utilization of Hunter and Huntington in future years and the erosion of the cost-effectiveness of physical controls that would accompany such a reduction, UDAQ is establishing enforceable mass-based limits on future emissions from these facilities to reduce uncertainty and ensure that the plants operate at or below emissions levels at which physical controls are not cost-effective. To identify these limits, UDAQ calculated the utilization and resulting emissions levels that would result in a $5,750/ton level for SNCR and SCR for all units at both plants, as shown in Table 58 and Table 59 below. UDAQ then used the more stringent of the two scenarios (based on SCR) to set limits at which both SNCR and SCR are not cost-effective.

**Table 58: 2028 Mass-based $NO_x$ Limit - SNCR Cost-effectiveness**

| Item (unit) | Hunter 1 | Hunter 2 | Hunter 3 | Huntington 1 | Huntington 2 | Total |
|---|---|---|---|---|---|---|
| 2028 Utilization (% of 2015-2019 Average) | 144.6% | 134.2% | 85.6% | 133.0% | 138.3% | |
| 2015-2019 Average Heat Input (MMBTU) | 28,482,643 | 30,101,030 | 31,182,279 | 28,063,728 | 27,150,145 | |
| 2028 Limit Heat Input (MMBTU) | 41,183,800 | 40,400,840 | 26,683,091 | 37,329,312 | 37,542,964 | |
| Existing Control Rate (lb/MMBTU) | 0.200 | 0.193 | 0.280 | 0.212 | 0.208 | |
| Proposed Control Rate (lb/MMBTU) | 0.160 | 0.154 | 0.224 | 0.169 | 0.166 | |
| Emissions w/ Existing Controls (tons/year) | 4,109 | 3,895 | 3,730 | 3,948 | 3,906 | |
| Emissions w/ Control (tons/year) | 3,295 | 3,111 | 2,989 | 3,154 | 3,116 | |
| Emissions Reduction (tons/year) | 814 | 785 | 742 | 793 | 790 | |
| Annualized Capital Costs | $1,546,424 | $1,546,424 | $1,546,424 | $ 1,560,724 | $ 1,560,724 | |
| Total Annual O&M Costs | $ 3,135,346 | $ 2,964,595 | $ 2,718,259 | $ 3,001,112 | $ 2,981,296 | |
| Total Annual Cost | $4,681,770 | $4,511,019 | $4,264,683 | $4,561,836 | $4,542,020 | |
| **$/ton** | **$ 5,750** | **$ 5,750** | **$ 5,750** | **$ 5,750** | **$ 5,750** | |
| **2028 Emission Limit (tons)** | | **Hunter Plantwide:** | **11,735** | **Huntington Plantwide:** | **7,854** | **19,588** |

**Table 59: 2028 Mass-based $NO_x$ Limit – SCR Cost-effectiveness**

| Item (unit) | Hunter 1 | Hunter 2 | Hunter 3 | Huntington 1 | Huntington 2 | Total |
|---|---|---|---|---|---|---|

| | | | | | | |
|---|---|---|---|---|---|---|
| **2028 Utilization (% of 2015-2019 Average)** | 115.9% | 115.0% | 73.6% | 104.6% | 111.0% | |
| **2015-2019 Average Heat Input (MMBTU)** | 28,482,643 | 30,101,030 | 31,182,279 | 28,063,728 | 27,150,145 | |
| **2028 Limit Heat Input (MMBTU)** | 33,016,004 | 34,628,669 | 22,963,607 | 29,357,153 | 30,136,124 | |
| **Existing Control Rate (lb/MMBTU)** | 0.1995 | 0.1928 | 0.2796 | 0.2115 | 0.2081 | |
| **Proposed Control Rate (lb/MMBTU)** | 0.0500 | 0.0500 | 0.0500 | 0.0500 | 0.0500 | |
| **Emissions w/ Existing Controls (tons/year)** | 3,294 | 3,339 | 3,210 | 3,105 | 3,135 | |
| **Emissions w/ Control (tons/year)** | 825 | 866 | 574 | 734 | 753 | |
| **Emissions Reduction (tons/year)** | 2,469 | 2,473 | 2,636 | 2,371 | 2,382 | |
| **Annualized Capital Costs** | $12,141,691 | $12,141,691 | $13,490,472 | $11,787,158 | $11,787,158 | |
| **Total Annual O&M Costs** | $ 2,052,876 | $ 2,078,799 | $ 1,667,280 | $ 1,844,255 | $ 1,909,166 | |
| **Total Annual Cost** | $14,194,567 | $14,220,490 | $15,157,752 | $13,631,413 | $13,696,324 | |
| **$/ton** | **$ 5,750** | **$ 5,750** | **$ 5,750** | **$ 5,750** | **$ 5,750** | |
| **2028 Emission Limit (tons)** | | **Hunter Plantwide:** | **9,843** | **Huntington Plantwide:** | **6,240** | **16,083** |

While UDAQ is not establishing a cost-effectiveness threshold per se, the agency believes that a level of $5,750/ton for physical controls, when balanced against the remaining three statutory factors, is not cost-effective. As a result, UDAQ concludes that physical controls are not necessary to demonstrate reasonable progress. What follows is a brief summary of the remaining factors, beyond cost-effectiveness, that help in leading UDAQ to this conclusion:

*Time Necessary for Compliance*
Due to the delayed nature of the round 2 regional haze SIPs, there is only a short window available for control installation of approximately five years, depending the final approval date. This is likely not enough time for the potential installation of SNCR or SCR at up to five units. In contrast, enforceable annual mass-based limits can begin to be implemented immediately upon approval of the round 2 regional haze SIP.

*Energy and non-air quality environmental impacts*
According to PacifiCorp's four-factor analysis, the installation of SCR on Hunter and Huntington would result in a large parasitic load of 12.5 MW at Hunter and 8.6 MW at Huntington, which equates to 115,687 and 79,743 more tons of $CO_2$, respectively. In addition, the installation of SNCR or SCR could potentially lead to increases in water use, coal consumption, coal combustion residuals, and other consumables and waste products associated with coal combustion (e.g., water treatment chemicals, anhydrous ammonia reagent, urea reagent, mercury control system reagent, and diesel fuel), since physical controls would enable the plants to operate more under the existing PALs relative to mass-based limits. In addition, these plants are currently projected to assist in the transition towards intermittent renewable resources. Should the cost of physical controls lead to early plant closures, alternative resources will be required to provide such support.

*Remaining Useful Life*

The currently anticipated economic life of Huntington is approximately 14 years (16 years fewer than EPA's 30-year control life of SCR). The economic life of Hunter is approximately 20 years (10 years fewer than EPA's 30-year control life of SCR). While the respective closure years of 2036 and 2042 are not currently enforceable, closure of these facilities at or before the end of their economic life would further erode the cost-effectiveness of physical controls by shortening the amortization period for control costs. Ongoing scrutiny of expenditures associated with coal-fired power plants by state public service commissions and the establishment of clean energy requirements in California, Oregon, and Washington increase the risk that these facilities may face early closure.

### Mass-based Limits and Flexible Compliance

While Table 59 above shows the emissions levels that would result from constraining cost-effectiveness at $5,750/ton for SCR at the unit level, UDAQ is summing these estimated unit-level emissions at each plant to develop plantwide emission limits to provide compliance flexibility. In particular, UDAQ is establishing a 2028 plantwide $NO_x$ limit of 9,843 tons per year for Hunter and a 2028 plantwide $NO_x$ limit of 6,240 tons per year for Huntington. In addition, UDAQ is establishing an initial plantwide $NO_x$ limit for Hunter of 11,041 tons per year and an initial plantwide $NO_x$ limit for Huntington of 6,604 tons per year, both effective upon SIP approval. These initial levels are based on each plant's highest emission value over the past five years (2017-2021). Finally, UDAQ is establishing an interim 2025 plantwide limit of 10,442 tons per year for Hunter and an interim 2025 plantwide limit of 6,422 tons per year for Huntington, to create a compliance glidepath to aid in the transition from recent actual utilization levels to the final 2028 limits. The interim limits for each plant were calculated as the average of (i.e., the midpoint between) the initial and 2028 plantwide limits for each plant. The limits are compared to recent actual emissions and the outgoing PAL in Table 60 and Table 61 below. UDAQ notes that flexible compliance mechanisms such as plantwide limits and glidepaths are commonly used in environmental regulation (e.g., plantwide applicability limits; Tier 3 fuel averaging, banking, and trading; the Tier 3 vehicle fleet averaging glidepath from 2017-2025; cap and trade programs, etc.) and are appropriate in this application.

**Table 60: Hunter Actuals and Limits**

| Year or Limit | Unit 1 | Unit 2 | Unit 3 | Total |
|---|---|---|---|---|
| **2015** | 3,274 | 3,210 | 5,107 | 11,591 |
| **2016** | 2,806 | 2,556 | 3,506 | 8,869 |
| **2017** | 2,518 | 2,789 | 4,466 | 9,773 |
| **2018** | 2,422 | 2,975 | 4,372 | 9,770 |
| **2019** | 3,188 | 2,981 | 4,344 | 10,514 |
| **2020** | 2,996 | 2,955 | 3,336 | 9,287 |
| **2021** | 3,032 | 2,905 | 5,103 | 11,041 |
| **2022 Initial Limit** | | | | **11,041** |
| **2025 Interim Limit** | | | | **10,442** |
| **2028 Final Limit** | | | | **9,843** |
| **Outgoing PAL** | | | | **15,095** |

**Table 61: Huntington Actuals and Limits**

| Year or Limit | Unit 1 | Unit 2 | | Total |
|---|---|---|---|---|
| **2015** | 3,563 | 2,899 | | 6,462 |
| **2016** | 2,810 | 3,400 | | 6,210 |
| **2017** | 2,990 | 2,940 | | 5,931 |
| **2018** | 2,462 | 2,692 | | 5,153 |
| **2019** | 3,013 | 2,193 | | 5,206 |
| **2020** | 2,476 | 2,337 | | 4,814 |
| **2021** | 3,111 | 3,493 | | 6,604 |
| **2022 Initial Limit** | | | | **6,604** |
| **2025 Interim Limit** | | | | **6,422** |
| **2028 Final Limit** | | | | **6,240** |
| **Outgoing PAL** | | | | **7,971** |

As discussed previously, UDAQ has historically used plantwide limits (i.e., PALs) to limit emissions from Hunter and Huntington power plants while providing PacifiCorp operational flexibility. According to EPA's 2020 "Guidance on Plantwide Applicability Limitation Provisions Under the New Source Review Regulations":[172]

> *A PAL is an optional flexible permitting mechanism available to major stationary sources that involves the establishment of a plantwide emissions limit, in tons per year, for a regulated NSR pollutant. A PAL represents a simplified NSR applicability approach that provides a source with the ability to manage physical and operational changes, and the impacts of those changes on facility-wide emissions, without triggering major NSR or the need to conduct project-by-project major NSR applicability analyses. The added flexibility of a PAL allows a source to respond rapidly to market changes with reduced permitting burden and greater regulatory certainty.*

While sources may favor such regulatory flexibility, the ability for emissions to vary from unit to unit under a plantwide limit raises the question of how such variations might impact visibility at CIAs. On this point, UDAQ notes that the distance between the outermost stacks at Hunter is approximately 596 feet, and the distance between the stacks for units 1 and 2 at Huntington is 265 feet. In contrast, the distance between each plant and the CANYI IMPROVE monitor for Arches and Canyonlands is 431,589 feet (Hunter) and 490,433 feet (Huntington). While distances from these facilities to each IMPROVE site vary, the CANY1 example illustrates that differences in visibility impairment that stem from the proximity effects associated with plantwide limits are likely to be negligible. Visibility impacts related to using plantwide limits are more likely to stem from other factors that might favor or constrain the utilization of one unit relative to other units than from differences in proximity to CIAs among units.

[172] https://www.epa.gov/sites/default/files/2020-08/documents/pal_guidance_final_-_signed.pdf

### Cost-effectiveness Thresholds

On the subject of decision thresholds, the 2019 Guidance notes that states “may” use thresholds, but the use of such thresholds must be justified with respect to consideration for other relevant factors:

> *A state may find it useful to develop thresholds for single metrics to organize and guide its decision-making. As the Ninth Circuit explained in NPCA v. EPA, 788 F.3d at 1142, the Regional Haze Rule does not prevent states from implementing “bright line” rules, such as thresholds, when considering costs and visibility benefits. However, the state must explain the basis for any thresholds or other rules (see 40 CFR 51.308(f)(2)). If a state applies a threshold for any particular metric to remove control measures from further consideration before all other relevant factors are considered, it should explain why its selected threshold is appropriate for that purpose, i.e., why its application is consistent with the requirement to make reasonable progress.*

In general, UDAQ believes that such “bright line” thresholds are neither required nor appropriate for determining reasonable progress. As discussed in Section 7.A.1 regarding the selection of sources for controls determination, UDAQ’s Q/d threshold value of 6 is only the starting point for screening sources for further evaluation. UDAQ augments this threshold with both a secondary screening and a WEP analysis to ensure that it has accurately captured sources in need of evaluation. Similarly, a bright line cost-effectiveness threshold (i.e., cost/ton) is not required and may be of limited utility. In fact, the 2019 Guidance states that such cost/ton thresholds must be justified, and comparisons among various cost/ton estimates may or may not be useful for assessing compliance costs:

> *If a state applies a threshold for cost/ton to evaluate control measures, we recommend that the SIP explain why the selected threshold is appropriate for that purpose and consistent with the requirement to make reasonable progress.*
>
> *… a cost/ton metric and comparisons to the cost/ton values for measures that have been previously implemented may or may not be useful in determining the reasonableness of compliance costs.*

Historically, UDAQ has not utilized cost-effectiveness thresholds for compliance cost assessment, whether for RACT, BACT, or other air quality program control measures. Selecting a cost-effectiveness threshold provides a “target” that sources could potentially exploit to adjust their compliance cost analyses to avoid control requirements. In the round 2 regional haze context, the selection of a bright line $/ton threshold would inappropriately limit UDAQ’s ability to consider the remaining three statutory factors and related considerations. That said, a review of cost-effectiveness thresholds and ranges in various states – either incorporated directly into regional haze SIPs, used internally by staff and shared via the interstate coordination process, or shared by commenters on the proposed SIP – reveals that UDAQ’s determination that physical controls are not cost-effective at a $5,750/ton level is in line with the range considered by other states as shown in Figure 61 below.

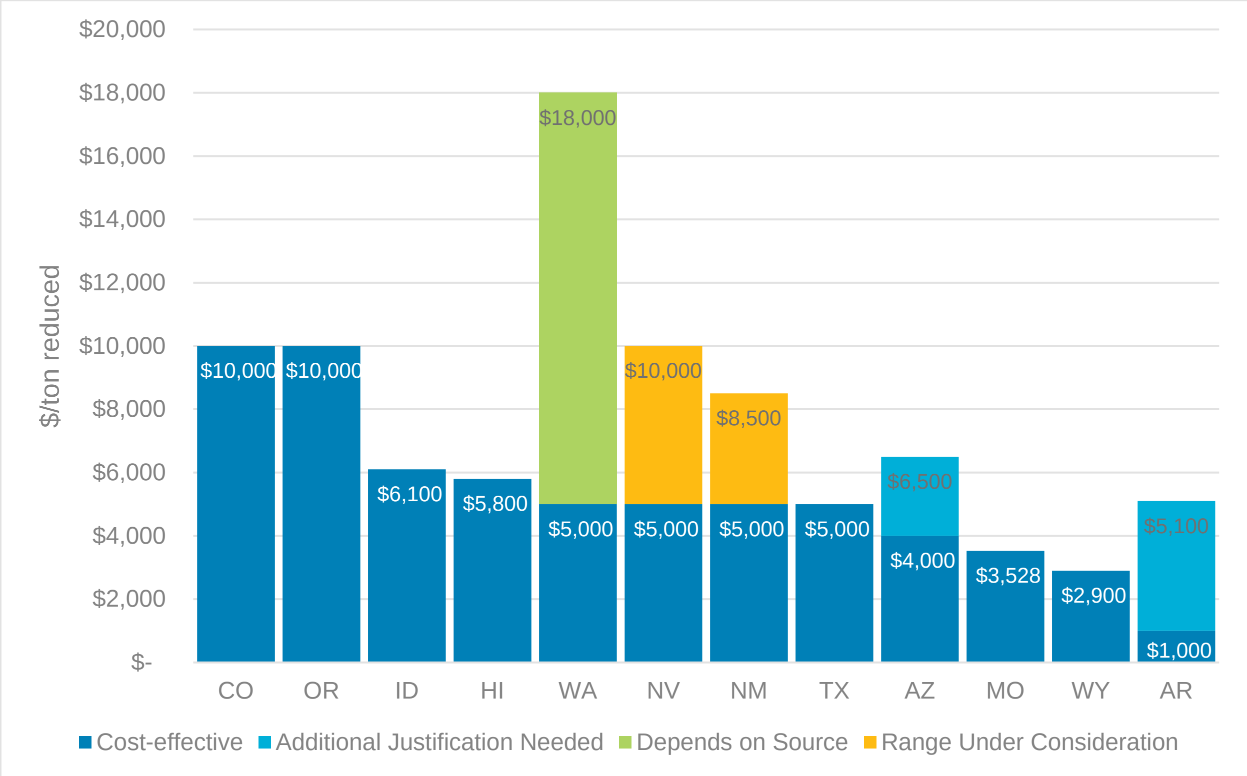


**Figure 61: State Control Cost-effectiveness Ranges**

Annual Limits vs. Short-term Limits or Emission Rates

Given concerns that the use of an annual limit might not be sufficiently short to limit visibility impairment on Most Impaired Days (MIDs), UDAQ evaluated the seasonality of nitrate impairment on MIDs at Utah's CIAs using the last five available years of visibility data.[173] As shown in Figure 62, nitrate impairment is largely seasonal with the MIDs with the highest light extinction happening during the winter months. This result is consistent with the secondary formation of particulates that UDAQ sees along the Wasatch Front and is not unexpected.

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[173] Source: "TSS Ambient Species Composition of Daily Light Extinction by Percentile Days - Product #XATP_ECSB_GDYR." WRAP Technical Support System (TSS); The Western Regional Air Partnership (WRAP) and the Cooperative Institute for Research in the Atmosphere (CIRA), 20 Jun 2022

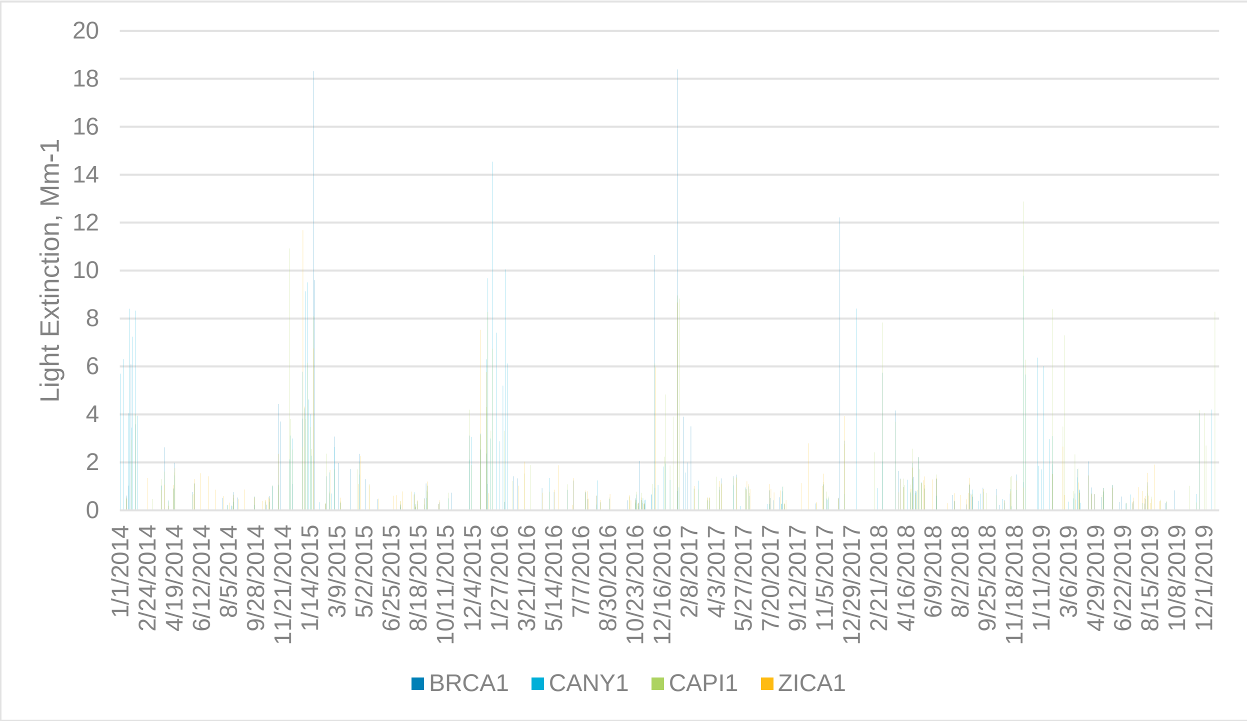


**Figure 62: Daily Nitrate Light Extinction MIDs at Utah CIA IMPROVE Sites, 2014-2019**

While nitrate light extinction has a single annual peak in the wintertime, the Hunter and Huntington power plants have two gross load (and associated $NO_x$ emissions) peaks each year, one in the summer and one in the winter, as shown in Figure 63 below. As a result, UDAQ believes that the company is unlikely to utilize the majority of its annual mass-based $NO_x$ limit for each plant during the wintertime gross load and MID nitrate impairment peaks, since it must retain enough headroom to accommodate the summer gross load peak. Thus, UDAQ concludes that an annual mass-based limit is a sufficient to reduce the likelihood of excess emissions impact CIAs during periods of high electricity demand.

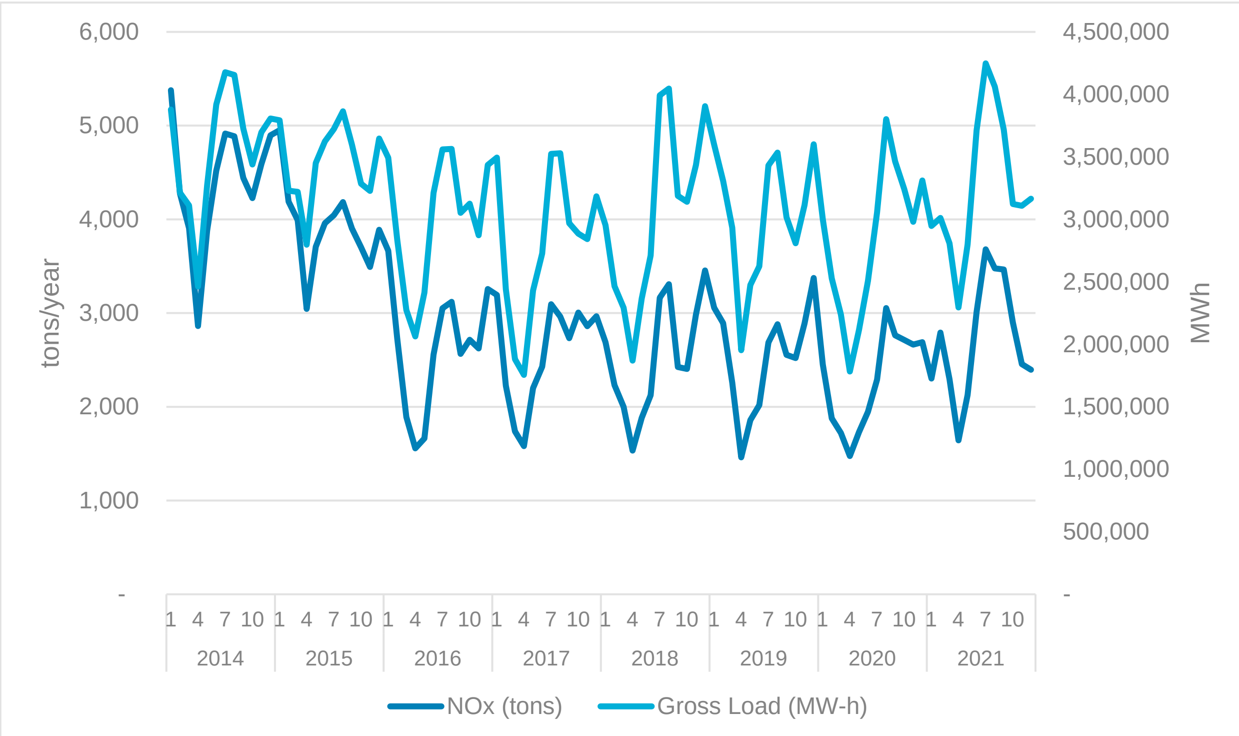


**Figure 63: Combined Hunter and Huntington Monthly NOx Emissions vs. Monthly Gross Load, 2014-2021**

## Other Considerations

UDAQ finds it additionally compelling to incorporate these enforceable mass-based emission limits to ensure that the EGU nitrate contribution to light extinction at Utah (and other states) CIAs does not exceed the emissions levels utilized in WRAP's photochemical modeling.[174] Such mass-based emission limits would help ensure that Utah is making reasonable progress as demonstrated by the WRAP modeling, while eliminating the possibility of backsliding on past emissions reductions. Importantly, the mass-based emissions limits outlined above result in combined emissions that are generally consistent with WRAP's 2028 OTB projections that are explicitly accounted for in Utah's projected 2028 RPGs, such as the example shown for Canyonlands in Figure 64.

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[174] See Appendix A for UDAQ's proposed Part H language for emission limits and controls enforcement


**Figure 64: Example of projected RPGs for Canyonlands and Arches CIAs**

Finally, this approach provides regulatory flexibility for PacifiCorp, which can meet the mass-based emission limits either by limiting or otherwise modifying operation, installing controls, switching fuels, closing units, or some combination of these options. Refer to section 8.D.3 for UDAQ's reasonable progress determinations for the Hunter and Huntington power plants.

## 7.C.4 Sunnyside Cogeneration Associates- Sunnyside Cogeneration Facility Four-Factor Analysis Summary and Evaluation[175]

### *Facility Identification*

**Name:** Sunnyside Cogeneration Facility
**Address:** State Road 123, #1 Power Plant Road, Sunnyside, Utah
**Owner/Operator**: Sunnyside Cogeneration Associates
**UTM coordinates**: 552,984 m Easting, 4,377,786 m Northing, UTM Zone 12

### *Facility Process Summary*

The Sunnyside Cogeneration Facility (Sunnyside) is in Sunnyside, Carbon County, Utah (approximately 25 miles southeast of Price). The nearest Class I areas and their respective distance from the facility are Canyonlands National Park, (91 miles), Capitol Reef National Park (95 miles), Bryce Canyon National Park (171 miles) and Zion National Park (217 miles). The Sunnyside power plant began operations in May of 1993. The electricity it produces is sold to PacifiCorp, operating as Utah Power and Light [UPLC). The plant qualifies as a small power production facility and qualifying cogeneration facility ("QF") under the Public Utility Regulatory

[175] Sunnyside's full four-factor analysis can be found in appendix C.4.A or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2020-008928.pdf

Policy Act of 1997 (‘PURPA”). The facility operates a coal-fired combustion boiler that features circulating fluidized bed (CFB), a baghouse and a limestone injection system. The facility also operates an emergency diesel engine and emergency generator. All process units are currently permitted in its UDAQ Title V air operating permit (Permit # 700030004) which was renewed on April 30, 2018. The CFB boiler is subject to the NESHAPS Part 63, Subpart UUUUU Mercury and Air Toxics Standards [MATSI Rule. As a result, Sunnyside is required to meet a standard of 0.2 lb./MMBtu of $SO_2$.

This standard requires continuous monitoring with a continuous emission monitor system (CEMS). The plant’s CFB boiler, designed by Tampella Power, produces steam that drives a Dresser Rand turbine generator. The CFB boiler and baghouse uses limestone injection. Historically, CFB boilers have been one of the primary low emission combustion technologies for commercial and small utility installations using low grade fuels. This trend continues with CFB technology being considered for smaller coal fired units as a means to effectively utilize lower quality fuels and meet environmental requirements. The current boiler produces emissions from one stack at Sunnyside’s cogeneration facility. For the purposes of a control technology review, only the emissions from the boiler stack itself are considered as well as the operations from the emergency diesel engine and emergency generator.

### *Facility Criteria Air Pollutant Emissions Sources*

The source consists of the following emission units:

- Circulating Fluidized Bed Combustion Boiler – Rated at 700 MMBtu/hr and fueled by coal, coal refuse or alternative fuels, and fueled by diesel fuel during startup, shutdown, upset condition and flame stabilization. This boiler is equipped with a limestone injection system to the fluidized bed and a baghouse. This boiler is subject to 40 CFR 60, Subpart Da and CAM.
- One diesel engine, approximately 201 HP, used to power the emergency backup fire pump, and various portable I/C engines to power air compressors, generators, welders and pumps.
- A 500-kW emergency standby diesel generator, used in the event of disruption of normal electrical power and testing/maintenance. 1.4 Facility Current Potential to Emit The current PTE values for Sunnyside, as established by the most recent NSR permit issued to the source (DAQE-AN100960029-13) are as follows (in tons/year): $SO_2$ 1,289.26 $NO_x$ 771.2.

### *Facility Current Potential to Emit*

The current PTE values for Sunnyside, as established by the most recent NSR permit issued to the source (DAQE-AN100960029-13) are as follows:

**Table 62: Sunnyside: Current Potential to Emit (Tons/Year)**

| Pollutant | Potential to Emit (tons/yr) |
|---|---|
| **$SO_2$** | 1,289.26 |
| **$NO_x$** | 771.2 |

## Sunnyside Four Factor Analysis Conclusion

The facility currently uses CFB technology to lower $NO_x$ emissions and achieves Title V permitting $NO_x$ limits as currently operated. SCR is a technically feasible control option for this boiler but is not cost effective with a control cost greater than $10,000 per ton of $NO_x$ removed. While SNCR may represent a cost-effective option for $NO_x$ emissions reduction, the introduction of substantial ammonia slip has the potential to cause adverse environmental impacts. The ammonia and $PM_{2.5}$ emissions have the potential to cause direct health impacts for those in the area, and present additional safety concerns for the storage and transportation of ammonia. Despite not having SNCR or SCR installed, the Sunnyside boiler is achieving a $NO_x$ emission rate on a lb./MMBtu basis that is comparable to PSD BACT levels set on CFB boilers. Therefore, additional add-on controls for $NO_x$ emissions reductions are not necessary on the Sunnyside CFB boiler.

## UDAQ Evaluation Summary and Conclusion[176]

UDAQ noted several potential errors in Sunnyside's analysis:

1. The Sunnyside four-factor analysis for $SO_2$ eliminated both wet scrubbers and spray dry scrubbers from consideration as an $SO_2$ control because it does not have the water rights that would be needed for operation of the wet scrubber or a spray dry absorber.
2. Sunnyside Cogen did not provide justification for including the cost for a new replacement baghouse with a dry scrubbing option.
3. Sunnyside's analysis was inconsistent regarding the amount of sorbent required and the possible resulting efficiency.
4. The Sunnyside dry sorbent injection analysis assumed too high of a cost for auxiliary power.
5. The Sunnyside dry scrubbing cost analysis improperly included annual costs for taxes and insurance and assumed unreasonably high annual costs for administrative charges.
6. The Sunnyside dry scrubbing cost analysis improperly assumed a 30% increase in cost as a retrofit factor.
7. The Sunnyside dry sorbent injection cost analysis used too high of an interest rate and too short expected life when amortizing costs.
8. Sunnyside assumed too high of an interest rate and too short of a life of controls in determining the annualized capital costs of SNCR and SCR The Sunnyside SCR and SNCR cost effectiveness analyses assumed a 4.75% interest rate and a 20- year life of both SCR and SNCR.
9. Sunnyside assumed a very high cost for aqueous ammonia that was not justified. In its SNCR and SCR cost analyses, Sunnyside Cogen assumed a cost for 29.4% aqueous ammonia of $2.50 per gallon.

[176] UDAQ's full evaluation of Sunnyside's four-factor analysis submittal can be found in appendix C.4.B or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2021-009630.pdf

10. Sunnyside assumed a higher cost for electricity than it assumed in its dry sorbent injection analysis in its SCR and SNCR cost analysis.

At this time, UDAQ is unable to proceed with its review and requests additional information as follows:

1. The source needs to resubmit the Four Factor analysis correcting the errors mentioned above.
2. Additional information must be provided regarding the infeasibility of SCR. A. This information can include additional details on economics as well as technical limitations.
3. Additional information must be provided regarding the infeasibility of SNCR. A. As with SCR, this information can include additional details on economics as well as technical limitations.
4. Any other pertinent information Sunnyside feels is warranted should also be provided in order to assist UDAQ in the review process.

### Sunnyside's Evaluation Response[177]

1. HAR technology is not feasible as flue gas exiting the CFB boiler at Sunnyside typically contains approximately 10% unreacted calcium oxide in the in the fly ash and even less in the bottom ash.[178] Additionally, there is a significant amount of ash already entrained in the CFB boiler which would make additional ash infeasible. SDA technology requires significant amounts of water that Sunnyside is unable to adequately source, thus they find it infeasible. Given the configuration of existing units, there is not enough space between the CFB boiler and existing baghouse for the addition of a further CDS/CFBS unit without significant reconfiguration of existing equipment. Of all the add on control technologies considered, CDS/CFBS is the only potentially feasible option. Existing controls for $SO_2$ as defined in Sunnyside's Title V air operation permit (#700030004) Condition II.A.2 currently provide $SO_2$ controls to the circulating fluidized bed (CFB) boiler, which involves limestone injection.
2. Sunnyside included a cost analysis for a CDS/CFBS as per UDAQ request as it is the only technically feasible add-on unit. However, the average estimated cost for a CDS/CFBS able to achieve 90% $SO_2$ control ranges from $81 to $400 million plus another $1.7 million for a new baghouse required with this technology. Ash Grove does not consider this device economically feasible.
3. Sunnyside has updated this formula in the revised cost analysis to utilize the Sargent & Lundy formula for estimating the amount of lime needed for the Sunnyside CFB boiler. This formula now assumes that use of lime could achieve 74% $SO_2$ reduction resulting in a lime injection rate of 0.0921 tons per hour or 184 lb/hour.
4. Sunnyside has revised the cost for auxiliary power to be consistent with the UDAQ comments. Specifically, the busbar cost for electricity has now been calculated based on

[177] Sunnyside's full evaluation response can be found in appendix C.4.C or at: https://documents.deq.utah.gov/air-quality/pm25-serious-sip/DAQ-2021-017202.pdf
[178] Based on fly ash characterization results conducted at Sunnyside Cogeneration Associates.

2018 operating data. The resulting rate is $49.45 per MW. Additionally, the electrical usage rate has been updated to match the UDAQ comments and as displayed below: 0.028% x 58.33 MW x 8031 hours/yr x $49.45/MW-hr = $6,486 per year.

The analysis provided under Question 2, 3, and 4 along with the attached cost analysis should replace information found in Sections 5.4 and 5.5 of the Four Factor Analysis.

5. The UDAQ suggested that there are tax exemptions in Utah for control equipment. UAC R307-120 exempts the purchase of control equipment from sales/use tax. As a result, sales tax is no longer included in CDS/CFBS cost analysis provided. Sales tax rates and property taxes are not used in either the SCR or SNCR cost analyses due to the equation format provided by EPA. Insurance rate was based on a 1% of the Total capital investment (TCI) which is documented in the EPA Cost Control Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, Subsection 2.6.5.8 Property Taxes, Insurance, Administrative Charges and Permitting Costs. The administrative cost calculation has been updated to be consistent with SCR as suggested by the UDAQ.
6. The UDAQ questioned the retrofit factor (RF) of 1.3 used all cost analyses, as a result Sunnyside reevaluated the use of this factor on a technology specific basis. Referencing the EPA Control Cost Manual, Sunnyside believes the 1.3 retrofit factor is justified for use in their cost calculations for CDS/CFBS and SCR. They reconsidered their SNCR calculations and instead used a 1.0 retrofit factor.
7. A 20-year life span and 7% interest rate has been applied to the cost control analyses provided by Sunnyside.
8. The equipment life and interest rate explanations provided in Question 7 are not control technology specific. Thus, the same conclusions are applicable, namely, a 20-year life span and 7% interest rate are appropriate for the cost analyses provided.
9. In response to the UDAQ's request, Sunnyside obtained a cost estimate for 19% aqua ammonia from Thatcher Group, Inc (Thatcher). Thatcher quoted $0.18 per lb. of solution. Based on this value, if we assume a density of 19% ammonia is estimated to be 7.46 lbs/gal to 7.99 lbs/gal. This results in a cost per gallon ranges from 1.34 $/gal to 1.438 $/gal. This cost is significantly higher than the EPA estimate of $0.293, which is acceptable as it states, "User should enter actual value if known". Furthermore, it should be noted that the cost for ammonia based on the most recent U.S. Geological Survey, Minerals Commodity Summaries, which was quoted in the original Four Factor Analysis is also significantly higher and based on a density of 29% ammonia. Since the $1.438 is still less than the originally used $2.5 per gallon, these calculations have been updated to include the vendor quote.
10. As discussed in Question 4, Sunnyside has revised the cost for auxiliary power to be consistent with the UDAQ's comments. Please see section 4 for additional information. A revised cost analysis for SCR and SNCR have been provided in Attachment A to replace the cost analysis in the original Four Factor Analysis.

## UDAQ Response Conclusion

UDAQ agrees with the amendments included in Sunnyside's evaluation response and finds the answer's provided in the facility's response satisfactory. Refer to section 8.D.5 for UDAQ's reasonable progress determinations for the Sunnyside Cogeneration Facility.

## 7.C.5 US Magnesium LLC- Rowley Plant[179]

### *Facility Identification*

**Name:** Rowley Plant Address: 12819 North Skull Valley Road 15 Miles North Exit 77, I-80, Rowley, Utah
**Owner/Operator:** US Magnesium LLC
**UTM coordinates:** 4,530,490 m Northing, 354,141 m Easting, Zone 12

### *Facility Process Summary*

US Magnesium LLC (USM) operates a primary magnesium production facility at its Rowley Plant, located in Tooele County, Utah. USM produces 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 (CRB) and converted into hydrochloric acid (HCl). 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 CO, $NO_x$, $PM_{10}$, $PM_{2.5}$, and VOCs.

### *Facility Criteria Air Pollutant Emissions Sources*

The source consists of the following emission units:

- Three (3) gas turbines/generators and duct/process burners (natural gas/fuel oil)
- Chlorine reduction burner (CRB), and associated equipment
- Riley Boiler, 60 MMBtu/hr (natural gas)
- Solar pond diesel engines, 30 engines rated between 90 and 420 hp
- Fire pump engine, one additional diesel engine rated at 292 hp

### *Facility Current Potential to Emit*

The current PTE values for the Rowley Plant, as established by the most recent NSR permit issued to the source (DAQE-AN107160050-20) are as follows:

**Table 63: Current Potential to Emit**

| Pollutant | Potential to Emit |
|---|---|
| **$SO_2$** | 24.10 |
| **$NO_x$** | 1,260.99 |

[179] US Magnesium's full four-factor analysis submittal for the Rowley Plant can be found in appendix C.5.A or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2020-014024.pdf

## US Magnesium Four-Factor Analysis Conclusion

This outlines USM's evaluation of possible retrofit options for all $NO_x$ emitting units onsite at their Rowley Plant located in Tooele County, Utah, in an attempt at reducing their $NO_x$ emissions facility wide and reducing their impact on visibility impairment issues. The results of this report found that it is potentially technologically and economically feasible to install a flue gas recirculation unit on the Riley boiler, reducing their $NO_x$ emissions by an estimated 22.6 tons annually. Aside from this change, there were currently no other technically or economically feasible options available for USM's Rowley Plant. Pending further technological and cost refinement, the implementation schedule for the installation of the FGR unit may be installed prior to the end of 2028. Therefore, the emissions for the 2028 modeling scenario could be an estimated 22.6 tons less than the 2018 baseline year $NO_x$ emissions.

## UDAQ Evaluation[180]

Several errors were made during the analysis of the various control options outlined in this document. While the errors ultimately do not change the outcome or results of the analysis, they should be corrected prior to final acceptance by DAQ. The following lists the errors noticed by DAQ and the resulting effect each error leads to in the final result:

Incorrect interest rate used for control cost calculation – rather than using the current bank prime rate of 3.25%, the source calculated all control costs with either an interest rate of 7% (used as the default in the control cost manual) or 5.5% (used as the default in the SCR control cost spreadsheet). Both calculations result in a higher control cost in $/ton. Second, the source used only a 20-year expected life for application of an SCR, which is lower than the standard 30-year lifespan. Again, this would artificially inflate the control cost by increasing the annualized cost. However, the overall cost of the SCR system as estimated by the source was lower than expected, with an initial cost of just $87,000. The low initial cost serves to lower the resulting control cost. DAQ reanalyzed the use of SCR on the Riley Boiler under two different scenarios. Under PTE, assuming full load, the application of SCR might be expected to remove as much as 188 tons of $NO_x$ at a control cost of $4,073/ton of $NO_x$ removed – assuming the same 90% removal efficiency as did the source. However, the Riley Boiler did not operate at that high an output level – reporting just 45.25 tons of actual emissions in 2018. Adjusting the emission reduction for 90% of the actual emissions gives a removal of 40.7 tons of $NO_x$ (as opposed to the 38 tons suggested by the source), at a control cost of $18,800/ton of $NO_x$ removed. Similar errors were made with respect to the FGR calculations on the Riley Boiler. The incorrect interest rate was used – 7% vs 3.25%. FGR systems typically have a potential lifespan of 15 years rather than the 20 years suggested by the source. DAQ recalculated the control costs correcting for these errors and obtained a modified value of 22.5 tons of $NO_x$ removed at a control cost of $1,880/ton of $NO_x$ removed. None of the other equipment requires additional evaluation, as each is currently well controlled. While the same types of errors were

[180] UDAQ's full evaluation of US Magnesium's four-factor analysis submittal can be found in appendix C.5.B or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/DAQ-2021-009628.pdf

made in the source's analysis, the resulting outcomes and conclusions remain unchanged. DAQ recommends that FGR be considered for retrofit control application on the Riley boiler. Should the source increase utilization of the Riley boiler, then the application of SCR should be considered.

### US Magnesium's Evaluation Response[181]

US Magnesium re-evaluated the status of the Riley boiler and the Riley boiler $NO_x$ emission factor utilized in US Magnesium's 2018 air emission inventory (AEI) that was the basis for the 4-factor analysis of that unit. In summary, the US Magnesium 2018 AEI grossly overstated the $NO_x$ emissions associated with the Riley boiler in two ways: 1) the Riley boiler is a 60 MMBTU boiler but the AP42 emission factor in the 2018 AEI is for a >100 MMBTU boiler, and 2) the Riley boiler, from the time of its installation, is outfitted with a low $NO_x$ burner, but the AP42 emission factor in the 2018 AEI is for an "uncontrolled burner." The implications are summarized in the table below:

**Table 64: US Magnesium's Reevaluation of Riley Boiler Controls**

| Riley Boiler 2018 | $NO_x$ emission factor | AP 42 Table1.4-1. Emission Factors for $NO_x$ and CO from Natural Gas Combustion | | Estimated $NO_x$ emissions (TPY) |
|---|---|---|---|---|
| **AEI as submitted** | 190 lbs./MMscf | >100MMBTU (Large) | Uncontrolled | 45.2499 |
| **AEI corrected for actual status of Riley boiler** | 50 lbs./MMscf | <100MMBTU (Small) | Controlled - Low $NO_x$ burner | 11.9074 |

Corrected 2018 $NO_x$ emissions for the Riley boiler, implications on the 4-factor analysis:

- Using the same reductions assumed for FGR (up to 50% $NO_x$), the estimated reduction would be about 6 tons/year.
- Using the same reductions assumed for SCR (up to 90% $NO_x$), the estimated reduction would be about 10.7 tons/year.
- Using DAQ's modified calculation for FGR: $1,880/ton * 22.5 tons = $42,000/yr. Correcting to 6 ton/yr reduction = $7,050/ton.
- Using DAQ's modified calculation for SCR: $18,800/ton * 40.7 tons = $765,160/yr. Correcting to 11.9 ton/yr reduction = $64,300/ton.

### UDAQ Response Conclusion

UDAQ does not agree with US Magnesium's evaluation response. We do not possess any records of an LNB control on the Riley boiler. Using the original four-factor analysis submittal,

[181] US Magnesium's full evaluation response can be found in appendix C.5.C or at: https://documents.deq.utah.gov/air-quality/planning/air-quality-policy/regional-haze/DAQ-2021-011902.pdf

FGR on the Riley boiler remains a cost-effective and viable control option. UDAQ would require proof of the existence of the LNB and its $NO_x$ removal efficacy before agreeing it is a satisfactory justification for altering the control cost calculations. Refer to section 8.D.6 to review UDAQ's reasonable progress and controls determination for the Rowley Plant.

# **Chapter 8:** Determination of Reasonable Progress Goals

## 8.A Reasonable Progress Requirements

The RHR requires Utah to submit a long-term strategy (LTS) that includes measures necessary to achieve the Reasonable Progress Goals (RPGs) in each CIA. This strategy must consider major and minor stationary sources, mobile sources, and area sources. Section 169A (a)(4) and other subsections of the Clean Air Act call for reasonable progress "toward meeting the national goal" of eliminating anthropogenic (manmade) impairment of visibility. Utah is required under the RHR to establish visibility deciview goals for each of its five CIAs that allow them to meet the RPGs towards natural visibility by 2064. RPGs are interim goals that represent incremental visibility improvement over time toward the goal of natural background conditions and are developed in consultation with FLMs and nearby affected states. In determining the criteria for reasonable progress, Utah was required under Section 169A(g) of the CAA to consider four factors: cost of compliance, the time necessary for compliance, energy and non-air environmental impacts of compliance, and the remaining useful life of existing sources that contribute to visibility impairment.[182]

## 8.B. Regional Modeling of the LTS to set RPGs

The RHR requires states to demonstrate progress every ten years toward the CAA goal of no manmade visibility impairment. WRAP conducted the modeling necessary to track this progress for Utah. EPA guidance for tracking visibility progress[183] defines a visibility impairment tracking metric (measured in deciviews) using observations from the IMPROVE monitoring network sites that represent CIAs. EPA defined in the RHR and guidance a Uniform Rate of Progress (URP) glidepath for the 20% most impaired days as the straight line from the 2000-2004 IMPROVE 5-year average baseline to EPA estimates of future natural visibility conditions, plotted for 2064. In the first regional haze planning period, 2000-2018, EPA guidance[184] defined most impaired days as those days with highest total haze. States were required to demonstrate visibility progress by 2018 compared to the URP glidepath for the haziest days and no degradation of visibility on the clearest days from the 2000-2004 IMPROVE 5-year average baseline. Visibility on the clearest days improved between 2000 and 2018 across the Class I areas in the western U.S. However,

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[182] *See* 42 USC § 7492(g)(1).
[183] The EPA Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program can be found at: https://www.epa.gov/sites/default/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf
[184] The EPA Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program can be found at: https://www.epa.gov/sites/default/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf

smoke from wildfire and wildland prescribed fire events and dust events on the haziest days made tracking the visibility benefits due to reducing U.S. anthropogenic emissions more difficult.

For the second regional haze implementation period, 2018-2028, states are required to demonstrate visibility progress by 2028 for the most impaired days and no visibility degradation for the clearest days. EPA guidance[185] defined most impaired days as those days with the highest fractional contribution to aerosol light extinction from anthropogenic sources. EPA statistical methods use IMPROVE measurements of carbon and crustal materials to separate contributions from episodic extreme natural events (e.g., wildfire or dust) from routine natural and anthropogenic contributions. Ammonium sulfate and ammonium nitrate are assigned primarily to anthropogenic emissions with smaller contributions from routine natural sources. This statistical approach does not separate contributions due to U.S. anthropogenic emissions from those of international anthropogenic emissions. Since states do not have authority to reduce international emissions, WRAP conducted source apportionment modeling analyses to evaluate U.S. anthropogenic contributions to haze and progress in reducing U.S. anthropogenic contributions to haze over time.

## 8.C URP Glidepath Checks[186]

These charts illustrate the Uniform Rate of Progress (URP) Glidepath, as defined by EPA guidance,[187] compared to IMPROVE measurements for the period 2000-2018. The URP glidepath is constructed (in deciviews) for the 20% most impaired days (MID) or clearest days using observations from the IMPROVE monitoring site representing a Class I area. The URP glidepath starts with the IMPROVE MID for the 2000-2004 5-year baseline and draws a straight line to estimated natural conditions in 2064. For clearest days, the goal is no degradation of visibility from the 2000-2004 5-year baseline, therefore glidepath for clearest days is a straight line from the 2000-2004 baseline to 2064. In the second regional haze planning period, 2064 natural conditions estimates are the same as the 15-year average of natural conditions on most impaired days or clearest days in each year 2000-2014. IMPROVE annual average values are presented as points. IMPROVE 5-year average values are presented as solid lines covering the periods 2000-2004 and 2014-2018.

The 2028 On the Books (2028OTBa2) visibility projection in deciviews is illustrated as a point that can be compared to the Uniform Rate of Progress glidepath. UDAQ has chosen the “2028OTBa2 w/o fire” projection that excludes wildfire from MID to more accurately represent future emissions from sources UDAQ is better able to control. This projection reduces the impact of elemental carbon and organic carbon from fires from the original 2028 EPA projection to remove additional fire impacts that were not fully eliminated by the move from haziest days metric (used during the first planning period) to most impaired days metric (used during the

[185] The EPA Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program can be found at: https://www.epa.gov/sites/default/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf

[186] 40 C.F.R. § 51.308(f)(3)(i)

[187] The EPA Guidance for Tracking Progress Under the Regional Haze Rule can be found at https://www.epa.gov/sites/default/files/2021-03/documents/tracking.pdf

second planning period). The 2028OTBa2 visibility projection reflects Utah's LTS, including the results of the reasonable progress determinations found in 8.D, with the exception of the anticipated 22.5 tons of $NO_x$ emissions reductions associated with the installation of FGR controls on the Riley Boiler at U.S. Magnesium's Rowley Plant. However, the resulting reduction in $NO_x$ emissions is a small percentage of Utah's total 2028 $NO_x$ emissions. The 2028OTBa2 visibility projection includes emissions from the now-closed Kennecott Power Plant, which was projected to have 1,152 tons of $NO_x$, 2,152 tons of $SO_2$, and 135 tons of $PM_{2.5}$ emissions in 2028. The 2028 projections also include emissions from the Tesoro Refinery not accounting for the refinery's recent PM2.5 SIP BACT analysis which resulted in an annual mass-based $SO_2$ limit and an estimated 408-ton $SO_2$ reduction. The omission of these emissions reductions in the 2028OTBa2 projection make our glidepath comparisons conservative, as actual 2028 visibility can be expected to improve due to lower emissions levels. Refer to section 6.A.10 to review Utah's Long-Term Strategy and additional details on the emissions reductions UDAQ is relying on to make reasonable progress in the second implementation period.

### 8.C.1 Bryce Canyon National Park

The 2000-2004 URP baseline in Bryce Canyon for MID is 8.4 dv. The 2014-2018 average observations for MID is 6.6, meaning visual range on the most impaired days has increased from 104.62 miles to 125.26 miles, an improvement of 20.64 miles. The projected visibility in 2028 without fire impacts is 6 dv, which, represented by the orange triangle on the graph, is below the URP glidepath. For clearest days, the 2000-2004 baseline for Bryce Canyon is 2.8 dv. The 2014-2018 average observations for clearest days are 1.5 dv meaning that visual range on the clearest days has increased from 183.16 miles to 208.59 miles, an increase of 25.43 miles.

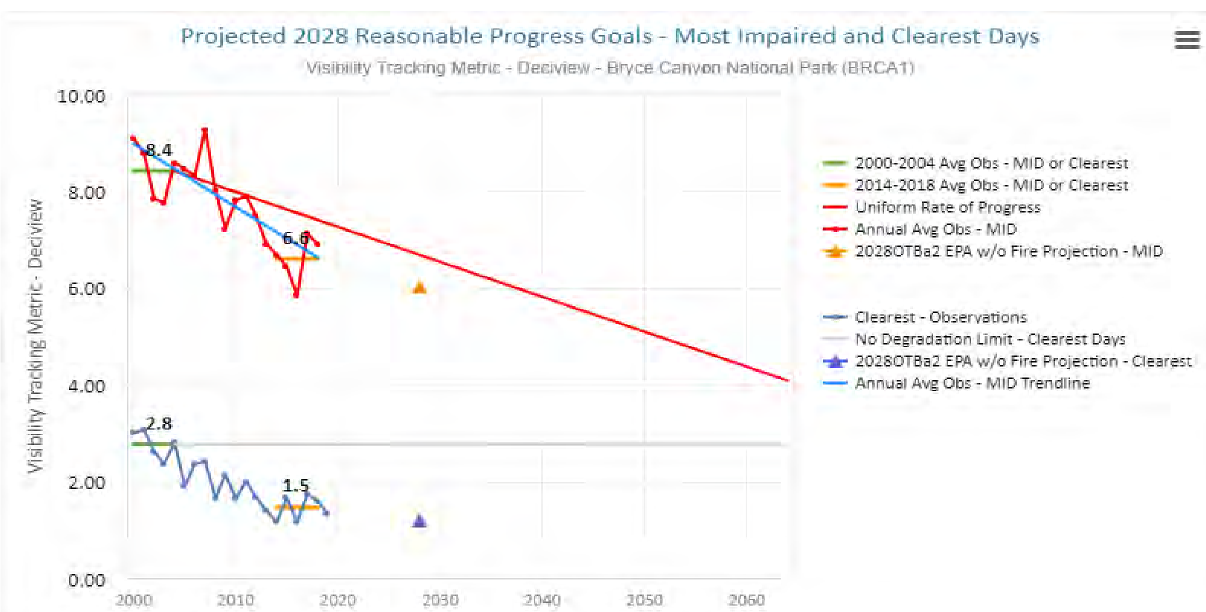


Figure 65: Projected 2028 RPG Bryce Canyon National Park

The projected 2028 visibility on clearest days is 1.2 dv, which, represented by the blue triangle, is below the no degradation limit for clearest days.

### 8.C.2 Canyonlands and Arches National Park

The 2000-2004 URP baseline in Canyonlands and Arches National Park for MID is 8.8 dv. The 2014-2018 average observations for MID is 6.8, meaning visual range on the most impaired days has increased from 100.52 miles to 122.78 miles, an improvement of 22.26 miles. The projected visibility for MID in 2028 without fire impacts is 6.2 dv, which is below the URP glidepath. For clearest days, the 2000-2004 baseline for Canyonlands and Arches is 3.7 dv. The 2014-2018 average observations for clearest days are 2.2 dv meaning that visual range on the clearest days has increased from 167.40 miles to 194.49 miles, an increase of 27.09 miles. The projected 2028 visibility on clearest days is 1.9 dv, which is also below the no degradation limit for clearest days.


**Figure 66: Projected 2028 RPG Canyonlands and Arches National Parks**

## 8.C.3 Capitol Reef National Park

The 2000-2004 URP baseline in Capitol Reef for MID is 8.8 dv. The 2014-2018 average observations for MID is 7.2, meaning visual range on the most impaired days has increased from 100.52 miles to 117.96 miles, an improvement of 17.44 miles. The projected visibility for MID in 2028 without fire impacts is 6.6 dv, which is below the URP glidepath. For clearest days, the 2000-2004 baseline for Capitol Reef is 4.1 dv. The 2014-2018 average observations for clearest days are 2.4 dv meaning that visual range on the clearest days has increased from 160.83 miles to 190.64 miles, an increase of 29.81 miles. The projected 2028 visibility on clearest days is 2.1 dv, which is below Capitol Reef's no degradation limit for clearest days.

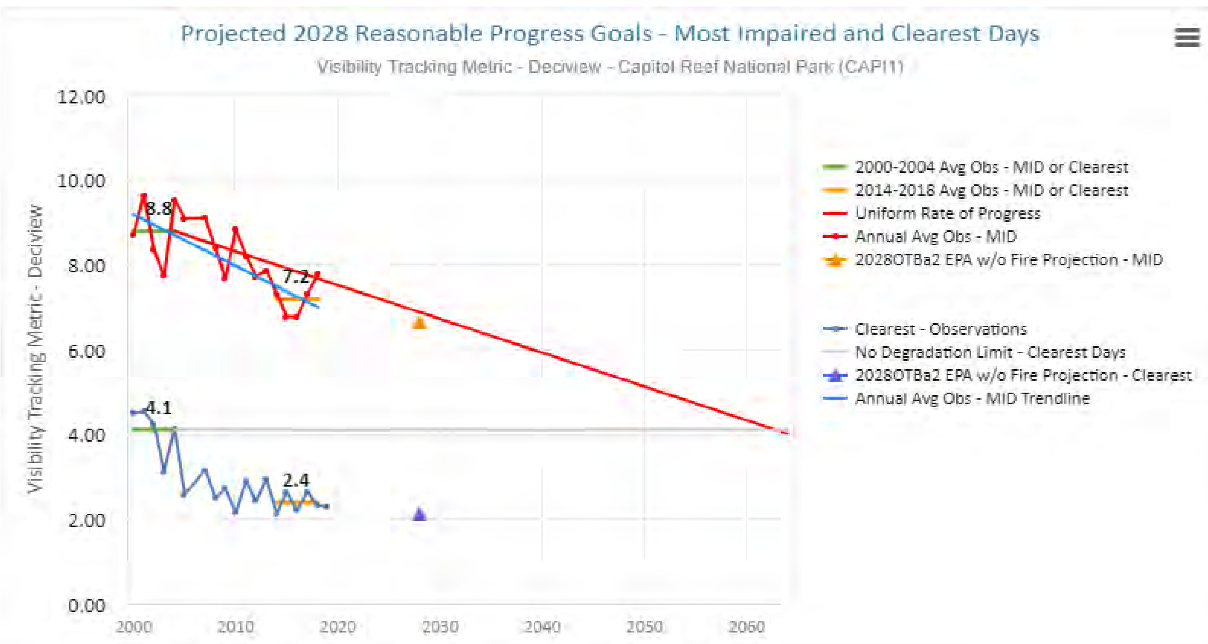


**Figure 67: Projected 2028 RPG Capitol Reef National Park**

## 8.C.4 Zion National Park

The 2000-2004 URP baseline in Zion National Park for MID is 10.4 dv. The 2014-2018 average observations for MID is 8.7, meaning visual range on the most impaired days has increased from 85.66 miles to 101.53 miles, an improvement of 15.87 miles. The projected visibility for MID in 2028 without fire impacts is 8.3 dv, which is below the URP glidepath. For Zion's clearest days, the 2000-2004 baseline for is 4.5 dv. The 2014-2018 average observations for clearest days are 3.9 dv meaning that visual range on the clearest days has increased from 154.53 miles to 164.08 miles, an increase of 9.55 miles. The projected 2028 visibility on clearest days is 3.5 dv, which is below the no degradation limit for clearest days in Zion.


Figure 68: Projected 2028 RPG Zion National Park

### 8.C.5 Summary of URP Glidepaths

The table below summarizes the information from Figures 65-68 above, comparing visibility on the most impaired and clearest days for the baseline, 2028 URP, and 2028 EPA w/o fire projection values for each of Utah's CIAs in addition to stating whether the CIA is below the URP glidepath and no degradation line.

**Table 65: Comparison of baseline, 2028 URP, 2028 EPA w/o fire projection for worst and clearest days**

| CIA IMPROVE Site | WORST DAYS | | | | | CLEAREST DAYS | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Baseline (dv) | 2028 URP (dv) | 2028 EPA w/o Fire Projection (dv) | % Progress to 2028 URP | 2028 Below URP Glidepath? (Y/N) | Baseline (dv) | 2028 EPA Projection (dv) | 2028 EPA w/o Fire Projection (dv) | 2028 Below No Degradation Line? (Y/N) |
| BRCA1 | 8.42 | 6.68 | 6.03 | 137.60% | YES | 2.77 | 1.22 | 1.20 | YES |
| CANY1 | 8.79 | 6.92 | 6.19 | 139.10% | YES | 3.75 | 1.94 | 1.92 | YES |
| CAPI1 | 8.78 | 6.87 | 6.63 | 112.28% | YES | 4.10 | 2.17 | 2.10 | YES |
| ZICA1 | 10.40 | 8.35 | 8.27 | 103.73% | YES | 4.48 | 3.65 | 3.54 | YES |

## 8.D Reasonable Progress Determinations

The following sections contain UDAQ's determinations on what controls are necessary for Utah's CIAs to make reasonable progress in this implementation period. UDAQ believes these determinations will help protect reasonable further progress demonstration and visibility in Utah. All emissions limits, operating procedures, and compliance strategies for the following reasonable progress determinations which limit $NO_x$, $SO_2$, and PM are identified in SIP Subsection IX.H.21 and 23, which are made enforceable through EPA approval and incorporation into the Utah Air Quality Rules.

### 8.D.1 Reasonable Progress Determination for Ash Grove Cement Company – Leamington Cement Plant

Upon reviewing Ash Grove's four-factor analysis for the Leamington Cement Plant and their evaluation response, UDAQ finds that it is adequately controlled for the purposes of the Second Implementation Period. UDAQ has determined that the existing SCNR control and emissions limits for the Leamington Cement Plant are effective measures necessary for reasonable progress in Utah's Second Implementation Period of regional haze planning. The Leamington Cement Plant's existing controls and emissions limits will be implemented and enforced through SIP Subsection IX.H.23 to ensure the plant will continue to implement existing measures and will not increase its emission rate. Refer to section 7.B.3 to review the four-factor analysis and evaluation response results for the Leamington Cement Plant.

### 8.D.2 Reasonable Progress Determination for Graymont Western US Incorporated – Cricket Mountain Plant

Upon reviewing the Graymont Western US Inc. four-factor analysis for their Cricket Mountain Plant and their evaluation response, UDAQ finds that additional controls are not required for reasonable progress in this implementation period based on their cost/ton and the potential proprietary costs of SNCR technology for the kilns. UDAQ has determined that the existing controls and emissions limits for the Cricket Mountain Plant are effective measures necessary for reasonable progress in Utah's Second Implementation Period of regional haze planning. The Cricket Mountain Plant's controls and emissions limits will be implemented and enforced through SIP Subsection IX.H.23 to ensure the plant will continue to implement existing measures and will not increase its emission rate. Refer to section 7.B.4 to review the four-factor analysis and evaluation response results for the Cricket Mountain Plant.

### 8.D.3 Reasonable Progress Determination for PacifiCorp: Hunter and Huntington Power Plants

Upon reviewing PacifiCorp's four-factor analysis and evaluation response, UDAQ is establishing plantwide annual mass-based $NO_x$ emission limits. At the resulting utilization and emissions levels, UDAQ finds SNCR and SCR not to be cost-effective. UDAQ is also adding PacifiCorp's existing $SO_2$ emission limits from their Title V permit for all five units to ensure federal enforceability in the regional haze context. These emission limits are to be implemented and enforced through SIP Subsection IX.H.23. Please refer to section 7.C.3 to view PacifiCorp's and UDAQ's complete analysis and conclusions.

### 8.D.4 Reasonable Progress Determination for Sunnyside Cogeneration Associated – Sunnyside Cogeneration Facility

Upon reviewing the Sunnyside Cogeneration Associated four-factor analysis and evaluation response containing corrections to their analysis of the Sunnyside Cogeneration Facility, UDAQ has found no cost-efficient control options for the facility for the purposes of the Second Implementation Period. UDAQ has determined that the existing controls and emissions limits for the Sunnyside Cogeneration Facility are effective measures necessary for reasonable progress in Utah's Second Implementation Period of regional haze planning. The Sunnyside Cogeneration Facility's controls and emissions limits will be implemented and enforced through SIP Subsection IX.H.23 to ensure the facility will continue to implement existing measures and will not increase its emission rate. Refer to section 7.B.6 to review the four-factor analysis and evaluation response results for the Sunnyside Power Plant.

### 8.D.5 Reasonable Progress Determination for US Magnesium LLC – Rowley Plant

Upon reviewing US Magnesium LLC's four factor analysis for their Rowley Plant, UDAQ does not agree with its assessment of an LNB on the Riley Boiler. UDAQ has no record of the existence of an LNB on this unit or it's $NO_x$ reducing efficacy. UDAQ therefore refers to US Magnesium's original four-factor analysis submittal information suggesting that FGR is a cost-effective and viable control option for the Riley Boiler. UDAQ recommends the installation of

FGR on the Riley Boiler to ensure that Utah makes reasonable progress in this implementation period. UDAQ has also determined that the existing controls and emissions limits for the Rowley Plant are measures necessary for reasonable progress in Utah's Second Implementation Period of regional haze planning to ensure the plant will continue to implement existing measures and will not increase its emission rate. Implementation of these control determinations are to be enforced through SIP Subsection IX.H.23. Refer to section 7.B.7 to review the four-factor analysis and evaluation response results for the Rowley Plant.

### 8.D.6 Intermountain Power Service Corporation – Intermountain Generation Station

As discussed in section 7.A.2, the planned replacement of the IGS coal-fired units with an EPS-compliant combined-cycle natural gas plant is expected to dramatically decrease regional haze-causing pollutants (PM, $SO_2$, and $NO_x$). Though the coal-fire units are expected to cease operation by mid-2025, UDAQ has established a firm closure date of no later than December 31, 2027 to ensure that the coal-fired units at IGS will not continue operation beyond the conclusion of the second implementation period while allowing flexibility for closing the plant in addition to rescinding its permit and approval order. UDAQ has also determined that the existing controls and emissions limits for IGS are measures necessary for reasonable progress in Utah's Second Implementation Period of regional haze planning to ensure the plant will continue to implement existing measures and will not increase its emission rate. The implementation of the IGS closure and its existing control measures are to be enforced through SIP Subsection IX.H.23.

# **Chapter 9:** Consultation, Public Review, Commitment to further Planning

## 9.A Federal requirements

In developing each reasonable progress goal, Utah must consult with those States which may reasonably be anticipated to cause or contribute to visibility impairment in CIAs within Utah.[188] Where the State has emissions that are reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area located in another State, Utah must consult with the other State(s) in order to develop coordinated emission management strategies.[189] Utah must demonstrate that it has included in its implementation plan all measures agreed to during state-to-state consultations or a regional planning process, or measures that will provide equivalent visibility improvement and document all substantive interstate consultations.[190] Utah must also provide the FLMs with an opportunity for consultation no less than 60 days prior to the SIP public hearing or public commenting opportunity.[191] This consultation must include the opportunity for FLMs to discuss their assessment of the visibility impairment at CIAs and their recommendations on the development and implementation of strategies to address visibility impairment.[192] Utah must include a description in their implementation period of how it addressed any comment provided by FLMs.[193]

## 9.B Interstate Consultation

Throughout the second implementation period, Utah has met regularly with its surrounding states. Utah also participates in WESTAR Planning Committee and Four Corners meetings for state RH planning coordination. Table 66 includes a summary of interstate meetings UDAQ took part of. See Appendix B for further documentation of interstate consultation and agreements. UDAQ conducted further consultation and SIP review of the second implementation period status of the non-Utah sources identified in UDAQ's WEP analysis and included this information in Table 67 to Table 68. As shown, all out-of-state sources identified by UDAQ's WEP analysis of Utah's CIAs are either:

- outside state jurisdiction,
- have Q/d values too low to be screened in by the state,
- were screened out due to effective Round 1 BACT controls, or
- are subject to controls or closure in this implementation period.

[188] *See* 40 CFR § 51.308 (d)(1)(iv)
[189] *See id*., § 51.308 (d)(3)(i)
[190] *See id*., § 51.308 (f)(2)(ii)(C)
[191] *See id*., § 51.308 (i)(ii)(2)
[192] *See id*., § 51.308 (i)(ii)(2)
[193] *See id*., § 51.308 (i)(4)

**Table 66: Summary of Interstate Meetings with UDAQ**

| Date | Time | Entity | Topic | Result |
|---|---|---|---|---|
| **4/28/2021** | 10-11a | Wyoming | Wyoming and Utah Regional Haze Second Planning Period Update | Debrief after PacifiCorp meeting. Shared draft Montana SIP with Wyoming. They shared their draft SIP with us. We offered ours as soon as it is more complete. |
| **4/30/2021** | 1-2:30p | Four Corners States | Regional Haze Consultations | Four corners states do not expect to require other states to enforce controls for emissions affecting their Class I Areas. NM discussed in length where they are in their SIP writing process. |
| **5/5/2021** | 9-9:30a | Wyoming | WY-UT RH Coordination Call | Discussion emissions affecting the other state. |
| **5/5/2021** | 2-4p | WESTAR | Regional Haze Results Meeting #9 | Discussion of different modeling resources available and uses. |
| **5/6/2021** | 2-3p | WESTAR | WESTAR Planning Committee Call | RH updates and deadline considerations. |
| **5/12/2021** | 2:30-3:30p | New Mexico | NM-UT DEQ Regional Haze Consultation | NM described their SIP writing process and showed us the modeling tools they plan to use for the out of state emissions section. We offered to exchange draft SIPs. |
| **6/1/2021** | 1:30-2p | Colorado | CO-UT Regional Haze Consultation | Discussed controls implementation. |
| **9/9/2021** | 12-12:30p | Arizona | UT-AZ RH Consultation | Neither state is looking for additional controls in the other. Consulted about interest rates and control cost thresholds. |
| **9/9/2021** | 2-3:30p | WESTAR | State-Only RH Call | |
| **10/15/2021** | 10-11a | New Mexico (Mark Jones) | Control Cost Consultation | Discussed control cost thresholds and justification. |
| **11/04/2021** | 2-3p | WESTAR | Planning Committee Meeting | Discussed RH updates and interstate consultation documentation emails. |
| **11/08/2021** | 1-2p | Wyoming | RH Controls Implementation Consultation | Discussed sources and controls implementation. |
| **11/15-16,2021** | 10a-4p | 4 Corners | Annual AQ Meeting | Participated in giving RH updates with other 4 corners states. |
| **1/7/22** | 10-11a | New Mexico | WEP Analysis Consultation | Discussed WEP analysis methodologies and CAMx photochemical low-level source apportionment. |
| **1/13/22** | 1:30-3p | WVPPI | Western Visibility Protection and Planning Initiative | Discussion of the key components of Section 169a of the CAA. |
| **2/10/22** | 1:30-3p | WVPPI | Western Visibility Protection and Planning Initiative | Discussed, RH history, the relationship between reasonable progress and long-term strategies. Utah volunteered to help plan an in-person meeting between states, FLMs, and EPA. |
| **2/24/22** | 1-2p | RHPWG | Regional Haze Planning Work Group | Discussed the NGO actions letter submitted to EPA and 60-day notice to file suit. |
| **3/3/22** | 2-3p | WESTAR | Planning Committee | Discussed RH updates. |
| **3/10/22** | 1:30-3p | WVPPI | Western Visibility Protection and Planning Initiative | States discussed reasonable progress and long-term strategies. |
| **4/5-4/7/22** | 8a-5p | WESTAR/WRAP | Spring Meeting | States presented on air quality, visibility, and wildfire modeling and updates. |
| **4/13/22** | 1:30-3p | WVPPI | Western Visibility Protection and Planning Initiative | States discussed how reasonable progress can be determined and challenges faced by states whose largest sources of impairment are not anthropogenic sources. |
| **4/14/22** | 2-3p | WESTAR | Planning Committee | States gave RH updates. |
| **5/5/22** | 2-3p | WESTAR | Planning Committee | States discussed visibility modeling strategies |

| | | | | |
|---|---|---|---|---|
| **5/12/22** | 1:30-3p | WVPPI | Western Visibility Protection and Planning Initiative | States discussed how to incorporate EJ into RH planning. |
| **6/9/22** | 2-3p | WESTAR | Planning Committee | States were updated by the WRAP work groups. |
| **6/16/22** | 2-3:30p | WVPPI | Western Visibility Protection and Planning Initiative | States discussed challenges with incorporating EJ into RH planning due to a lack of guidance on how to address or make decisions considering EJ in visibility standards for CIAs. |
| **6/21/22** | Various | CA, CO, NM, and NV | RH SIP Controls | UDAQ corresponded with neighbor states inquiring the controls status of non-UT sources ranking in WEP analysis for UT CIAs. |

### Table 67: Second Implementation Period Status of Non-Utah Sources Identified in $NO_3$ WEP Analysis

| Facility Name | Source State | Utah CIA | WEP NOx Rank | NOx Q/d | WEP_NO3 (% of total) | Four-Factor Analysis? (Y/N) | Proposed Controls | Notes |
|---|---|---|---|---|---|---|---|---|
| **Bonanza** | TR | **CANY1** | 3 | 30.8 | 59,301.8 (6.4%) | N | | Likely closure in 2030 due to settlement |
| **McCarran Intl** | NV | **ZICA1** | 3 | 11.1 | 9,235.4 (3.7%) | N | | Majority of NOX emissions from non-road sources (aircraft take-offs and landings) |
| **PNM - San Juan Generating Station** | NM | **CANY1** | 4 | 33.7 | 47,113.4 (5.1%) | Y | TBD, NM has not finalized their second implementation period draft | Subject to four-factor analysis in NM's draft SIP. PNM has announced plant closure in 2022 |
| **Four Corners Power Plant** | TR | **CANY1** | 6 | 17.8 | 24,859.3 (2.7%) | N | | APS has announced plant closure in 2031 |
| **Pg&E Topock Compressor Station** | CA | **ZICA1** | 6 | 3.2 | 7,620.0 (3.1%) | N | | Not subject to four-factor analysis in CA's proposed SIP due to low NOx Q/d |
| **Chaco Gas Plant** | NM | **CANY1** | 8 | 7.8 | 14,056.2 (1.5%) | N | | Not subject to four-factor analysis in NM's proposed SIP |
| **Bonanza** | TR | **CAPI1** | 8 | 21.9 | 9,450.1 (1.1%) | N | | Likely closure in 2030 due to settlement |
| **Lhoist North America and Granite Const. (Apex)** | NV | **ZICA1** | 9 | 7.5 | 7,041.9 (2.8%) | Y | NV proposed SIP requires SNCR on Kilns 1, 3, & 4 as well as LNB on Kiln 1. Kilns 3 & 4 have existing LNBs. | NV's proposed SIP requires SNCR on Kilns 1, 3, & 4 as well as LNB on Kiln 1. Kilns 3 & 4 have existing LNBs. |
| **RED ROCK GATHERING-PREMIER BAR X C.S.** | CO | **CANY1** | 10 | 0.6 | 11,567.0 (1.3%) | N | | Not subject to four-factor analysis in CO's proposed SIP due to low NOX Q/d |

### Table 68: Second Implementation Period Status of Non-Utah Sources Identified in $SO_4$ WEP Analysis

| Facility Name | Source State | Utah CIA | Rank | SO2 Q/d | WEP_SO4 (% of Total) | Four-Factor Analysis Y/N | Proposed New Controls | Notes |
|---|---|---|---|---|---|---|---|---|
| **CHEMICAL LIME NELSON PLANT** | AZ | **BRCA1** | 1 | 8 | 43,684.7 (21.8%) | N | | Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls |
| **CHEMICAL LIME NELSON PLANT** | AZ | **ZICA1** | 1 | 10.9 | 38,687.4 (24.8%) | N | | Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls |
| **ASARCO LLC - HAYDEN SMELTER** | AZ | **ZICA1** | 3 | 6 | 6,672.2 (4.3%) | N | | Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls |
| **Four Corners Power Plant** | TR | **CANY1** | 4 | 11.1 | 32,557.0 (8.0%) | N | | APS has announced plant closure in 2031 |
| **CHEMICAL LIME NELSON PLANT** | AZ | **CAPI1** | 4 | 5.7 | 25,448.1 (6.4%) | N | | Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls |
| **McCarran Intl** | NV | **ZICA1** | 4 | 1.2 | 4,713.6 (3.0%) | N | | Majority of NOX emissions from non-road sources |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | (aircraft take-offs and landings) |
| **ASARCO LLC - HAYDEN SMELTER** | AZ | **BRCA1** | 5 | 5.8 | 14,391.7 (7.2%) | N | | Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls |
| **ASARCO LLC - HAYDEN SMELTER** | AZ | **CAPI1** | 6 | 5.2 | 10,351.8 (2.6%) | N | | Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls |
| **Phoenix Sky Harbor Intl** | AZ | **ZICA1** | 6 | 0.6 | 4,554.6 (2.9%) | N | | Majority of NOX emissions from non-road sources (aircraft take-offs and landings) |
| **Four Corners Power Plant** | TR | **BRCA1** | 7 | 7.4 | 5,413.2 (2.7%) | N | | APS has announced plant closure in 2031 |
| **TUCSON ELECTRIC POWER CO - SPRINGERVILLE** | AZ | **CANY1** | 7 | 15.1 | 13,923.7 (3.4%) | Y | SO2 Limits for Units 1 & 2: a) 16.1 tons SO2/day based on a daily rolling 20-calendar day average. b) 3,729 tons SO2/12-month rolling total | New SO2 limits for units 1 & 2 included in AZ's proposed SIP |
| **California Portland Cement Co.** | CA | **ZICA1** | 7 | 2.8 | 4,038.8 (2.6%) | N | | Not subject to four-factor analysis in CA's proposed SIP not required because it is subject to AB 617 which requires local air districts to evaluate large stationary sources to ensure reasonable controls are installed. |
| **CHEMICAL LIME NELSON PLANT** | AZ | **CANY1** | 8 | 4.6 | 13,409.0 (3.3%) | N | | Not subject to four-factor analysis in AZ's proposed SIP due to Round 1 BART FIP controls |
| **Republic Services Sunrise** | NV | **ZICA1** | 8 | 1 | 4,025.8 (2.6%) | N | | Not subject to four-factor analysis in NV's proposed SIP due to low Q/d |
| **TUCSON ELECTRIC POWER CO - SPRINGERVILLE** | AZ | **BRCA1** | 9 | 15.4 | 3,654.7 (1.8%) | Y | SO2 Limits for Units 1 & 2: a) 16.1 tons SO2/day based on a daily rolling 20-calendar day average. b) 3,729 tons SO2/12-month rolling total | New SO2 limits for units 1 & 2 included in AZ's proposed SIP |
| **Bonanza** | TR | **CANY1** | 9 | 6.9 | 11,908.4 (2.9%) | N | | Likely closure in 2030 due to settlement |
| **NORTH VALMY GENERATING STATION** | NV | **CAPI1** | 9 | 4 | 5,620.2 (1.4%) | Y | Permanent closure of units 1 and 2 by 12/31/28 | NV's proposed SIP includes a federally enforceable closure date of 12/31/28 |
| **TUCSON ELECTRIC POWER CO - SPRINGERVILLE** | AZ | **ZICA1** | 9 | 14.5 | 3,447.7 (2.2%) | Y | SO2 Limits for Units 1 & 2: a) 16.1 tons SO2/day based on a daily rolling 20-calendar day average. b) 3,729 tons SO2/12-month rolling total | New SO2 limits for units 1 & 2 included in AZ's proposed SIP |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Phoenix Sky Harbor Intl** | AZ | **BRCA1** | 10 | 0.6 | 3,615.9 (1.8%) | | | Majority of NOX emissions from non-road sources (aircraft take-offs and landings) |
| **PNM - San Juan Generating Station** | NM | **CANY1** | 10 | 3.7 | 10,995.1 (2.7%) | Y | | Subject to four-factor analysis in NM's draft SIP. PNM has announced plant closure in 2022 |
| **Bonanza** | TR | **CAPI1** | 10 | 4.9 | 4,809.0 (1.2%) | | | Likely closure in 2030 due to settlement |

## 9.C Documentation of Federal Land Manager consultation and commitment to continuing consultation

UDAQ continuously met with the FLMs throughout the second implementation period planning process. A summary of the meetings UDAQ held with the FLMs is outlined in the table below. UDAQ will continue to consult and collaborate with the FLMs in its future regional haze planning efforts.

**Table 69: Summary of FLM Meetings with UDAQ**

| Date | Time | Entity | Topic | Result |
|---|---|---|---|---|
| **5/5/21** | 8-9a | Utah DEQ/US Forest Service | Prescribed Fire and Regional Haze | Brief history of Utah's smoke management program and policy regarding it. |
| **5/6/21** | 1-1:30p | FLM | FLM/UT – Regional Haze Check-In | Updated FLMs on timeline and current RH SIP progress. They informed us on their view that visibility should not be main focus of 2nd planning period and to follow the rule more than the guidance document. They are primarily concerned about 4-factor analyses. |
| **6/22/21** | 12-12:30p | US Forestry Service - Ples Mcneel | RH update, introductions | Introduction to Ples Mcneel. Wants to be included in updates to FLMs and Paul Corrigan. |
| **10/12/21** | 12-11a | NPS | Regional Haze Update/Timeline change | Discussed RH SIP draft submittal. |
| **2/9/22** | 11:30a-1p | NPS | NPS UT Regional Haze Consultation | NPS presented UDAQ with the results of their 60-day review period |
| **2/23/22** | 11a-12p | USFS – Ples Mcneel and Paul Corrigan | Rx Fire Endpoint Adjustments | Discussed the Rx fire endpoint adjustments available to Utah. |
| **3/13/22** | 1:04p | NPS | RH Public Comment Schedule | Corresponded via email on the public comment process for UT's RH SIP. |
| **5/2/22** | 9:56a | NPS | Appendix D.2.C | Provided PDF version of appendix D.2.C via email. |
| **5/3/22** | 4:20p | NPS | Additional Source Information | Corresponded via email about additional information submittal by Sunnyside and Paradox. |
| **4/21-5/18/22** | Various | NPS | Additional Source Information | UDAQ provided additional information provided by Sunnyside, PacifiCorp, and USM via email. |
| **5/16-5/17/22** | Various | NPS | Public Comment Hearing | Corresponded via email on the logistics of the RH SIP public hearing. |
| **5/31/22** | 3:20p | NPS | Public Comment Submittal | NPS provided UDAQ with their comments on the RH SIP. |
| **6/7/22** | 7:13p | NPS | Additional Source Information | UDAQ provided NPS with comment submittals from Sunnyside and PacifiCorp as well as the link to all public comments. |
| **6/26/22** | 1:25p | NPS | Additional Source Information | UDAQ provided NPS with an additional information submittals by Sunnyside. |

### 9.C.1 FLM SIP Review[194]

UDAQ submitted its draft RH SIP for the second implementation period to the NPS on December 7th, 2021 and the USFS on December 15th, 2021. On February 14th, NPS and USFS provided UDAQ with their respective SIP reviews which can be found in Appendix D. Documentation of the public notice published by UDAQ on its website from April 25th to June 2nd, 2022 can be found in Appendix F.

### 9.C.2 NPS Feedback Summary and UDAQ Responses[195]

1. In general, NPS agrees that Utah's source selection process resulted in a reasonable subset of sources to evaluate in the draft SIP. Utah's recommendation to use a lower emission over distance threshold of six versus ten—as recommended by the WRAP—is more rigorous and resulted in a reasonable selection of facilities for evaluation.

2. UDAQ has not identified a cost threshold under which the evaluated controls would be considered reasonable. Many of the controls identified in the four-factor analyses for Utah sources are cost-effective based on cost criteria/thresholds identified by other states. NPS also feels that PacifiCorp should be subject to a higher cost threshold due to their plant's proximity to Utah's CIAs. The SIP should document the full rationale upon which the reasonable progress decisions are based.

   UDAQ Response: UDAQ will not be establishing a control cost threshold at this time. Please refer to chapter 8 for Utah's reasonable progress determinations for the second implementation period and the accompanying justifications, which UDAQ believes are sufficient.

3. NPS recommends that UDAQ require all technically feasible, cost-effective controls identified through four-factor analysis in this planning period.

   UDAQ Response: UDAQ has required all controls it has deemed technically feasible and cost effective. Please refer to the updated part H language in Appendix A to view the enforceable actions resulting from UDAQ's reasonable progress determinations for the purposes of the second implementation period.

4. In the draft SIP UDAQ writes that "Utah has analyzed the WRAP photochemical modeling for OTB 2028 and found that emissions from Utah do not significantly impact visibility at CIAs in other states." While it does not appear that this conclusion impacted the source selection process, it is not clear how Utah used this conclusion or whether it influenced their control technology determinations. NPS believes UDAQ's conclusion is

[194] See Appendix D for all FLM RH SIP review documents
[195] See Appendix D.1 and D.2 to view the full NPS review of Utah's RH SIP and supporting cost analyses

not compatible with their findings regarding the impact of Utah sources in Class I areas of neighboring states, and NPS recommends that UDAQ revise this section of the draft SIP by using a 1% threshold for determining significant impacts.

UDAQ Response: Section 6.A.2 has been revised in response to this comment.

5. Utah requested more information regarding where Utah stands in terms of RAVI for Class I areas. RAVI is a separate process from periodic SIP revisions. This avenue is rarely used by the FLMs to address specific sources causing visibility impairment at Class I areas. The NPS will not likely pursue RAVI certification unless the approaches identified in the periodic SIP revisions do not adequately address documented impairment.

6. UDAQ asked for feedback on using prescribed fire data from USFS to adjust projections. NPS does not take a position on the adjustment of glidepath end points for prescribed fire. We support UDAQ's determination to not use glidepath adjustments for estimated contributions from international emissions.

7. In Table 27: Sources initially selected to perform a Four-Factor analysis in draft SIP, section 7.A.1, NPS recommends identifying the nearest Class I area referenced in the "distance to nearest Class I area" column.

   UDAQ Response: A column identifying the nearest CIA has been added to Table 27 in section 7.A.1.

8. In section 8.D.6 there appears to be a typographical error listing Intermountain Generation Station closing in 2017.

   UDAQ Response: The typographical error in section 8.D.6 has been fixed and the closing year for IGS now reads as 2027.

9. NPS recommends UDAQ revise the permit limits for the Paradox Resources Lisbon Natural Gas Processing Plant to reflect the assumptions used to exclude this facility from four-factor analysis. NPS also recommends including the plant's recent actual emissions data in the SIP.

   UDAQ Response: UDAQ has received 2021 inventory data for the Lisbon Plant and created an emissions summary with resulting Q/d values in section 7.A.2.

10. NPS recommends that UDAQ conducts or requires a four-factor analysis for the Intermountain Power Intermountain Generation Station exploring opportunities to

improve the efficiency of the existing $SO_2$ scrubbers considering $NO_x$ emissions for the remaining useful life of the facility.

UDAQ Response: UDAQ has been in contact with IGS concerning this matter. UDAQ believes the station's existing $SO_2$ scrubbers are sufficient and that the plant is well controlled. UDAQ has also included IGS's 2028 closure in the proposed part H language for this SIP located in Appendix A, which would make the closure federally enforceable.

11. NPS requests that UDAQ provide a breakdown of emissions from the Kennecott units the state can regulate versus those it cannot regulate. UDAQ should explain how its $PM_{2.5}$ SIP includes in-use requirements for this equipment.

    UDAQ Response: Section 7.A.2 was revised and a breakdown of Kennecott's emissions was included in response to this comment.

12. NPS recommends that UDAQ reduce haze causing $SO_2$ emissions from Hunter and Huntington facilities by requiring an evaluation of $SO_2$ scrubber optimization and potential efficiency improvements and implement any technically feasible and cost-effective options identified.

    UDAQ Response: PacifiCorp has provided additional information concerning their existing $SO_2$ scrubbing[196]. The existing FGD $SO_2$ controls at the Hunter and Huntington power plants all have control efficiencies of at least 90% and each unit at these plants are subject to an $SO_2$ emissions limit of 0.12 lb/mmBtu through their respective Title V permits. It is PacifiCorp's stance that these controls are running as efficiently as possible and there are no cost-efficient upgrades available. The "RPELs" proposed in PacifiCorp's original four-factor analysis "combined operational adjustments (such as reduced until utilization) with incremental capital and O&M costs". Additionally, PacifiCorp cited EPA's 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" ("2019 Guidance") which recognizes that it "may be reasonable for a state not to select an effectively controlled source. A source may already have effective controls in place as a result of a previous regional haze SIP or to meet another CAA requirement."[197] UDAQ is adding the existing $SO_2$ emission limits for all five units to SIP Section IX.H23, Source Specific Emission Limitations: Regional Haze Requirements, Reasonable Progress Controls, to ensure federal enforceability of PacifiCorp's $SO_2$ limits in the regional haze context. Section 7.C.3 has been revised to include this information and additional discussion in response to this NPS comment.

[196] Please refer to Appendix D.2.C to view PacifiCorp's document on Regional Haze Second Planning Period Issues Regarding $SO_2$ Controls for PacifiCorp's Power Plants
[197] See page 22 of https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf?VersionId=QC2nPZHuAH1VYmm3EuhV9ABIGm5rQynb.

13. NPS generally agrees with UDAQ's revisions to PacifiCorp's $NO_x$ control technology cost analyses and used similar adjustments in their cost assessments. NPS also agrees with UDAQ that PacifiCorp's demonstration that the interest rate of 7.303% is their site-specific value and appropriate for use in their four-factor analyses.

14. NPS shares UDAQ's concerns with PacifiCorp's RPEL recommendation and support UDAQ's rejection of this proposal. RPEL would essentially be a "paper" reduction in emissions that would not reduce haze-causing emissions affecting visibility in Utah's CIAs.

15. NPS suggest that UDAQ could consider environmental co-benefits of $NO_x$ emission reduction as part of this factor. $NO_x$ is an ozone pre-cursor emission and ozone is known to affect both human and ecosystem health.

    UDAQ Response: UDAQ recognizes the co-benefits associated with pollutant emissions reductions and may highlight these benefits in the final draft of this SIP. However, UDAQ also recognizes the four-factor analysis[198] being the primary decision-making tool in this second implementation period and other benefits do not necessarily impact UDAQ's reasonable progress determinations.

16. NPS believes the cost of controls for the Sunnyside Cogeneration Facility are more economical than the company's estimates based on their calculations derived from the EPA Control Cost Manual. NPS disagrees with Sunnyside's use of a 7% interest rate and recommends UDAQ consider their control costs using the bank prime interest rate of 3.25%.

    UDAQ Response: Sunnyside Cogeneration provided additional justification found in Appendix D.2.A for the 7% interest rate they used in their control cost analysis. This rate was supported by a variety of institutions and most closely matched the financial indicators known by Sunnyside. UDAQ agrees with the final iterations of Sunnyside's estimated control costs.

17. NPS does not believe that Sunnyside has provided sufficient justification to exclude dry sorbent injection technology as technically feasible.

    UDAQ Response: UDAQ has received additional information regarding the feasibility and cost-effectiveness of dry sorbent injection technology from Sunnyside which has been included in Appendix D.2.G.

[198] Please refer to section 7.B to view the four factors used to determine control feasibility in this implementation period.

18. NPS's review of the Ash Grove Leamington Cement Plant suggests potential improvements may be available for their existing SNCR system. NPS recommends UDAQ request further evaluation of this opportunity to reduce $NO_x$ emissions from the facility.

    UDAQ's Response: In response to UDAQ's four-factor analysis evaluation, Ash Grove provided additional information on the efficiency of their SNCR system[199]. Based on this information, UDAQ believes this facility is well controlled for the purposes of this implementation period.

19. NPS's review of the Graymont Cricket Mountain Plant finds that their permitted emissions levels are significantly higher than their recent emissions levels. NPS believes the costs of controls would be more cost effective if emissions increased to permitted levels. NPS recommends UDAQ consider tightening permitted emissions limits for $NO_x$ and $SO_2$ to reflect future potential emissions and prevent backsliding.

    UDAQ Response: UDAQ contacted Graymont concerning their permitted emissions levels. The Cricket Mountain facility has seen a decrease in production over the past few years with special emphasis on the impacts of the COVID-19 pandemic. Graymont views this as a temporary decrease as the market is currently in the midst of recovery while they anticipate growth in their market. As this decrease is temporary, Graymont does not foresee the need to reduce its limits at this facility as it could reduce their flexibility to meet the market recovery and growth.

20. NPS recommends that numerical $NO_x$ and $SO_2$ emissions limits be incorporated into US Magnesium's current permit for the turbines/duct burners, chlorine reduction burner, melt/reactor, riley boiler, and the diesel engines would ensure that reasonable progress assumptions and determinations for the facility are adhered to.

    UDAQ Response: UDAQ issued an order to US Magnesium to obtain the information required to respond to these comments. USM provided responses on April 26th and May 11th, 2022 which can be found in Appendix D.2.E and F.

21. NPS recommends UDAQ re-evaluate the feasibility and costs of US Magnesium installing SCR on their turbines.

    UDAQ Response: See response to comment 20.

22. NPS recommends UDAQ reconsider requiring implementation of SCR on US Magnesium's riley boiler as part of this implementation period. Additionally, actual emission assumptions relied on to eliminate SCR from consideration be reflected in permit limitations for this unit.

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[199] Located in section 7.C.1 in Ash Grove's Evaluation Response

UDAQ Response: See response to comment 20.

23. NPS requests additional information and emissions verification on US Magnesium's diesel engines and engine replacement and/or electrification be included as additional emission control options in their four-factor analysis.

    UDAQ Response: See response to comment 20.

24. NPS recognizes the jurisdictional complexity of the Uintah and Paradox basins with 80% of the land being under tribal and EPA control. However, NPS recommends that air quality improvement will require cooperative and commensurate efforts from all agencies involved in air quality management in the basin and suggests UDAQ implement statewide rules to address oil and gas emission sources throughout Utah.

    UDAQ Response: Over the past several years, UDAQ has proposed and adopted a series of statewide rules specific to oil and gas operations found in Utah's state administrative rules R307-500 to 511. Though these rules have been focused on controlling VOC emissions, there is also a state-specific rule for natural gas-powered engines associated with oil and gas production. Since the rule was put in place in 2018, several sources have provided engine stack test data that have led UDAQ, EPA, and the Tribes to initiate further research and compliance studies on engines in the Basin, with a focus on two-stroke smaller horsepower engines that power pump jacks associated with oil-producing wells. The data collected have indicated lower values for $NO_x$ emissions than what was reported in the 2017 oil and gas emission inventory for these engines, yet much higher emissions of VOCs. UDAQ will be evaluating this data and will be evaluating future rulemaking for engines associated with oil and gas operations that would be statewide. UDAQ will coordinate with EPA and the Tribe to encourage that rules are consistent across all regulatory jurisdictions, but ultimately any controls under EPA jurisdiction on sources in Indian Country will be determined by EPA and the Tribe.

    The main pollutant of concern in the Uinta Basin is ozone, with VOCs and $NO_x$ being the actual precursor emissions that create ozone. Photochemical modeling has been a challenge in this area due to the complexity of the chemical reactions and unique geography and wintertime conditions. Therefore, it has not yet been determined what emission reductions will be the most effective to lower ozone values. However, initial thoughts are that the area is $NO_x$ limited. If this is shown to be the case, then $NO_x$ reductions will have a greater impact and as about 80% of $NO_x$ emissions in the Basin are associated with engines, UDAQ will definitely evaluate the reduction in $NO_x$ limits. As part of this evaluation, UDAQ will also keep in mind the NPS comments regarding the potential positive impacts on regional haze management. In summary, the evaluation of potentially lower VOC and $NO_x$ limits for engines associated with oil and gas production is actively in progress and Utah is working on further controlling $NO_x$ from engines for separate health standards.

### 9.C.3 USFS Feedback Summary and UDAQ Responses[200]

The USFS recognizes the emission reductions made in Utah over the past decade that have resulted in improvements in visibility at the Forest Service Class I Wilderness Areas and appreciates the working relationship among our respective staff. Overall, the USDA Forest Service found that the draft RH SIP is well organized and comprehensive. The Long-Term Strategies for this planning period appear to indicate that Forest Service Class I Wilderness Areas will continue to show visibility improvements better than the Uniform Rate of Progress (URP) through 2028, and USFS appreciates the commitment by UDEQ to evaluate progress in meeting the visibility goals during the 5-year progress reports.

40 CFR 51.308(f)(1)(vi)(B) allows states to adjust the glidepath to account for prescribed fire. The draft SIP states that no glidepath adjustment was made to account for prescribed fire emissions. The USFS encourages Utah DEQ to use the adjustment of glidepaths for the increased prescribed fire projections reflected in the “Future Fire Scenario 2” available in Product 18 of Modeling Express Tools of the WRAP TSS.

When considering the $R_x$ fire end-point adjustment, the USFS is concerned that industry or other groups could improperly argue that additional controls are not necessary to make further progress if modeling demonstrates that the Class I Area in Utah is below adjusted glidepaths, essentially arguing that the glidepath provides safe harbor from additional control requirements. The USFS believes this “safe harbor” argument is erroneous and is not supported by the Regional Haze Rule.

UDAQ Response: UDAQ appreciates the feedback from USFS as well as their work on the wildland prescribed fire adjustment. UDAQ acknowledges the visibility impacts expected future increases in wildland prescribed fire may have on Utah as well as the importance of prescribed fire for conservation. However, the impact of USFS’s glidepath adjustment is less significant for Utah’s CIAs than for those in other states. While the international and wildland prescribed fire adjustments are available for Utah’s CIA glidepaths, UDAQ is choosing to remain conservative for the purposes of this implementation period by not using them. However, this choice does not preclude the use of glidepath adjustments in future planning periods, since international and wildland prescribed fire emissions do impact Utah CIAs and are largely beyond the control of individual states and since prescribed fires are seen to be an increasingly important tool for land managers in the future.

[200] See Appendix D.3 to view the full USFS RH SIP review document

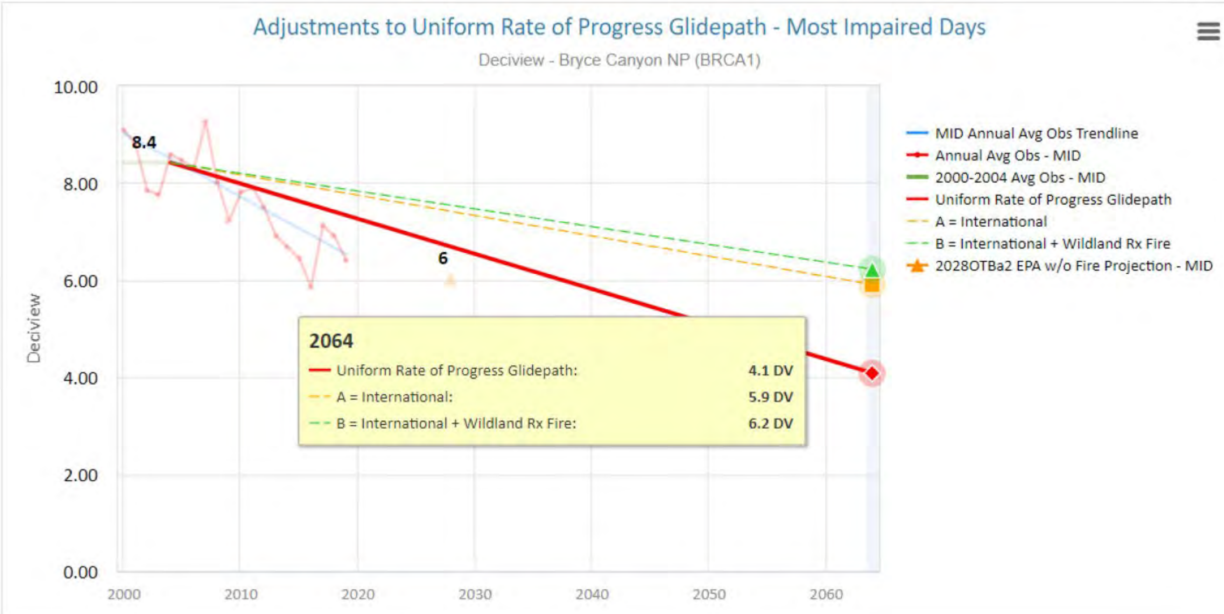


**Figure 69: USFS Fire Glidepath Adjustment for Bryce Canyon**

## 9.D Coordination with Indian tribes

Utah has five major tribes: the Ute, Dine' (Navajo), Paiute, Goshute, and Shoshone. There is one source in Northeast Utah where the Bonanza Power Plant is situated, but it resides in EPA jurisdiction. UDAQ sent the regional haze SIP draft to the tribes in Utah on December 9th, 2021, concurrently with submission to EPA and FLMs for a 60-day review. UDAQ has received no feedback from the tribes as of the submittal of this SIP. Documentation of this outreach can be found in Appendix E.

## 9.E Stakeholder Outreach and Communication

In the process of developing this SIP, Utah has been in contact with the five major sources subject to a four-factor analysis for controls feasibility. Upon evaluation of the five source's original four-factor analysis submittals, Utah evaluated and requested responses from each of the sources. This correspondence is summarized in Chapter 7. Utah has had several meetings with PacifiCorp concerning the implementation of controls in its Hunter and Huntington facilities. Utah also holds regular industry stakeholder meetings and environmental advocate meetings to update these groups on Utah's regional haze planning progress and address any questions or concerns they have regarding regional haze. Throughout the second implementation period, Utah also met with other state departments for coordination including the Department of Public Utilities and the Office of Energy Development.

**Table 70: Summary of Stakeholder Meetings with UDAQ**

| Date | Time | Entity | Topic | Result |
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| **4/27/21** | 4-5p | PacifiCorp and Wyoming | Regional Haze Pre-Meeting | Discussed possible controls and power plant planning. |
| **5/19/21** | 2-3p | Air Quality Advocates | DAQ-Utah Advocates Regional Haze Catch Up | Introduction to members of HEAL Utah, Sierra Club, and NPCA. They expect requirements for additional controls at power plants, especially Hunter and Huntington. |
| **6/23/21** | 12-1:05p | PacifiCorp | Presentation on legal risks and 4-factor evaluation | Discussed possible controls and issues with 4-factor analysis. |
| **7/7/21** | 10:30a-12p | RH Advocates Meeting | RH Update | Gave RH updates and discussed guidance vs rule issue. |
| **7/15/21** | 3:30-4:30p | DAQ, OED, DPU | RH and Power Plant Planning | Gave RH overview/update, informed them of PacifiCorp 4-factor eval, control options, and rule vs. guidance. |
| **7/19/21** | 9a | PacifiCorp | RH primer scheduling | Kirsten Merrit called about times for RH backgrounder. |
| **7/20/21** | 9:15a | PacifiCorp | RH primer scheduling | Kirsten Merrit called about invitees for RH backgrounder. |
| **10/27/21** | 8-9a | PacifiCorp | RH Follow-Up/Update | We discussed implementing new PALs for Hunter based on the emissions reductions installing SCR on Hunter 3 would have and Huntington based on their recent actuals in the 2028OTB modeling. |
| **11/3/21** | 10:30-11:30a | Air Quality Advocates | RH Update | Gave presentation with RH overview, Utah's RH history, current planning, and updated timeline for Utah's round two SIP. |
| **11/10/21** | 11a-12p | NPCA, Western Resources, & Sierra Club | RH Presentation Follow-Up | UDAQ addressed additional question resulting from the presentation given at the Air Quality Advocates Meeting. |
| **12/3/21** | 11a-12p | PacifiCorp | RH Update | Discussed control options for Hunter and Huntington. |
| **1/5/22** | 10:30-11:30a | Air Quality Advocates | RH Update | Offered to send the draft UT RH SIP to those who requested it via email. |
| **1/26/22** | 11:49a | Sunnyside | Information Submittal | Sunnyside provided control cost spreadsheets via email by NPS request |
| **3/2/22** | 10-11:30a | Air Quality Advocates | RH Update | Offered to send the FLM comment documents to those who requested it via email. |
| **3/4/22** | 10-10:15a | PacifiCorp – Kirsten Merrit | RH Information | Offered technical responses to FLM comments concerning the Hunter and Huntington power plants |
| **3/14/22** | 2-3p | Paradox Resources | RH Planning | Met with Paradox Resources to discuss FLM comments regarding their source, updating their permit for the Lisbon Plant, and obtaining 2021 inventory data. |
| **3/17/22** | 3-4p | PacifiCorp | RH Planning | Discussed PacifiCorp's SO2 scrubbing equipment and efficiency as well as the possibility of optimization. |
| **3/14/22** | 2-3p | Paradox | Information Request | Discussed emissions inventory data. |
| **3/14/22** | 1:12p | Sunnyside | Interest Rates | Sunnyside provided interest rate justification via email. |
| **3/17/22** | 4:12p | PacifiCorp | SO2 Scrubbing | PacifiCorp provided additional justification for SO2 scrubbing |
| **3/21/22** | 1-2p | Sunnyside | Information Request | Discussed DSI feasibility. |
| **4/18/22** | 1-2p | PacifiCorp | RH Discussion | Discussed future utilization. |
| **4/20/22** | 4:42p | PacifiCorp | EPA Comments | UDAQ provided EPA public comments. |
| **5/4/22** | 10-11:30a | Air Quality Advocates | RH Update | UDAQ provided the advocates with a RH update. |
| **5/24/22** | 1:30-2:30p | Sunnyside | NPS Comment Questions | Sunnyside requested clarification on NPS comments. |
| **5/24/22** | 2p | PacifiCorp | Public Hearing | Discussed public hearing logistics. |
| **5/27/22** | 11:58a | Sunnyside | Public Comment Submittal | Sunnyside submitted public comments. |
| **5/31/22** | 4:25p | PacifiCorp | Public Comment Submittal | PacifiCorp provided public comments on the RH SIP. |

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|---|---|---|---|---|
| **6/10/22** | 1-2p | PacifiCorp | RH Information | Discussed SO2 scrubbing. |
| **6/22/22** | 10-11a | Sunnyside | Water Rights/CDS | Discussed water rights and CDS feasibility. Sunnyside provided additional documentation via email. |
| **6/22/22** | 10:05a | PacifiCorp | Air Preheaters | PacifiCorp provided information on air preheater costs. |

## 9.F Public Comment Period

Utah's RH SIP for the second implementation period was presented to the Air Quality Board at their April 6th, 2022 meeting. The Board approved a 30-day public comment period beginning on May 1st, 2022 and ending on May 31st, 2022. Notices regarding the public comment period and availability of the SIP draft were published in the State Bulletin, posted on the UDAQ webpage, published in the Salt Lake Tribune (04/26/2022), Deseret News (04/27/2022) and the Spectrum (05/01/2022), and the AQ board actions update. UDAQ held a public hearing on May 26th, 2022 for the submission of verbal comments. UDAQ's public notice was published on UDAQ's webpage from April 30th to June 2nd, 2022. Documentation of this notice can be found in Appendix F.

## 9.G Comment Conclusions

During the public comment period, UDAQ received written and verbal comments from the following:

- EPA
- NPS
- The Conservation Organizations[201]
- Utah Petroleum Association
- Utah Mining Association
- PacifiCorp
- US Magnesium
- Sunnyside Cogeneration
- Intermountain Power Service Corporation
- Utah Associated Municipal Power Systems
- City of Moab
- Grand County Commission
- 657 individuals

[201] Comments submitted jointly by the National Parks Conservation Association, Sierra Club, Utah Physicians for a Healthy Environment, The Coalition to Protect America's National Parks, the Healthy Environmental Alliance of Utah, and O2 Utah

UDAQ reviewed all comments[202] which are summarized by topic and responded to in Appendix H. Some comments resulted in SIP revisions which include:

- Updated inventory graphs in Section 3.A.4 upon request from the Air Quality Board.
- Section 6.A.10 was updated with a table detailing emission reduction quantification for the long-term strategy. Strategies were not changed; the table was added for clarification.
- A new table in Section 7.A.2 to show existing controls in Utah's SIP for screened sources that have resulted from other SIP revisions, including $PM_{2.5}$.
- Part of section 7.A.3 was struck out and rewritten for clarity and improved justification for emission limits at Hunter and Huntington power plants.
- An environmental justice analysis and writeup was added to section 7.A.5.
- Additions to appendices to include additional information that sources have submitted.
- Multiple minor additions or deletions due to oversights, or for clarifications.
- SIP Subsection IX.H.23 changes include:
    - emission limits for screened-in sources' existing limits that were not already in IX.H,
    - annual stack testing at US Magnesium,
    - $SO_2$ limit exemptions were removed for startup, shutdown, and malfunction for Huntington, and
    - minor adjustments to Hunter and Huntington limits based on the improved justification.

## 9.H Commitment to Further Planning

Utah will continue its regional haze planning efforts through consultation efforts, participation in regional haze work groups, and SIP development.

### 9.H.1 Process for conducting future emissions inventories and future monitoring strategy

Utah will continue to triennially update its statewide emissions inventory as dictated by the Air Emissions Reporting Requirements (AERR)[203] and Utah's Continuous Emissions Monitoring Program[204] to track regional haze progress, participate in regional haze modeling efforts, and track emissions trends.

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[202] All public comments received by UDAQ on this SIP revision can be found on UDAQ's Current Regional Haze Planning web page here: https://deq.utah.gov/air-quality/regional-haze-in-utah#planning

[203] 73 Fed. Reg. 76539, 76552 (Dec. 17 2008). The AERR rule can be found at https://www.epa.gov/air-emissions-inventories/air-emissions-reporting-requirements-aerr

[204] Utah Admin. Code r. R307-170.

### 9.H.2 Commitment to provide other elements necessary to report on visibility, including reporting, recordkeeping, and other measures

Utah will provide any additional reporting, recordkeeping, and other measures necessary to continue its regional haze progress deemed necessary by the EPA or the regional haze work groups Utah participates in. At this time, no such additional efforts have been identified.

### 9.H.3 Commitment to submit January 31, 2025 progress report

Under the RHR, states must submit periodic progress reports to EPA evaluating their progress towards their RPGs. The 2017 RHR amendments adjusted the next progress report due date to be submitted by January 31, 2025. Utah commits to submitting this progress report and confirms that it will contain the following elements pursuant to the RHR:[205]

- Status of implementation of SIP measures for RPGs in Utah's CIAs and those outside the State identified as being impacted by emissions from within the state.
- Summary of emissions reductions in Utah adopted or identified as part of the RPG strategy.
- A five-year annual average assessment of the most and least impaired days for each CIA in Utah including the current visibility conditions, difference between current conditions and baseline, and change in visibility impairment over the five-year period.

[205] See page 6 of https://gardner.utah.edu/wp-content/uploads/ERG2022-Full.pdf?x71849.

# Certification

**R307-110**
**File number 54498 AMD**
**Effective July 7, 2022**

CERTIFIED A TRUE COPY
Office of Administrative Rules

**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 July 6, 2022, pursuant to Section 19-2-104, is incorporated by reference and made a part of these rules.

**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 July 6, 2022, pursuant to Section 19-2-104, is incorporated by reference and made a part of these rules.

**KEY: air pollution, PM10, PM2.5, ozone**
**Date of Last Change: July 7, 2022**
**Notice of Continuation: December 1, 2021**
**Authorizing, and Implemented or Interpreted Law: 19-2-104**

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I, Robert S. Wood, Rules Coordinator for the Utah Division of Air Quality, do hereby certify that the public comment periods held to receive comments regarding Utah State Implementation Plan Section XX.A, Section IX Part H.21, Part H.23, R307-110.17, and R307-110.28 (OAR #54498) were held in accordance with the information provided in the published public notices and as defined in Utah Code 19-2-109. These amendments to the SIP and associated rules were adopted by the Utah Air Quality Board on July 6, 2022.

Signed this first day of August, 2022.

Robert S. Wood