# *Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado*

## *Colorado Air Pollution Control Division*

***Revised Regional Haze Plan***
***Air Quality Control Commission, approved 01/07/2011***

# Table of Contents

# Preface/Disclaimer

The following document contains Colorado's State Implementation Plan for Regional Haze. Unless specifically stated in the text, all references to existing regulations or control measures are intended only to provide information about various aspects of the program described. Many of these controls are neither being submitted to EPA for approval nor being incorporated into the SIP as federally enforceable measures and are mentioned only as examples or references to Colorado air quality programs.

In developing and updating its Long Term Strategy (LTS) for reasonable progress, the State of Colorado takes into account the visibility impacts of several ongoing state programs that are not federally enforceable. These include statewide Colorado requirements applying to open burning, wildland fire smoke management, and renewable energy.

References in this SIP revision to such programs are intended to provide information that Colorado considers in developing its LTS and in its reasonable progress process. These programs are neither being submitted for EPA approval, nor for incorporation into the SIP by reference, nor are they intended to be federally enforceable. The Air Quality Control Commission Rules that govern them implement Colorado's programs and are not federally required. The state is precluded from submitting such programs for incorporation into this SIP by 25-7-105.1, C.R.S.

The following dates reflect actions by the Air Quality Control Commission associated with Colorado State Implementation Plan for Regional Haze:

| Regional Haze Plan | Approval Date |
|---|---|
| Original | 12/21/2007 |
| First Revision | 12/19/2008 |
| Second Revision<br>(Fully Replaces All Previous RH Plans) | 01/07/2011 |

# Chapter 1 Overview

## 1.1 Introduction

The Clean Air Act (CAA) defines the general concept of protecting visibility in each of the 156 Mandatory Class I Federal Areas across the nation. Section 169A from the 1977 CAA set forth the following national visibility goal:

> "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution."

The federal visibility regulations (40 CFR Part 51 Subpart P – Visibility Protection 51.300 - 309) detail a two-phased process to determine existing impairment in each of the Class I areas; how to remedy such impairment; and how to establish goals to restore visibility to 'natural conditions' by the year 2064. The federal regulations require states to prepare a State Implementation Plan (SIP) to:

- include a monitoring strategy
- address existing impairment from major stationary facilities (Reasonably Attributable Visibility Impairment)
- prevent future impairment from proposed facilities
- address Best Available Retrofit Technology (BART) for certain stationary sources
- consider other major sources of visibility impairment
- calculate baseline current and natural visibility conditions
- consult with the Federal Land Managers (FLMs) in the development or change to the SIP
- develop a long-term strategy to address issues facing the state
- set and achieve reasonable progress goals for each Class I area
- review the SIP every five years

Phase 1 of the visibility program, also known as Reasonably Attributable Visibility Impairment (RAVI), addresses impacts in Class I areas by establishing a process to evaluate source specific visibility impacts, or *plume blight*, from individual sources or small groups of sources. Part of that process relates to evaluation of sources prior to construction through the Prevention of Significant Deterioration (PSD) permit program looking at major stationary sources. The plume blight part of the Phase 1 program also allows for the evaluation, and possible control, of reasonably attributable impairment from existing sources.

Section 169B was added to the Clean Air Act Amendments of 1990 to address Regional Haze. Since Regional Haze and visibility problems do not respect state and tribal boundaries, the amendments authorized EPA to establish visibility transport regions as a way to combat regional haze.

Phase 2 of the visibility program addresses Regional Haze. This form of visibility impairment focuses on overall decreases in visual range, clarity, color, and ability to discern texture and details in Class I areas. The responsible air pollutants can be generated in the local vicinity or carried by the wind often many hundreds or even thousands of miles from where they originated. For technical and legal reasons the second part of the visibility program was not implemented in regulation until 1999. In 1999 the EPA finalized the Regional Haze Rule (RHR) requiring States to adopt a State Implementation Plans (SIPs) to address this other aspect of visibility impairment in the Class I areas. Under current rules the Regional Haze SIP were to be submitted to the EPA by December 31st, 2007. Colorado adopted key components of the Regional Haze SIP in 2007 and 2008 which were submitted to EPA in 2008 and 2009, respectively. EPA subsequently noted deficiencies in the BART determination and Reasonable Further Progress elements, as well as other, more minor issues. Colorado has proceeded to take steps to remedy these alleged deficiencies. This SIP addresses EPA's concerns. Updates to the BART evaluations and Reasonable Further Progress analyses constitute the major revisions to this 2010 plan. In addition, revisions to other chapters have been made to update emissions and monitoring data and descriptions of program changes impacting emissions regulations favoring improved visibility in the State.

The Regional Haze Rule envisions a long period, covered by several planning phases, to ultimately meet the congressionally established National Visibility Goal targeted to be met in 2064. Thus, the approach taken by Colorado, and other states, in preparing the plan is to set this initial planning period (2007-2018) as the "foundational plan" for the subsequent planning periods. This is an important concept when considering the nature of this SIP revision as compared to a SIP revision developed to address a nonattainment condition. The nonattainment plan must demonstrate necessary measures are implemented to meet the NAAQS by a specific time. On the other hand, the Regional Haze SIP must, among other things, set a Reasonable Progress Goal for each Class I area to protect the best days and to improve visibility on the worst days during the applicable time period for this SIP (2007-2018).

Colorado developed, and EPA approved, a SIP for the first Phase 1 of the visibility program. This Plan updates Phase 1 as well as establishing Phase 2 of the program, Regional Haze. The two key requirements of the Regional Haze program are:

- Improve visibility for the most impaired days, and
- Ensure no degradation in visibility for the least impaired days.

Though national visibility goals are targeted to be achieved by the year 2064,this plan is designed to meet the two requirements stated above for the period ending in 2018 (the first planning period in the federal rule), while also establishing enforceable controls to that will help to address the long term goal.

This SIP is intended to meet the requirements of EPA's Regional Haze rules that were adopted to comply with requirements set forth in the Clean Air Act. Elements of this Plan address the core requirements pursuant to 40 CFR 51.308(d) and the Best Available Retrofit Technology (BART) components of 40 CFR 50.308(e). In addition, this SIP addresses Regional Planning, State/Tribe and Federal Land Manager coordination, and contains a commitment to provide Plan revisions and adequacy determinations.

## 1.2 Visibility Impairment

Most visibility impairment occurs when pollution in the form of small particles scatter or absorb light. Air pollutants come from a variety of natural and anthropogenic sources. Natural sources can include windblown dust and smoke from wildfires. Anthropogenic sources can include motor vehicles and other transportation sources, electric utility and industrial fuel burning, minerals, oil and gas extraction and processing and manufacturing operations. More pollutants mean more absorption and scattering of light which reduces the clarity and color of a scene. Some types of particles such as sulfates scatter more light, particularly during humid conditions. Other particles like elemental carbon from combustion processes are highly efficient at absorbing light. Commonly, the receptor is the human eye and the object may be a single viewing target or a scene.

In the 156 Class I areas across the country, visual range has been substantially reduced by air pollution. In eastern parks, average visual range has decreased from 90 miles to 15-25 miles. In the West, visual range has decreased from an average of 140 miles to 35-90 miles. Colorado has some of the best visibility in the West but also has a number of areas where visibility is impaired due to a variety of sources. This SIP is designed to address regional haze requirements for the twelve mandatory Federal Class I areas in Colorado.

Some haze-causing particles are directly emitted to the air. Others are formed when gases emitted to the air form particles as they are transported many miles from the source of the pollutants. Some haze forming pollutants are also linked to human health problems and other environmental damage. Exposure to increased levels of very small particles in the air has been linked with increased respiratory illness, decreased lung function, and premature death. In addition, particles such as nitrates and sulfates contribute to acid deposition potentially making lakes, rivers, and streams less suitable for some forms of aquatic life and impacting flora in the ecosystem. These same acid particles can also erode materials such as paint, buildings or other natural and manmade structures.

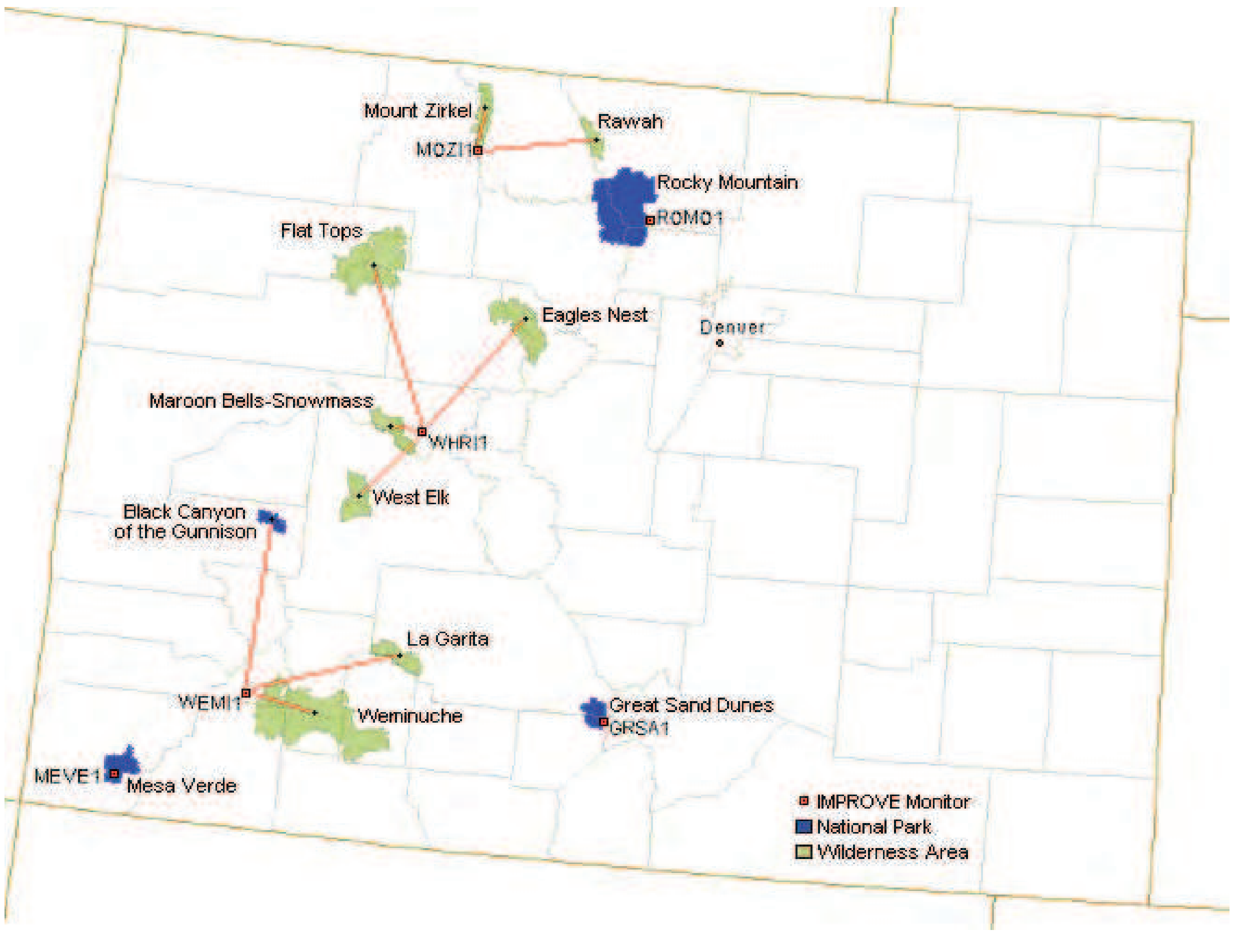
## 1.3 Description of Colorado's Class I Areas

There are 12 Mandatory Federal Class I Areas in the State of Colorado:

*Black Canyon of the Gunnison National Park*
*Eagles Nest Wilderness Area*
*Flat Tops Wilderness Area*
*Great Sand Dunes National Park*
*La Garita Wilderness Area*
*Maroon Bells-Snowmass Wilderness Area*
*Mesa Verde National Park*
*Mount Zirkel Wilderness Area*
*Rawah Wilderness Area*
*Rocky Mountain National Park*
*Weminuche Wilderness Area*
*West Elk Wilderness Area*

A detailed description of each of these areas, along with photographs, summaries of monitoring data containing an overview of current visibility conditions and sources of pollution in each area, is contained in individual Technical Support Documents (TSDs) for this plan (see list in Chapter 10). Each Class I area has been designated as impaired for visual air quality by the Federal Land Manager responsible for that area. Under the federal visibility regulations, the Colorado visibility SIP needs to address the visibility status of and control programs specific to each area. Figure 1-1 shows the location of these areas and the Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) monitoring site that measures particulate air pollution representative of each Class I area.

**Figure 1-1 Colorado Class I Areas and IMPROVE Monitor Locations**




## 1.4 Programs to Address Visibility Impairment

Colorado adopted a Phase 1 visibility SIP to address the PSD permitting, source specific haze, and plume blight aspects of visibility in 1987. The most recent plan update was approved by the EPA in December 2006.

As stated in the preface to this Plan, unless specifically stated in the text, all references to existing regulations or control measures are intended only to provide information about various aspects of the program described and are neither being submitted to EPA for approval nor being incorporated into the SIP as Federally enforceable measures. This comprehensive visibility plan, which now contains both Phase 1 and Phase 2 visibility requirements, addresses all aspects of Colorado's visibility improvement program. Colorado has numerous emission control programs to improve and protect visibility in Class I areas. In addition to the traditional Title V, New Source Performance Standards, Maximum Achievable Control Technology and new source review permitting programs for stationary sources, Colorado also has Statewide emission control requirements for oil and gas sources, open burning, wildland fire, smoke management, automobile emissions for Front Range communities, and residential woodburning, as well as PM10 nonattainment/maintenance area requirements, dust suppression for construction areas and unpaved roads and renewable energy requirements.

Colorado adopted legislation to address renewable energy by establishing long-term energy production goals. This program is expected to reduce future expected and real emissions from coal-fired power plants. This renewable energy measure was considered a key feature of the Grand Canyon Visibility Transport Commission's recommendations. Although the Colorado renewable energy program was not specifically adopted to meet regional haze requirements, emissions from fossil-fuel fired electricity generation are avoided in the future.

Colorado is also setting emission limits (as part of this plan) for those sources subject to Best Available Retrofit Technology (BART) requirements of Phase 2 of the visibility regulations for Regional Haze (described in detail in Chapter 6 of this plan). To comply with these BART limits sources subject to BART are required to install

and operate BART as expeditiously as practicable, but not later than 5 years after EPA's approval of the implementation plan revision.

As such, this Plan documents those programs, regulations, processes and controls deemed appropriate as measures to reduce regional haze and protect good visibility in the State toward meeting the 2018 and 2064 goals established in EPA regulations and the CAA.

## 1.5 Reasonable Progress Towards the 2064 Visibility Goals

As described in detail in Chapters 8 and 9 of this plan, reasonable progress goals for each Class I area have been established. The Division has worked with the Western Regional Air Partnership (WRAP) and with the WRAP's ongoing modeling program to establish and refine Reasonable Progress Goals (RPGs) for Colorado Class I Areas.

Technical analyses described in this Plan demonstrate emissions both inside and outside of Colorado have an appreciable impact on the State's Class I areas. Emission controls from many sources outside Colorado are reflected in emission inventory and modeling scenarios for future cases as detailed in the WRAP 2018 PRP18b control case. Progress toward the 2064 goal is determined based on emission control scenarios described in the WRAP inventory documentation plus the state's BART and reasonable progress determinations.

# Chapter 2 Plan Development and Consultation

This chapter discusses the process Colorado participated in to address consultation requirements with the federal land managers, tribes and other states in the Western Regional Air Partnership (WRAP) during the development of this Plan and future commitments for consultation.

Colorado has been a participating member of the WRAP since its inception. The WRAP completed a long-term strategic plan in 2003.[1] The Strategic Plan provides the overall schedule and objectives of the annual work plans and may be revised as appropriate. Among other things, the Strategic Plan (1) identifies major products and milestones; (2) serves as an instrument of coordination; (3) provides the direction and transparency needed to foster stakeholder participation and consensus-based decision making, which are key features of the WRAP process; and (4) provides guidance to the individual plans of WRAP forums and committees.

Much of the WRAP's effort is focused on regional technical analysis serving as the basis for developing strategies to meet the RHR requirement to demonstrate reasonable progress towards natural visibility conditions in Class I national parks and wilderness areas. This includes the compilation of emission inventories, air quality modeling, and ambient monitoring and data analysis. The WRAP is committed to using the most recent and scientifically acceptable data and methods. The WRAP does not sponsor basic research, but WRAP committees and forums interact with the research community to refine and incorporate the best available tools and information pertaining to western haze.

## 2.1 Consultation with Federal Land Managers (FLM)

Section 51.308(i) requires coordination between states and the Federal Land Managers (FLMs). Colorado has provided agency contacts to the Federal Land Managers as required. In development of this Plan, the Federal Land Managers were consulted in accordance with the provisions of 51.308(i)(2). Specifically, the rule requires the State to provide the Federal Land Manager with an opportunity for consultation, in person, and at least 60 days prior to holding any public hearing on an implementation plan or plan revision for regional haze. This consultation must include the opportunity for the affected Federal Land Managers to discuss their assessment of impairment of visibility in any mandatory Class I Federal area and recommendations on the development of the reasonable progress goal and on the development and implementation of strategies to address visibility impairment. The State must include a description of how it addressed any comments provided by the Federal Land Managers. Finally, the plan or revision must provide procedures for continuing consultation between the State and Federal Land Manager on the implementation of the visibility protection program required including development and review of implementation plan revisions and 5-year progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class I Federal areas.

[1] See http://www.wrapair.org/forums/sp/docs.html

Colorado participated in the WRAP to develop many elements of the SIP. The WRAP represents a conglomeration of stakeholder representing FLMs, industry, States, Tribes environmental groups and the general public. Through participation in this process, a significant portion of the consultation process with FLMs and other states has been met. In the WRAP process these stakeholders participated in various forums to help develop a coordinated emissions inventory and analysis of the impacts sources have on regional haze in the west. Coordination and evaluation of monitoring data and modeling processes were also overseen by WRAP participants. Through these coordinated technical evaluations, a regional haze-oriented evaluation of Colorado's Class I areas was constructed. Summaries of this information are available in the technical support documents of this Plan.

Public meetings were held at the Colorado Air Quality Control Commission in 2007 and 2008 to provide a comprehensive review of the technical basis for the Plan. Following these meetings, additional meetings were held with the FLMs directly concerning each of the affected Class I areas and the development of the SIP. Prior to the requests for a public hearing on the Regional Haze SIP in August and September 2010, the Division again met with the FLMs to review additions, corrections and changes to the SIP made to address both FLM concerns over the analysis of additional controls on sources not subject to BART and the completion of BART analyses occurring after the 2008 hearings (these new analyses and inventories are reflected later on in this SIP document).

The FLMs have provided comments to the Division regarding proposed regional haze determinations over the course of several years in 2007 and 2008, and again in 2010. The state has carefully considered these comments and has made changes to many of its proposed determinations based in part on these comments. For example, the state has deleted its regulatory prohibition on consideration of post-combustion controls as part of the BART analysis. The state also revisited its earlier BART determinations that relied in some respects on EPA's so called 'presumptive' emission limits for NOx and SO2, and in turn conducted robust facility-specific 5 and 4 factor analyses under BART and RP.

Most recently, the FLMs formally commented on the revised, proposed BART and RP determinations, as well as reasonable progress goals, in November and December 2010. The National Park Service, the Fish and Wildlife Service and the U.S. Forest Service provided support for the modeling approach used by the state in the BART determinations, complimented the state on thorough 5 and 4 factor analyses, clear criteria, area source evaluations, and comprehensive/improved BART and RP determinations, and presented recommendations for cost/emission limit re-evaluations. The state appreciates the supportive input from the FLMs, especially in the areas of modeling and the establishment of the RPGs. The state gave serious consideration to the recent recommendations for revising cost estimates and lowering emission limits, but the comments ultimately did not alter the state's conclusions and resulting proposals.

Regarding the costs of control, the FLMs provided numerous recommendations for revising BART and RP control costs. The state notes that there is no regulatory approach for determining costs of controls. The state considered the relevant factors for BART and RP determinations as set forth in the statute, the regulations and guidance, and consistent with the discretion expressly afforded to states under the statute and regulations. The state received detailed source-specific information for the facilities evaluated, checked this information using many different resources, and made adjustments/normalization when appropriate. The state employed engineering judgment and discretion when preparing BART and RP determinations, and found that the relevant present day and estimated future costs generally fell within the range of typical control costs nationwide. The state considered broader cost survey information to be relevant, and considered such information but did not find it dispositive; the state was informed more on facility-specific information as provided to the state to support its analyses and determinations. For most facilities even if different cost assumptions were employed or were re-assessed, expected visibility from the relevant control did not satisfy the state's guidance criteria for visibility improvement, and thus would not change the state's determination. Further, the state finds metrics like dollar per kilowatt hours or dollar per deciview of improvement of limited utility in considering the 5 or 4 factors, and opted to use its own more straightforward approach to balance and weigh costs of control and related visibility improvement. The costs used by the state were determined to be appropriate and reasonable, were balanced with the state's consideration of related visibility improvement, and further revisions based on FLM comments were not incorporated. The resulting emissions reductions from the state's BART and RP determinations for NOx and SO2 are significant and will benefit Class I Areas.

Regarding CALPUFF modeling, the FLMs provided support for the state's BART and RP modeling efforts, including the modeling protocol and methodologies. However, the state respectfully disagrees with the FLMs recommendations to cumulate visibility improvement impacts from emission controls across multiple Class I Areas. It is the state's position that the approach employed is consistent with a straightforward application of the regional haze regulation, and that the approach suggested by the FLMs, while an option that could be considered, as a general rule is not appropriate. The Commission in making its determinations on certain BART sources was aware that emissions reductions would have some level of visibility improvement in other than the most impacted Class I Area. The CALPUFF modeling output files have been and continue to be available to the FLMs or to the public to perform such analyses.

Regarding BART and RP emission limits, the FLMs provided numerous comments to the state, identifying opportunities for tightening most of the proposed limits. The state notes that there is no regulatory formula for establishing limits in the Regional Haze rule and the state applied professional judgment and utilized appropriate and delegated discretion in establishing appropriate emission limits. The stringency of the limits are tight enough to satisfy BART and RP requirements, but are not operationally unachievable. The emission limits fall within the range of limits adopted nationwide and were developed considering the requirements of the Regional Haze rule and related guidance.

Thus, between the WRAP, AQCC and individual meetings with the FLMs, the State has met the FLM consultation requirements.

Colorado commits to continued coordination and consultation with the Federal Land Managers during the development of future progress reports and Plan revisions, in accordance with the requirements of 51.308(i)(4).

## 2.2 Collaboration with Tribes

The Southern Ute Tribal lands in the southwest corner of Colorado are adjacent to Mesa Verde National Park, one of Colorado's Class I areas. As described above, Colorado participated in the collaborative WRAP process where Tribes were represented in all levels of the process. In addition, the Colorado Air Quality Control Commission had joint meetings with the Tribal Air Quality Council concerning regulatory and other processes related to air quality control and planning. The Southern Ute Tribe has numerous major and minor sources operating on their lands. Major source permitting is coordinated through a joint agreement with EPA Region IX. Minor sources on Tribal lands in Colorado are subject to the jurisdiction of the Tribes and this Plan contains no regulatory provisions for sources on Southern Ute lands in Colorado. The Tribes have the opportunity to develop Tribal Implementation Plans to address sources of pollution impacting visibility in their area.

## 2.3 Consultation with Other States

Pursuant to 40 CFR Section 51.308(d)(iv), Colorado consulted with other states during ongoing participation in the Regional Planning Organization, the Western Regional Air Partnership (WRAP), in developing the SIP. The WRAP is a collaborative effort of tribal governments, state governments and various federal agencies to implement the Grand Canyon Visibility Transport Commission's recommendations and to develop the technical and policy tools needed by western states and tribes to comply with the U.S. EPA's regional haze regulations. The WRAP is administered jointly by the Western Governors' Association and the National Tribal Environmental Council. WRAP activities are conducted by a network of committees and forums composed of WRAP members and stakeholders who represent a wide range of viewpoints. The WRAP recognizes that residents have the most to gain from improved visibility and that many solutions are best implemented at the local, state, tribal or regional level with public participation. Alaska, Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming have agreed to work together to address regional haze in the western United States. Colorado held specific discussions with states that have a primary impact on Colorado Class I areas. These include California, Utah, New Mexico and Arizona regarding the impacts from sources in these states on Colorado Class I areas.

The major amount of state consultation in the development of SIPs was through the Implementation Work Group (IWG) of the WRAP. Colorado participated in the IWG which took the products of the WRAP technical analysis and consultation process discussed above and developed a process for establishing reasonable progress goals in the western Class I areas. A description of that process is discussed in Chapter 8 -- Reasonable Progress Section of the State SIP.

Through the WRAP consultation process Colorado has reviewed and analyzed contributions from other states that reasonably may cause or contribute to visibility impairment in Colorado's Class I areas. While emissions from sources outside of Colorado have resulted in a slower rate of improvement in visibility than the rate that would be needed to attain natural conditions by 2064, most of these emissions are beyond the control of any state in the regional planning area of the WRAP. The emission sources include: emissions from outside the WRAP domain; emissions from Canada and Mexico; emissions from wildfires and windblown dust; and emissions from offshore shipping. Colorado anticipates that the long-term strategies when adopted by other states in their SIPs and approved by EPA will include emission reductions from a variety of sources that will reduce visibility impairment in Colorado's Class I areas.

Colorado's analysis of interstate impacts from specific nearby sources indicated the need for specific consultation with Nebraska, Wyoming, Utah, New Mexico and Arizona and California. In Nebraska the Gerald Gentleman Power Plant was analyzed for BART as part of the Nebraska RH process. Colorado commented to the State of Nebraska on this BART determination since emissions from this plant were indicated to impact Rocky Mountain National Park. Colorado similarly communicated with the State of Wyoming concerning BART determinations for its sources since impacts from Wyoming power plants were indicated to impact the Mt. Zirkel Wilderness Area. Colorado participated in the Four Corners Task force with Utah, New Mexico and Arizona and Tribal representatives to identify sources in the region adversely affecting air quality in the region. One element of that process was to consider sources impacting Mesa Verde or other Colorado Class I areas specifically for regional haze purposes. Through this process these States were made aware of Colorado's concerns about emissions from the Four Corners Power Plant, as it significantly impacts Mesa Verde. EPA Region IX was notified of Colorado's concerns with this facility since they are responsible for issuing and overseeing permits on this facility. Finally, California was contacted to discuss NOx emissions impacting Colorado Class I areas. California identified measures being taken in the State to reduce NOx emissions from mobile and other sources. Additional details concerning the Four Corners Task Force can be found in Section 9.5.5.3 of this Regional Haze SIP.

During the 2010 public hearing process, Colorado provided notification to the WRAP-member states and to other nearby states that a Regional Haze SIP revision had been prepared and invited review and comment on the plan and supporting documents.

By participating in the WRAP and the Four Corner's Task Force, and through specific comments and communications with the participating states, Colorado has satisfied the state consultation requirement.

## 2.4 General Consultation

As part of the regional haze SIP development process Colorado will continue to coordinate and consult with parties as summarized in the long-term strategy described in Chapter 9.

# Chapter 3 Monitoring Strategy

Federal regulations in 40 CFR 51.305 and 51.308(d)(4) require states to have a monitoring strategy in the SIP sufficient to characterize reasonable progress at each of the Class I areas, specifically Phase 1: reasonably attributable visibility impairment (RAVI) and Phase 2: regional haze visibility impairment in federal Class I areas within the state. Because Colorado adopted a visibility SIP to address the Phase 1 requirements (51.305), a monitoring strategy is currently in place through an approved SIP. The State of Colorado utilizes data from the IMPROVE monitoring system which is designed to provide a representative measure of visibility in each of Colorado's Class I areas.

## 3.1 RAVI Monitoring Strategy in Current Colorado LTS

States are required by EPA to have a monitoring strategy for evaluating visibility in any Class I area by visual observation or other appropriate monitoring techniques. The monitoring strategy in the RAVI LTS is based on meeting the following four goals:

1. To provide information for new source visibility impact analysis.
2. To determine existing conditions in Class I areas and the source(s) of any certified impairment.
3. To determine actual affects from the operation of new sources or modifications to major sources on nearby Class I areas.
4. To establish visibility trends in Class I areas to evaluate progress towards meeting the national visibility goal.

Potential new major source operators must conduct visibility analyses utilizing existing visibility data. If data are adequate and/or representative of the potentially impacted Class I area(s), the permit holder will be notified of the visibility levels against which impacts are to be assessed. If visibility data are not adequate, pre-construction monitoring of visibility may be required.

If the Federal Land Managers (FLMs) or the State of Colorado certifies existing impairment in a Class I area, the Division will determine if emissions from a local source(s) operator(s) can be reasonably attributed to cause or contribute to the documented visibility impairment. In making this determination the Division will consider all available data including the following:

1. Data supplied by the FLM;
2. The number and type of sources likely to impact visibility in the Class I area;
3. The existing emissions and control measures on the source(s);
4. The prevailing meteorology near the Class I area; and
5. Any modeling that may have been done for other air quality programs.

If available information is insufficient to make a decision regarding "reasonable attribution" of visibility impairment from an existing source(s) the State will initiate cooperative studies to help make such a determination. Such studies could involve the FLMs, the potentially affected source(s), the EPA, and others.

The monitoring strategy also included a commitment from the State to sponsor or share in the operation of visibility monitoring stations with FLMs as the need arises and resources allow.

The State commits to periodically compile information about visibility monitoring conducted by various entities throughout the State and assembling and evaluating visibility data.

Colorado law (C.R.S. 25-7-212(3)(a)) requires the federal land management agencies of Class I areas in Colorado (i.e., U.S.D.I. National Park Service and U.S.D.A. Forest Service) to “develop a plan for evaluating visibility in that area by visual observation or other appropriate monitoring technique approved by the federal environmental protection agency and shall submit such plan for approval by the division for incorporation by the commission as part of the state implementation plan.” The agencies indicated they developed, adopted, and implemented a monitoring plan through the Class I visibility monitoring collaborative known as IMPROVE. EPA’s Regional Haze Rule (40 CFR 51.308(d)(4)) indicates, “The State must submit with the Implementation Plan a monitoring strategy for measuring, characterizing, and reporting regional haze visibility impairment representative of all mandatory Class I Federal areas within the State….Compliance with this requirement may be met through participating in the Interagency Monitoring of Protected Visual Environments [IMPROVE] network.” The federal agencies’ monitoring plan relies on this network and ensures each Class I area in Colorado will have a monitor representative of visibility in the Class I area. In the LTS revision, submitted to EPA in 2008, the Division provided letters from the federal land managers and approval letters from the Division indicating this requirement was being met.

### 3.2 Regional Haze Visibility Impairment Monitoring Strategy

Under 40 CFR 51.308(d), a State must develop a monitoring strategy in the RH SIP to measure, characterize, and report regional haze visibility impairment representative of all federal Class I areas within the State. This monitoring strategy must be coordinated with the monitoring strategy described in Section 3.1 above, and will be met by participating in the IMPROVE network.

Colorado’s monitoring strategy is to participate in the IMPROVE monitoring network. To insure coordination with the RAVI monitoring strategy, it includes the same four goals as in the RAVI LTS plus an additional goal:

> To provide regional haze monitoring representing all visibility-protected federal Class I areas

## 3.3 Associated Monitoring Strategy Requirements

Other associated monitoring strategy requirements in 40 CFR 51.308(d)(4) and Colorado's associated SIP commitment are enumerated below:

1. Establishment of any additional monitoring sites or equipment to evaluate achievement of reasonable progress goals [40 CFR 51.308(d)(4)(i)].
    a. Colorado will work collaboratively with IMPROVE, EPA, the Federal Land Managers and other potential sponsors to ensure that representative monitoring continues for all of its Class I areas. If necessary, additional monitoring sites or equipment will be established to evaluate the achievement of reasonable progress goals.
    b. If funding for a site(s) is eliminated by EPA, the Division will consult with FLMs and IMPROVE to determine the best remaining site to use to represent the orphaned Class I areas.
2. Procedures describing how monitoring data and other information are used in determining the State's contribution of emissions to visibility impairment in any federal Class I area [40 CFR 51.308(d)(4)(ii)].
    a. Colorado has participated extensively in the WRAP. One of the Regional Modeling Center (RMC) tools is the PSAT (PM Source Apportionment Technology) that relates emission sources to relative impacts at Class I areas. Details about PSAT are contained in the Technical Support Documents for each Class I area. Colorado will utilize the PSAT method and other models as needed and recommended by EPA modeling guidance for visibility evaluations, or other tools, to assist in determining the State's emission contribution to visibility impairment in any federal Class I area. As part of this process the State commits to consult with the EPA and FLMs or other entities as deemed appropriate when using monitoring and other data to determine the State's contribution of emissions to impairment in any Class I area.
    b. Colorado will continue to review monitoring data from the IMPROVE sites and examine the chemical composition of individual specie concentrations and trends, to help understand the relative contribution of emissions from upwind states on Colorado Class I areas and any contributions from Colorado to downwind Class I areas in other states. This will occur no less than every five years in association with periodic SIP, LTS and monitoring strategy progress reports and reviews.
3. Provisions for annually reporting visibility monitoring data to EPA [40 CFR 51.308(d)(4)(iv)].
    a. IMPROVE data are centrally compiled and made available to EPA, states and the public via various electronic formats and websites including IMPROVE (http://vista.cira.colostate.edu/improve/) and VIEWS (http://vista.cira.colostate.edu/views/)Through participation in the IMPROVE network, Colorado will partially satisfies the requirement to annually report to EPA visibility data for each of Colorado's Class I areas.

b. An annual compilation of the Colorado data will be prepared and reported to the EPA electronically.

4. A statewide emissions inventory of pollutants reasonably expected to cause or contribute to visibility impairment for a baseline year, most recent year data is available, and future projected year [40 CFR 51.308(d)(4)(v)].

   a. Section 5.4 of this Plan includes a summary of Colorado statewide emissions by pollutant and source category. The inventory includes air pollution sources that can reasonably be expected to cause or contribute to visibility impairment to federal Class I areas.

      i. The WRAP-developed Plan02d (March 2008) inventory is both the baseline and most recent year of data available for a statewide inventory. It is an inventory intended to represent typical annual emissions during the baseline period, 2000-2004. From the baseline/current inventory, projections were made to 2018. The WRAP's 2018 Base Case or PRP18b inventory was utilized for final model projections. This represented the most recent BART determinations reported by the States and EPA offices, projection of future fossil-fuel electric generation plants, revised control strategy rulemaking and updated permit limits for point and area sources in the WRAP region as of Spring 2009 (http://www.wrapedms.org/InventoryDesc.aspx). The emission inventory information was collaboratively developed between Division staff and the WRAP. A summarized western state and boundary condition inventory is available at: http://vista.cira.colostate.edu/TSS/Results/emis_smry_p02c_b18b_a5.xls

5. Commitment to update the emissions inventory [40 CFR 51.308(d)(4)(v)].

   a. Colorado will update its portion of the regional inventory, on the tri-annual cycle as dictated by the Air Emissions Reporting Rule (AERR) (see section 3.5) in order to track emission change commitments and trends as well as for input to regional modeling exercises.

6. Any additional reporting, recordkeeping, and measures necessary to evaluate and report on visibility [40 CFR 51.308(d)(4)(vi)].

   a. Colorado will provide any additional reporting, recordkeeping and measures necessary to evaluate and report on visibility but is unaware of the need for any specific commitment at this time beyond those made in this section and in the LTS section.

## 3.4 Overview of the IMPROVE Monitoring Network

In the mid-1980's, the IMPROVE program was established to measure visibility impairment in mandatory Class I Federal areas throughout the United States. The monitoring sites are operated and maintained through a formal cooperative relationship between the EPA, National Park Service, U.S. Fish and Wildlife Service, Bureau of Land Management, and U.S. Forest Service. In 1991, several additional organizations joined the effort: State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials, Western States Air Resources

Council, Mid-Atlantic Regional Air Management Association, and Northeast States for Coordinated Air Use Management.

The objectives of the IMPROVE program include establishing the current visibility and aerosol conditions in mandatory Class I federal areas; identifying the chemical species and emission sources responsible for existing human-made visibility impairment; documenting long-term trends for assessing progress towards the national visibility goals; and support the requirements of the federal visibility rules by providing regional haze monitoring representing all visibility-protected federal Class I areas where practical.

The data collected at the IMPROVE monitoring sites are used by land managers, industry planners, scientists, consultants, public interest groups, and air quality regulators to better understand and protect the visual air quality resource in Class I areas.  Most importantly, the IMPROVE Program scientifically documents for American citizens, the visual air quality of their wilderness areas and national parks.

In Colorado, there are six IMPROVE monitors that are listed under the site name in Figure 3-1. As shown, some monitors serve multiple Class I areas.  For example, the monitor with site name Mount Zirkel is located just south of the Mount Zirkel Wilderness Area (on Buffalo Pass) but this monitor is also designated to represent the Rawah Wilderness Area.

**Figure 3-1 Colorado Class I Areas and IMPROVE Monitor Locations**

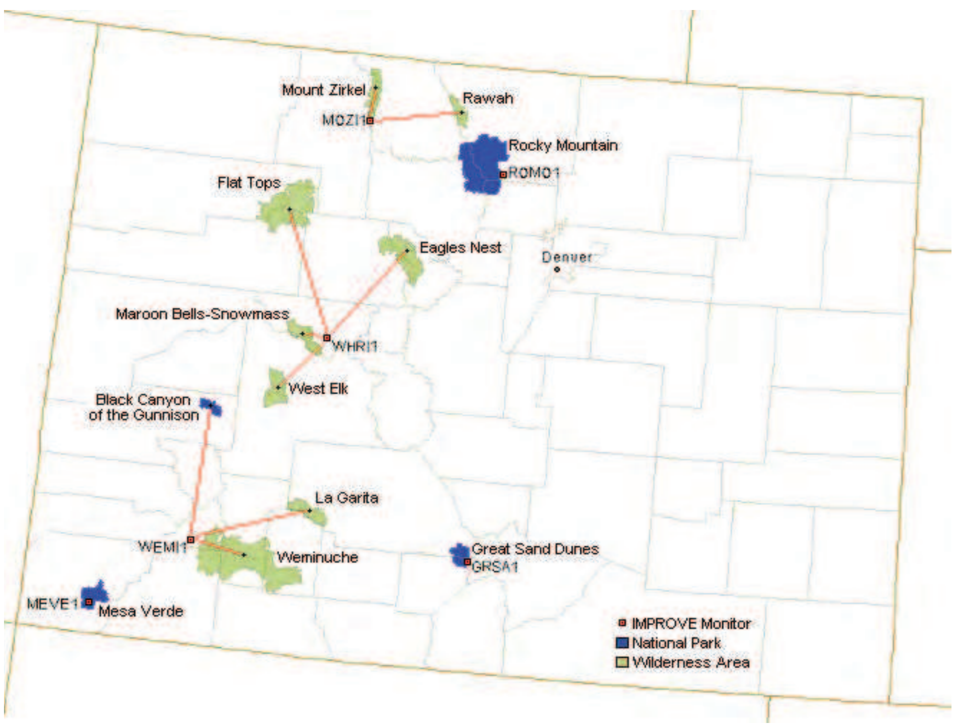



Figure 3-2 includes summary information for each IMPROVE monitor.  The National Park Service (NPS) and the U.S. Forest Service (USFS) each operate and maintain three IMPROVE monitors in the State.

**Figure 3-2 Colorado IMPROVE Monitoring Site Information**

| Mandatory Class I Federal Area | Operating Agency | IMPROVE Monitor | Elevation [ft] | Start Date |
|---|---|---|---|---|
| Great Sand Dunes National Park | NPS | GRSA1 | 8,215 | 5/4/1988 |
| Mesa Verde National Park | NPS | MEVE1 | 7,142 | 3/5/1988 |
| Mount Zirkel Wilderness | USFS | MOZI1 | 10,640 | 7/30/1994 |
| Rawah Wilderness | | | | |
| Rocky Mountain National Park | NPS | ROMO1 | 9,039 | 9/19/1990 |
| Weminuche Wilderness | USFS | WEMI1 | 9,072 | 3/2/1988 |
| Black Canyon of Gunnison NP | | | | |
| La Garita Wilderness | | | | |
| Eagles Nest Wilderness | USFS | WHRI1 | 11,214 | 7/17/2000 |
| Flat Tops Wilderness | | | | |
| Maroon Bells-Snowmass Wilderness | | | | |
| West Elk Wilderness | | | | |

## 3.5 Commitment for Future Monitoring

The State commits to continue utilizing the IMPROVE monitoring data and emission data to track reasonable progress. The State commits to providing summary visibility data in electronic format to the EPA on an annual basis from the IMPROVE monitoring, or other relevant sites. Also, the State commits to continue developing updated emission inventories on a tri-annual basis as required under the Air Emissions Reporting Rule sufficient to allow for the tracking of emission increases or decreases attributable to adopted strategies or other factors such as growth, economic downturn, or voluntary or permit related issues. These monitoring and emissions data will be available for electronic processing in future modeling or other emission tracking processes. Information collected from the monitoring system and emission inventory work will be made available to the public.

Colorado will depend on the Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) monitoring program[2] to collect and report aerosol monitoring data for reasonable progress tracking as specified in the Regional Haze Rule (RHR). Because the RHR is a long-term tracking program with an implementation period nominally set for 60 years, the state expects the configuration of the monitors, sampling site locations, laboratory analysis methods and data quality assurance, and network operation protocols will not change, or if changed, will remain directly comparable to those operated by the IMPROVE program during the 2000-04 RHR baseline period. Technical analyses and reasonable progress goals in RHR plans are based on data from these sites. The state must be notified and agree to any changes in the IMPROVE program affecting the RHR tracking sites, before changes are made. Further, the state notes resources to operate a complete and representative monitoring network of these long-term reasonable progress tracking sites is currently the responsibility of the Federal government. Colorado is satisfying the monitoring requirements by participating in the IMPROVE network. Colorado will continue to work with EPA in refining monitoring

[2] http://vista.cira.colostate.edu/improve/

strategies as new technologies become available in the future. If resource allocations change in supporting the monitoring network the state will work with the EPA and FLMs to address future monitoring requirements.

Colorado depends on IMPROVE program-operated monitors at six sites as identified in Figures 3.1 and 3.2 for tracking RHR reasonable progress. Colorado will depend on the routine timely reporting of monitoring data by the IMPROVE program for the reasonable progress tracking sites. Colorado commits to provide a yearly electronic report to the EPA of representative visibility data from the Colorado sites based on data availability from this network.

As required under 40 CFR 51.308(d)(4)(v) the State of Colorado has prepared a statewide inventory of emissions reasonably expected to cause or contribute to visibility impairment in Federal Class I Areas. Section 5.4 of this Plan summarizes the emissions by pollutant and source category.

The State of Colorado commits to updating statewide emissions on a tri-annual basis as required under the December 17, 2008 Air Emissions Reporting Rule (AERR). The updates will be used for state tracking of emission changes, trends, and input into any regional evaluation of whether reasonable progress goals are being achieved. Should no regional coordinating/planning agency exist in the future, Colorado commits to continue providing required emission updates as specified in the AERR and 40 CFR 51.308(d)(4)(v).

The State will use the Fire Emissions Tracking System (FETS)[3] to store and access fire emissions data. Should this system become unavailable Colorado will work with the FLMs and the EPA to establish a process to track and report fire emissions data if continued use of such information is deemed necessary. The State will also depend upon periodic collective emissions inventory efforts by other states meeting emission reporting requirements of the AERR to provide a regional inventory for future modeling and evaluations of regional haze impacts. Colorado recognizes that other inventories of a nature more sophisticated than available from the AERR may be required for future regional haze or other visibility modeling applications. In the past, such inventories were developed through joint efforts of states with the WRAP, and it is currently beyond available resources to provide an expanded regional haze modeling quality inventory if one is needed for future evaluations. The State will continue to depend on and use the capabilities of the WRAP-sponsored Regional Modeling Center (RMC)[4] or other similar joint modeling efforts to simulate the air quality impacts of emissions for haze planning purposes. The State notes the resources to ensure data preparation, storage, and analysis by the state and regional coordinating agencies such as the WRAP will require adequate ongoing resources. Colorado commits to work with other states, tribes, the FLMs and the EPA to help ensure future multi-state modeling, monitoring or inventory processes can be met but makes no commitment in this SIP to fund such processes. Colorado will track data related to RHR haze plan implementation for sources for which the state has regulatory authority.

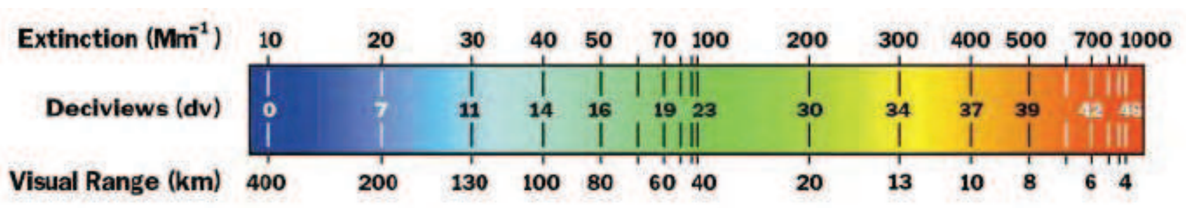
[3] http://www.wrapfets.org/
[4] http://pah.cert.ucr.edu/aqm/308/

# Chapter 4 Baseline and Natural Visibility Conditions in Colorado, and Uniform Progress for Each Class I Area

## 4.1 The Deciview

Each IMPROVE monitor collects particulate concentration data which are converted into reconstructed light extinction through a complex calculation using the IMPROVE equation (see Technical Support Documents for any Class I area). Reconstructed light extinction (denoted as $b_{ext}$) is expressed in units of inverse megameters (1/Mm or $Mm^{-1}$). The Regional Haze Rule requires the tracking of visibility conditions in terms of the Haze Index (HI) metric expressed in ***the deciview (dv)*** unit [(40 CFR 51.308(d)(2)]. Generally, a one deciview change in the haze index is likely humanly perceptible under ideal conditions regardless of background visibility conditions.

The relationship between extinction ($Mm^{-1}$), haze index (dv) and visual range (km) are indicated by the following scale:




## 4.2 Baseline and Current Visibility Conditions

EPA requires the calculation of baseline conditions [(40 CFR 51.308(d)(2)(i) and (ii)]. The baseline condition for each Colorado Class I area is defined as the five year average (annual values for 2000 - 2004) of IMPROVE monitoring data (expressed in deciviews) for the most-impaired (20% worst) days and the least-impaired (20% best) days. For this first regional haze SIP submittal, the baseline conditions are the reference point against which visibility improvement is tracked. For subsequent RH SIP updates (in the year 2018 and every 10 years thereafter), baseline conditions are used to calculate progress from the beginning of the regional haze program.

Current conditions for the best and worst days are calculated from a multiyear average, based on the most recent 5-years of monitored data available [40 CFR 51.308(f)(1)]. This value will be revised at the time of each periodic SIP revision, and will be used to illustrate: (1) The amount of progress made since the last SIP revision, and (2) the amount of progress made from the baseline period of the program.

Colorado has established baseline visibility for the cleanest and worst visibility days for each Class I area based on, on-site data from the IMPROVE monitoring sites. A five-year average (2000 to 2004) was calculated for each value (both best and worst). The calculations were made in accordance with 40 CFR 51.308(d)(2) and EPA's *Guidance for Tracking Progress Under the Regional Haze Rule* (EPA-454/B-03-004, September 2003). The IMPROVE II algorithm as described in the TSDs has been utilized for the calculation of Uniform Rate of Progress glide slopes for all Class I areas. Figure 4-4 contains the baseline conditions for each IMPROVE monitor site in Colorado.

## 4.3 Monitoring Data

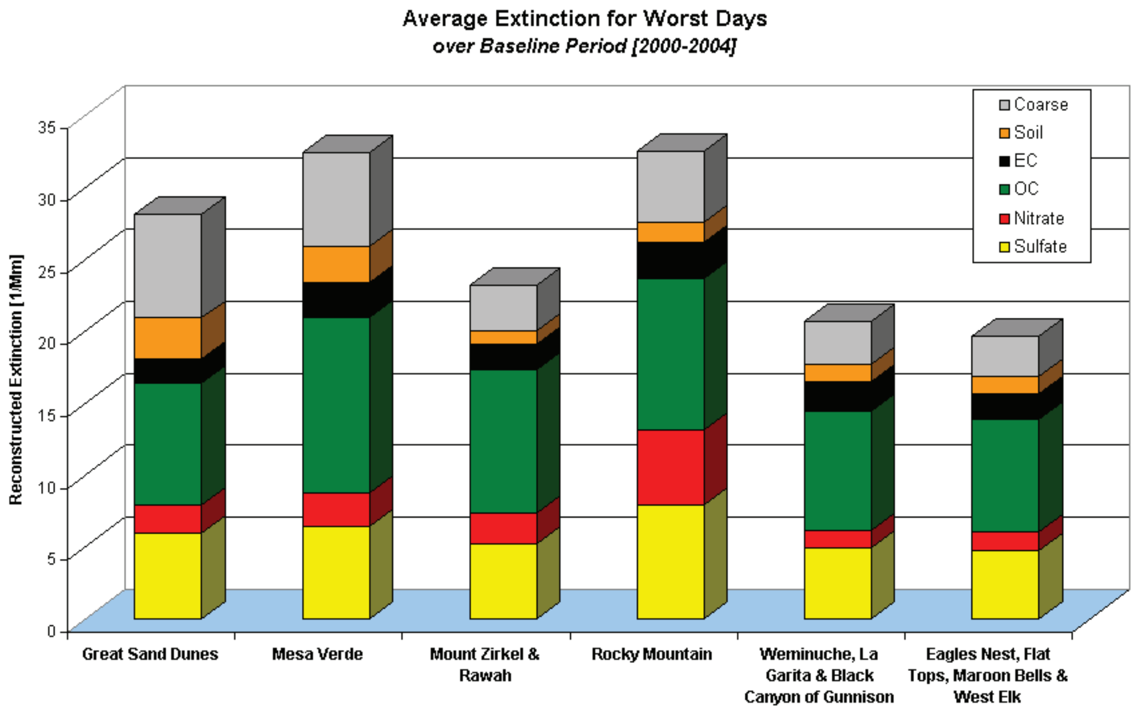
Visibility-impairing pollutants both reflect and absorb light in the atmosphere, thereby affecting the clarity of objects viewed at a distance by the human eye. Each haze pollutant has a different light extinction capability. In addition, relative humidity changes the effective light extinction of both nitrates and sulfates. Since haze pollutants can be present in varying amounts at different locations throughout the year, aerosol measurements of each visibility-impairing pollutant are made every three days at the IMPROVE monitors located in or near each Class I area.

In addition to extinction, the Regional Haze Rule requires another metric for analyzing visibility impairment, known as the “Haze Index”, which is based on the smallest unit of uniform visibility change that can be perceived by the human eye. The unit of measure is the deciview (denoted dv).

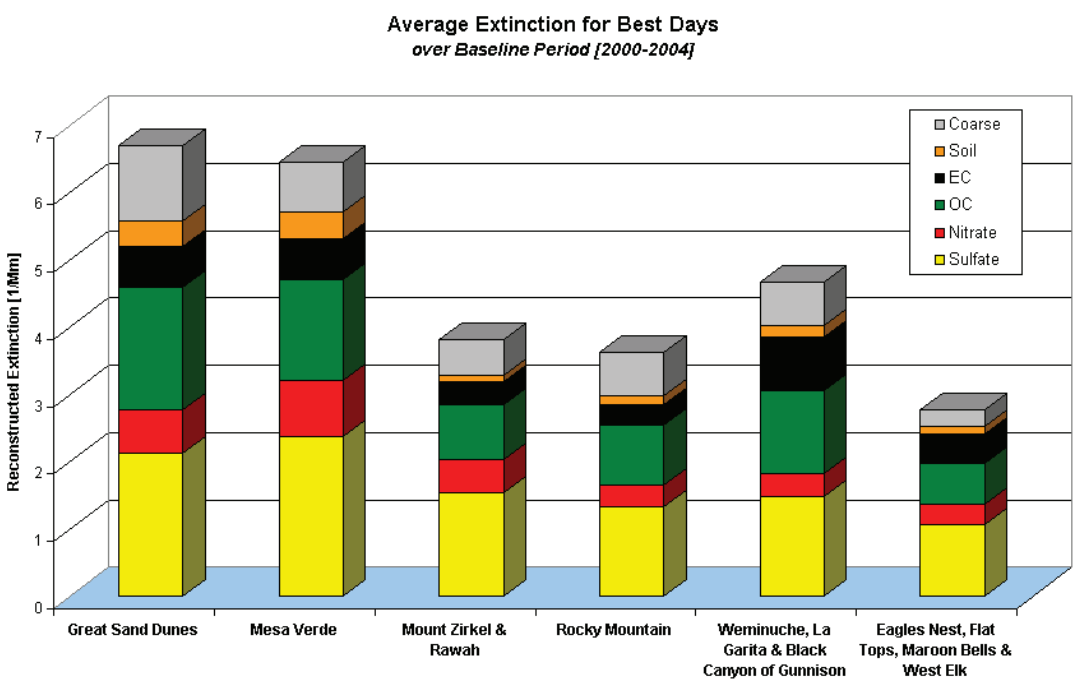
More detailed information on the methodology for reconstructing light extinction along with converting between the haze index and reconstructed light extinction can be found in the Technical Support Documents for any of Colorado’s twelve Class I areas.

The haze pollutants reported by the IMPROVE monitoring program are sulfates, nitrates, organic carbon, elemental carbon, fine soil and coarse mass. Summary data in Figures 4-1 and 4-2 are provided below for the worst and best days from the 6 IMPROVE monitors for the 6 haze pollutants.

## Figure 4-1 Reconstructed Aerosol Components for 20% Worst Days (2000-2004)




## Figure 4-2 Reconstructed Aerosol Components for 20% Best Days (2000-2004)




More detailed information on reconstructed extinction for each Class I area can be found in the Technical Support Document.

## 4.4 Natural Visibility Conditions

The natural condition for each Class I area represents the visibility goal expressed in deciviews for the most-impaired (20% worst) days and the least-impaired (20% best) days that would exist if there were only naturally occurring impairment. Natural visibility conditions must be calculated by estimating the degree of visibility impairment existing under natural conditions for the most impaired and least impaired days, based on available monitoring information and appropriate data analysis techniques. [(40 CFR 51.308(d)(iii)].

Figure 4-3, lists the 2064 natural conditions goal in deciviews for each Colorado Class I area. The natural conditions estimates were calculated consistent with EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* (EPA-454/B-03-005, September 2003). The natural conditions goal can be adjusted as new visibility information becomes available. The Natural Haze Level II Committee methodology was utilized as described in the TSD.

**Figure 4-3: 2064 Natural Conditions Goal for Worst Days**

| Mandatory Class I Federal Areas in Colorado | 2064 Natural Conditions for 20% Worst Days [Deciview] |
|---|---|
| Great Sand Dunes National Park & Preserve | 6.66 |
| Mesa Verde National Park | 6.81 |
| Mount Zirkel & Rawah Wilderness Areas | 6.08 |
| Rocky Mountain National Park | 7.15 |
| Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas | 6.21 |
| Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas | 6.06 |

## 4.5 Uniform Progress

For the worst days, uniform progress for each Colorado Class I area is the calculation of a uniform rate of progress per year to achieve natural conditions in 60 years [(40 CFR 51.308(d)(1)(i)(B)]. In this initial SIP submittal, the first benchmark is the 2018 deciview level based on the uniform rate of progress applied to the first fourteen years of the program. This is also shown in Figure 4-4 in the column "2018 Uniform Progress Goal (Deciview)".

For the 20% worst days, the uniform rate of progress (URP) in deciviews per year (i.e. slope of the glide path) is determined by the following equation:

*URP = [Baseline Condition - Natural Condition] / 60 years*

By multiplying the URP by the number of years in the 1$^{st}$ planning period one can calculate the uniform progress needed by 2018 to be on the path to achieving natural visibility conditions by 2064:

*2018 UPG = [URP] x [14 years]*

The 14 years comprising the 1st planning period includes the 4 years between the end of the baseline period and the SIP submittal date plus the standard 10-year planning period for subsequent SIP revisions.

More detailed information on the worst days along with the calculations and glide slope associated with each CIA can be found in Section 3 of the Technical Support Documents for any of Colorado's twelve Class I areas. This calculation is consistent with EPA's *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Rule* (June 1, 2007).

For the best days at each Class I area, the State must ensure no degradation in visibility for the least-impaired (20% best) days over the same period. More detailed information on the best days, along with the determination of the best day's baseline for a particular CIA, can be found in Section 3 of the Technical Support Document.

Figure 4-4 provides the 2018 uniform rate of progress chart for the worst days and the baseline that must not be exceeded over the years in order to maintain the best days. As with natural conditions, uniform rate of progress can be adjusted as new visibility information becomes available.

### Figure 4-4: Uniform Rate of Progress for Each Colorado Class I Area

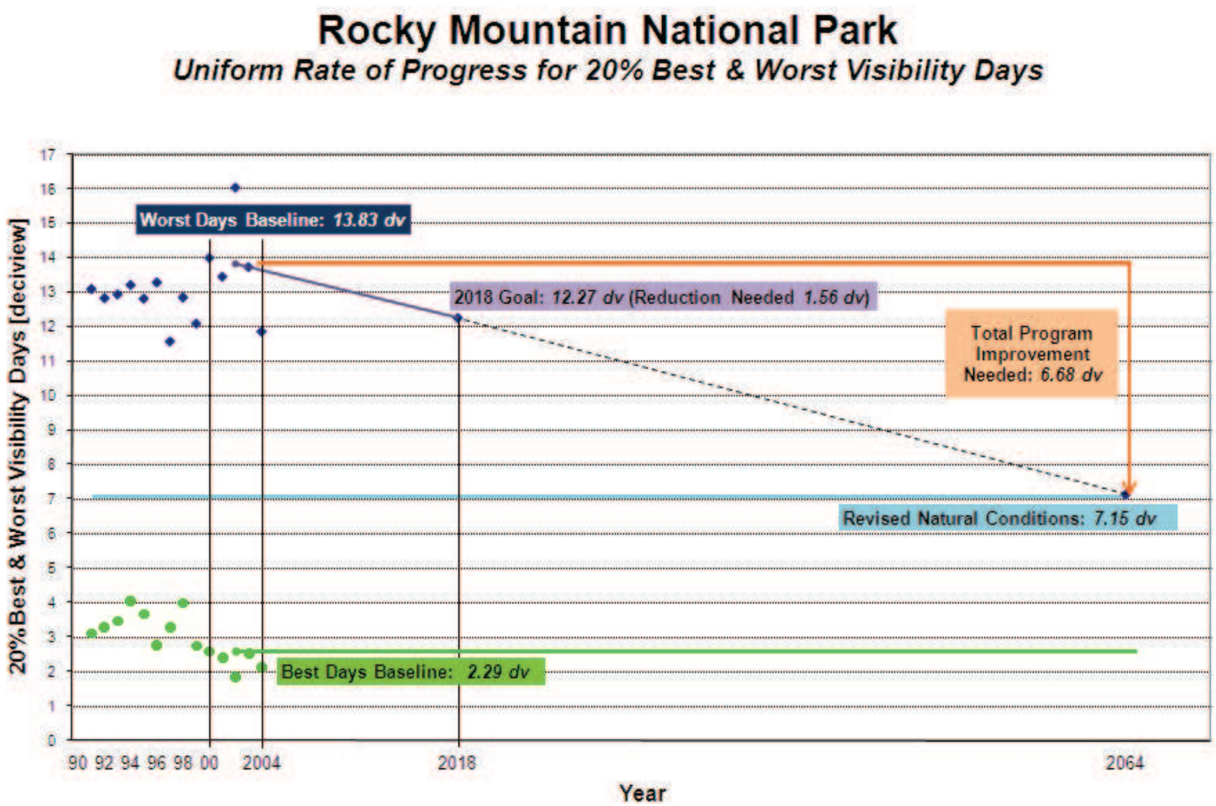
**Baseline Summary of Best & Worst Days in Haze Index Metric**

***Baseline Period (2000-2004)***

| | 20% Worst Days | | | | | 20% Best Days |
|---|---|---|---|---|---|---|
| Mandatory Class I Federal Area | Baseline Condition [Deciview] | 2018 Uniform Progress Goal [Deciview] | 2018 Goal Delta [Deciview] | 2064 Natural Conditions [deciview] | 2064 Delta (Baseline - 2064 NC) [deciview] | Best Days Baseline Condition [Deciview] |
| Great Sand Dunes National Park & Preserve | 12.78 | 11.35 | 1.43 | 6.66 | 6.12 | 4.50 |
| Mesa Verde National Park | 13.03 | 11.58 | 1.45 | 6.81 | 6.22 | 4.32 |
| Mount Zirkel & Rawah Wilderness Areas | 10.52 | 9.48 | 1.04 | 6.08 | 4.44 | 1.61 |
| Rocky Mountain National Park | 13.83 | 12.27 | 1.56 | 7.15 | 6.68 | 2.29 |
| Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas | 10.33 | 9.37 | 0.96 | 6.21 | 4.12 | 3.11 |
| Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas | 9.61 | 8.78 | 0.83 | 6.06 | 3.55 | 0.70 |

Figure 4-5 provides a visual example of 2018 uniform progress glide slope for the worst days and the best days baseline.

**Figure 4-5: Example of Uniform Progress for 20% Best & Worst Days at Rocky Mountain National Park**



# Chapter 5 Sources of Impairment in Colorado

## 5.1 Natural Sources of Visibility Impairment

Natural sources of visibility impairment include anything not directly attributed to human-caused emissions of visibility-impairing pollutants. Natural events (e.g. windblown dust, wildfire, volcanic activity, biogenic emissions) also introduce pollutants contributing to haze in the atmosphere. Natural visibility conditions are not constant; they vary with changing natural processes throughout the year. Specific natural events can lead to high short-term concentrations of visibility-impairing particulate matter and its precursors. Natural visibility conditions, for the purpose of Colorado's regional haze program, are represented by a long-term average of conditions expected to occur in the absence of emissions normally attributed to human activities. Natural visibility conditions reflect contemporary vegetated landscape, land-use patterns, and meteorological/climatic conditions. The 2064 goal is the natural visibility conditions for the 20% worst natural conditions days.

Natural sources contribute to visibility impairment but natural emissions cannot be realistically controlled or prevented by Colorado and therefore are beyond the scope of this plan. Current methods of analysis of IMPROVE data do not provide a distinction between natural and anthropogenic emissions. Instead, for the purposes of this SIP, they are estimated as described in Section 4.4.

## 5.2 Anthropogenic Sources of Visibility Impairment

Anthropogenic or human-caused sources of visibility impairment include anything directly attributable to human-caused activities producing emissions of visibility-impairing pollutants. Some examples include transportation, agriculture activities, mining operations, and fuel combustion. Anthropogenic visibility conditions are not constant and vary with changing human activities throughout the year. Generally anthropogenic emissions include not only those anthropogenic emissions generated or originating within the boundaries of the United States but also international emissions transported into a state. Some examples include emissions from Mexico, Canada, and maritime shipping emissions in the Pacific Ocean.

Although anthropogenic sources contribute to visibility impairment, international emissions cannot be regulated, controlled or prevented by the states and therefore are beyond the scope of this planning document. Any reductions in international emissions would likely fall under the purview of the U.S. EPA administrator.

## 5.3 Overview of Emission Inventory System -TSS

The Western Regional Air Partnership (WRAP) developed the Technical Support System (TSS) as an Internet access portal to all the data and analysis associated with the development of the technical foundations of Regional Haze plans across the Western US. The TSS provides state, county, and grid cell level emissions information for typical criteria pollutants such as SO2 & NOx and other secondary particulate forming pollutants such as VOC and NH3. Eleven different emission inventories were developed comprising the following source categories: point, area, on-road mobile, off-road mobile, oil and gas, anthropogenic fire, natural fire, biogenic, road dust, fugitive dust and windblown dust. Summaries of the emissions data for sources in Colorado are contained in subsequent Figures 5-1 through 5-8 in this section. In addition the Emissions Inventory TSD in this SIP contains a more detailed accounting of sources in Colorado used in the modeling exercise.

In the WRAP process, member states and the EPA agreed the tremendous amount of data collected, analyzed and maintained by the WRAP and the Regional Modeling Center would be impracticable and nearly infeasible to include in individual TSDs for individual States. For the purposes of administrative efficiency, WRAP data and analysis upon which the member states built their Regional Haze SIPs are available through the WRAP on the TSS Web site. For a more complete description of the emission inventory and process and for access information related to the web site containing comprehensive detail about the inventory please refer to the Emissions Inventory TSD in this SIP.

## 5.4 Emissions in Colorado

Federal visibility regulations (40 CFR 51.308(d)(4)(v)) require a statewide emission inventory of pollutants reasonably anticipated to cause or contribute to visibility impairment in any Class I area. The pollutants inventoried by the WRAP that Colorado used for this SIP include sulfur dioxide (SO2), nitrogen oxides (NOx), volatile organic compounds (VOC), primary organic aerosol (POA), elemental carbon (EC), fine particulate (Soil-PM2.5), coarse particulate (PM-2.5 to PM-10), and ammonia (NH3). An inventory was developed for the baseline year 2002, and projections of future emissions have been made for 2018. Colorado will provide updates to the EPA on this inventory on a three year basis as required by the AERR. Not all of the categories used for modeling purposes are contained in the AERR. A summary of the inventory results follows; the complete emission inventory is included in Section 5 of the Technical Support Document.

Emission inventories form one leg of the analysis stool to evaluate sources' impacts on visibility. Emission inventories are created for all of critical chemicals or species known to directly or indirectly impact visual air quality. These inventories become inputs to air quality models predicting concentrations of pollutants over a given space and time. For this SIP, the WRAP developed emission inventories for each state with input from participating stakeholders. A complete description of the development and content of the emission inventories can be found on the WRAP Technical Support System web site: http://vista.cira.colostate.edu/TSS/Results/Emissions.aspx and a summary description of the inventory is found in the Emission Inventory TSD.

Dispersion modeling predicts daily atmospheric concentrations of pollutants for the baseline year and these modeled results are compared to monitored data taken from the IMPROVE network. A second inventory is created to predict emissions in 2018 based on expected controls, growth, or other factors. Additional inventories are created for future years to simulate the impact of different control strategies. The process for inventorying sources is similar for all species of interest. The number and types of sources is identified by various methods. For example, major stationary sources report actual annual emission rates to the EPA national emissions database. Colorado collects annual emission data from both major and minor sources and this information is used as input into the emissions inventory. In other cases, such as mobile sources, an EPA mobile source emissions model is used to develop emission projections. Colorado vehicle registration, vehicle mile traveled information and other vehicle data are used to tailor the mobile source data to best represent statewide and area specific emissions. Population, employment and household data are used in other parts of the emissions modeling to characterize emissions from area sources such as home heating. Thus, for each source type, emissions are calculated based on an emission rate and the amount of time the source is operating. Emission rates can be based on actual measurements from the source, or EPA emission factors based on data from tests of similar types of emission sources. In essence all sources go through the same process. The number of sources is identified, emission rates are determined by measurements of those types of sources and the time of operation is determined. By multiplying the emission rate times the hours of operation in a day, a daily emission rate can be calculated.

It is noted that certain source categories are more difficult to make current and future projections for. This is simply because market dynamics, growth factors, improvements in emission factors, types and number of sources, improvements in controls and changes in regulations make the future less predictable. Oil and gas sources in Colorado can be substantial for selected pollutants and significant efforts went into this SIP to improve emissions estimates for Colorado and other western states to help make the modeling as reflective as possible of known and future emissions. Future SIP updates will take into account any new information related to this, and other, source categories.

The following presents the Colorado emissions from the TSS, as provided to the WRAP early 2009. The “Plan 2002(d)” and “PRP 2018(b)” phrases on each of the emission inventory tables signify the version of inventories by year. A detailed explanation of each plan can be found in the Emission Inventory TSD. These inventories do not reflect the additional emission reductions that will result from the 2010 revised Best Available Retrofit Technology and reasonable progress determinations. An accounting of these emission reductions are presented in Chapter 9 of this plan.

**Figure 5-1 Colorado SO2 Emission Inventory – 2002 & 2018**

| Colorado Planning and Projection Emission Inventories | | | |
|---|---|---|---|
| Source Category | Statewide SO2 Emissions | | |
| | Plan 2002(d) *[tons/year]* | PRP 2018(b) *[tons/year]* | Net Change |
| Point | 97,984 | 44,062 | -55% |
| Area | 6,533 | 7,644 | 17% |
| On-Road Mobile | 4,389 | 677 | -85% |
| Off-Road Mobile | 3,015 | 754 | -75% |
| WRAP Area O&G | 118 | 11 | -91% |
| Road Dust | 4 | 6 | 34% |
| Fugitive Dust | 6 | 5 | -13% |
| Anthro Fire | 108 | 91 | -15% |
| Natural Fire | 3,335 | 3,335 | 0% |
| Biogenic | - | - | - |
| **Total:** | **115,492** | **56,585** | **-51%** |

Sulfur dioxide emissions produce sulfate particles in the atmosphere. Ammonium sulfate particles have a significantly greater impact on visibility than pollutants like dust from unpaved roads due to the physical characteristics causing greater light scattering from the particles. Sulfur dioxide emissions come primarily from coal combustion at electrical generation facilities but smaller amounts come from natural gas combustion, mobile sources and even wood combustion. Other than natural fire there are no biogenic SO2 emissions of significance in Colorado. Even allowing for those fire-related sulfur dioxide emissions to be counted as 'natural' these represent only 3% of the statewide inventory. A 51% statewide reduction in SO2 emissions is expected by 2018 due to planned controls on existing point sources, even with a growth consideration for electrical generating capacity for the State. Similar reductions in the West are expected from other states as BART or other planned controls take effect by 2018. The only sulfur dioxide category expected to increase is area sources. Area sources of sulfur oxides are linked to population growth as the activity factor. As population increases in Colorado from the base case to 2018, this category is expected to increase. A typical area source for sulfur dioxide would be home heating.

**Figure 5-2 Colorado $NO_x$ Emission Inventory – 2002 & 2018**

| Colorado Planning and Projection Emission Inventories | | | |
|---|---|---|---|
| Source Category | Statewide NOx Emissions | | |
| | Plan 2002(d) *[tons/year]* | PRP 2018(b) *[tons/year]* | Net Change |
| Point | 118,667 | 101,818 | -14% |
| Area | 11,729 | 16,360 | 39% |
| On-Road Mobile | 141,883 | 45,249 | -68% |
| Off-Road Mobile | 62,448 | 37,916 | -39% |
| WRAP Area O&G | 23,518 | 33,517 | 43% |
| Road Dust | 1 | 1 | 32% |
| Fugitive Dust | 16 | 14 | -13% |
| Anthro Fire | 520 | 408 | -21% |
| Natural Fire | 9,377 | 9,377 | 0% |
| Biogenic | 37,349 | 37,349 | 0% |
| **Total:** | **405,507** | **282,010** | **-30%** |

Nitrogen oxides (NOx) are generated during any combustion process where nitrogen and oxygen from the atmosphere combine together under high temperature to form nitric oxide, and to a lesser degree nitrogen dioxide. Other odd oxides of nitrogen are also produced to a much smaller degree. Nitrogen oxides react in the atmosphere to form nitrate particles. Larger nitrate particles have a slightly greater impact on visibility than do sulfate particles of the same size and are much more effective at scattering light than mineral dust particles. Nitrogen oxide emissions in Colorado are expected to decline by 2018, primarily due to significant emission reductions from point, mobile and area sources. Off-road and on-road vehicles emissions will decline by more than 80,000 tons per year from the base case emissions total of 204,000 tons per year. Increases in area sources, as with sulfur dioxide, are related to population growth with an expected 4,000 tons per year increase by 2018. Again, home heating would be a typical area source of NOx with growth in emissions related to population increases. Oil and gas development by 2018 is also expected to increase statewide emissions by about 10,000 tons per year.

**Figure 5-3 Colorado VOC Emission Inventory – 2002 & 2018**

| Colorado Planning and Projection Emission Inventories | | | |
|---|---|---|---|
| Source Category | Statewide VOC Emissions | | |
| | Plan 2002(d) [tons/year] | PRP 2018(b) [tons/year] | Net Change |
| Point | 91,750 | 77,312 | -16% |
| Area | 99,191 | 136,032 | 37% |
| On-Road Mobile | 100,860 | 41,489 | -59% |
| Off-Road Mobile | 38,401 | 24,684 | -36% |
| WRAP Area O&G | 27,259 | 43,639 | 60% |
| Road Dust | - | - | - |
| Fugitive Dust | - | - | - |
| Anthro Fire | 915 | 666 | -27% |
| Natural Fire | 20,404 | 20,404 | 0% |
| Biogenic | 804,777 | 804,777 | 0% |
| **Total:** | **1,183,557** | **1,149,002** | **-3%** |

Volatile organic compounds (VOCs) are expected to decline slightly by 2018. Among other sources, volatile organic compounds from automobiles, industrial and commercial facilities, solvent use, and refueling automobiles all contribute to VOC loading in the atmosphere. Substantial natural emissions of VOCs come from vegetation. VOCs can directly impact visibility as emissions condense in the atmosphere to form an aerosol. Of more significance is the role VOCs play in the photochemical production of ozone in the troposphere. Volatile organic compounds react with nitrogen oxides to produce nitrated organic particles that impact visibility in the same series of chemical events that lead to ozone. Thus, strategies to reduce ozone in the atmosphere often lead to visibility improvements. The large increase in area sources is again related to population increases. Use of solvents such as in painting, dry cleaning, charcoal lighter, and windshield washer fluids, and many home use products, show up in the area source category and increases in this area are linked to population growth.

**Figure 5-4 Colorado Primary Organic Aerosol (POA) Emission Inventory – 2002 & 2018**

| Colorado Planning and Projection Emission Inventories | | | |
|---|---|---|---|
| Source Category | Statewide POA Emissions | | |
| | Plan 2002(d) *[tons/year]* | PRP 2018(b) *[tons/year]* | Net Change |
| Point | 17 | 3 | -83% |
| Area | 8,432 | 8,738 | 4% |
| On-Road Mobile | 1,280 | 1,288 | 1% |
| Off-Road Mobile | 1,286 | 843 | -34% |
| WRAP Area O&G | - | - | - |
| Road Dust | 102 | 135 | 33% |
| Fugitive Dust | 777 | 677 | -13% |
| Anthro Fire | 850 | 621 | -27% |
| Natural Fire | 30,581 | 30,581 | 0% |
| Biogenic | - | - | - |
| **Total:** | **43,325** | **42,886** | **-1%** |

Primary Organic Aerosols (POAs) are organic carbon particles emitted directly from the combustion of organic material. A wide variety of sources contribute to this classification including cooking of meat to diesel emissions and combustion byproducts from wood and agricultural burning. Area sources and automobile emissions dominate this classification. Increases in areas sources are due to population increases. These increases are offset by expected improvements in automobile emissions and by 2018 emissions from this category are expected to decline by about 5%.

**Figure 5-5 Colorado Elemental Carbon (EC) Emission Inventory – 2002 & 2018**

| Colorado Planning and Projection Emission Inventories | | | |
|---|---|---|---|
| | Statewide EC Emissions | | |
| Source Category | Plan 2002(d) [tons/year] | PRP 2018(b) [tons/year] | Net Change |
| Point | - | - | - |
| Area | 1,264 | 1,325 | 5% |
| On-Road Mobile | 1,448 | 408 | -72% |
| Off-Road Mobile | 3,175 | 1,344 | -58% |
| WRAP Area O&G | - | - | - |
| Road Dust | 9 | 11 | 33% |
| Fugitive Dust | 53 | 46 | -13% |
| Anthro Fire | 92 | 74 | -20% |
| Natural Fire | 6,337 | 6,337 | 0% |
| Biogenic | - | - | - |
| **Total:** | **12,377** | **9,545** | **-23%** |

Elemental carbon is the carbon black, or soot, a byproduct of incomplete combustion. It is the partner to primary organic aerosols and represents the more complete combustion of fuel producing carbon particulate matter as the end product. A carbon particle has a sixteen times greater impact on visibility than a coarse particle of granite has. Emissions, and reductions, in this category are dominated by mobile sources and expected new federal emission standards for mobile sources, especially for diesel engines, along with fleet replacement are the reason for these reductions.

### Figure 5-6 Colorado Soil (PM Fine) Emission Inventory – 2002 & 2018

| Colorado Planning and Projection Emission Inventories | | | |
|---|---|---|---|
| Source Category | Statewide Soil (fine PM) Emissions | | |
| | Plan 2002(d) *[tons/year]* | PRP 2018(b) *[tons/year]* | Net Change |
| Point | 6 | 85 | 1404% |
| Area | 4,170 | 4,311 | 3% |
| On-Road Mobile | - | - | - |
| Off-Road Mobile | - | - | - |
| WRAP Area O&G | - | - | - |
| Road Dust | 1,082 | 1,435 | 33% |
| Fugitive Dust | 13,401 | 11,679 | -13% |
| Windblown Dust | 15,105 | 15,105 | 0% |
| Anthro Fire | 253 | 169 | -33% |
| Natural Fire | 1,948 | 1,948 | 0% |
| Biogenic | - | - | - |
| **Total:** | **35,964** | **34,732** | **-3%** |

Fine soil emissions are largely related to agricultural and mining activities, windblown dust from construction areas and emissions from unpaved and paved roads. A particle of fine dust has a relative impact on visibility one tenth as great as a particle of elemental carbon. Monitoring at all sites in Colorado indicates soil is present as a small but measurable part of the visibility problem. On any given visibility event where poor visual air quality is present in a scene, the impact of dust can vary widely. Overall, on the 20% worst days, fine soil has about the same impact as nitrate particles. Agricultural activities, dust from unpaved roads and construction are prevalent in this source category and changes in emissions are tied to population and vehicle miles traveled. Since soil emissions are not directly from the tailpipe of the vehicle, the category of mobile sources does not show any emissions and all vehicle related emissions from paved and unpaved roads show up in the fugitive dust category.

**Figure 5-7 Colorado Coarse Mass (PM Coarse) Emission Inventory – 2002 & 2018**

| Colorado Planning and Projection Emission Inventories | | | |
|---|---|---|---|
| Source Category | Statewide Coarse PM Emissions | | |
| | Plan 2002(d) [tons/year] | PRP 2018(b) [tons/year] | Net Change |
| Point | 21,096 | 26,828 | 27% |
| Area | 1,363 | 1,388 | 2% |
| On-Road Mobile | 794 | 917 | 15% |
| Off-Road Mobile | - | - | - |
| WRAP Area O&G | - | - | - |
| Road Dust | 8,930 | 11,826 | 32% |
| Fugitive Dust | 67,642 | 67,910 | 0% |
| Windblown Dust | 135,945 | 135,945 | 0% |
| Anthro Fire | 51 | 32 | -37% |
| Natural Fire | 5,973 | 5,973 | 0% |
| Biogenic | - | - | - |
| **Total:** | **241,794** | **250,818** | **4%** |

Particulate matter, also identified as coarse mass particles emissions, are closely related to the same sources as fine soil emissions but other activities like rock crushing and processing, material transfer, open pit mining and unpaved road emissions can be prominent sources. Coarse mass particles travel shorter distances in the atmosphere than some other smaller particles but can remain in the atmosphere sufficiently long enough to play a role in regional haze. Coarse mass particulate matter has the smallest direct impact on regional haze on a particle-by-particle basis where one particle of coarse mass has a relative visibility weight of 0.6 compared to a carbon particle having a weight of 10. Nevertheless, they are commonly present at all monitoring sites and are a greater contributor to regional haze than the fine soil component. Substantial increases in coarse mass are seen in the fugitive dust category. This is due to the fact that construction and emissions from paved and unpaved roads are lined to population, vehicle miles traveled and employment data. Growth in these factors results in these categories increasing from 2002 to 2018. For this planning period, the state evaluated PM from stationary sources, but not from natural sources.

**Figure 5-8 Colorado Ammonia (NH3) Emission Inventory – 2002 & 2018**

| Colorado Planning and Projection Emission Inventories | | | |
|---|---|---|---|
| Source Category | Statewide Ammonia Emissions | | |
| | Plan 2002(d) [tons/year] | PRP 2018(b) [tons/year] | Net Change |
| Point | 453 | 571 | 26% |
| Area | 60,771 | 60,791 | 0% |
| On-Road Mobile | 4,317 | 5,894 | 37% |
| Off-Road Mobile | 43 | 60 | 38% |
| WRAP Area O&G | - | - | - |
| Road Dust | - | - | - |
| Fugitive Dust | - | - | - |
| Anthro Fire | 137 | 95 | -31% |
| Natural Fire | 1,965 | 1,965 | 0% |
| Biogenic | - | - | - |
| **Total:** | **67,686** | **69,375** | **2%** |

Ammonia emissions come from a variety of sources including wastewater treatment facilities, livestock operations, and fertilizer application and to a small extent, mobile sources. Increases in ammonia emission from the base case year to 2018 are linked to population statistics and increased vehicular traffic. Ammonia is directly linked to the production of ammonium nitrate and ammonium sulfate particles in the atmosphere when sulfur dioxide and nitrogen oxides eventually convert over to these forms of particles. Expected growth in the mobile source emissions from 2002 to 2018 is due to the fact that no specific controls on mobile sources are implemented and increases in vehicle miles traveled links directly to increased ammonia emissions.

# Chapter 6 Best Available Retrofit Technology

## 6.1 Introduction

One of the principal elements of Section 169A of the 1977 Clean Air Act Amendments addresses the installation of Best Available Retrofit Technology (BART) for certain existing sources of pollution. The provision, 169A (b)(2), demonstrates Congress' intent to focus attention directly on pollution from a specific group of existing sources. The U.S. Environmental Protection Agency's (EPA) Regional Haze Rule requires certain emission sources that may reasonably be anticipated to cause or contribute to visibility impairment in downwind Class I areas to install BART. *See* 40 CFR §51.308(e); *see also* 64 Fed. Reg. 35714 *et seq.* (July 1, 1999). These requirements are intended to reduce emissions from certain large sources that, due to age, were exempted from other requirements of the Clean Air Act.

BART requirements pertain to 26 specified major point source categories including power plants, cement kilns and industrial boilers. To be considered BART-eligible, sources from these categories must have the potential to emit 250 tons or more of haze forming pollution and must have commenced operation in the 15-year period prior to August 7, 1977.

Because of the regional focus of this requirement in the Regional Haze Rule, BART applies to a larger number of sources than the Phase 1 reasonably attributable visibility impairment requirements. In addition to source-by-source command and control BART implementation, EPA has allowed for more flexible alternatives if they achieve greater progress toward the state's visibility goals than the standard BART approach.

This document demonstrates how Colorado has satisfied the BART requirements in EPA's Regional Haze Rule. Colorado's review process is described and a list of BART-eligible sources is provided. A list of sources that are subject to BART is also provided, along with the requisite modeling analysis approach and justification.

## 6.2 Overview of Colorado's BART Regulation

Colorado's Air Quality Control Commission approved a State-only BART regulation (Regulation 3 Part F) on March 16, 2006, that became effective in May 2006. A summary of the Colorado BART program and determinations is set out below, in Section 6.3. More detail is provided in Regulation Number 3 Part F, Appendix C to this document, the Technical Support Document (TSD), and at the Division's BART website at: http://www.cdphe.state.co.us/ap/RegionalHazeBART.html.

Colorado's BART Rule includes the following major provisions:

1. Visibility impairing pollutants are defined to include SO2, NOx and particulate matter.
2. Visibility impact levels are established for determining whether a given source causes or contributes to visibility impairment for purposes of the source being

subject-to-BART (or excluded). The causation threshold is 1.0 deciview and the contribution threshold is 0.5 deciview. Individual sources are exempt from BART if the 98th percentile daily change in visibility from the facility, as compared against natural background conditions, is less than 0.5 deciview at all Class I federal areas for each year modeled and for the entire multi-year modeling period.

3. BART controls are established based on a case-by-case analysis taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source or unit, the remaining useful life of the source or unit, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. These factors are established in the definition of Best Available Retrofit Technology.
4. Provision that the installation of regional haze BART controls exempts a source from additional BART controls for regional haze, but does not exempt a source from additional controls or emission reductions that may be necessary to make reasonable progress under the regional haze SIP.

## 6.3 Summary of Colorado's BART Determinations

Colorado's Air Quality Control Commission elected to assume that all BART-eligible sources are subject to BART, but required the Division to perform modeling to determine whether BART-eligible sources will cause or contribute to visibility impairment at any Class I area. The threshold for causing or contributing to impairment was 0.5 or greater deciview impact. BART-eligible sources that did not cause or contribute 0.5 or greater deciview impact would not be subject to BART.

Once the complete list of eligible sources had been assembled, the list was reviewed to determine the current status of each source. A number of sources were eliminated for various reasons. One plant was being shut down. Two others were found not to be subject to BART because the size of the boilers was less than the 250 MMBtu/hour limit identified in the EPA BART Rule. Two sources were not subject to BART because they had been re-constructed after the BART period, and two were exempt because VOCs are not a visibility impairing pollutant under Colorado's BART Rule. The final list of sources was modeled by the Division to determine if they met the "cause or contribute" criteria. The results of this modeling are reflected in Table 6 - 1 below.

**Table 6 - 1 Results of Subject-to-BART Modeling**

| Modeled BART–Eligible Source | Division Modeling (98th percentile delta-deciview value) | Division Approved Refined Modeling from Source Operator (98th percentile delta-deciview value) | Contribution Threshold (deciviews) | Impact Equal to or Greater Than Contribution Threshold? |
|---|---|---|---|---|
| CEMEX - Lyons Cement Kiln & Dryer | 1.533 | | 0.5 | Yes |
| CENC (Trigen-Colorado) Units 4 & 5 | 1.255 | | 0.5 | Yes |
| Cherokee Station – Unit 4 | 1.460 | | 0.5 | Yes |
| Comanche Station – Units 1 and 2 | 0.701 | | 0.5 | Yes |
| Craig Station – Units 1 & 2 | 2.689 | | 0.5 | Yes |
| Hayden Station – Units 1 & 2 | 2.538 | | 0.5 | Yes |
| Lamar Light & Power – Unit 6 | 0.064 | | 0.5 | No |
| Martin Drake Power Plant – Units 5, 6 & 7 | 1.041 | | 0.5 | Yes |
| Pawnee Station – Unit 1 | 1.189 | | 0.5 | Yes |
| Ray D. Nixon Power Plant – Unit 1 | 0.570 | 0.481 | 0.5 | No |
| Suncor Denver Refinery | 0.239 | | 0.5 | No |
| Valmont Station – Unit 5 | 1.591 | | 0.5 | Yes |

Notes:

1. The contribution threshold has an implied level of precision equal to the level of precision reported from the model.
2. Source operator modeling results are shown only if modeling has been approved by Division.
3. Roche is not included because it is a VOC source and the Division has determined that anthropogenic VOC emissions are not a significant contributor to visibility impairment.
4. Denver Steam is not included because it is exempt by rule (natural gas only <250 MMBtu).
5. Holcim Cement (Florence) and Rocky Mountain Steel Mills (Pueblo) are not included because of facility reconstruction.
6. Changes to the Ray D. Nixon Power Plant modeling included refinement of the meteorological fields and emission rates. The Division has issued a permit modification for this facility that includes a 30-day rolling emission limit for SO2.
7. Suncor Denver Refinery (including the former Valero Refinery) was not included because it is a VOC source and the Division has determined that anthropogenic VOC emissions are not a significant contributor to visibility impairment. Moreover, Suncor has installed controls to comply with MACT standards.

Of the BART-eligible sources listed above, those sources with a visibility contribution threshold equal to or greater than 0.5 deciview were determined to be subject-to-BART. Tables 6 - 2 and 6 - 3 include the BART determinations that will apply to each source.

| Table 6 - 2 BART Determinations for Colorado Sources | | | | | |
|---|---|---|---|---|---|
| **Emission Unit** | **Assumed ** NOx Control Type** | **NOx Emission Limit** | **Assumed ** $SO_2$ Control Type** | **$SO_2$ Emission Limit** | **Assumed ** Particulate Control and Emission Limit** |
| **Cemex - Lyons** Kiln | Selective Non-Catalytic Reduction System | 255.3 lbs/hr (30-day rolling average)<br><br>901.0 tons/yr (12-month rolling average) | None | 25.3 lbs/hr (12-month rolling average)<br><br>95.0 tons/yr (12-month rolling average) | Fabric Filter Baghouse *<br><br>0.275 lb/ton of dry feed<br><br>20% opacity |
| **Cemex - Lyons** Dryer | None | 13.9 tons/yr | None | 36.7 tons/yr | Fabric Filter Baghouse*<br><br>22.8 tons/yr<br><br>10% opacity |
| **CENC** Unit 4 | Low NOx Burners with Separated Over-Fire Air | 0.37 lb/MMBtu (30-day rolling average)<br><br>Or<br><br>0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average) | None | 1.0 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.07 lb/MMBtu |
| **CENC** Unit 5 | Low NOx Burners with Separated Over-Fire Air, and Selective Non-Catalytic Reduction System | 0.19 lb/MMBtu (30-day rolling average)<br><br>Or<br><br>0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average) | None | 1.0 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.07 lb/MMBtu |
| **Comanche** Unit 1 | Low NOx Burners* | 0.20 lb/MMBtu (30-day rolling average)<br><br>0.15 lb/MMBtu (combined annual average for units 1 & 2) | Lime Spray Dryer* | 0.12 lb/MMBtu (30-day rolling average)<br><br>0.10 lb/MMBtu (combined annual average for units 1 & 2) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |

| Table 6 - 2 BART Determinations for Colorado Sources | | | | | |
|---|---|---|---|---|---|
| **Emission Unit** | **Assumed ** NOx Control Type** | **NOx Emission Limit** | **Assumed ** $SO_2$ Control Type** | **$SO_2$ Emission Limit** | **Assumed ** Particulate Control and Emission Limit** |
| **Comanche** Unit 2 | Low NOx Burners* | 0.20 lb/MMBtu (30-day rolling average)<br><br>0.15 lb/MMBtu (combined annual average for units 1 & 2) | Lime Spray Dryer* | 0.12 lb/MMBtu (30-day rolling average)<br><br>0.10 lb/MMBtu (combined annual average for units 1 & 2) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Craig** Unit 1 | Selective Non-Catalytic Reduction System | 0.28 lb/MMBtu (30-day rolling average) | Wet Limestone scrubber* | 0.11 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Craig** Unit 2 | Selective Catalytic Reduction System | 0.08 lb/MMBtu (30-day rolling average) | Wet Limestone scrubber* | 0.11 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Hayden** Unit 1 | Selective Catalytic Reduction System | 0.08 lb/MMBtu (30-day rolling average) | Lime Spray Dryer* | 0.13 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Hayden** Unit 2 | Selective Catalytic Reduction System | 0.07 lb/MMBtu (30-day rolling average) | Lime Spray Dryer* | 0.13 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Martin Drake** Unit 5 | Ultra Low-NOx Burners (including Over-Fire Air) | 0.31 lb/MMBtu (30-day rolling average) | Dry Sorbent Injection | 0.26 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Martin Drake** Unit 6 | Ultra Low-NOx Burners (including Over-Fire Air) | 0.31 lb/MMBtu (30-day rolling average) | Lime Spray Dryer or Equivalent Control Technology | 0.13 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Martin Drake** Unit 7 | Ultra Low-NOx Burners (including Over-Fire Air) | 0.29 lb/MMBtu (30-day rolling average) | Lime Spray Dryer or Equivalent Control Technology | 0.13 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |

* Controls are already operating

** Based on the state's BART analysis, the "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed in the above table is not a requirement.

| Table 6 - 3 BART Determinations for PSCo's BART Alternative Sources [5, 6, 7] | | | | | |
|---|---|---|---|---|---|
| **Emission Unit** | **NOx Control Type** | **NOx Emission Limit** | **$SO_2$ Control Type** | **$SO_2$ Emission Limit** | **Particulate Control and Emission Limit** |
| **Cherokee** Unit 1 | Shutdown No later than 7/1/2012 | 0 | Shutdown No later than 7/1/2012 | 0 | Shutdown No later than 7/1/2012 |
| **Cherokee** Unit 2 | Shutdown 12/31/2011 | 0 | Shutdown 12/31/2011 | 0 | Shutdown 12/31/2011 |
| **Cherokee** Unit 3 | Shutdown No later than 12/31/2016 | 0 | Shutdown No later than 12/31/2016 | 0 | Shutdown No later than 12/31/2016 |
| **Cherokee** Unit 4 | Natural Gas Operation 12/31/2017 | 0.12 lb/MMBtu (30-day rolling average) by 12/31/2017 | Natural Gas Operation 12/31/2017 | 7.81 tpy (rolling 12 month average) | Fabric Filter Baghouse*<br><br>0.03 lbs/MMBtu<br><br>Natural Gas Operation 12/31/2017 |
| **Valmont** Unit 5 | Shutdown 12/31/2017 | 0 | Shutdown 12/31/2017 | 0 | Shutdown 12/31/2017 |
| **Pawnee** Unit 1 | SCR** | 0.07 lb/MMBtu (30-day rolling average) by 12/31/2014 | Lime Spray Dryer** | 0.12 lbs/MMBtu (30-day rolling average) by 12/31/2014 | Fabric Filter Baghouse*<br><br>0.03 lbs/MMBtu |
| **Arapahoe** Unit 3 | Shutdown 12/31/2013 | 0 | Shutdown 12/31/2013 | 0 | Shutdown 12/31/2013 |
| **Arapahoe** Unit 4 | Natural Gas Operation | 600 tpy (rolling 12 month average) 12/31/2014 | Natural Gas operation 12/31/2014 | 1.28 tpy (rolling 12 month average) | Fabric Filter Baghouse*<br><br>0.03 lbs/MMBtu<br><br>Natural Gas operation 12/31/2014 |

* Controls are already operating

** The "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed for Pawnee in the above table is not a requirement.

For all BART and BART alternative determinations, approved in the Federal State Implementation Plan, the state affirms that the BART emission limits satisfy Regional Haze requirements for this planning period (through 2017) and that no other Regional

[5] Emission rates would begin on the dates specified, the units would not have 30 days of data until 30 days following the dates shown in the table.
[6] 500 tpy NOx will be reserved from Cherokee station for netting or offsets.
[7] 300 tpy NOx will be reserved from Arapahoe station for netting or offsets for additional natural gas generation.

Haze analyses or Regional Haze controls will be required by the state during this timeframe.

## 6.4 Overview of Colorado's BART Determinations

Colorado has been evaluating BART issues for many years and has closely followed EPA's proposals and final rules. The list of Colorado BART-eligible sources has been well known since the 1990's, based on EPA's expected applicability dates of between August 7, 1962 and August 7, 1977. Colorado has been involved in four BART-like proceedings involving known BART sources. Two of these determinations resulted from actions related to the Hayden and Craig power plants. These plants were identified in a certification of impairment made by the U.S. Forest Service regarding visibility impacts at Mt. Zirkel Wilderness Area, located northeast of Steamboat Springs. Colorado conducted two additional BART proceedings for all sources in 2007 and in 2008, which were submitted to EPA for approval. A number of these determinations were revised in 2010 based on adverse comments from EPA; Table 6-2 presents the 2010 BART determinations.

### *6.4.1 The State's Consideration of BART Factors*

In identifying a level of control as BART, States are required by section 169A(g) of the Clean Air Act to "take into consideration" the following factors:

(1) The costs of compliance,
(2) The energy and non-air quality environmental impacts of compliance,
(3) Any existing pollution control technology in use at the source,
(4) The remaining useful life of the source, and
(5) The degree of visibility improvement that may reasonably be anticipated from the use of BART.

42 U.S.C. § 7491(g)(2).

Colorado's BART regulation requires that the five statutory factors be considered for all BART sources. *See,* Regulation No. 3, Part E, Section IV.B.1. In making its BART determination for each Colorado source, the state took into consideration the five statutory factors on a case-by case basis, and for significant NOx controls the Division also utilized the guidance criteria set forth in Section 6.4.3 consistent with the five factors. Summaries of the state's facility-specific consideration of the five factors and resulting determinations for each BART source are provided in this Chapter 6. Documentation reflecting the state's analyses and supporting the state's BART determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix C of this document.

***6.4.1.1 The costs of compliance.*** The Division requested, and the companies provided, source-specific cost information for each BART unit. The cost information ranged from the installation and operation of new SO2 and NOx control equipment to upgrade analyses of existing SO2 controls. The cost for each unit is summarized below, and the state's consideration of this factor for each source is presented in detail in Appendix C.

***6.4.1.2 The energy and non-air quality environmental impacts of compliance.*** This factor is typically used to identify non-air issues associated with different types of control equipment. The Division requested, and the companies provided, source-specific energy and non-air quality information for each BART unit. The state has particular concerns with respect to potential non-air quality environmental impacts associated with wet scrubber systems for SO2, as further described below.

***6.4.1.3 Any existing pollution control technology in use at the source.*** The state has taken into consideration the existing PM, SO2 and NOx pollution control equipment in use at each Colorado source, as part of its BART determination process.

The Division has reviewed available particulate controls. Based on a review of NSPS, MACT and RACT/BACT/LAER, the state has determined that fabric filter baghouses are the best PM control available. The Portland cement MACT confirms that "a well-performing baghouse represents the best performance for PM" s*ee* 74 Fed. Reg. 21136, 21155 (May 6, 2009). The RACT/BACT/LAER Clearinghouse identifies baghouses as the PM control for the newer cement kilns and EGUs. Additional discussion of PM controls, including baghouse controls, is contained in the source specific analyses in Appendix C.

The Division also reviewed various SO2 controls applicable to EGUs and boilers. Two of the primary controls identified in the review are wet scrubbers and dry flue gas desulphurization (FGD). Based upon its experience, and as discussed in detail elsewhere in this Chapter 6, in Appendix C and in the TSD, the state has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including very significant water usage. This is a significant issue in Colorado and the arid West, where water is a costly, precious and scarce resource. There are other costs and environmental impacts that the state also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Moreover, on-site storage of wet ash is an increasing regulatory concern. EPA recognizes that some control technologies can have significant secondary environmental impacts. *See* 70 Fed. Reg. 39104, 39169 (July 6, 2005). EPA has specifically noted that the limited availability of water can affect the feasibility and costs of wet scrubbers in the arid West. These issues were examined in each source specific analysis in Appendix C.

With respect to NOx controls, the state has assessed pre-combustion and post-combustion controls and upgrades to existing NOx controls, as appropriate

When determining the emission rates for each source, the state referred to and considered recent MACT, NSPS and RACT/BACT/LAER determinations to inform emission limits. While relying on source specific information for the final limit, and considering that BART relates to retrofitting sources (vs. new or reconstructed facilities), a review of other determinations was used to better substantiate the source specific information provided by the source.

***6.4.1.4 The remaining useful life of the source.*** None of Colorado's BART sources are expected to retire over the next twenty years. Therefore, this factor did not affect any of the state's BART determinations.

***6.4.1.5 The degree of visibility improvement which may reasonably be anticipated from the use of BART.*** The state took into consideration the degree of visibility improvement which may reasonably be anticipated from the use of BART. Modeling information for each BART determination is presented below and in Appendix C.

### *6.4.2 SIP Requirements from EPA's Regional Haze Rule*

The following section includes information addressing the SIP elements contained in EPA's Regional Haze Rule. The section numbers refer to provisions in 40 CFR § 51.308(e), the BART provision of the Regional Haze Rule.

(i) A list of all BART-eligible sources within the State.

Table 6 - 3 below lists the initial group of Colorado sources subject to BART. This initial list was created based on historical information contained in the Division's source files and is based on the 1962-1977 time frame and source category list contained in Appendix Y. This list was then examined to see if any of the sources identified would be exempt from BART. EPA allows sources to be exempt from BART if they have undergone permitted reconstruction, emit *de minimis* levels of pollution, or are fossil-fuel boilers with an individual heat input rating below 250 million Btu/hour. Colorado's BART rule allows sources to be exempt from BART if modeling demonstrates the impact at any Class I area is below the "cause or contribute" thresholds of 1.0 and 0.5 deciviews. Table 6 - 3 lists the current status of the original BART sources and notes which sources were exempted and why.

**Table 6 - 4 Colorado's BART Eligible Sources**

| Plant Name | Source Owner | Rating, Heat Input or Source type | Start Year | Current Status |
|---|---|---|---|---|
| **Cemex - Lyons** Kiln | Cemex | Portland Cement | <1977 | Subject-to-BART |
| **Cemex - Lyons** Dryer | Cemex | Portland Cement | <1977 | Subject-to-BART |
| **CENC** Unit 4 | Colorado Energy Nations Company (CENC) | 360 MMBtu/hr | 1975 | Subject-to-BART |
| **CENC** Unit 5 | CENC | 650 MMBtu/hr | 1979 | Subject-to-BART |
| **Cherokee** Unit 4 | Public Service Company of Colorado (PSCO) | 350 MW | 1968 | Subject-to-BART |
| **Comanche** Unit 1 | PSCO | 350 MW | 1973 | Subject-to-BART |
| **Comanche** Unit 2 | PSCO | 350 MW | 1976 | Subject-to-BART |
| **Craig** Unit 1 | Tri-State Generation and | 446 MW | 1979 | Subject-to-BART |

| Table 6 - 4 Colorado's BART Eligible Sources | | | | |
|---|---|---|---|---|
| **Plant Name** | **Source Owner** | **Rating, Heat Input or Source type** | **Start Year** | **Current Status** |
| | Transmission, Inc. | | | |
| **Craig** Unit 2 | Tri-State | 446 MW | 1979 | Subject-to-BART |
| **Hayden** Unit 1 | PSCO | 190 MW | 1965 | Subject-to-BART |
| **Hayden** Unit 2 | PSCO | 275 MW | 1976 | Subject-to-BART |
| **Martin Drake** Unit 5 | Colorado Springs Utilities (CSU) | 55 MW | 1962 | Subject-to-BART |
| **Martin Drake** Unit 6 | CSU | 85 MW | 1968 | Subject-to-BART |
| **Martin Drake** Unit 7 | CSU | 145 MW | 1974 | Subject-to-BART |
| **Pawnee** Unit 1 | PSCO | 500 MW | 1981 | BART Alternative |
| **Valmont** Unit 5 | PSCO | 188 MW | 1964 | Subject-to-BART |
| **Denver Steam** Unit 1 | PSCO | Steam only 210 MMBtu/hr | 1972 | Not subject-to-BART since this boiler is less than 250 MMBtu/hr, see 70 FR 39110 |
| **Denver Steam** Unit 2 | PSCO | Steam only 243 MMBtu/hr | 1974 | Not subject-to-BART since this boiler is less than 250 MMBtu/hr, see 70 FR 39110 |
| **Holcim** Kiln | Holcim | Portland Cement | <1977 | Not subject-to-BART since Kiln built after BART time period. Other sources < 250 TPY total emissions. |
| **Lamar Utilities** | City of Lamar | 25 MW | 1972 | Plant will be shutdown; so will no longer be subject. |
| **Oregon Steel** | Oregon Steel | Steel Mfg. | <1977 | Not subject-to-BART since Arc furnace rebuilt after BART time period. Other sources < 250 TPY total emissions. |
| **Ray Nixon** Unit 1 | CSU | 227 MW | 1980 | Not Subject-to-BART (enforceable emission limitations and refined CALPUFF modeling result in less than 0.5 dv visibility impact) |
| **Roche** | Roche | Pharmaceutical Mfg. | <1977 | Not subject-to-BART since VOC determined as not a visibility impairing pollutant in CO |
| **Suncor/Valero** | Suncor | Refinery | <1977 | Not subject-to-BART since VOC determined as not a visibility impairing pollutant in CO |

(ii) *A determination of BART for each BART-eligible source.*

Table 6 - 2 lists the state's BART determinations for sources that cause or contribute to visibility impairment in Class I areas.

(iii) *The determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the State. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.*

Summaries of the state's facility-specific consideration of the five factors and resulting determinations are provided in this chapter 6. Documentation reflecting the state's analyses and supporting the state's BART determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix C of this document.

(iv) *The determination of BART for fossil-fuel fired power plants having a total generating capacity greater than 750 megawatts must be made pursuant to the guidelines in Appendix Y of this part (Guidelines for BART Determinations Under the Regional Haze Rule).*

Colorado has only one source with two BART eligible EGUs that have a combined rating exceeding 750 MW, which is Tri-State Generation and Transmission Association's Craig plant located in Moffat County. The Division's BART determination for the Craig facility is discussed in more detail below.

(v) *A requirement that each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.*

This requirement is addressed in Colorado's BART Rule, and Regulation No. 3 Part F Section VI.

(vi) *A requirement that each source subject-to-BART maintain the control equipment required by this subpart and establish procedures to ensure such equipment is properly operated and maintained.*

Operation and maintenance plans are required by the BART Rule, and Regulation No. 3. Part F Section VII.

### *6.4.3 Overview of the BART Determinations and the Five Factor Analyses for Each BART Source*

This section presents an overview of the BART determinations for the subject to BART sources.

The Regional Haze rule requires states to make determinations about what is appropriate for BART, considering the five statutory factors:

(1) The costs of compliance,
(2) The energy and non-air quality environmental impacts of compliance,
(3) Any existing pollution control technology in use at the source,
(4) The remaining useful life of the source, and

(5) The degree of visibility improvement that may reasonably be anticipated from the use of BART.

The rule gives the states broad latitude on how the five factors are to be considered to determine the appropriate controls for BART. The Regional Haze rule provides little, if any, guidance on specifically how states are to use these factors in making the final determinations regarding what controls are appropriate under the rule, other than to consider the five factors in reaching a determination.[8] The manner and method of consideration is left to the state's discretion; states are free to determine the weight and significance to be assigned to each factor.[9]

For the purposes of the five factor review for the three pollutants that the state is assessing for BART, SO2 and PM have been assessed utilizing the five factors on a case by case basis to reach a determination. This is primarily because the top level controls for SO2 and PM are already largely in use on electric generating units in the state, and certain other sources require a case by case review because of their unique nature. For NOx controls on BART electric generating units, for reasons described below, the state is employing guidance criteria to aid in its assessment and determination of BART using the five factors for these sources, largely because significant NOx add-on controls are not the norm for Colorado electric generating units, and to afford a degree of uniformity in the consideration of BART for these sources.

With respect to SO2 emissions, there are currently ten lime spray dryer (LSD) SO2 control systems operating at electric generating units in Colorado.[10] There are also two wet limestone systems in use in Colorado. The foregoing systems have been successfully operated and implemented for many years at Colorado sources, in some cases for over twenty years. The LSD has notable advantages in Colorado given the non-air quality consideration of its relatively lower water usage in reducing SO2 emissions in the state and other non-air quality considerations. Each of these systems will meet EPA's presumptive limits, and in some cases surpass those limits.[11] The

[8] The EPA "BART Guidelines" provide information relating to implementation of the Regional Haze rule, which the state has considered. However, Colorado also notes that Appendix Y is expressly not mandatory with respect to EGUs of less than 750 MWs in size, and Craig Station (Tri-State Generation and Transmission) is the only such BART electric generating unit in the state. *See* 70 Fed. Reg. at 39108. Thus, the state has substantial discretion in how it considers and applies the five factors (and any other factors that it deems relevant) to BART electric generating units in the state that are below this megawatt threshold, and for non-EGU sources. *See, e.g., id.* at 39108, 39131 and 39158.

[9] *See, e.g.*, 70 Fed. Reg. at 39170.

[10] EGUs with LSD controls include Cherokee Units 3 & 4, Comanche Units 1, 2 & 3, Craig Unit 3, Hayden Units 1 & 2, Rawhide Unit 1, Valmont Unit 5.

[11] In preparing Appendix Y, EPA conducted extensive research and analysis of emission controls on BART sources nationwide, including all BART EGU sources in Colorado. *See* 70 Fed. Reg. at 39134. Based upon this analysis, EPA established presumptive limits that it deems to be appropriate for large EGU sources of greater than 750 MW, including sources greater than 200 MW located at such plants. EPA's position is that the presumptive limits are cost effective and will lead to a significant degree of visibility improvement. *Id. See also,* 69 Fed. Reg. 25184, 25202 (May 5, 2004); *Technical Support Document for BART NOx Limits for Electric Generating Units* and *Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet*, Memorandum to Docket OAR 2002-0076, April 15, 2006; *Technical Support Document for BART SO2 Limits for Electric Generating Units*,

Division has determined in the past that these systems can be cost-effective for Colorado's BART sources, and the Air Quality Control Commission approved LSD systems as BART for Colorado Springs Utilities' Martin Drake Units #6 and #7 in 2008. With this familiarity and use of the emissions control technology, the state has assessed SO2 emissions control technologies and/or emissions rates for BART sources on a case by case basis in making its BART determinations.

With respect to PM emissions, fabric filter baghouses and appropriate PM emissions rates are in place at all power plants in Colorado. Fabric filter baghouse systems have been successfully operated and implemented for many years at Colorado sources, typically exceeding a control efficiency of 95%. The emission limits for these units reflect the 95% or greater control efficiency and are therefore stringent and appropriate. The state has determined that fabric filter baghouses are cost effective through their use at all coal-fired power plants in Colorado, and the Air Quality Control Commission approved these systems as BART in 2007. With this familiarity and use of the emissions control technology, the state has assessed PM emissions control technologies and/or emissions rates for BART sources on a case by case basis in making its BART determinations. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for PM emissions was not necessary for Colorado's BART-subject units.

With respect to NOx emissions, post-combustion controls for NOx are generally not employed in Colorado at BART or other significant coal-fired electric generating units. Accordingly, this requires a direct assessment of the appropriateness of employing such post-combustion technology at these sources for implementation of the Regional Haze rule. There is only one coal-fired electric generating unit in the state that is equipped with a selective catalytic reduction (SCR) system to reduce NOx emissions, and that was employed as new technology designed into a new facility (Public Service Company of Colorado, Comanche Unit #3, operational 2010). There are no selective non-catalytic reduction (SNCR) systems in use on coal-fired electric generating units in the state to reduce NOx emissions.

In assessing and determining appropriate NOx BART controls for individual units for visibility improvement under the regional haze rule, the state has considered the five statutory factors in each instance. Based on its authority, discretion and policy judgment to implement the Regional Haze rule, the state has determined that costs and the anticipated degree of visibility improvement are the factors that should be afforded the most weight.[12] In this regard, the state has utilized screening criteria as a means of generally guiding its consideration of these factors. More specifically, the state finds most important in its consideration and determinations for individual units: (i) the cost of controls as appropriate to achieve the goals of the regional haze rule (*e.g.*, expressed as annualized control costs for a given technology to remove a ton of Nitrogen Oxides (NOx) from the atmosphere, or $/ton of NOx removed); and, (ii) visibility improvement

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Memorandum to Docket OAR 2002-0076, April 1, 2006; and *Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations*, U.S. EPA, June 2005.

[12] *See* 70 Fed. Reg. at 39170 and 39137.

expected from the control options analyzed (*e.g.*, expressed as visibility improvement in delta deciview (Δdv) from CALPUFF air quality modeling).

- Accordingly, as part of its five factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.For the highest-performing NOx post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NOx post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

The foregoing criteria guide the state's general approach to these policy considerations. They are not binding, and the state is free to deviate from this guidance criteria based upon its consideration of BART on a case by case basis.

The cost criteria presented above is generally viewed by the state as reasonable based on the state's extensive experience in evaluating industrial sources for emissions controls. For example, the $5,000/ton criterion is consistent with Colorado's retrofit control decisions made in recent years for reciprocating internal combustion engines (RICE) most commonly used in the oil and gas industry.[13] In that case, a $5,000/ton threshold, which was determined by the state Air Quality Control Commission as a not-to-exceed control cost threshold, was deemed reasonable and cost effective for an initiative focused on reducing air emissions to protect and improve public health.[14] The $5,000/ton criterion is also consistent and within the range of the state's implementation of reasonably achievable control technology (RACT), as well as best achievable control technology (BACT) with respect to new industrial facilities. Control costs for Colorado RACT can be in the range of $5,000/ton (and lower), while control costs for Colorado BACT can be in the range of $5,000/ton (and higher).

In addition, as it considers the pertinent factors for regional haze, the state believes that the costs of control should have a relationship to visibility improvement. The highest-performing post-combustion NOx controls, *i.e.*, SCR, has the ability to provide significant NOx reductions, but also has initial capital dollar requirements that can

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[13] Air Quality Control Commission Regulation No. 7, 5 C.C.R. 1001-9, Sections XVII.E.3.a.(ii) (statewide RICE engines), and XVI.C.4 (8-Hour Ozone Control Area RICE engines).

[14] The RICE emissions control regulations were promulgated by the Colorado Air Quality Control Commission in order to: (i) reduce ozone precursor emissions from RICE to help keep rapidly growing rural areas in attainment with federal ozone standards; (ii) for reducing transport of ozone precursor emissions from RICE into the Denver Metro Area/North Front Range (DMA/NFR) nonattainment area; and, (iii) for the DMA/NFR nonattainment area, reducing precursor emissions from RICE directly tied to exceedance levels of ozone.

approach or exceed $100 million per unit.[15] The lesser-performing post-combustion NOx controls, *e.g.*, SNCR, reduce less NOx on a percentage basis, but also have substantially lower initial capital requirements, generally less than $10 million.[16] The state finds that the significantly different capital investment required by the different types of control technologies is pertinent to its assessment and determination. Considering costs for the highest-performing add-on NOx controls (*i.e.*, SCR), the state anticipates a direct level of visibility improvement contribution, generally 0.50 Δdv or greater of visibility improvement at the primary affected Class I Area.[17] For the lesser-performing add-on NOx controls (*e.g.*, SNCR), the state anticipates a meaningful and discernible level of visibility improvement that contributes to broader visibility improvement, generally 0.20 Δdv or greater of visibility improvement at the primary affected Class I Area.

Employing the foregoing guidance criteria for post-combustion NOx controls, as part of considering the five factors under the Regional Haze rule, promotes a robust evaluation of pertinent control options, including costs and an expectation of visibility benefit, to assist in determining what are appropriate control options for the Regional Haze rule.

#### *6.4.3.1 BART Determination for Cemex's Lyons Cement Plant*

The Cemex facility manufactures Portland cement and is located in Lyons, Colorado, approximately 20 miles from Rocky Mountain National Park. The Lyons plant was originally constructed with a long dry kiln. This plant supplies approximately 25% of the clinker used in the regional cement market. There are two BART eligible units at the facility: the dryer and the kiln.

In 1980, the kiln was cut to one-half its original length, and a flash vessel was added with a single-stage preheater. The permitted kiln feed rate is 120 tons per hour of raw material (kiln feed), and on average yields approximately 62 tons of clinker per hour. The kiln is the main source of SO2 and NOx emissions. The raw material dryer emits minor amounts of SO2 and NOx; in 2008 Cemex reported SO2 and NOx emissions from the dryer as 0.89 and 10.41 tons per year respectively based on stack test results. Due to the low emission rates from the dryer the BART review focuses on the kiln.

Newer multistage preheater/precalciner kilns are designed to be more energy efficient and yield lower emissions per ton of clinker due to this when compared to the Cemex

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[15] *See, e.g.,* Appendix C, reflecting Public Service of Colorado, Comanche Unit #2, $83MM; Public Service of Colorado, Hayden Unit #2, $72MM; Tri-State Generation and Transmission, Craig Station Unit #1, $210MM.

[16] *See, e.g.*, Appendix C, reflecting CENC (Tri-gen), Unit #4, $1.4MM; Public Service Company of Colorado, Hayden Unit #2, $4.6MM; Tri-State Generation and Transmission, Craig Station Unit #1, $13.1MM

[17] The EPA has determined that BART-eligible sources that affect visibility above 0.50 Δdv are not to be exempted from BART review, on the basis that above that level the source is individually contributing to visibility impairment at a Class I Area. 70 Fed. Reg. at 39161. The state relied upon this threshold when determining which Colorado's BART eligible sources became subject to BART. *See*, Air Quality Control Commission Regulation No. 3, Section III.B.1.b. Thus, a visibility improvement of 0.50 Δdv or greater will also provide significant direct progress towards improving visibility in a Class I Area from that facility.

Lyons kiln. The newer Portland cement plants studied by EPA, utilize multistage preheater/precalciner designs that are not directly comparable. Cemex has a unique single stage preheater/precalciner system with different emission profiles and energy demands. New Portland cement plants have further developed the preheater/precalciner design with multiple stages to reduce emissions and energy requirements for the process. Additionally, new plant designs allow for the effective use of Selective Non-Catalytic Reduction (SNCR), which requires ammonia like compounds to be injected into appropriate locations of the preheater/precalciner vessels where temperatures are ideal (between 1600-2000ºF) for reducing NOx to elemental Nitrogen.

Cemex submitted a BART analysis to the Division on August 1, 2006, with revisions submitted on August 28, 2006; January 15, 2007; October 2007 and August 29, 2008. In response to a Division request, Cemex submitted additional information on July 27 and 28, 2010

CALPUFF modeling provided by the source, using a maximum SO2 emission rate of 123.4 lbs/hour for both the dryer and kiln combined indicates a 98$^{th}$ percentile visibility impact of 0.78 delta deciview (Δdv) at Rocky Mountain National Park. The modeled 98$^{th}$ percentile visibility impact from the kiln is 0.76 Δdv. Thus, the visibility impact of the dryer alone is the resultant difference which is 0.02 Δdv. Because the dryer uses the cleanest fossil fuel available and post combustion controls on such extremely low concentrations are not practical, the state has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable controls on the dryer. Accordingly, the state has determined that no additional emission control analysis of the dryer is necessary or appropriate since the total elimination of the emissions would not result in any meaningful visibility improvement which is a fundamental factor in the BART evaluation. For the dryer, the BART SO2 emission limitation is 36.7 tpy and the BART NOx emission limitation is 13.9 tpy, which are listed in the existing Cemex Title V permit.

### SO2 BART Determination for Cemex Lyons - Kiln

Lime addition to kiln feed, fuel substitution (coal with tire derived fuel), dry sorbent injection (DSI), and wet lime scrubbing (WLS) were determined to be technically feasible for reducing SO2 emissions from Portland cement kilns.

The following table lists the most feasible and effective options:

| Cemex Lyons -Kiln | | | | |
|---|---|---|---|---|
| SO2 Control Technology | Estimated Control Efficiency | Annual Controlled Hourly SO2 Emissions (lbs/hr) | Annual Controlled SO2 Emissions (tpy) | Annual Controlled SO2 Emissions (lb/ton of Clinker) |
| Baseline SO2 Emissions | | 25.3 | 95.0 | 0.40 |
| Lime Addition to Kiln Feed | 25% | 18.9 | 71.3 | 0.30 |
| Fuel Substitution (coal with TDF) | 40% | 15.2 | 57.0 | 0.24 |

| Cemex Lyons -Kiln | | | | |
|---|---|---|---|---|
| SO2 Control Technology | Estimated Control Efficiency | Annual Controlled Hourly SO2 Emissions (lbs/hr) | Annual Controlled SO2 Emissions (tpy) | Annual Controlled SO2 Emissions (lb/ton of Clinker) |
| Dry Sorbent Injection | 50% | 12.6 | 47.5 | 0.20 |
| Wet Lime Scrubbing (Tailpipe scrubber) | 90% | 2.5 | 9.5 | 0.04 |

The energy and non-air quality impacts of the alternatives are as follows:

- Lime addition to kiln feed and dry sorbent injection - there are no energy or non-air quality impacts associated with these control options
- Wet lime scrubbing - significant water usage, an additional fan of considerable horsepower to move the flue gas through the scrubber, potential increase in PM emissions and sulfuric acid mist
- Tire-derived fuel – the community has expressed concerns regarding the potential for increased air toxics emissions, and opposed the use of tire derived fuel at this facility; a 2-year moratorium on use of permitted tire derived fuel was codified in a 2006 state enforcement matter for this facility. *See,* Cemex Inc., Case No. 2005-049 (Dec. 2006) Para. 1b.

There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period. Cemex's limestone quarry may have a shorter life-span, but the source has not committed to a closure date.

The following table lists the SO2 emission reduction, annualized costs and the control cost effectiveness for the feasible controls:

| Cemex Lyons - Kiln | | | | |
|---|---|---|---|---|
| SO2 Control Technology | SO2 Emission Reduction (tons/yr) | Annualized Cost ($/yr) | Cost Effectiveness ($/ton) | Incremental Cost Effectiveness ($/ton) |
| Baseline SO2 Emissions | - | | | |
| Lime Addition to Kiln Feed | 23.8 | $3,640,178 | $153,271 | |
| Fuel Substitution (coal supplemented with TDF) | 38.0 | $172,179 | $4,531 | $243,368 |
| Dry Sorbent Injection | 47.5 | Not provided | - | |
| Wet Lime Scrubbing (Tailpipe scrubber) | 85.5 | $2,529,018 | $29,579 | $49,618 |

The following table lists the projected visibility improvements for SO2 controls:

| Cemex Lyons - Kiln | | |
|---|---|---|
| SO2 Control Method | 98th Percentile Impact (Δdv) | 98th Percentile Improvement (Δdv) |
| Maximum (24-hr max) | 0.760 | |
| Baseline (95 tpy)* | 0.731 | - |
| Lime Addition to Kiln Feed (71.3 tpy)* | 0.727 | 0.033 |
| Fuel Substitution (57 tpy)* | 0.725 | 0.034 |
| Dry Sorbent Injection (47.5 tpy)* | 0.725 | 0.036 |
| Wet Lime Scrubbing (9.5 tpy)* | 0.720 | 0.040 |

** Visibility impacts rescaled from original BART modeling*

For the kiln, based upon its consideration and weighing of the five factors, the state has determined that no additional SO2 emissions control is warranted as the added expense of these controls were determined to not be reasonable for the small incremental visibility improvement of less than 0.04 deciviews. However, the use of low sulfur coal and the inherent control resulting from the Portland cement process provides sufficient basis to establish annual BART SO2 emission limits for the kiln of:

25.3 lbs/hour and

95.0 tons of SO2 per year

No additional controls are warranted because 80% of the sulfur is captured in the clinker, making the inherent control of the process the SO2 control. Additional SO2 scrubbing is also provided by the limestone coating in the baghouse as the exhaust gas passes through the baghouse filter surface.

### SO2 BART Determination for Cemex Lyons - Dryer

For the dryer, the state has determined that since the total elimination of the emissions would not result in any meaningful visibility improvement (less than 0.02 deciview), the SO2 BART requirement is 36.7 tpy, which is taken from the existing Title V permit.

### Particulate Matter BART Determination for Cemex Lyons - Kiln and Dryer

The state has determined that the existing fabric filter baghouses and the existing regulatory emissions limits of 0.275 lb/ton of dry feed and 20% opacity for the kiln and 10% opacity for the dryer represent the most stringent control option. The kiln and dryer baghouses exceed a PM control efficiency of 95%, and the emission limits are BART for $PM/PM_{10}$. The state assumes that the BART emission limits can be achieved through the operation of the existing fabric filter baghouse.

### NOx BART Determination for Cemex Lyons - Kiln

Water injection, firing coal supplemented with tire-derived fuel (TDF), indirect firing with low NOx burners, and selective non-catalytic reduction (SNCR) were determined to be technically feasible and appropriate for reducing NOx emissions from Portland cement kilns. As further discussed in Appendix C, the state has determined that SCR is not commercially available for Portland cement kilns. Presently, SCR has not been applied to a cement plant of any type in the United States. Cemex notes that the major SCR vendors have indicated that SCR is not commercially available for cement kilns at this time. The state does not believe that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe, constitutes "available" control technology for purposes of BART. The state believes that commercial demonstration of SCR controls on a cement plant in the United States is appropriate when considering whether a control technology is "available" for purposes of retrofitting such control technology on an existing source. Accordingly, the state has eliminated SCR as an available control technology for purposes of BART. Moreover, as further discussed in Appendix C, if SCR were considered commercially available, it is not technically feasible for the Lyons facility due to the unique design of the kiln.

The following table lists the most feasible and effective options:

| Cemex Lyons - Kiln | | | | |
|---|---|---|---|---|
| NOx Control Technology | Estimated Control Efficiency | Annual Controlled Hourly NOx Emissions (lbs/hr) | Annual Controlled NOx Emissions (tpy) | Annual Controlled NOx Emissions (lb/ton of Clinker) |
| Baseline NOx Emissions | - | 464.3 | 1,747.1 | 7.39 |
| Water Injection | 7.0% | 431.8 | 1,624.8 | 6.87 |
| Coal w/TDF | 10.0% | 417.8 | 1,572.3 | 6.65 |
| Indirect Firing with LNB | 20.0% | 371.4 | 1,397.6 | 5.91 |
| SNCR (30-day rolling) | 45.0% | 255.3 | 960.9 | 4.06 |
| SNCR (12-month rolling) | 48.4% | 239.4 | 901.0 | 3.81 |
| SNCR w/LNB | 55% | 208.9 | 786.2 | 3.33 |

The energy and non-air quality impacts of the alternatives are as follows:

- Low-NOx burners - there are no energy or non-air quality impacts
- Water injection - significant water usage
- Tire-derived fuel – the community has expressed concerns regarding the potential for increased air toxics emissions, and opposed the use of tire derived fuel at this facility; a 2-year moratorium on use of permitted tire derived fuel was codified in a 2006 state enforcement matter for this facility. *See,* Cemex Inc., Case No. 2005-049 (Dec. 2006) Para. 1b.
- SNCR - none

There are no remaining useful life issues for the alternatives as the state has presumed that the source will remain in service for the 20-year amortization period. Cemex's limestone quarry may have a shorter life-span, but the source has not committed to a closure date.

The following table lists the emission reductions, annualized costs and the control cost effectiveness for the feasible controls:

| Cemex Lyons - Kiln | | | | |
|---|---|---|---|---|
| NOx Control Technology | NOx Emission Reduction | Annualized Cost | Cost Effectiveness | Incremental Cost Effectiveness |
| | (tons/yr) | ($/yr) | ($/ton) | ($/ton) |
| Baseline NOx Emissions | - | | | |
| Water Injection | 122.3 | $43,598 | $356 | - |
| Coal w/TDF | 174.7 | $172,179 | $986 | $2,453 |
| Indirect Firing with LNB | 349.4 | $710,750 | $2,034 | $3,083 |
| SNCR (45.0% control) | 786.2 | $1,636,636 | $2,082 | $2,120 |
| SNCR (48.4% control) | 846.1 | $1,636,636 | $1,934 | $1,864 |
| SNCR w/LNB (55.0% control w/uncertainty) | 960.9 | $1,686,395 | $1,755 | $434 |

The following table lists the projected visibility improvements for NOx controls for the kiln:

| Control Method | 98th Percentile Impact ($\Delta$dv) | 98th Percentile Improvement (from 24-hr Max) ($\Delta$dv) |
|---|---|---|
| 24-hr Maximum (≈ 656.9 lbs/hr)) | 0.760 | |
| Revised Baseline ( ≈ 464.3 lbs/hr)* | 0.572 | 0.188 |
| Original Baseline (≈ 446.8 lbs/hr)* | 0.555 | 0.205 |
| Water Injection (≈ 431.8 lbs/hr)* | 0.540 | 0.220 |
| Firing TDF (≈417.9 lbs/hr)* | 0.526 | 0.234 |
| Indirect Firing with LNB (≈ 371.4 lbs/hr)* | 0.481 | 0.279 |
| Original BART Limit – SNCR (≈ 268.0 lbs/hr) | 0.380 | 0.380 |
| Proposed BART Limit (30-day) – SNCR (≈ 255.3 lbs/hr)** | 0.368 | 0.392 |
| Proposed BART Limit (annual) – SNCR (≈ 239.0 lbs/hr)** | 0.352 | 0.408 |
| SNCR w/LNB (≈208.9 lbs/hr)** | 0.322 | 0.438 |

The Cemex – Lyons facility is a unique kiln system most accurately described as a modified long dry kiln, the characteristics of a modified long dry kiln system are not similar to either a long wet kiln or a multi stage preheater/precalciner kiln. The temperature profile in a long dry kiln system (>1500$^{o}$F) is significantly higher at the exit than a more typical preheater precalciner kiln (650$^{o}$F). This is a significant distinction that limits the location and residence time available for an effective NOx control system. The combination of SNCR with LNB has an uncertain level of control due to unique nature of the Lyons kiln. Furthermore, the associated incremental reduction in NOx emissions associated with SNCR in combination with LNB would afford only a minimal or negligible visibility improvement (less than 0.03 delta deciview). Therefore, the Division believes that SNCR is the best NOx control system available for this kiln.

For the kiln, because of the unique characteristics of the Cemex facility, the state has determined that the BART emission limits for NOx are:

255.3 pounds per hour (30-day rolling average) and

901.0 tons per year (12-month rolling average)

The emissions rate and the control efficiency reflect the best performance from the control options evaluated. This BART determination affords the most NOx reduction from the kiln (846.1 tpy) and contributes significant visibility improvement (0.38 Δdv). The determination affirms a prior Air Quality Control Commission BART determination for SNCR for this facility (2008). The state assumes that the BART emission limits can be achieved through the installation and operation of SNCR.

### NOx BART Determination for Cemex Lyons - Dryer

For the dryer, the state has determined that since the total elimination of the emissions would not result in any meaningful visibility improvement (less than 0.02 deciview), the NOx BART requirement is 13.9 tpy, which is taken from the existing Title V permit.

A complete analysis that further supports the BART determination for the Cemex Lyons facility can be found in Appendix C.

### *6.4.3.2 BART Determination for Colorado Energy Nations Company (CENC)*

This facility is located adjacent to the Coors brewery in Golden, Jefferson County. Boilers 4 and 5 are considered BART-eligible, being industrial boilers with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and having commenced operation in the 15-year period prior to August 7, 1977. Initial air dispersion modeling performed by the Division demonstrated that the CENC facility contributes to visibility impairment (a 98$^{th}$ percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Trigen (now CENC) submitted a BART Analysis to the Division on July 31, 2006. CENC also provided information in its "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado" Submittal provided on November 16, 2009, as well as additional information upon the Division's request on February 8, 2010, and May 7, 2010.

The CENC facility includes two coal-fired boilers that supply steam and electrical power to Coors Brewery. The boilers are rated as follows: Unit 4 at 360 MMBtu/hr and Unit 5 at 650 MMBtu/hr. These are approximately equivalent to 35 and 65 MW power plant boilers, based on the design heat rates.

### SO2 BART Determination for CENC - Boilers 4 and 5

Dry sorbent injection (DSI) and $SO_2$ emission management were determined to be technically feasible for reducing SO2 emissions from Boilers 4 and 5. These options were considered as potentially BART by the Division. Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts. Dry FGD controls were determined to be not technically feasible. SO2 emissions management uses a variety of options to reduce SO2 emissions: dispatch natural gas-fired capacity, reduce total system load, and/or recue coal firing rate to maintain a new peak SO2 limit.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| CENC Boiler 4 - SO2 Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| $SO_2$ Emissions Management | 1.0 | $44,299 | $43,690 |
| DSI – Trona | 468.0 | $1,766,000 | $3,774 |

| CENC Boiler 5 - SO2 Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| $SO_2$ Emissions Management | 0.8 | $65,882 | $78,095 |
| DSI – Trona | 844.0 | $2,094,000 | $2,482 |

The energy and non-air quality impacts of the remaining alternative are as follows:

- DSI - reduced mercury capture in the baghouse, and fly ash contamination with sodium sulfate, rendering the ash unsalable as a replacement for concrete and rendering it landfill material only.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to DSI are as follows:

| SO2 Control Method | CENC - Boiler 4 | | CENC - Boiler 5 | |
|---|---|---|---|---|
| | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.90 | | 0.98 | |
| DSI – Trona (annual avg.) | 0.26 | 0.08 | 0.29 | 0.13 |

SO2 emissions management was eliminated from consideration due to the high cost/effectiveness ratios and anticipated small degree of visibility improvement that would result from one tpy or less of SO2 reduction.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

CENC Boiler 4: 1.0 lb/MMBtu (30-day rolling average)

CENC Boiler 5: 1.0 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved without additional control technology. Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement afforded.

### Particulate Matter BART Determination for CENC - Boilers 4 and 5

The Division has determined that for Boilers 4 and 5, an emission limit of 0.07 lb/MMBtu (PM/PM10) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for $PM/PM_{10}$. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

### NOx BART Determination for CENC - Boilers 4 and 5

Low NOx burners (LNB), LNB plus separated overfire air (SOFA), selective non-catalytic reduction (SNCR), SNCR plus LNB plus SOFA, and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at CENC Boilers 4 and 5.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

| CENC Boiler 4 - NOx Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | 0 | $0 |
| LNB | 59.9 | $193,433 | $3,227 |
| SNCR | 179.8 | $694,046 | $3,860 |
| LNB+SOFA | 209.8 | $678,305 | $3,234 |
| LNB+SOFA + SNCR | 368.0 | $1,372,351 | $3,729 |
| SCR | 515.4 | $4,201,038 | $8,150 |

| CENC Boiler 5 - $NO_x$ Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| LNB | 48.4 | $249,858 | $5,166 |
| LNB+SOFA | 127.3 | $815,829 | $6,383 |
| SNCR | 207.3 | $923,996 | $4,458 |
| LNB+SOFA + SNCR | 353.7 | $1,739,825 | $4,918 |
| SCR | 550.0 | $6,469,610 | $11,764 |

The energy and non-air quality impacts of the alternatives are as follows:

- LNB – not significant
- LNB + SOFA – may increase unburned carbon in the ash, commonly referred to as loss on ignition
- SNCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| NOx Control Method | CENC - Boiler 4 | | CENC - Boiler 5 | |
|---|---|---|---|---|
| | NOx Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | NOx l Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.67 | | 0.66 | |
| LNB (annual avg.) | 0.45 | 0.05 | 0.30 | 0.17 |
| SNCR (annual avg.) | 0.35 | 0.07 | 0.24 | 0.21 |
| LNB + SOFA (annual avg.) | 0.32 | 0.08 | 0.24 | 0.21 |
| LNB + SOFA + SNCR (annual avg.) | 0.19 | 0.12 | 0.17 | 0.26 |
| SCR | 0.07 | 0.18 | 0.07 | 0.31 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART for Boiler 4 is the following NOx emission rates:

CENC Boiler 4: 0.37 lb/MMBtu (30-day rolling average)

Or

0.26 lb/MMBtu Boiler 4 and Boiler 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NOx burners with separated over-fire air. Although the other alternatives achieve better emissions reductions, achieving lower limits through different controls was determined to not be reasonable based on the high cost/effectiveness ratios coupled with the low visibility improvement afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.04 dv for SNCR and 0.10 dv for SCR). Thus, it is not warranted to select emission limits associated with either SNCR or SCR for CENC Unit 4.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART for Boiler 5 is the following NOx emission rates:

CENC Boiler 5: 0.19 lb/MMBtu (30-day rolling average)

Or

0.26 lb/MMBtu Boiler 4 and 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NOx burners with separated over-fire air and selective non-catalytic reduction.

For the emission limits above, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria discussed above in section 6.4.3.

- Boiler 5: $4,918 per ton NOx removed; 0.26 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Though SCR achieves better emissions reductions, achieving lower limits through SCR was determined to not fall into the guidance cost and visibility improvement criteria discussed in section 6.4.3.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.05 dv). Thus, it is not warranted to select emission limits associated SCR for CENC Unit 5.

A complete analysis that supports the BART determination for the CENC facility can be found in Appendix C.

#### *6.4.3.3 BART Determination for Public Service Company Comanche Units 1 and 2*

Comanche Units 1 and 2 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, both boilers are subject-to-BART. PSCo submitted a BART analysis to the Division on September 14, 2006 with revisions submitted on November 1, 2006 and January 8,

2007. In response to a Division request, PSCo submitted additional information on May 25, and July 14, 2010.

**SO2 BART Determination for Comanche - Units 1 and 2**

*Semi-Dry FGD Upgrades* – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following dry scrubber upgrades should be considered for Comanche Units 1 and 2, if technically feasible.

- *Use of performance additives* - The supplier of Comanche's dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, for dry scrubbers. Because low-sulfur coal is used at Comanche, the use of performance additives on the scrubbers would not be expected to increase the $SO_2$ removal.
- *Use of more reactive sorbent* - PSCo is using a highly reactive lime with 92% calcium oxide content reagent that maximizes $SO_2$ removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the $NO_x$ in the flue gas into $NO_2$. Since $NO_2$ is a visible gas, large coal-fired units can generate a visible brown/orange plume at high $SO_2$ removal rates, such as those experienced at Comanche. There are no known acceptable reagents without this side effect that would allow additional $SO_2$ removal in the dry scrubbing systems present at the Comanche Station.
- *Increase the pulverization level of sorbent* – PSCo uses the best available grinding technologies, and other pulverization techniques have not been proven more effective.
- *Engineering redesign of atomizer or slurry injection system -* The supplier offers no upgrade in atomizer design to improve $SO_2$ removal at Comanche. PSCo asserts and the state agrees that a third scrubber module on Comanche Units 1 and 2 is not feasible due to the current layout of the ductwork and space constraints around the scrubbers.
- *Additional equipment and maintenance* - Comanche Units 1 and 2 are already achieving 30-day average emission rates of 0.12 lbs/MMBtu, 30-day rolling average, and 0.10 lbs/MMBtu, 12-month average for the two units combined, as adopted in 2007 by the Commission. It is not technically feasible to install an extra scrubber module at the site; therefore no additional equipment or maintenance will decrease SO2 emissions or achieve a lower limit.

Consequently, further capital upgrades to the current high performing SO2 removal system were deemed technically infeasible, and a lower emissions limit is not achievable.

The projected visibility improvements attributed to the alternatives are as follows:

| SO2 Control Method | Comanche – Unit 1 | | Comanche – Unit 2 | |
|---|---|---|---|---|
| | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.75 | | 0.74 | |
| Semi-Dry FGD (LSD) (annual avg.) | 0.12 | 0.35 | 0.12 | 0.33 |
| Semi-Dry FGD (LSD) (annual avg.) | 0.08 | 0.37 | 0.08 | 0.36 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that the following existing SO2 emission rates are BART:

Comanche Unit 1: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)

Comanche Unit 2: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). A 30-day rolling SO2 limit of 0.12 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology. A complete analysis that supports the BART determination for the Comanche facility can be found in Appendix C.

**Particulate Matter BART Determination for Comanche - Units 1 and 2**

Based on recent BACT determinations, the state has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu ($PM/PM_{10}$) represents the most stringent level of available control for $PM/PM_{10}$. The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for $PM/PM_{10}$ as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

**NOx BART Determination for Comanche - Units 1 and 2**

SNCR and SCR were determined to be technically feasible for reducing NOx emissions at Comanche Unit 1, and only SCR was determined feasible at Unit 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Comanche Unit 1 - $NO_x$ Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| SNCR | 445.6 | $1,624,100 | $3,644 |
| SCR | 770.4 | $12,265,014 | $15,290 |

| Comanche Unit 2 - $NO_x$ Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| SCR | 1,480 | $14,650,885 | $9,900 |

The energy and non-air quality impacts of the alternatives are as follows:

- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| NOx Control Method | Comanche – Unit 1 | | Comanche – Unit 2 | |
|---|---|---|---|---|
| | NOx Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | NOx Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (1-yr) using new LNBs | 0.20 | | 0.20 | |
| SNCR (annual avg.) | 0.10 | 0.11 | Not Feasible | – |
| SCR (annual avg.) | 0.07 | 0.14 | 0.07 | 0.17 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following existing NOx emission rates:

Comanche Unit 1: 0.20 lb/MMBtu (30-day rolling average)
0.15 lb/MMBtu (combined annual average for units 1 & 2)

Comanche Unit 2: 0.20 lb/MMBtu (30-day rolling average)
0.15 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing low NOx burners. Although the other alternatives achieve better emissions reductions, the added expense of achieving lower limits through different controls were determined to not be reasonable based on the high cost/effectiveness ratios coupled with the low visibility improvement (under 0.2 delta deciview) afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the State's BART determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.10 dv for SNCR and 0.13 dv for SCR for Unit 1, and 0.17 dv for SCR for Unit 2). SNCR was found not to be technically feasible for Comanche Unit 2. Thus, it is not warranted to select emission limits associated with either SNCR or SCR for Comanche Units 1 and 2.

A complete analysis that supports the BART determination for PSCo's Comanche Units 1 and 2 can be found in Appendix C.

#### *6.4.3.4 BART Determination for Tri-State Generation and Transmission Association's Craig Facility*

Craig Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change. Tri-State submitted a BART Analysis to the Division on July 31, 2006 with revisions, updates, and/or comments submitted on October 25, 2007, December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

**SO2 BART Determination for Craig - Units 1 and 2**

*Wet FGD Upgrades* – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following wet scrubber upgrades were considered for Craig Units 1 and 2, if technically feasible.

- *Elimination of bypass reheat*: The FGD system bypass was redesigned to eliminate bypass of the FGD system except for boiler safety situations in 2003-2004.
- *Installation of liquid distribution rings:* TriState determined that installation of perforated trays, described below, accomplished the same objective.
- *Installation of perforated trays:* Upgrades during 2003-2004 included installation of a perforated plate tray in each scrubber module.
- *Use of organic acid additives:* Organic acid additives were considered but not selected for the following reasons:
    1. Dibasic Acid (DBA) has not been tested at the very low inlet $SO_2$ concentrations seen at Craig Units 1 and 2.
    2. DBA could cause changes in sulfite oxidation with impacts on $SO_2$ removal and solids settling and dewatering characteristics.

3. Installation of the perforated plate tray accomplished the same objective of increased $SO_2$ removal.

- *Improve or upgrade scrubber auxiliary equipment:* 2003-2004 upgrades included installation of the following upgrades on limestone processing and scrubber modules on Craig 1 and 2:

1. Two vertical ball mills were installed for additional limestone processing capability for increased $SO_2$ removal. The two grinding circuit trains were redesigned to position the existing horizontal ball mills and the vertical ball mills in series to accommodate the increased quantity of limestone required for increased removal rates. The two mills in series also were designed to maintain the fine particle size (95% <325 mesh or 44 microns) required for high $SO_2$ removal rates.
2. Forced oxidation within the $SO_2$ removal system was thought necessary to accommodate increased removal rates and maintain the dewatering characteristics of the limestone slurry. Operation, performance, and maintenance of the gypsum dewatering equipment are more reliable with consistent slurry oxidation.
3. A ventilation system was installed for each reaction tank.
4. A new mist eliminator wash system was installed due to the increased gas flow through the absorbers since flue gas bypass was eliminated, which increased demand on the mist eliminator system. A complete redesign and replacement of the mist eliminator system including new pads and wash system improved the reliability of the individual modules by minimizing down time for washing deposits out of the pads.
5. Tri-State installed new module outlet isolation damper blades. The new blades, made of a corrosion-resistant nickel alloy, allow for safer entry into the non-operating module for maintenance activities.
6. Various dewatering upgrades were completed. Dewatering the gypsum slurry waste is done to minimize the water content in waste solids prior to placements of the solids in reclamation areas at the Trapper Mine. The gypsum solids are mixed or layered with ash and used for fill during mine reclamation at Trapper Mine. The installed system was designed for the increased capacity required for increased $SO_2$ removal. New hydrocyclones and vacuum drums were installed as well as a new conveyor and stack out system for solid waste disposal.
7. Instrumentation and controls were modified to support all of the new equipment.

- *Redesign spray header or nozzle configuration:* The slurry spray distribution was modified during 2003-2004. The modified slurry spray distribution system improved slurry spray characteristics and was designed to minimize pluggage in the piping.

Therefore, there are no technically feasible upgrade options for Craig Station Units 1 and 2. However, the state evaluated the option of tightening the emission limit for Craig Units 1 and 2 through the five-factor analysis and determined that a more stringent 30-day rolling $SO_2$ limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control for this wet FGD control technology based on current emissions and operations. The tighter emission limits are achievable without additional capital investment. An SO2 limit lower than 0.11 lbs/MMBtu would likely require additional capital expenditure and is not reasonable for the small incremental visibility improvement of 0.02 deciview.

The projected visibility improvements attributed to the alternatives are as follows:

| SO2 Control Method | Craig – Unit 1 | | Craig – Unit 2 | |
|---|---|---|---|---|
| | SO2 Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | SO2 Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.17 | | 0.16 | |
| Wet FGD | 0.11 | 0.03 | 0.11 | 0.03 |
| Wet FGD | 0.07 | 0.05 | 0.07 | 0.05 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

Craig Unit 1: 0.11 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). The 30-day rolling SO2 limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology.

### Particulate Matter BART Determination for Craig - Units 1 and 2

The Division has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu ($PM/PM_{10}$) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for $PM/PM_{10}$. The state assumes that the BART emission limit can be achieved through the operation of the existing pulse jet fabric filter baghouses.

### NOx BART Determination for Craig - Units 1 and 2

Potential modifications to the ULNBs, neural network systems, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Craig Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Craig Unit 1 - $NO_x$ Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| SNCR | 779 | $3,797,000 | $4,877 |
| SCR | 3,855 | $25,036,709 | $6,445 |

| Craig Unit 2 - NOx Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| SNCR | 806 | $3,797,000 | $4,712 |
| SCR | 3,975 | $25,036,709 | $6,299 |

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, and hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| NOx Control Method | Craig – Unit 1 | | Craig – Unit 2 | |
|---|---|---|---|---|
| | NOx Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | NOx Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.35 | | 0.35 | |
| SNCR | 0.24 | 0.31 | 0.23 | 0.31 |
| SCR | 0.07 | 1.01 | 0.07 | 0.98 |

While potential modifications to the ULNB burners and a neural network system were also found to be technically feasible, these options did not provide the same level of reductions as SNCR or SCR, which are included within the ultimate BART Alternative determination for Units 1 and 2. Therefore, these options were not further considered in the technical analysis.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following NOx emission rates:

Craig Unit 1: 0.27 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.27 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of SNCR. For the BART emission limits at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented above.

- Unit 1: $4,877 per ton NOx removed; 0.31 deciview of improvement
- Unit 2: $4,712 per ton NOx removed; 0.31 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements, leads the state to this determination. To the extent practicable, any technological application Tri-State utilizes to achieve these BART emission limits shall be installed, maintained, and operated in a manner consistent with good air pollution control practices for minimizing emissions. Although emission limits associated with SCR achieve better emissions reductions, the cost-effectiveness of SCR for this BART determination was determined to be excessive and above the cost guidance criteria presented above. The state reached this conclusion after considering the associated visibility improvement information and after considering the SCR cost information in the SIP materials and provided during the pre-hearing and hearing process by the company, parties to the hearing, and the FLMs.

Per Section 308(e)(2) of EPA's Regional Haze Rule, as an alternative to BART (or "BART alternative") it was proposed and the state agreed to a more stringent NOx emissions control plan for these BART units that consists of emission limits assumed to be associated with the operation of SNCR for Unit 1 and the operation of SCR for Unit 2. These NOx emission rates are as follows:

Craig Unit 1: 0.28 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.08 lb/MMBtu (30-day rolling average)

Unit 1's 0.28 lb/MMBtu NOx emission rate equates to a 14% control and a NOx reduction of 727 tons per year, which is slightly less than the 15% control and a NOx reduction of 779 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination.

Unit 2's 0.08 lb/MMBtu NOx emission rate equates to a 74% control and a NOx reduction of 3,975 tons per year, which is much greater than the 15% control and a NOx reduction of 806 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination.

The total NOx emission reduction resulting from the BART determination is 1,585 tons per year (779 + 806 = 1,585 tons per year). The total NOx emission reduction resulting from the BART Alternative is 4,702 tons per year (727 + 3,975 = 4,702 tons per year). Given the far greater emission reduction achieved by the BART Alternative when compared to the BART determinations for the individual units, the state determines, in accordance with the federal Regional Haze regulations, that the BART Alternative emission rates are appropriate for Craig Units 1 and 2 as providing greater reasonable progress than the application of BART as set forth in the federal BART Alternative regulation.

The state also evaluated the NOx emission reduction associated with both units (Craig 1 & 2) in contrast to the existing NOx rates, presumptive BART NOx rate, source-by-source determination, and the final RH determination to determine the total NOx reduction benefit. In the below table, the existing NOx emissions from both units is 10,562 tons/year which is much lower than the existing presumptive BART emissions of 14,849 tons/year. The source-by-source BART determination resulted in NOx emissions of 8,978 tons/year which is well above the 5,860 tons/year in NOx emissions calculated to result from application of the BART Alternative. These tons/year calculations provide an emissions based comparison to demonstrate that the Craig BART Alternative provides greater reasonable progress than, and is superior to, source by source BART for these units. The table below is illustrative for demonstration purposes only. The tons per year projections provide an emission based comparison and are not enforceable requirements.

| NOx Analysis | Units | Craig 1 | Craig 2 | Total |
|---|---|---|---|---|
| Annual Average Heat Input* | *[MMBtu]* | 36,933,572 | 39,214,982 | |
| Annual Average NOx Rate* | *[lb/MMBtu]* | 0.28 | 0.27 | |
| Annual Average NOx Emissions* | *[tons/year]* | 5,190.3 | 5,371.6 | 10,562 |
| Presumptive NOx Rate | *[lb/MMBtu]* | 0.39 | 0.39 | |
| Presumptive NOx Emissions | *[tons/year]* | 7,202.1 | 7,646.9 | 14,849 |
| Source-by-Source Determination | *[lb/MMBtu]* | 0.27 | 0.27 | |
| Source-by-Source Determination | *[tons/year]* | 4,411.8 | 4,565.9 | 8,978 |
| Final Regional Haze Determination | *[lb/MMBtu]* | 0.28 | 0.08 | |
| Final Regional Haze Determination | *[tons/year]* | 4,463.7 | 1,396.6 | 5,860 |

** Data from CAMD used for period (2006-2007)*

Based on the above analysis and demonstration, the BART Alternative (final RH determination) achieves more NOx emissions reductions, which are well below the source-by-source BART determinations for each unit. Consequently, the BART Alternative will result in more visibility improvement at nearby Class I areas, and the state adopts this BART Alternative as appropriate to comply with the Regional Haze rule for these units. The state notes that this BART Alternative is not a trading program per Section 308(e)(2) and provisions associated with trading are not applicable.

Under EPA's Alternative to BART rule (40 CFR § 51.308(e)(2)), a state must show that the alternative measure or alternative program achieves greater reasonable progress than would be achieved through the installation and operation of BART. The demonstration addresses these requirements, as follows. (A complete description of these federal requirements is presented in section 6.4.3.7 below.)

1) *51.308(e)(2)(i)(A)* A listing of all BART-eligible sources can be found in Table 6-3 above.
2) *51.308(e)(2)(i)(B)* The two BART-eligible sources are Craig Units 1 and 2.
3) *51.308(e)(2)(i)(C)* The BART determinations presented herein describe the control information and the projected total NOx reduction of 1,585 tons per year for source-by-source BART.
4) *51.308(e)(2)(i)(D)* The BART Alternative achieves a projected NOx reduction of 4,702 tons per year.
5) *51.308(e)(2)(i)(E)* The BART Alternative achieves more than 3,100 tons of projected NOx reduction per year over what would be achieved by the installation of BART.
6) *51.308(e)(2)(iii)* The Craig BART Alternative will be implemented as expeditiously as practicable but no later than five years after EPA's approval of this BART Alternative, as required by Regulation No. 3 Part F. The regulation requires that a compliance schedule be developed by the source and submitted to the state within six months from EPA's approval. The compliance and

monitoring provisions of the BART Alternative have also been incorporated into Regulation No. 3, Part F.

7) *51.308(e)(2)(iv)* The emission reductions associated with the Craig BART Alternative have not been used for other SIP purposes, thus they are surplus.

8) *51.308(e)(2)(v)* The state is not proposing a geographic enhancement for reasonably attributable impairment.

9) *51.308(e)(2)(vi)* Since Colorado is not using a trading program for the Craig BART Alternative, this section does not apply.

10) *51.308(e)(3)* There are only two units at the same facility under the Craig BART Alternative and thus there is no change in the distribution of emissions than under BART, and, as stated above, the alternative measure results in greater emission reductions than case-by-case BART. Therefore the Craig BART Alternative is deemed to achieve greater reasonable progress.

11) *51.308(e)(3)(i)* Since the Craig BART Alternative includes only two units at the same facility, the state has determined that visibility does not decline in any Class I area due to the Craig BART Alternative when compared to case-by-case BART.

12) *51.308(e)(3)(ii)* Because the Craig BART Alternative has been demonstrated to achieve more emission reductions than would occur through case-by-case BART, the state determines that there will be an overall improvement in visibility over all affected Class I areas.

13) *51.308(e)(4)* Colorado is not participating in the CAIR program and cannot rely on this program for the Craig BART Alternative.

14) The state acknowledges that the core requirements will otherwise apply as set forth in the Regional Haze Rule.

15) *51.308(e)(6)* No Colorado BART sources have applied for an exemption from BART.

A complete analysis that supports the BART determination and BART Alternative for Craig Station Units 1 and 2, including substantial cost information for NOx controls, can be found in Appendix C.

### *6.4.3.5 BART Determination for Public Service Company's Hayden Station*

Hayden Units 1 and 2 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, both boilers are subject-to-BART. Public Service Company (PSCo) submitted a BART analysis to the Division on September 14, 2006 with revisions submitted on November 1, 2006 and January 8, 2007. In response to a Division request, PSCo submitted additional information on May 25, 2010.

### SO2 BART Determination for Hayden - Units 1 and 2

*Semi-Dry FGD Upgrades* – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following dry scrubber upgrades were considered for Hayden Units 1 and 2, if technically feasible.

- *Use of performance additives* - The supplier of Hayden's dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, for dry scrubbers. Because low-sulfur coal is used at Hayden, the use of performance additives on the scrubbers would not be expected to increase the $SO_2$ removal.
- *Use of more reactive sorbent* - PSCo is using a highly reactive lime with 92% calcium oxide content reagent that maximizes $SO_2$ removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the $NO_x$ in the flue gas into $NO_2$. Since $NO_2$ is a visible gas, large coal-fired units can generate a visible brown/orange plume at high $SO_2$ removal rates, such as those experienced at Hayden. This side effect is unacceptable in a region with numerous Class I areas in close proximity to the source. There are no known acceptable reagents without this side effect that would allow additional $SO_2$ removal in the dry scrubbing systems present at Hayden Station.
- *Increase the pulverization level of sorbent* – PSCo uses the best available grinding technologies, and other pulverization techniques have not been proven more effective.
- *Engineering redesign of atomizer or slurry injection system -* The supplier offers no upgrade in atomizer design to improve $SO_2$ removal at Hayden. However, an additional scrubber module could be added along with spare parts and maintenance personnel in order to meet a lower emission limit. This option is technically feasible.
- *Additional equipment and maintenance* - Hayden Units 1 and 2 can achieve a lower 30-day average emission rate limit than the 2008 State-adopted BART emission limit of 0.16 lbs/MMBtu by purchasing additional spare atomizer parts and increasing annual operating and maintenance through increased labor and reagent requirements. This emissions limit is 0.13 lbs/MMBtu, which is the current rolling 90-day limit.

The additional scrubber module, and additional spare atomizer parts with additional operation and maintenance were determined to be technically feasible for reducing SO2 emissions from Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Hayden Unit 1 - $SO_2$ Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| Semi-Dry FGD Upgrade – Additional Equipment and Maintenance | 61 | $141,150 | $2,317 |
| Additional Scrubber Module | 488 | $4,142,538 | $8,490 |

| Hayden Unit 2 - $SO_2$ Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| Semi-Dry FGD Upgrade – Additional Equipment and Maintenance | 39 | $141,150 | $3,626 |
| Additional Scrubber Module | 589 | $4,808,896 | $8,164 |

The additional scrubber module option was eliminated from consideration due to the high cost/effectiveness ratios and anticipated small degree of visibility improvement (less than 0.1 deciview) that would result from this upgrade.

There are no energy and non-air quality impact associated with the remaining semi-dry FGD upgrade alternative (additional equipment and maintenance).

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| SO2 Control Method | Hayden – Unit 1 | | Hayden – Unit 2 | |
|---|---|---|---|---|
| | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.34 | | 0.40 | |
| Existing Semi-Dry FGD (LSD) (annual avg.) | 0.16 | 0.09 | 0.16 | 0.18 |
| Semi-Dry FGD Upgrade (annual avg.) | 0.13 | 0.10 | 0.13 | 0.21 |
| Additional Scrubber Module (annual avg.) | 0.07 | 0.14 | 0.07 | 0.26 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

Hayden Unit 1: 0.13 lb/MMBtu (30-day rolling average)

Hayden Unit 2: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). The state evaluated the option of tightening the emission limit for Hayden Units 1 and 2 and determined that a more stringent 30-day rolling SO2 limit of 0.13 lbs/MMBtu represents an appropriate level of emissions control for semi-dry FGD control technology. The tighter emission rate for both units is achievable with a negligible investment and the facility operator has offered to undertake these actions to allow for refinement of the emissions rate appropriate for this technology at this source despite the lack of appreciable modeled visibility improvement, and the state accepts this.

### Particulate Matter BART Determination for Hayden - Units 1 and 2

Based on recent BACT determinations, the state has determined that the existing Unit 1 and Unit 2 emission limit of 0.03 lb/MMBtu ($PM/PM_{10}$) represents the most stringent level of available control for $PM/PM_{10}$. The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for $PM/PM_{10}$ as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

### NOx BART Determination for Hayden - Units 1 and 2

LNB upgrades, SNCR and SCR were determined to be technically feasible for reducing NOx emissions at Hayden Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Hayden Unit 1 - $NO_x$ Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| LNB | 1,391 | $572,010 | $411 |
| SNCR | 1,391 | $1,353,500 | $973 |
| SCR | 3,120 | $10,560,612 | $3,385 |

| Hayden Unit 2 - $NO_x$ Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| LNB | 1,303 | $992,729 | $762 |
| SNCR | 1,610 | $1,893,258 | $1,176 |
| SCR | 3,032 | $12,321,491 | $4,064 |

The energy and non-air quality impacts of the alternatives are as follows:

- LNB – not significant

- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| NOx Control Method | Hayden – Unit 1 | | Hayden – Unit 2 | |
|---|---|---|---|---|
| | NOx Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | NOx Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.61 | | 0.37 | |
| LNB (annual avg.) | 0.26 | 0.69 | 0.21 | 0.40 |
| SNCR (annual avg.) | 0.26 | 0.69 | 0.18 | 0.48 |
| SCR (annual avg.) | 0.07 | 1.12 | 0.06 | 0.85 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following NOx emission rates:

Hayden Unit 1: 0.08 lb/MMBtu (30-day rolling average)

Hayden Unit 2: 0.07 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of selective catalytic reduction (SCR). For these emission limits, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented above.

- Unit 1: $3,385 per ton NOx removed; 1.12 deciview of improvement
- Unit 2: $4,064 per ton NOx removed; 0.85 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements leads the state to this determination. The NOx emission limits of 0.08 lb/MMBtu (30-day rolling average) for Unit 1; and 0.07 lb/MMBtu (30-day rolling average) for Unit 2; are technically feasible and have been determined to be BART for Hayden Units 1 and 2.

A complete analysis that supports the BART determination for PSCo's Hayden Units 1 and 2 can be found in Appendix C.

### *6.4.3.6 BART Determination for Colorado Springs Utilities' Martin Drake Plant*

Colorado Springs Utilities' Boilers 5, 6, and 7 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and having commenced operation in the 15-year period prior to August 7, 1977. The combined emissions of these boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, all three boilers are subject-to-BART. Initial air dispersion modeling performed by the Division demonstrated that the Martin Drake Plant contributes to visibility impairment (a 98th percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Colorado Springs Utilities (CSU) submitted a BART Analysis to the Division on August 1, 2006 with updated cost information submitted on March 29, 2007. CSU also provided information in its "NOx and SO2 Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 as well as additional information upon the Division's request on February 21, 2010, March 21, 2010, May 10, 2010, May 28, 2010, June 2, 2010, and June 15, 2010.

### SO2 BART Determination for Martin Drake - Units 5, 6 and 7

Dry sorbent injection (DSI) was determined to be feasible for all units and dry FGD were determined to be technically feasible for reducing SO2 emissions from Units 6, and 7. These options were considered as potential BART level controls by the Division. Lime or limestone-based wet FGD system is also technically feasible but was determined to be not reasonable due to adverse non-air quality impacts. Drake is conducting a trial on a new wet FGD system design (NeuStream-S) that uses much less water along with a smaller operational footprint that may provide, if successfully demonstrated, a reasonable alternative to traditional wet FGD systems.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Drake Unit 5 - $SO_2$ Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| DSI | 762 | $1,340,663 | $1,760 |

| Drake Unit 6 - SO2 Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| DSI | 1,671 | $2,910,287 | $1,741 |
| Dry FGD (LSD) @ 82% control (0.15 lb/MMBtu annual average) | 2,284 | $6,186,854 | $2,709 |
| Dry FGD (LSD) @ 85% control (0.12 lb/MMBtu annual average) | 2,368 | $6,647,835 | $2,808 |
| Dry FGD (LSD) @ 90% control (0.08 lb/MMBtu annual average) | 2,507 | $7,452,788 | $2,973 |

| Drake Unit 7 - $SO_2$ Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| DSI | 2,657 | $3,723,826 | $1,405 |
| Dry FGD (LSD) @ 82% control (0.15 lb/MMBtu annual average) | 3,632 | $8,216,863 | $2,263 |
| Dry FGD (LSD) @ 85% control (0.12 lb/MMBtu annual average) | 3,764 | $8,829,321 | $2,345 |
| Dry FGD (LSD) @ 90% control (0.08 lb/MMBtu annual average) | 3,986 | $9,898,382 | $2,483 |

The energy and non-air quality impacts of the remaining alternative are as follows:

- DSI - reduced mercury capture in the baghouse, fly ash contamination with sodium sulfate, rendering the ash unsalable as a replacement for concrete and rendering it landfill material only
- Dry FGD – less mercury removal compared to unscrubbed units, significant water usage

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| SO2 Control Method | Drake – Unit 5 | | Drake – Unit 6 | | Drake – Unit 7 | |
|---|---|---|---|---|---|---|
| | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Max (3-yr) | 0.94 | | 1.00 | | 0.99 | |
| DSI (annual avg.) | 0.25 | 0.12 | 0.33 | 0.18 | 0.33 | 0.29 |
| Dry FGD (LSD) (annual avg.) | Not feasible | | 0.12 | 0.24 | 0.12 | 0.39 |
| Dry FGD (LSD) (annual avg.) | Not feasible | | 0.07 | 0.26 | 0.07 | 0.41 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART for Unit 5 is the following SO2 emission rate:

Drake Unit 5: 0.26 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limit can be achieved through the installation and operation of dry sorbent injection. Other alternatives are not feasible.

- Unit 5: $1,760 per ton SO2 removed; 0.12 deciview of improvement

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART for Unit 6 and Unit 7 is the following SO2 emission rates:

Drake Unit 6: 0.13 lb/MMBtu (30-day rolling average)

Drake Unit 7: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of lime spray dryers (LSD). A lower emissions rate for Units 6 and 7 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.02 delta deciview for both units respectively).

These emission rates for Units 6 and 7 provide 85% SO2 emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 6: $2,808 per ton SO2 removed; 0.24 deciview of improvement
- Unit 7: $2,345 per ton SO2 removed; 0.39 deciview of improvement

**Particulate Matter BART Determination for Martin Drake - Units 5, 6 and 7**

The state determines that the existing regulatory emissions limit of 0.03 lb/MMBtu (PM/PM10) for the three units represent the most stringent control options. The units are exceeding a PM control efficiency of 95%, and the emission limits are BART for $PM/PM_{10.}$ The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

**NOx BART Determination for Martin Drake - Units 5, 6 and 7**

Ultra low NOx burners (ULNB), ULNB including OFA, SNCR, SNCR plus ULNB, and SCR were determined to be technically feasible for reducing NOx emissions at Drake Units 5, 6 and 7.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Drake Unit 5 - $NO_x$ Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| Overfire air (OFA) | 154 | $141,844 | $923 |
| Ultra-low NOx burners (ULNBs) | 200 | $147,000 | $736 |
| ULNBs + OFA | 215 | $288,844 | $1,342 |
| Selective Non-Catalytic Reduction (SNCR) | 231 | $1,011,324 | $4,387 |
| ULNB/SCR layered approach | 626 | $4,467,000 | $7,133 |
| Selective Catalytic Reduction (SCR) | 626 | $4,580,000 | $7,314 |

| Drake Unit 6 - NOx Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| Overfire air (OFA) | 283 | $104,951 | $371 |
| Selective Non-Catalytic Reduction (SNCR) | 424 | $1,208,302 | $2,851 |
| Ultra-low NOx burners (ULNBs) | 452 | $232,800 | $515 |
| ULNBs + OFA | 509 | $337,751 | $664 |
| ULNB/SCR layered approach | 1,175 | $6,182,800 | $5,260 |
| Selective Catalytic Reduction (SCR) | 1,175 | $6,340,000 | $5,395 |

| Drake Unit 7 - NOx Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| Overfire air (OFA) | 416 | $75,217 | $181 |
| Ultra-low NOx burners (ULNBs) | 583 | $386,000 | $662 |
| Selective Non-Catalytic Reduction (SNCR) | 624 | $2,018,575 | $3,233 |
| ULNBs + OFA | 749 | $461,217 | $616 |
| ULNB/SCR layered approach | 1,709 | $8,196,000 | $4,797 |
| Selective Catalytic Reduction (SCR) | 1,709 | $8,510,000 | $4,981 |

The energy and non-air quality impacts of the alternatives are as follows:

- OFA and ULNB – not significant
- ULNB – not significant
- SNCR and SCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| NOx Control Method | Drake – Unit 5 | | Drake – Unit 6 | | Drake – Unit 7 | |
|---|---|---|---|---|---|---|
| | NOx Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | NOx Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | NOx Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Max (3-yr) | 0.62 | | 0.83 | | 0.71 | |
| OFA (annual avg.) | 0.30 | 0.07 | 0.33 | 0.18 | 0.31 | 0.22 |
| ULNB (annual avg.) | 0.28 | 0.08 | 0.28 | 0.193 | 0.28 | 0.24 |
| ULNB + OFA (annual avg.) | 0.27 | 0.08 | 0.27 | 0.20 | 0.25 | 0.26 |
| SNCR (annual avg.) | 0.27 | 0.08 | 0.29 | 0.19 | 0.28 | 0.24 |
| ULNB + SCR | 0.07 | 0.12 | 0.07 | 0.27 | 0.07 | 0.37 |
| SCR (annual avg.) | 0.07 | 0.12 | 0.07 | 0.27 | 0.07 | 0.37 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOX BART for Units 5, 6 and 7 is the following NOx emission rates:

Drake Units 5 and 6: 0.31 lb/MMBtu (30-day rolling average)

Drake Unit 7: 0.29 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of ultra low-NOx burners (including over-fire air).

- Unit 5: $1,342 per ton NOx removed
- Unit 6: $664 per ton NOx removed
- Unit 7: $616 per ton NOx removed

The extremely low dollars per ton control costs leads the state to selecting this emission rate for each of the Drake units. SNCR is not selected as that technology provides an equivalent emissions rate, similar level of NOx reduction coupled with equivalent visibility improvement at a much higher cost per ton of pollutant removed along with potential energy and non-air quality impacts. SCR is not selected as the cost/effectiveness ratios for Units 5 and 6 are too high and the visibility improvement at all units do not meet the criteria guidance described above (*e.g.* less than 0.50 Δdv)

For Drake Units 5 and 6, EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.04 dv for SCR on Unit 5 and 0.07 dv for SCR on Unit 6). Thus, it is not warranted to select emission limits associated with SCR for Martin Drake Units 5 and 6.

For Drake Unit 7, EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's BART determination because the degree of visibility improvement achieved by SCR is below the state's guidance criteria of 0.5 dv. Moreover, the incremental visibility improvement associated with SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.11 dv for SCR). Thus, it is not warranted to select emission limits associated with SCR for Martin Drake Unit 7.

A complete analysis that supports the BART determination for CSU's Martin Drake Units 5, 6 and 7 can be found in Appendix C.

#### *6.4.3.7 BART Determination for Public Service Company's Cherokee Unit 4, Valmont Unit 5 and the Pawnee Station as a BART Alternative, which Includes Reasonable Progress Determinations for Arapahoe Units 3 and 4 and Cherokee Units 1, 2 and 3*

**Background**

Section 308(e)(2) of EPA's Regional Haze Rule allows a state to approve a BART alternative:

> *A State may opt to implement or require participation in an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART. Such an emissions trading program or other alternative measure must achieve greater reasonable progress than would be achieved through the installation and operation of BART. For all such emission trading programs or other alternative measures, the State must submit an implementation plan containing the following plan elements and include documentation for all required analyses: (i) A demonstration that the emissions trading program or other alternative measure will achieve greater reasonable progress than would have resulted from the installation and operation of BART at all sources subject to BART in the State and covered by the alternative program. This demonstration must be based on the following: (A) A list of all BART-eligible sources within the State. (B) A list of all BART-eligible sources and all BART source categories covered by the alternative program. The State is not required to include every BART source category or every BART-eligible source within a BART source category in an alternative program, but each BART-eligible source in the State must be subject to the requirements of the alternative program, have a federally enforceable emission limitation determined by the State and approved by EPA as meeting BART in accordance with section 302(c) or paragraph (e)(1) of this section, or otherwise addressed under paragraphs (e)(1) or (e)(4) of this section.*

The PSCo BART Alternative Program (““PSCo BART Alternative”) was proposed by Public Service Company of Colorado (PSCo). The PSCo BART Alternative is not a trading program and does not include any complete source categories, although all facilities in the PSCo BART Alternative are electric generating units. The PSCo BART Alternative is based on reductions achieved as a result of a combination of unit shutdowns and the application of emissions controls planned as part of the Colorado HB 10-1365, the “Clean Air – Clean Jobs Act” ( § 40-3.2-201 C.R.S., *et. seq*.). The PSCo BART Alternative includes ten units at four facilities. The facilities included in the PSCo Alternative and the proposed controls are listed below.

**Table 6-5: Actions and Dates under the PSCo Alternative**

| Facility | Unit | Action or Control | Effective Date |
|---|---|---|---|
| Arapahoe | Unit 3 | Shutdown | 12/31/2013 |
| | Unit 4 | Operation on Natural Gas only (peaking unit) | 12/31/2014 |
| Cherokee | Unit 1 | Shutdown | No later than 7/1/2012 |
| | Unit 2 | Shutdown | 12/31/2011 |
| | Unit 3 | Shutdown | No later than 12/31/2016 |
| | Unit 4 | Operation on Natural Gas only | 12/31/2017 |
| Valmont | | Shutdown | 12/31/2017 |
| Pawnee | | SCR & LSD | 12/31/2014 |

The state in evaluating the PSCo Alternative followed the EPA July 6, 2005, BART guidelines and the EPA October 13, 2006, regulation referred to as Provisions Governing Alternative to Source-Specific BART Determinations (71Fed.Reg. 60612-60634 (10/13/2006); 40 CFR § 51.308(e)(2), “Alternative to BART rule”). Under the Alternative to BART rule, a state must show that the alternative measure or alternative program achieves greater reasonable progress than would be achieved through the installation and operation of BART. The demonstration must include five elements:

1) A list of all BART-eligible sources within the state;
2) A list of all BART-eligible sources and source categories covered by the alternative program;
3) An analysis of the best system of continuous emission control technology available and the associated reductions;
4) An analysis of the projected emissions reductions achievable through the alternative measure; and
5) A determination that the alternative measure achieves greater reasonable progress than would be achieved through the installation of BART.

The PSCo Alternative includes both BART and non-BART sources. The non-BART sources are older than the BART timeframe, and in effect will all be controlled and reduce their NOx and SO2 emissions as a result of enforceable facility retirement dates and, for one unit, operating only on natural gas as a “peaking” unit. The BART sources, Cherokee 4, Pawnee and Valmont, will all be either controlled within the first planning period or shutdown with enforceable facility retirement dates.

The state's alternative program satisfies the requirements of 40 CFR § 51.308, as further described in the preambles to the BART guidelines and the Alternative to BART rule. The state's analysis must include:

> *An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program. This analysis must be conducted by making a determination of BART for each source subject to BART and covered by the alternative program as provided for in paragraph (e)(1) of this section, unless the emissions trading program or other alternative measure has been designed to meet a requirement other than BART (such as the core requirement to have a long-term strategy to achieve the reasonable progress goals established by States). In this case, the State may determine the best system of continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate.*

40 CFR § 51.308(e)(2)(i)(C).

Colorado's alternative program was designed to meet a requirement other than BART; namely, Colorado's HB 10-1365. The express purpose of the legislation leading to the alternative program being proposed is:

> THE GENERAL ASSEMBLY HEREBY FINDS, DETERMINES, AND DECLARES THAT THE FEDERAL "CLEAN AIR ACT", 42 U.S.C. SEC. 7401 ET SEQ., WILL LIKELY REQUIRE REDUCTIONS IN EMISSIONS FROM COAL-FIRED POWER PLANTS OPERATED BY RATE-REGULATED UTILITIES IN COLORADO. A COORDINATED PLAN OF EMISSION REDUCTIONS FROM THESE COAL-FIRED POWER PLANTS WILL ENABLE COLORADO RATE-REGULATED UTILITIES TO MEET THE REQUIREMENTS OF THE FEDERAL ACT AND PROTECT PUBLIC HEALTH AND THE ENVIRONMENT AT A LOWER COST THAN A PIECEMEAL APPROACH. A COORDINATED PLAN OF REDUCTION OF EMISSIONS FOR COLORADO'S RATE-REGULATED UTILITIES WILL ALSO RESULT IN REDUCTIONS IN MANY AIR POLLUTANTS AND PROMOTE THE USE OF NATURAL GAS AND OTHER LOW-EMITTING RESOURCES TO MEET COLORADO'S ELECTRICITY NEEDS, WHICH WILL IN TURN PROMOTE DEVELOPMENT OF COLORADO'S ECONOMY AND INDUSTRY.

§ 40-3.2-202, C.R.S. Similarly, Colorado's Clean Air – Clean Jobs Act further specifies that it is intended to address both current and reasonably foreseeable future requirements of the federal Clean Air Act. *See,* § 40-3.2-204, C.R.S.

PSCo BART Alternative measure for the subject coal-fired electric generating units is thus designed to meet the requirements of the regional haze rule, including BART, but also to address requirements beyond BART. This includes, for example, a revised national standard for ozone to be promulgated in 2011, other revised or to be revised national ambient air quality standards, or federal sector-specific regulations for hazardous air pollutants, among other federal regulatory requirements. Accordingly, the state will determine whether the PSCo BART Alternative represents the best system of continuous emission control technology and associated emission reductions for the sources included in the alternative. In the preamble to the Alternative to BART rule, EPA discusses whether the option exists for states to use simplifying assumptions in determining the BART benchmark, or whether states must establish the BART benchmark through a source-by-source BART analysis. EPA states:

> [T]here is no need to develop a precise estimate of the emissions reductions that could be achieved by BART in order simply to compare two programs. As EPA did in the CAIR, States should have the ability to develop a BART benchmark based on simplifying assumptions as to what the most-stringent BART is likely to achieve. The regulations finalized today therefore provide that where an emission trading program has been designed to meet a requirement other than BART, including the reasonable progress requirement, the State may establish a BART benchmark based on an analysis that includes simplifying assumptions about BART control levels for sources within a source category.

71 Fed. Reg. 60612, 60618 (October 13, 2006). EPA has thus determined that source-by source BART is not required when it is not necessary where a state has determined that greater reasonable progress can be achieved by an alternative means. *See also,* 70 Fed. Reg. 39104, 39137 (July 6, 2005). Thus, there is no need for states to conduct an extensive source-by-source BART assessment, and to then also go through the additional, resource intensive steps of developing an alternative program to BART. *See,* 71 Fed. Reg. at 60617.

Colorado has looked at several options to establish the BART benchmark. EPA establishes some criteria for the BART benchmark in the Alternative to BART rule, where the agency discusses simplifying assumptions.

> In today's final rule, the regulations make clear that, with one exception, States must follow the approach for making BART determinations under section 51.308(e)(1) in establishing a BART benchmark. This includes the requirement for States to use the BART guidelines in making BART determinations for EGUs at power plants of a certain size. As discussed above, the one exception to this general approach is where the alternative program has been designed to meet requirements other than BART; in this case, States are not required to make BART determinations under § 51.308(e)(1) and may use simplifying assumptions in establishing a BART benchmark based on an analysis of what BART is likely to be for similar types of sources within a source category. Under either approach to establishing a BART benchmark, we believe that the presumptions for EGUs in the BART guidelines should be used for comparison to a trading program or other alternative measure, unless the State determines that such presumptions are not appropriate for particular EGUs.

71 Fed. Reg. at 60619 (October 13, 2006). *See also, id*. at 60615 ("Where a trading program or other similar alternative program has been designed primarily to meet a Federal or State requirement other than BART, the State can use a more simplified approach to demonstrating that the alternative program will make greater reasonable progress than BART. Such an approach may be appropriate where the State believes the alternative program is clearly superior to BART and a detailed BART analysis is not

necessary to assure that the alternative program will result in greater reasonable progress than BART.”).

The PSCo BART Alternative includes only EGUs and, based on EPA’s Alternative to BART rule, one option available is a comparison to the presumptive limits in the BART guidelines. *Id*. The presumptive limits represent a reasonable estimate of stringent case BART, particularly when developing a BART benchmark to assess an alternative program, because they are applied equally to EGU’s of varying size and distance from Class I areas, and with varying impacts on visibility. *Id.* Because not all of the sources in the PSCo BART Alternative are BART sources, the state also considered other benchmarks that might be appropriate. For example, as part of the BART and reasonable progress analysis, the state has established guidelines for NOx based on control technology costs and visibility improvements. The state’s analysis substantiates that the PSCo BART Alternative provides greater reasonable progress than would have been achieved without the alternative.

**Analysis Under 40 CFR Part 51, § 308(e)**

*(2)(i)(A) A list of all Bart-eligible sources within the State.*

A listing of all BART-eligible sources can be found in Table 6-3 in this Chapter 6 of the Regional Haze State Implementation Plan.

*(2)(i)(B) A list of all BART-eligible sources and all BART source categories covered by the alternative program.*

The State is not required to include every BART source category or every BART-eligible source within a BART source category in an alternative program. However, each BART-eligible source in the State covered by the PSCo BART Alternative in this case must be subject to the requirements of the alternative program, have a federally enforceable emission limitation determined by the State and approved by EPA as meeting BART in accordance with section 302(c) or section 308(e)(1), or otherwise be addressed under section 308(e)(1) or (e)(4). The BART sources covered by the PSCo BART Alternative are shown in Table 6-6.

**Table 6-6: Sources Included Within the PSCo Alternative**

| Facility | Unit | Action or Control |
|---|---|---|
| Arapahoe | Unit 3 | Shutdown |
| | Unit 4 | Operation on natural gas only |
| Cherokee | Unit 1 | Shutdown |
| | Unit 2 | Shutdown |
| | Unit 3 | Shutdown |
| | Unit 4 (BART-eligible) | Operation on natural gas only |
| | New nat. gas-fired EGU | BACT where netting does not apply |
| Valmont | (BART-eligible) | Shutdown |
| Pawnee | (BART-eligible) | SCR & LSD |

*(2)(i)(C) An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program. This analysis must be conducted by making a determination of BART for each source subject to BART and covered by the alternative program as provided for in paragraph (e)(1) of this section, unless the emissions trading program or other alternative measure has been designed to meet a requirement other than BART (such as the core requirement to have a long-term strategy to achieve the reasonable progress goals established by States). In this case, the State may determine the best system of continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate.*

The PSCo BART Alternative includes the emission reductions achieved through Colorado HB 10-1365 (§ 40-3.2-201 C.R.S., *et seq*.). The PSCo BART Alternative was developed to address requirements other than BART, including to support the attainment of federal ambient air quality standards, to meet other federal requirements that can affect electric generating units, and improve air quality on the Front Range of Colorado. Since the PSCo BART Alternative was designed to address requirements other than BART, it meets the EPA SIP provision noted above that allows the state to determine the base case BART emissions using simplifying assumptions. This approach is discussed in EPA's Alternative to BART Rule. *See,* 71 Fed. Reg. at 60612 (October 13, 2006). Colorado has estimated base case BART emissions assuming that the plants included in the PSCo BART Alternative emit at the presumptive levels established by EPA for electric generating units of greater than 750 MW.[18] The emissions resulting from the PSCo BART Alternative are then compared to the analysis of base case BART emissions to indicate the degree of emissions reduction improvement provided by the PSCo BART Alternative.

*(2)(i)(D) An analysis of the projected emissions reductions achievable through the trading program or other alternative measure.*

The emission reductions achievable through PSCo's Alternative include the reductions associated with the combination of shutdowns and retrofit controls established under PSCo's emissions reduction plan, endorsed by the state Public Utilities Commission pursuant to HB 10-1365, and codified and made enforceable by the elements reflected in this State Implementation Plan. The following emissions reductions provided by the PSCo BART Alternative are reflected in Tables 6-7 and 6-8, below. With respect to SO2 emissions, the PSCo BART Alternative will reduce SO2 emissions from these units by 21,493 tons per

[18] None of the BART units included in this Alternative are larger than 750MW, thus the presumptive emissions standards for electric generating units set forth in EPA's BART guidelines are not mandatory for these units. *See, e.g.,* 70 Fed. Reg. at 39108. The non-BART units included in this Alternative are also not subject to the presumptive emissions standards as a mandatory element of Regional Haze. While not required as a matter of regulation the presumptive limits are employed in this instance solely for demonstrative and comparative purposes.

year in the first planning period (2010 to 2018). With respect to NOx emissions, the PSCo BART Alternative will reduce NOx emissions from these units by 15,994 tons per year in the first planning period (2010 to 2018).

*(2)(i)(E) A determination under paragraph (e)(3) of this section or otherwise based on the clear weight of evidence that the trading program or other alternative measure achieves greater reasonable progress than would be achieved through the installation and operation of BART at the covered sources.*

The PSCo BART Alternative has been evaluated according to the emissions based test discussed in EPA's Alternative to BART Rule. This is explained in further detail below, and demonstrates that for both SO2 and NOx, due to a combination of substantial retirements of coal-fired units and controls on other coal-fired units, the PSCo BART Alternative provides greater reasonable progress than would be afforded under BART at the covered sources.

*(2)(ii) [Reserved]*

*(2)(iii) A requirement that all necessary emission reductions take place during the period of the first long-term strategy for regional haze. To meet this requirement, the State must provide a detailed description of the emissions trading program or other alternative measure, including schedules for implementation, the emission reductions required by the program, all necessary administrative and technical procedures for implementing the program, rules for accounting and monitoring emissions, and procedures for enforcement.*

The PSCo BART Alternative for these electric generating units will be implemented during the first long-term strategy period, by December 31, 2017. The PSCo BART Alternative as set forth in this SIP establishes an expeditious implementation schedule for the coordinated shutdown of, and installation of retrofit emissions controls on the covered coal-fired electric generating units. As reflected in Table 6-12, emission limits for SO2 and NOx at Pawnee, operation on natural gas at Cherokee Unit 4, operation on natural gas at Arapahoe Unit 4 as a peaking unit only, and shutdowns at Arapahoe Unit 3, Cherokee Units 1, 2 and 3, and Valmont, will all occur during the first planning period. Some of the NOx emissions reductions will be reserved, and are not used in this alternative measure demonstration and not reflected in the emissions reductions in this SIP, to allow for natural gas replacement power at Cherokee and future "netting" or "offsets". The compliance and monitoring provisions of the PSCo BART Alternative have been incorporated into Regulation No. 3, Part F. Compliance will be determined through the use of continuous emission monitors for those facilities that are not shutdown. Enforceability of the shutdown of coal-fired units under the PSCo BART Alternative is reflected in this State Implementation Plan, as well as in Regulation No. 3, Part F. Colorado will also amend the relevant permits to include enforceable shutdown dates.

*(2)(iv) A demonstration that the emission reductions resulting from the emissions trading program or other alternative measure will be surplus to those reductions resulting from measures adopted to meet requirements of the CAA as of the baseline date of the SIP.*

The emission controls associated with the PSCo BART Alternative have not been used for other SIP purposes, thus they are surplus. The reductions from the shutdown of Arapahoe units 1 and 2 were used in an earlier PM SIP demonstration and are not included in this analysis.

*(2)(v) At the State's option, a provision that the emissions trading program or other alternative measure may include a geographic enhancement to the program to address the requirement under §51.302(c) related to BART for reasonably attributable impairment from the pollutants covered under the emissions trading program or other alternative measure.*

The Division is not proposing a geographic enhancement for reasonably attributable impairment.

*(2)(vi) For plans that include an emissions trading program that establishes a cap on total annual emissions of SO2 or NOx from sources subject to the program, requires the owners and operators of sources to hold allowances or authorizations to emit equal to emissions, and allows the owners and operators of sources and other entities to purchase, sell, and transfer allowances, the following elements are required concerning the emissions covered by the cap*:

Since Colorado is not using a trading program for the PSCo BART Alternative, this section does not apply. Electric generating units subject to this alternative have unit-specific compliance requirements reflected in this SIP and in Reg. No. 3, Part F.

*(3) A State which opts under 40 CFR 51.308(e)(2) to implement an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART may satisfy the final step of the demonstration required by that section as follows: If the distribution of emissions is not substantially different than under BART, and the alternative measure results in greater emission reductions, then the alternative measure may be deemed to achieve greater reasonable progress. If the distribution of emissions is significantly different, the State must conduct dispersion modeling to determine differences in visibility between BART and the trading program for each impacted Class I area, for the worst and best 20 percent of days. The modeling would demonstrate "greater reasonable progress" if both of the following two criteria are met:*

The Division has determined that the distribution of emissions under the PSCo BART Alternative is not substantially different than under BART, and the alternative measure results in greater emission reductions than case-by-case BART. The PSCo BART Alternative includes three BART units at four different facilities, all of which are in or immediately adjacent to the 8-Hour Ozone Non-Attainment Area in the Front Range of Colorado. Like the other three facilities, the fourth is the Arapahoe facility and it is central to the non-attainment area, and is only 17 kilometers from the Cherokee facility.

*(3)(i) Visibility does not decline in any Class I area, and*

Since the Metro Denver BART eligible sources are included in the PSCo BART Alternative along with other non–BART sources in the area, and the overall visibility-impairing pollutants from these units decrease substantially, the Division has determined that visibility does not decline in any Class I area in relation to this PSCo BART Alternative.

*(3)(ii) There is an overall improvement in visibility, determined by comparing the average differences between BART and the alternative over all affected Class I areas.*

The PSCo Alternative has been demonstrated to achieve more emission reductions than would occur through case-by-case BART. The reasons why the alternative provides greater reductions include:

a) Arapahoe Unit 3, Cherokee Units 1, 2 and 3, and Valmont (BART eligible unit), will be shutdown during the first planning period.

b) Arapahoe Unit 4 will operate on natural gas as a peaking unit.

c) Cherokee Unit 4 (BART eligible unit) will operate on natural gas only.

d) Pawnee Unit 1(BART eligible unit) will install and operate an LSD to control $SO_2$ emissions and SCR to control $NO_x$ emissions in 2014.

*(4) A State that chooses to meet the emission reduction requirements of the Clean Air Interstate Rule (CAIR) by participating in one or more of EPA's CAIR trading programs*

Colorado is not participating in the CAIR program.

*(5) After a State has met the requirements for BART or implemented an emissions trading program or other alternative measure that achieves more reasonable progress than the installation and operation of BART, BART-eligible sources will be subject to the requirements of paragraph (d) of this section in the same manner as other sources.*

The state acknowledges that the core requirements will otherwise apply as set forth in the Regional Haze Rule.

*(6) Any BART-eligible facility subject to the requirement under paragraph (e) of this section to install, operate, and maintain BART may apply to the Administrator for an exemption from that requirement. An application for an exemption will be subject to the requirements of §51.303(a)(2)–(h).*

No Colorado BART sources have applied for an exemption from BART.

**<u>Technical Analysis of the PSCo Alternative Emissions Reductions with Respect to the Section 308(e) Alternative Measure Demonstration</u>**

The following technical analysis of emissions reductions that result from the PSCo BART Alternative more fully demonstrates that the proposed alternative achieves greater reasonable progress than the installation of BART, as allowed under EPA's regional haze regulations. EPA's Regional Haze Rule requires that BART- eligible sources either install BART as determined for each source on a case-by-case basis, or install controls as required by a BART Alternative. EPA's BART guidance (70 Fed. Reg. 39104, July 6, 2005) and EPA's regulation on BART Alternatives (71 Fed. Reg. 60612, October 13, 2006) both provide guidance on how to evaluate whether a BART Alternative proposal achieves greater reasonable progress under the regulation. This determination can be made based on an emissions comparison or through a modeling analysis if the state determines that is appropriate. If the geographic distribution of emissions reductions from the programs is expected to be similar, the comparison can be made based on emissions alone. 70 Fed. Reg. at 39136; 71 Fed. Reg. at 60620. Because all the sources included in the PSCo BART Alternative are located in the same air shed and within a 100 mile area, the Division has determined that the BART eligible sources in the PSCo BART Alternative are in the same geographic region (namely, in the Denver Metro Area and also in or immediately adjacent to the existing 8-Hour Ozone Non-Attainment Area) for purposes of regional haze. Thus an emissions demonstration is appropriate and modeling is not warranted for an alternative measure demonstration.

EPA's BART guidance does not specify a quantity of emission reductions an alternative must exceed to satisfy the "achieves greater reasonable progress" criteria. In its BART guidance, EPA provides an emission-based demonstration of how EPA determined the Clean Air Interstate Rule (CAIR) to be better than case-by-case BART on individual sources. In that instance, EPA demonstrated that more tons of emission reductions would result from the CAIR rule than with source-by-source BART. *See, e.g.,* 70 Fed. Reg. at 39141. Similarly, the state has utilized the emission-based method to evaluate the PSCo BART Alternative. The state has determined that the PSCo BART Alternative achieves greater reasonable progress by evaluating the future emissions from the electric generating units under the operating scenarios reflected in the PSCo BART Alternative, and for demonstration purposes compared those emissions with the same units using the standard established by EPA of 95 percent removal or 0.15 lb/MMBtu for SO2 or a lb/MMBtu for NOx based on boiler and coal type. *See* 71 Fed. Reg. at 60619 ("States establishing a BART benchmark based on simplifying assumptions as to the most stringent BART for EGUs may rely on the presumptions, as EPA did in the CAIR rule.").

As previously discussed, the PSCo Alternative is based on a combination of emissions control retrofits and shutdowns resulting from Colorado HB 10-1365 and the PUC's actions. The PSCo BART Alternative includes Pawnee, Arapahoe Units 3 and 4, Valmont Unit 5, and Cherokee Units 1-4. Pawnee, Cherokee Unit 4 and Valmont Unit 5 are the only BART eligible units. The sources involved in the PSCo BART Alternative are either BART eligible sources or sources that precede the BART timeframe. For demonstration purposes, the emissions from the entire group of electric generating units in the PSCo BART Alternative were compared to the emissions from the units if the presumptive levels were applied, as allowed under EPA's regulation. Table 6-7 compares the tons of SO2 that would be emitted under the PSCo BART Alternative to the number of tons of SO2 that would be emitted by the same units if the standard of 0.15 lb SO2/MMBtu were applied. The 0.15 lb/MMBtu standard comes from the 70 Fed. Reg. 39132 (7/6/2005) in which EPA establishes "BART limits of 95 percent SO2 removal, or an emission rate of 0.15 lb SO2/MMBtu". The MMBtu used for the analysis is an average of the actual MMBtu reported by the units to the Clean Air Markets Division for 2006, 2007 and 2008. For units that will be shutdown or operated on natural gas (Arapahoe unit 4) under the PSCo BART Alternative an emissions factor of 0.0006 lb SO2/MMBtu was used for the alternative.

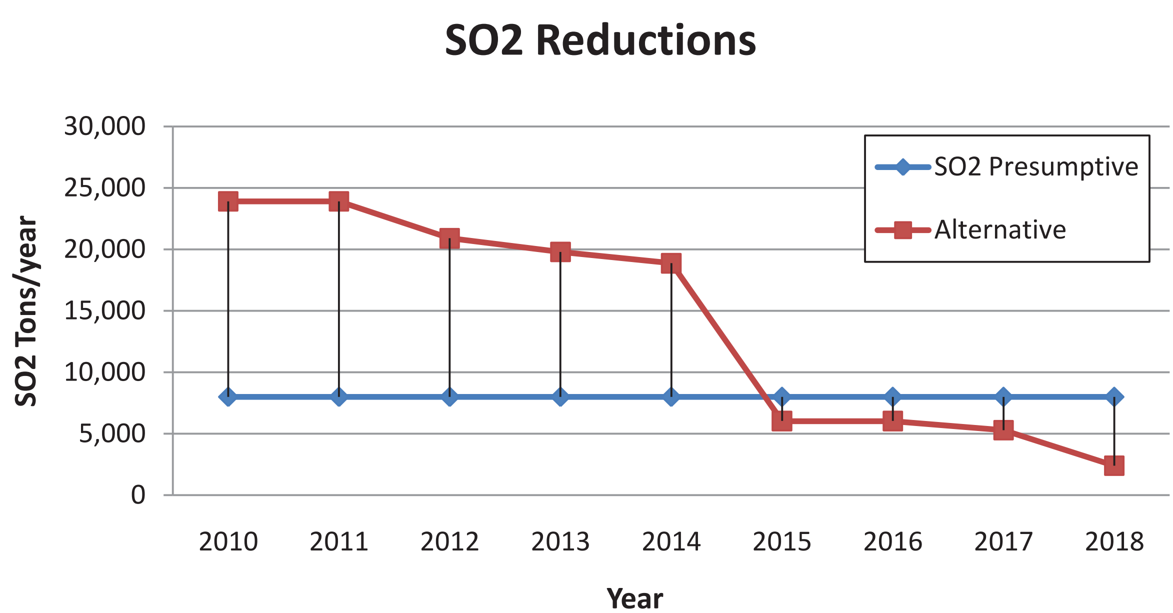
**Table 6-7: SO2 Reductions Beyond Presumptive BART for PSCo Alternative**

| Facility | MMBtu Average 2006 to 2008 | SO2 TPY Average 2006 to 2008 | SO2 TPY at 0.15 lb/MMBtu Presumptive | SO2 TPY under PSCo Alternative in 2018 | % Reduction Beyond Presumptive BART |
|---|---|---|---|---|---|
| Arapahoe | | | | | |
| Unit 3 | 4,380,121 | 924.97 | 328.51 | 0.00 | 100.00% |
| Unit 4 | 8,545,791 | 1,764.70 | 640.93 | 1.28[19] | 99.8% |
| Cherokee | | | | | |
| Unit 1 | 8,311,352 | 2,220.80 | 623.35 | 0.00 | 100.00% |
| Unit 2 | 5,586,021 | 1,888.37 | 418.95 | 0.00 | 100.00% |
| Unit 3 | 8,159,889 | 743.00 | 611.99 | 0.00 | 100.00% |
| Unit 4 | 26,047,648 | 2,135.43 | 1,953.57 | 7.81 | 99.6 % |
| Valmont | 13,722,507 | 758.47 | 1,029.19 | 0.00 | 100.00% |
| Pawnee | 40,093,753 | 13,472.07 | 3,007.03 | 2,405.63 | 20.00% |
| Total | 114,847,083 | 23,908 | 8,614 | 2,415 | 71.97% |

The comparison with the standard of 0.15 lb SO2/MMBtu shows that the PSCo BART Alternative provides 72% lower SO2 emissions.

Figure 6-1 provides a year by year comparison of the PSCo BART Alternative to the 0.15 lb SO2/MMBtu standard for this planning period.

**Figure 6-1: SO2 reductions beyond presumptive BART for PSCo Alternative**




[19] Emission factor of 0.0006 lb SO2/MMBtu and 50% capacity factor.

A similar analysis was completed for NOx emissions. Table 6-8 compares the PSCo BART Alternative to a standard based on NOx limits established by EPA in 70 Fed. Reg. 39135 (7/6/2005). EPA provides a NOx lb/MMBtu level based on the boiler type and the coal type burned. The PSCo BART Alternative reflects 600 tpy of NOx emitted from Arapahoe 4 operating on natural gas as a "peaking" unit, 300 tpy of NOx reserved for "netting" or "offsets" from the Arapahoe facility, and 500 tpy of NOx reserved for "netting" or "offsets" from the Cherokee facility.

**Table 6-8: NOx Reductions Beyond Presumptive BART for PSCo Alternative**

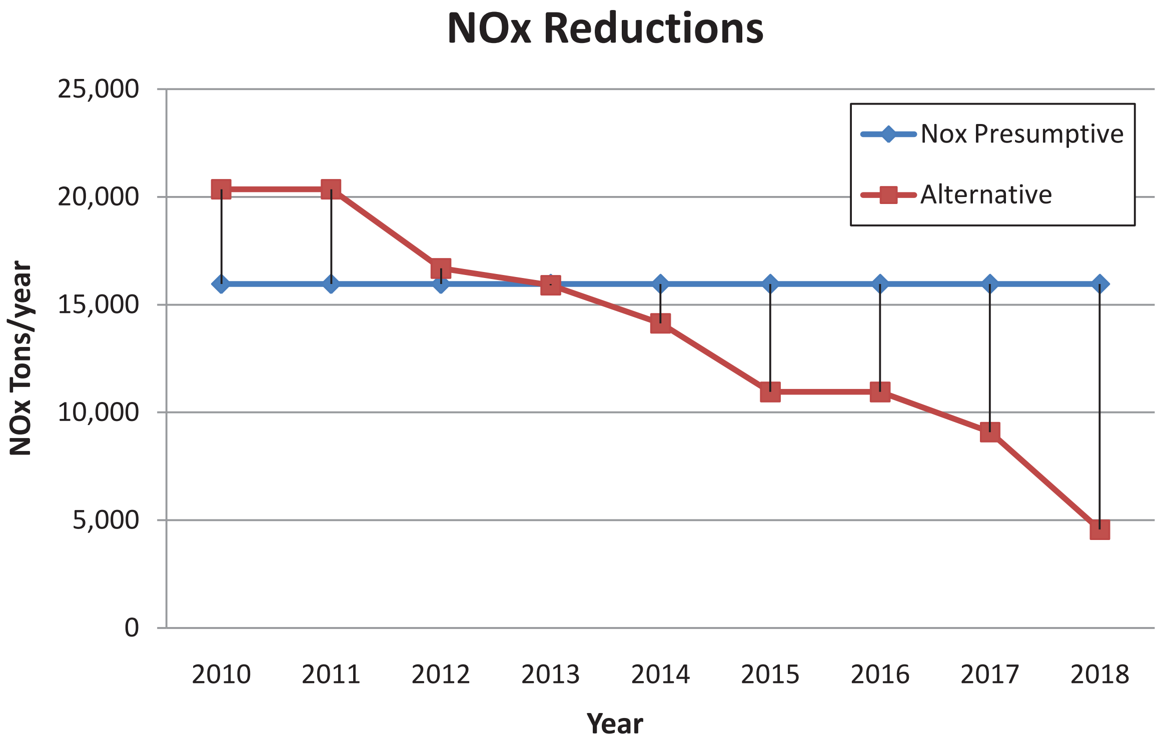
| Facility | MMBtu Average 2006 to 2008 | NOx TPY Average 2006 to 2008 | NOx lb/MMBtu Standard | TPY NOx at Standard | TPY NOx Under PSCo Alternative in 2018 | % Reduction Beyond Presumptive BART |
|---|---|---|---|---|---|---|
| Arapahoe | | | | | | |
| Unit 3 | 4,380,121 | 1,770.47 | 0.23 | 503.71 | 0.00 | 100.00% |
| Unit 4 | 8,545,791 | 1,147.67 | 0.23 | 982.77 | 900.00[20] | 8.42% |
| Cherokee | | | | | | |
| Unit 1 | 8,311,352 | 1,556.23 | 0.39 | 1,620.71 | 0.00 | 100.00% |
| Unit 2 | 5,586,021 | 2,895.20 | 0.39 | 1,089.27 | 0.00 | 100.00% |
| Unit 3 | 8,159,889 | 1,865.50 | 0.39 | 1,591.18 | 0.00 | 100.00% |
| Unit 4 | 26,047,648 | 4,274.00 | 0.28 | 3,646.67 | 2,062.86[21] | 43.43% |
| Valmont | 13,722,507 | 2,313.73 | 0.28 | 1,921.15 | 0.00 | 100.00% |
| Pawnee | 40,093,753 | 4,537.73 | 0.23 | 4,610.78 | 1,403.28 | 69.57% |
| Total | 114,847,083 | 20,361 | | 15,966 | 4,366 | 72.65% |

Figure 6-2 illustrates the year by year reductions achieved by the PSCo BART Alternative as compared to the standard derived from the EPA standard based on the configuration of each unit and the coal type burned by the unit in the PSCo BART Alternative.

[20] 600 tpy NOx from operation of Arapahoe 4 on natural gas as a "peaking" unit and 300 tpy NOx reserved for "netting" and "offsets" for additional natural gas generation. The 300 tpy NOx is associated with unit 4 for illustrative purposes, but may be associated with either unit.

[21] Cherokee 4 operating on natural gas at 0.12 lb NOx/mmBTU and 500tpy NOx reserved for "netting" or "offsets". The 500 tpy NOx is associated with unit 4 for illustrative purposes, but may be associated with any combination of the units.

**Figure 6-2: NOx Reductions Beyond Presumptive BART for PSCo Alternative**




The PSCo BART Alternative provides a reduction of 15,994 tons per year of NOx and 21,493 tons per year of SO2 from the baseline (average of 2006-2008 actuals) (89% and 77% reduction, respectively). These SO2 and NOx reductions provide significantly greater reductions as compared to the application of the standard set forth in 70 Fed. Reg. 39132-39135 (7/6/2005) applied all the units in the PSCo BART Alternative. The PSCo BART Alternative provides a 71% improvement in NOx reductions (See Table 6-8) over the presumptive levels, and a 72% improvement in SO2 reductions (See Table 6-7) over the presumptive levels. This is a significantly higher reduction than would have been achieved through the application of the presumptive limits. The state's alternative program is thus "clearly superior" to source-specific BART. *See* 71 Fed. Reg. at 60615. It provides not only for further emission reductions at units, but reflects the closure of numerous units, and thus the complete elimination of emissions from those units. Because these measures will provide greater emission reductions and will occur within the first planning period, the state has determined that they also satisfy reasonable progress for these sources. In this regard, Colorado has reasonably concluded that any control requirements imposed in the BART context also satisfy the RP related requirements in the first planning period. *See* U.S. EPA, "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," p. 4-2 (June 2007).

**Supplemental Technical Analysis Supporting the Alternative measure demonstration for the PSCo Alternative**

In addition to the foregoing demonstration that the PSCo BART Alternative satisfies the requirements of 40 CFR 51.308(e)(2) for an approvable alternative to EPA's BART regulation, the state undertook and provides the following additional technical analyses to support its determination that the PSCo BART Alternative demonstrates greater reasonable progress than the installation of BART on subject to BART units.

Colorado also evaluated the NOx reductions of the alternative program based on the criteria established by the state for BART and reasonable progress for NOx reductions. As part of its five factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.

- For the highest-performing NOx post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

- For lesser-performing NOx post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

For the PSCo BART Alternative sources included in the PSCo BART Alternative, SCR costs (where technically feasible) are greater than $5,000 per ton of NOx removed or the visibility improvement from SCR is less than 0.50 Δdv.  See analysis in appendix C. Under the state's criteria this would eliminate SCR from further consideration as a control alternative for BART and reasonable progress.  Thus, for demonstration purposes the state has compared the PSCo BART Alternative with the emission reductions achievable by SNCR.  The division used study of SNCR on coal fired boilers in the size range of those in the PSCO BART Alternative.  The study showed that the SNCR tested achieved a 35% reduction in NOx with less than 2ppm $NH_3$ slip and 54% reduction with a 10ppm $NH_4$ slip.[22]  Because of the high ammonia slip at the higher range of NOx removal the division determined that 50% removal was appropriate for this comparison.  Thus, for comparative purposes for the PSCo BART Alternative, the state will assume that SNCR is applied at a level of NOx reduction, of 50%, to assess performance of presumed SNCR on these units as against the PSCo BART Alternative for NOx.[23]  Table 6-9 provides a comparison of the costs for SCR and SNCR as provided by PSCo, SNCR at a 50% reduction (calculated from an average of NOx actual from 2006-2008 as reported to the Clean Air Markets Division) and the PSCo BART Alternative.

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[22] Environmental Controls Conference, Pittsburgh, PA (5/16/2006 to 5/18/2006)

[23] This level of NOx control efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that SNCR on these particular electric generating units could, in fact, achieve this level of NOx reduction performance from application of SNCR.

**Table 6-9: NOx reductions beyond state criteria for PSCo Alternative**

| Facility | SCR $/ton | SNCR $/ton | SNCR TPY at 50%[24] | PSCo Alternative TPY | % Reduction from SNCR at 50% Control |
|---|---|---|---|---|---|
| Arapahoe | | | | | |
| Unit 3 | | | 885.23 | 0 | 100.00% |
| Unit 4 | | | 573.83 | 900[25] | -56.84% |
| Cherokee | | | | | |
| Unit 1 | N/A | $8,737 | 778.12 | 0 | 100.00% |
| Unit 2 | N/A | $3,963 | 1,447.60 | 0 | 100.00% |
| Unit 3 | $10,134 | $3,485 | 932.75 | 0 | 100.00% |
| Unit 4 | $6,252 | $2,625 | 2,137.00 | 2,062[26] | 3.47% |
| Valmont | $8,647 | $3,328 | 1,156.87 | 0 | 100.00% |
| Pawnee | $4,371 | $3,082 | 2,268.87 | 1,403 | 38.15% |
| Total | | | 10,180 | 4,366 | 57.11% |

The PSCo BART Alternative results in 55% more reduction in NOx than the assumed installation of SNCR at all units covered by the PSCo BART Alternative. A similar analysis was not completed for SO2 because the state did not look at SO2 controls for reasonable progress as all sources were already controlled.

For both SO2 and NOx the state also evaluated the PSCo BART Alternative against a source by source analysis. For SO2 the state has done source specific analyses for Arapahoe Unit 4, Cherokee Unit 4 and Pawnee. For the remainder of the sources, for demonstration purposes, the state applied an aggressive 95% control level assumption to the uncontrolled emissions from those sources. The 95% was taken both from current operations and from uncontrolled emissions calculated using AP-42.[27] The analysis demonstrates that the alternative proposed is better than the source by source analysis by more than 52% as shown in Table 6-10. Figure 6-3 shows the reductions

[24] Fifty percent reduction was taken from an average of 2006-2008 actual NOx emissions as reported to the Clean Air Markets Division.

[25] 600 tpy NOx from operation of Arapahoe 4 on natural gas as a "peaking" unit and 300 tpy NOx reserved for "netting" and "offsets" for additional natural gas generation.

[26] Cherokee 4 operating on natural gas at 0.12 lb NOx/MMBtu and 500 tpy NOx reserved for "netting" or "offsets".

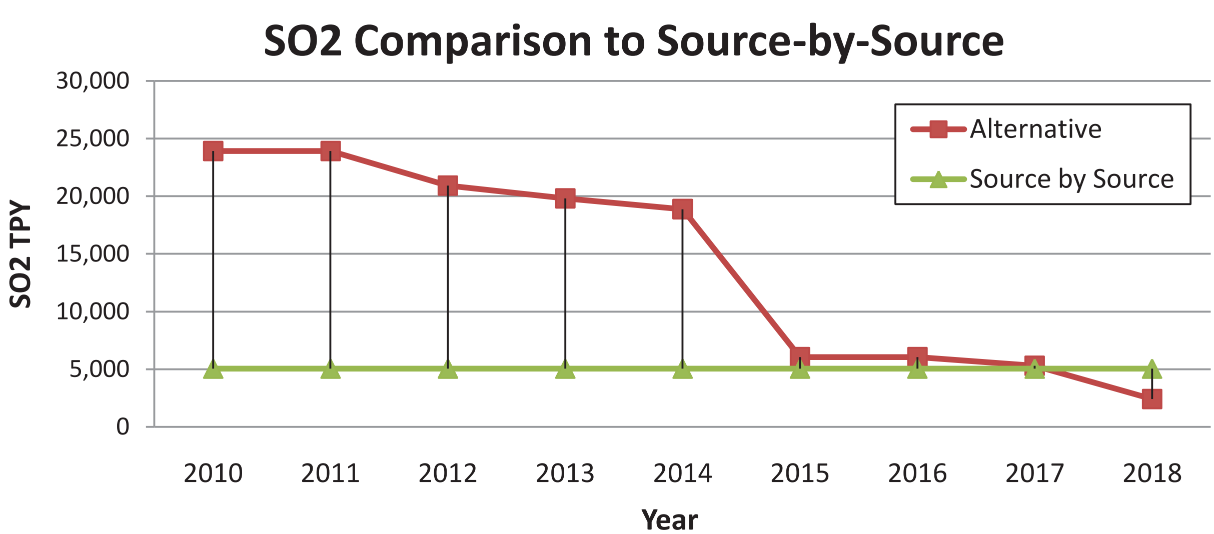
[27] This level of SO2 reduction efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that flue gas desulphurization systems on these particular electric generating units burning low-sulfur western coal, could, in fact, achieve this level of SO2 reduction performance. The AP 42 analysis reflects essentially the uncontrolled emissions from these facilities. This is different from the other analyses provided in this document, and when employing a 95% reduction assumption for demonstration purposes for an alternative measure makes the starting point for the sources in the Alternative more similar to uncontrolled eastern sources, where a higher sulfur content coal is generally utilized, which is more relevant to an assumed 95% reduction of SO2.

from the PSCo BART Alternative as compared to the source by source evaluation on a year to year basis.

**Table 6-10: SO2 Reductions Beyond Source-By-Source BART for PSCo Alternative**

| Facility | SO2 TPY from AP-42 | Source-by-Source | SO2 TPY from PSCo Alternative | % Reduction Beyond Source-by-Source |
|---|---|---|---|---|
| Arapahoe | | | | |
| Unit 3 | 1,076.53 | 53.82 | 0.00 | 100.00% |
| Unit 4 | 2,322.21 | 1.28 | 1.28 | 0.00% |
| Cherokee | | | | |
| Unit 1 | 2,803.67 | 140.18 | 0.00 | 100.00% |
| Unit 2 | 2,662.17 | 133.10 | 0.00 | 100.00% |
| Unit 3 | 3,438.79 | 171.93 | 0.00 | 100.00% |
| Unit 4 | 9,779.27 | 1,953.57[28] | 7.81 | 99.6% |
| Valmont | 3,822.73 | 191.13 | 0.00 | 100.00% |
| Pawnee | 8,342.36 | 2,405.62[29] | 2,405.63 | 0.00% |
| Total | 34,248 | 5,051 | 2,415 | 52.19% |

**Figure 6-3: SO2 Reductions Beyond Source-By-Source BART for PSCo Alternative**




[28] The Cherokee Unit 4 BART evaluation concluded that a 0.15 lb SO2/mmBTU limit was appropriate (See Appendix C). The TPY value was calculated from the average of 2006-2008 mmBTU values reported to the Clean Air Markets Division.

[29] The Pawnee BART evaluation concluded that a 0.12 lb SO2/mmBTU limit was appropriate (See Appendix C). The TPY value was calculated from the average of 2006-2008 mmBTU values reported to the Clean Air Markets Division.

For NOx the state looked at a source by source analysis for Arapahoe Unit 4, Cherokee Unit 4 and Pawnee. For the remainder of the sources, for demonstration purposes, the state applied an aggressive 90% control level assumption to the sources. The 90% was taken from emissions calculated using AP-42.[30] The source by source analysis considered the operation of Arapahoe Unit 4 with natural gas as a peaking unit and retaining 300 tpy of NOx for future netting or offsets from Arapahoe, the operation of Cherokee Unit 4 on natural gas at 0.12 lb/MMBTU and retaining 500 tpy of NOx from Cherokee for future netting, and control of Pawnee with SCR at 0.07 lb/MMBTU. The results of the comparison indicate that the alternative proposed is 49% better than the source by source analysis.

**Table 6-11: NOx Reductions Beyond Source-By-Source BART for PSCo Alternative**

| Facility | NOx TPY from AP-42 | Source-by-Source | NOx TPY from PSCo Alternative | % Reduction Beyond Source-by-Source |
|---|---|---|---|---|
| Arapahoe | | | | |
| Unit 3 | 2,149.15 | 214.91 | 0.00 | 100.00% |
| Unit 4 | 4,636.00 | 600 | 900.00[31] | -50.00% |
| Cherokee | | | | |
| Unit 1 | 3,596.54 | 359.65 | 0.00 | 100.00% |
| Unit 2 | 3,415.03 | 341.50 | 0.00 | 100.00% |
| Unit 3 | 4,411.28 | 441.12 | 0.00 | 100.00% |
| Unit 4 | 7,878.04 | 2,735.00[32] | 2,062.86[33] | 24.58% |
| Valmont | 2,061.04 | 206.10 | 0.00 | 100.00% |
| Pawnee | 7,945.11 | 3,608.43 | 1,403.28 | 61.11% |
| Total | 36,092 | 8,507 | 4,366 | 48.67% |

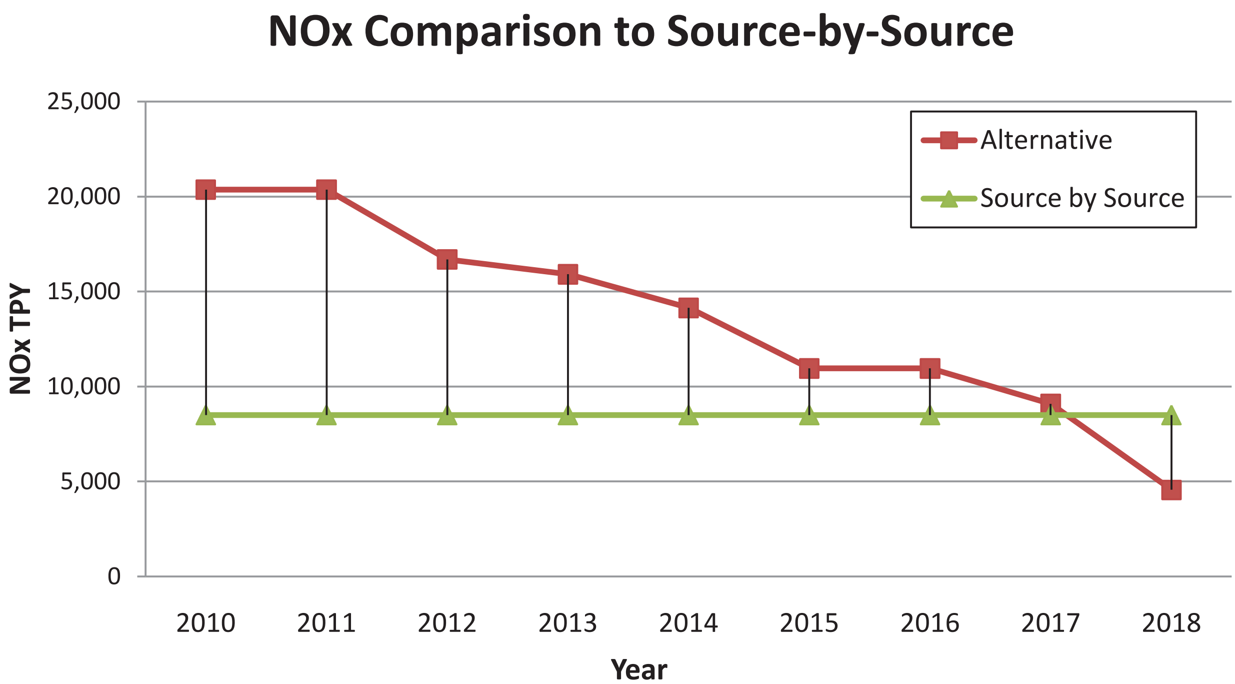
[30] This level of NOx reduction efficiency is for comparative purposes only, is an assumed maximum potential level of performance, and is not intended to reflect that flue gas desulphurization systems on these particular electric generating units, could, in fact, achieve this level of NOx reduction performance. The AP 42 analysis reflects essentially the uncontrolled emissions from these facilities.

[31] Natural gas operation as a peaking unit limited to 600 tpy with 300 tpy NOx reserved for offsets or netting for additional natural gas generation.

[32] Coal fired operation with SNCR at 0.21 lb NOx/MMBtu.

[33] Natural gas operation at 0.12 lb NOx/MMBtu with 500 tpy NOx reserved for offsets or netting.

**Figure 6-4: NOx Reductions Beyond Source-By-Source BART for PSCo Alternative**




## Conclusion

Under EPA regional haze regulations, Colorado has utilized an emission based comparison to demonstrate that that the PSCo BART Alternative provides greater reasonable progress than, and is clearly superior to, source by source BART. Although not necessary, as a means of further supporting its demonstration, the state has utilized other methodologies to demonstrate that the PSCo BART Alternative achieves greater reasonable progress than BART or individual reasonable progress requirements. The PSCo BART Alternative will result in early and significant reductions of visibility impairing pollutants.

## Table 6-12: PSCo Alternative Emissions Limits[34, 35, 36]

| Unit | NOx Control Type | NOx Emission Limit | SO2 Control Type | SO2 Emission Limit | Particulate Type And Limit |
|---|---|---|---|---|---|
| **Cherokee** Unit 1 | Shutdown No later than 7/1/2012 | 0 | Shutdown No later than 7/1/2012 | 0 | Shutdown No later than 7/1/2012 |
| **Cherokee** Unit 2 | Shutdown 12/31/2011 | 0 | Shutdown 12/31/2011 | 0 | Shutdown 12/31/2011 |
| **Cherokee** Unit 3 | Shutdown No later than 12/31/2016 | 0 | Shutdown No later than 12/31/2016 | 0 | Shutdown No later than 12/31/2016 |
| **Cherokee** Unit 4 | Natural Gas Operation | 0.12 lb/MMBtu (30-day rolling average) by 12/31/2017 | Natural Gas Operation 12/31/2017 | 7.81 tpy (12 month rolling average) | Fabric Filter Baghouse*<br><br>0.03 lbs/MMBtu<br><br>Natural Gas Operation 12/31/2017 |
| **Valmont** Unit 5 | Shutdown 12/31/2017 | 0 | Shutdown 12/31/2017 | 0 | Shutdown 12/31/2017 |
| **Pawnee** Unit 1 | SCR** | 0.07 lb/MMBtu (30-day rolling average) by 12/31/2014 | Lime Spray Dryer** | 0.12 lbs/MMBtu (30-day rolling average) by 12/31/2014 | Fabric Filter Baghouse*<br><br>0.03 lbs/MMBtu |
| **Arapahoe** Unit 3 | Shutdown 12/31/2013 | 0 | Shutdown 12/31/2013 | 0 | Shutdown 12/31/2013 |
| **Arapahoe** Unit 4 | Natural Gas Operation | 600 tpy (12 month rolling average) by 12/31/2014 | Natural Gas operation 12/31/2014 | 1.28 tpy (12 month rolling average) | Fabric Filter Baghouse*<br><br>0.03 lbs/MMBtu<br><br>Natural Gas operation 12/31/2014 |

** The "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed for Pawnee in the above table is not a requirement.

[34] Emission rates would begin on the dates specified, the units would not have 30 days of data until 30 days following the dates shown in the table.

[35] 500 tpy NOx will be reserved from Cherokee Station for netting or offsets.

[36] 300 tpy NOx will be reserved from Arapahoe Station for netting or offsets for additional natural gas generation.

# Chapter 7 Visibility Modeling and Apportionment

Modeling results and technical analyses indicate that Colorado sources contribute to visibility degradation at Class I areas. The modeling also shows out-of-state sources have the greatest impact on regional haze in Colorado. As such, this Plan anticipates local and regional solutions so that Colorado's 12 Class I areas make progress towards the 2018 and 2064 visibility goals.

## 7.1 Overview of the Community Multi-Scale Air Quality (CMAQ) Model

The Regional Modeling Center (RMC) Air Quality Modeling group is responsible the Regional Haze modeling for the WRAP. The RMC is located at the University of California - Riverside in the College of Engineering Center for Environmental Research and Technology.

The RMC modeling analysis is based on a model domain comprising the continental United States using the Community Multi-Scale Air Quality (CMAQ) model. The EPA developed the CMAQ modeling system in the late 1990s. CMAQ was designed as a "one atmosphere" modeling system to encompass modeling of multiple pollutants and issues, including ozone, PM, visibility, and air toxics. This is in contrast to many earlier air quality models that focused on single-pollutant issues (e.g., ozone modeling by the Urban Airshed Model). CMAQ is an Eulerian model - that is, it is a grid-based model in which the frame of reference is a fixed, three-dimensional (3-D) grid with uniformly sized horizontal grid cells and variable vertical layer thicknesses. The key science processes included in CMAQ are emissions, advection and dispersion, photochemical transformation, aerosol thermodynamics and phase transfer, aqueous chemistry, and wet and dry deposition of trace species.

A detailed summary of the CMAQ modeling for each Class I area is included in Section 6 of the Technical Support Document.

## 7.2 CMAQ Modeling Results for 2018

Figure 7-1 lists the 2018 Uniform Progress (UP) for each class I area along with the visibility modeling forecasts for 2018. These modeling results were released in 2006 by the WRAP and are preliminary; new modeling results with the latest emission estimates and control measure benefits are anticipated mid- to late 2007, and additional modeling is scheduled to be performed in 2008 and 2009. The results of this modeling will be utilized in defining (RPGs) for all 12 Colorado Class I areas by the year 2010 as described in Chapter 9.

As indicated by the 2006 modeling, reasonable progress for each Class I area falls short of meeting 2018 uniform progress for the 20% worst days, as indicated by the numbers in the blue highlighted box. Alternatively, all areas are forecast to maintain the best days in 2018.

More detailed information on the CMAQ modeling for a particular Class I area can be found in Section 6 of the Technical Support Document.

**Figure 7-1 Summary of CMAQ Modeling Progress Towards 2018 UP**

**Colorado Mandatory Class I Federal Areas**
**Uniform Progress Summary in Haze Index Metric**
***Based on WRAP CMAQ Modeling using the PRP 2018b***

| Mandatory Class I Federal Area | 20% Worst Days | | | | | 20% Best Days | | |
|---|---|---|---|---|---|---|---|---|
| | Worst Days Baseline Condition [dv] | Uniform Rate of Progress at 2018 [dv] | 2018 URP delta from Baseline [dv] | 2018 Modeling Projection [dv] | CMAQ Modeling % Towards 2018 URP | Best Days Baseline Condition [dv] | 2018 CMAQ Modeling Results [dv] | 2018 CMAQ Modeling Below Baseline? |
| Great Sand Dunes National Park & Preserve | 12.78 | 11.35 | 1.43 | 12.20 | 40.6% | 4.50 | 4.16 | Yes |
| Mesa Verde National Park | 13.03 | 11.58 | 1.45 | 12.50 | 36.6% | 4.32 | 4.10 | Yes |
| Mount Zirkel & Rawah Wilderness Areas | 10.52 | 9.48 | 1.04 | 9.91 | 58.7% | 1.61 | 1.29 | Yes |
| Rocky Mountain National Park | 13.83 | 12.27 | 1.56 | 12.83 | 64.1% | 2.29 | 2.06 | Yes |
| Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas | 10.33 | 9.37 | 0.96 | 9.83 | 52.1% | 3.11 | 2.93 | Yes |
| Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas | 9.61 | 8.78 | 0.83 | 8.98 | 75.9% | 0.70 | 0.53 | Yes |

## 7.3 Overview of Particulate Matter Source Apportionment Technology (PSAT) Modeling

The Regional Modeling Center (RMC) at the University of California – Riverside developed the PSAT algorithm in the Comprehensive Air quality Model with extensions (CAMx) model to assess source attribution. The PSAT analysis is used to attribute particle species, particularly sulfate and nitrate from a specific location within the Western Regional Air Partnership (WRAP) modeling domain. The PSAT algorithm applies nitrate-sulfate-ammonia chemistry to a system of tracers or “tags” to track the chemical transformations, transport and removal of emissions.

Each state or region (i.e. Mexico, Canada) is assigned a unique number that is used to tag the emissions from each 36-kilometer grid cell within the WRAP modeling domain. Due to time and computational limitations, only point, mobile, area and fire emissions were tagged.

The PSAT algorithm was also used, in a limited application (e.g. no state or regional attribution) due to resource constraints, to track natural and anthropogenic species of organic aerosols at each CIA. The organic aerosol tracer tracked both primary and secondary organic aerosols (POA & SOA). Appendix H includes more information on PSAT methodology.

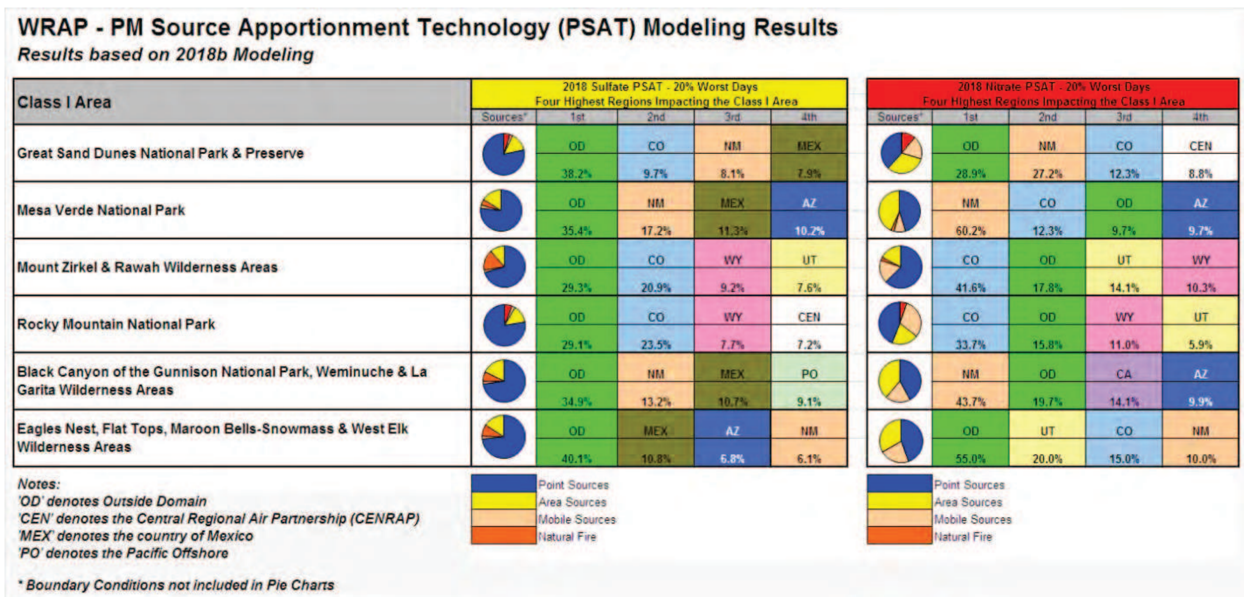
More detailed information on the PSAT modeling can be found in Section 7 of the Technical Support Document for each Class I area.

## 7.4 PSAT Modeling Results for 2018

Figure 7-2 provides the four highest source areas contributing sulfate and nitrate at each Class I area. As indicated, boundary conditions (BC) are the highest contributor to sulfate at all Colorado Class I areas. The boundary conditions represent the background concentrations of pollutants that enter the edge of the modeling domain. Depending on meteorology and the type of pollutant (particularly sulfate), these emissions can be transported great distances that can include regions such as Canada, Mexico, and the Pacific Ocean. Colorado appears to be a major contributor of particulate sulfate at those Class I areas near significant sources of SO2.

For nitrate, Colorado appears to be a major contributor at most of our Class I areas except for the Weminuche Wilderness, La Garita Wilderness and Black Canyon of Gunnison National Park. Although, boundary conditions also appear to be a major contributor of nitrate at all our Class I areas.

**Figure 7-2 Summary of PSAT Modeling for 2018**



**WRAP - PM Source Apportionment Technology (PSAT) Modeling Results**

*Results based on 2018b Modeling*

| Class I Area | 2018 Sulfate PSAT - 20% Worst Days Four Highest Regions Impacting the Class I Area | | | | | 2018 Nitrate PSAT - 20% Worst Days Four Highest Regions Impacting the Class I Area | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Sources* | 1st | 2nd | 3rd | 4th | Sources* | 1st | 2nd | 3rd | 4th |
| Great Sand Dunes National Park & Preserve | | OD 38.2% | CO 9.7% | NM 8.1% | MEX 7.9% | | OD 28.9% | NM 27.2% | CO 12.3% | CEN 8.8% |
| Mesa Verde National Park | | OD 35.4% | NM 17.2% | MEX 11.3% | AZ 10.2% | | NM 60.2% | CO 12.3% | OD 9.7% | AZ 9.7% |
| Mount Zirkel & Rawah Wilderness Areas | | OD 29.3% | CO 20.9% | WY 9.2% | UT 7.6% | | CO 41.6% | OD 17.8% | UT 14.1% | WY 10.3% |
| Rocky Mountain National Park | | OD 29.1% | CO 23.5% | WY 7.7% | CEN 7.2% | | CO 33.7% | OD 15.8% | WY 11.0% | UT 5.9% |
| Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas | | OD 34.9% | NM 13.2% | MEX 10.7% | PO 9.1% | | NM 43.7% | OD 19.7% | CA 14.1% | AZ 9.9% |
| Eagles Nest, Flat Tops, Maroon Bells-Snowmass & West Elk Wilderness Areas | | OD 40.1% | MEX 10.8% | AZ 6.8% | NM 6.1% | | OD 55.0% | UT 20.0% | CO 15.0% | NM 10.0% |

Point Sources
Area Sources
Mobile Sources
Natural Fire

*Notes:*
*'OD' denotes Outside Domain*
*'CEN' denotes the Central Regional Air Partnership (CENRAP)*
*'MEX' denotes the country of Mexico*
*'PO' denotes the Pacific Offshore*

** Boundary Conditions not included in Pie Charts*

Figure 7-3 identifies the change in the Colorado portion of particulate sulfate and nitrate concentrations, from 2002 to 2018 at each Class I area. For 2018, the PSAT modeling forecasts a reduction in the Colorado portion of sulfate at all Class I areas ranging from 25% to 33%. These particulate sulfate reductions are due to reductions from point and mobile source sulfur dioxide emissions (see Figure 5-1).

The 2018 forecasts for nitrate appear mixed with increases of 25% to 27% at the southwest Colorado Class I areas and nitrate reductions of 9% to 28% at all other areas. The increase in particulate nitrate in southwest Colorado is likely due to forecast increases in Colorado's and the region's NOx emissions from area sources and oil & gas development (see Figure 5-2). The projected particulate nitrate reductions at the remaining Class I areas are due to NOx reductions in mobile sources.

## Figure 7-3 Colorado Share of Modeled Sulfate and Nitrate Changes for 2018

**Change in Modeled Concentration for Colorado Share**

***Based PM Source Apportionment Technology (PSAT) Modeling Results (2018b)***

| Class I Area | Year | Total SO4 [ug/m3] | Colorado SO4 [ug/m3] | Colorado Share SO4 | Colorado Sulfate Change | Total NO3 [ug/m3] | Colorado NO3 [ug/m3] | Colorado Share NO3 | Colorado Nitrate Change |
|---|---|---|---|---|---|---|---|---|---|
| Great Sand Dunes National Park & Preserve | 2002 | 0.440 | 0.057 | 13% | | 0.116 | 0.017 | 15% | |
| | 2018 | 0.442 | 0.043 | 10% | -25% | 0.114 | 0.014 | 12% | -18% |
| Mesa Verde National Park | 2002 | 0.665 | 0.013 | 2% | | 0.249 | 0.026 | 10% | |
| | 2018 | 0.644 | 0.009 | 1% | -31% | 0.269 | 0.033 | 12% | +27% |
| Mount Zirkel & Rawah Wilderness Areas | 2002 | 0.649 | 0.175 | 27% | | 0.214 | 0.085 | 40% | |
| | 2018 | 0.621 | 0.130 | 21% | -26% | 0.185 | 0.077 | 42% | -9% |
| Rocky Mountain National Park | 2002 | 0.760 | 0.238 | 31% | | 0.339 | 0.128 | 38% | |
| | 2018 | 0.677 | 0.159 | 23% | -33% | 0.273 | 0.092 | 34% | -28% |
| Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas | 2002 | 0.484 | 0.024 | 5% | | 0.080 | 0.004 | 5% | |
| | 2018 | 0.484 | 0.018 | 4% | -25% | 0.071 | 0.005 | 7% | +25% |
| Eagles Nest, Flat Tops, Maroon Bells-Snowmass & West Elk Wilderness Areas | 2002 | 0.428 | 0.028 | 7% | | 0.020 | 0.004 | 20% | |
| | 2018 | 0.424 | 0.021 | 5% | -25% | 0.020 | 0.003 | 15% | -25% |

# Chapter 8 Reasonable Progress

## 8.1 Overview of Reasonable Progress Requirements

Based on the requirements of the Regional Haze Rule, 40 CFR 51.308(d)(1), the state must establish goals (expressed in deciviews) for each Class I area in Colorado that provide for Reasonable Progress (RP) towards achieving natural visibility conditions in 2018 and to 2064. These reasonable progress goals (RPGs) are to provide for improvement in visibility for the most-impaired (20% worst) days over the period of the State Implementation Plan (SIP) and ensure no degradation in visibility for the least-impaired (20% best) days over the same period.

In establishing the RPGs, the state must consider four factors: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. As well, the state must include a demonstration showing how these factors were taken into consideration in selecting the goals.

In establishing RPGs, the state must estimate the 2018 uniform rate of progress (URP) for each Class I area. The state must consider the URP and the emission reductions needed to achieve URP for the period covered by the plan. If the state ultimately establishes a Reasonable Progress Goal that provides for a slower rate of visibility improvement than would be necessary to meet natural conditions by 2064, the state must demonstrate that the uniform rate is not reasonable and that the state's alternative goal is reasonable, based on an evaluation of the 4 factors. In addition, the state must provide to the public an assessment of the number of years it would take to achieve natural conditions if improvement continues at the rate selected by the state. The detailed discussion of Reasonable Progress Goals can be found in Chapter 9, "Long Term Strategy". The establishment of the pollutants for RP evaluations and the evaluation of significant sources for reasonable progress is presented below.

## 8.2 Visibility Impairing Pollutants Subject to Evaluation

The state conducted a detailed evaluation[37] of the six particulate pollutants; ammonium sulfate, ammonium nitrate, organic carbon (OC), elemental carbon (EC), fine soil and coarse mass (CM) (both of which are commonly known as particulate matter (PM)), contributing to visibility impairment at Colorado's 12 mandatory Class I federal areas, and determined that the first Regional Haze Plan RP evaluation should focus on significant point sources of SO2 (sulfate precursor), NOx (nitrate precursor) and PM emissions. Emission sources are best understood for these three visibility-impairing pollutants, and stationary, or "point" sources, dominate the emission inventories and apportionment modeling. This determination is based on the well documented point source emission inventories for SO2 and NOx, and the Regional Model performance for sulfate and nitrate was determined to be acceptable. Significant point source PM emissions are also evaluated because of the Q/d screening methodology (Q = total

[37] *Significant Source Categories Contributing to Regional Haze at Colorado Class I Areas*, October 2, 2007. See the Technical support Document

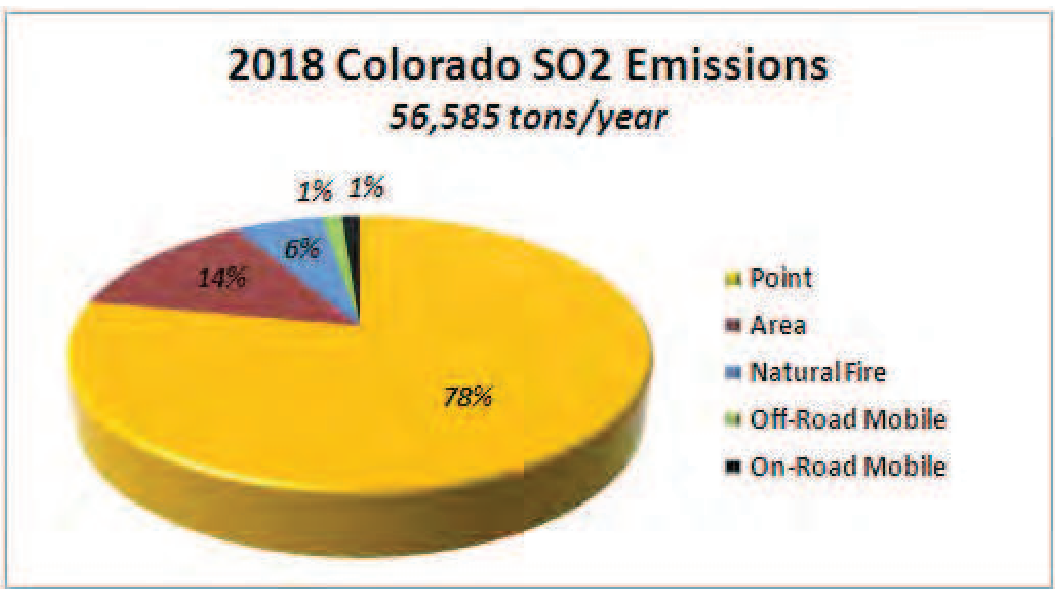
SO2, NOx and PM emissions; d = distance from the nearest Class I area, as further described in section 8.3), which includes PM emissions. PM emissions from other anthropogenic and natural sources are not being evaluated at this time.

Mobile and area sources were also identified as significant contributors to nitrates, and the RP evaluation of these two source categories is presented in section 8.2 above.

Generally, the sources of other visibility impairing pollutants, OC, EC, and PM, are not well documented because of emission inventory limitations associated with natural sources (predominantly wildfires), uncertainty of fugitive (windblown) emissions, and poor model performance for these constituents. Without a sound basis for making emission control determinations for sources that emit these three pollutants, Colorado determines that it is not reasonable in this planning period to recommend emission control measures; the State intends to address these pollutants and their emissions sources in future plan updates.

Figure 8-1 provides the statewide projected 2018 SO2 emissions, which reflects "on-the-books (OTB)" and "on-the-way (OTW)" emission control measures as of January 2009 (the latest year for a complete emissions inventory compiled by the Western Regional Air Partnership (WRAP)).

**Figure 8-1: Relative Source Contributions to Colorado SO2 Emissions in 2018**

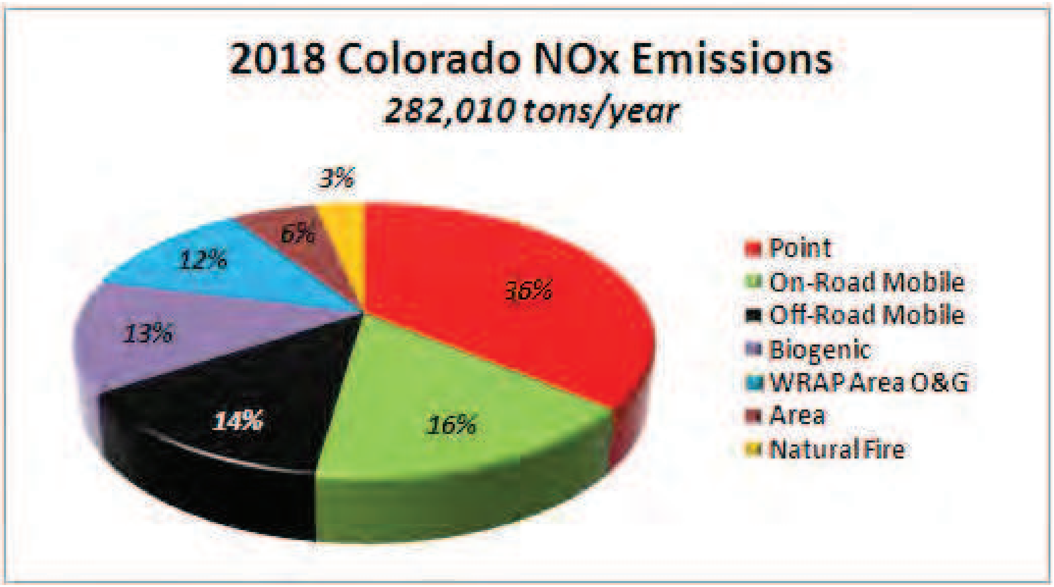



As indicated, 78% of total statewide SO2 emissions are from point sources – largely coal-fired boilers. Area source SO2 emissions (14%) are dominated by thousands of boilers and internal combustion engines statewide that burn distillate fuel. Depending on use and fuel grade, the maximum sulfur content of distillate fuel ranges between 500 ppm to 5000 ppm. SO2 emissions from natural fires are considered uncontrollable and vary from year-to-year depending on precipitation, fuel loading and lightning. Both off-road and on-road mobile sources are subject to federal ultra-low sulfur diesel (ULSD) fuel requirements that limit sulfur content to 15 ppm (0.0015 %) that was in widespread use after June 2010 for off-road mobile and June 2006 for on-road mobile.

The state has determined that point sources are the dominant source of emissions and, for this planning period, the only practical category to evaluate under reasonable progress for SO2.

Figure 8-2 provides the statewide projected 2018 NOx emissions, which reflects OTB and OTW emission control measures as of October 2009 (the latest year for a complete emissions inventory compiled by the WRAP).

**Figure 8-2: Relative Source Contributions to Colorado NOx Emissions in 2018**




Point sources comprise 36% of total NOx emissions that are mostly coal-fired external combustion boilers and natural gas-fired internal combustion engines (in oil and gas compression service). On-road and off-road mobile sources comprise 16% and 14% of statewide NOx emissions respectively. A portion of the on-road mobile source NOx emissions reflect some level of NOx control because of the Denver metro-area vehicle inspection program (IM-240). Both on/off road mobile also benefit from fleet turnover to cleaner vehicles resulting from more stringent federal emission standards. Because mobile exhaust emissions are primarily addressed, and will continue to be addressed, through federal programs, mobile sources will not be evaluated by Colorado for further RP control in this planning period. NOx emissions from biogenic activity and natural fire are considered uncontrollable and vary from year-to-year. Non-oil and gas area sources comprise about 6% of NOx emissions that involve thousands of combustion sources that are not practical to evaluate in this planning period.

The state has determined that large point sources are the dominant source of emissions and for this planning period are practical to evaluate under reasonable progress for NOx. Also, certain smaller point sources and area sources of NOx will also be evaluated under RP.

## 8.3 Evaluation of Smaller Point and Area Sources of NOx for Reasonable Progress

Oil and gas area source NOx emissions have been determined to significantly contribute to visibility impairment in Colorado's Class I areas. Because this source category is made up of numerous smaller sources, it is only practical to evaluate the category for RP control as a whole, unlike point sources where individual sources are evaluated separately. When reviewing O&G area sources, natural gas-fired heaters, and reciprocating internal combustion engines (RICE), are identified as the largest NOx emission sources. When reviewing point sources, natural gas-fired turbines were also identified as significant for review for RP.

### *8.3.1 Oil and Gas Heater Treaters*

A heater-treater is a device used to remove contaminants from the natural gas at or near the well head before the gas is sent down the production line to a natural gas processing plant. It prevents the formation of ice and natural gas hydrates that may form under the high pressures associated with the gas well production process. These solids can plug the wellhead.

The latest 2018 emissions inventory for the state assumes approximately 23,000 tons of NOx per year from 26,000 natural gas heater-treaters in Colorado at an emissions level of 0.88 tpy NOx per gas well heater-treater.

Emissions control research and control application for this source category is not well developed and has focused primarily on methane reductions. Though there are some technically feasible control options, the costs of compliance and the control effectiveness cannot be confidently determined. While the cumulative emissions make this a significant source category, the state determines that, for this planning period, requiring the control of 26,000 individual sources less than one ton per year in size is not practical or reasonable for reasonable progress.

A detailed 4-factor analysis for heater treaters can be found in Appendix D.

### *8.3.2 Reciprocating Internal Combustion Engines*

Power generated by large reciprocating internal combustion engines (RICE) is generally used to compress natural gas or to generate electricity in remote locations. The designation "large" refers to RICE that have an engine rating of at least 100 horsepower (hp) for the purpose of this reasonable progress analysis.

Stationary RICE produce power by combustion of fuel and are operated at various air-to-fuel ratios. If the stoichiometric ratio is used, the air and fuel are present at exactly the ratio to have complete combustion. RICE are operated with either fuel-rich ratios at or near stoichiometric, which are called rich-burn engines (RB), or air-rich ratios below stoichiometric, which are called lean-burn engines (LB). Undesirable emissions from RICE are primarily nitrogen oxides ($NO_x$; primarily nitric oxide and nitrogen dioxide), carbon monoxide (CO), and volatile organic compounds (VOCs). $NO_x$ are formed by thermal oxidation of nitrogen from the air. CO and VOCs are formed from incomplete combustion. Rich-burn engines inherently have higher NOx emissions by design, and lean burn engines are designed to have relatively lower NOx emissions.

Colorado has undertaken regulatory initiatives to control NOx emissions from RICE, beginning in 2004. For the Denver metro area/North Front Range ozone control area, Regulation No. 7 was revised to require the installation of controls on new and existing rich burn and lean burn RICE larger than 500 hp by May 1, 2005. Controls for rich burn RICE are non-selective catalytic reduction (NSCR) and an air-to-fuel ratio controller, which effectively controls NOx (95%), CO and VOCs. Controls for lean burn RICE are oxidation catalyst reduction, which effectively control CO and VOCs. An exemption from control for lean burn RICE could be obtained upon demonstration that cost of emission control would exceed $5,000 per ton. Selective catalytic reduction was considered for the control of NOx from lean burn engines, but was dismissed due to the high cost/effectiveness at approximately $22,000/ton (see Appendix D for complete analysis). EPA approved this requirement as part of the Colorado SIP on August 19, 2005 (70 Fed. Reg. 48652 (8/19/05)).

In December 2008, Colorado proceeded to adopt into Regulation No. 7 similar provisions for all existing RICE over 500 hp throughout the state. By July 1, 2010 all existing engines in Colorado, had to install controls as described in the paragraph above, with the one exception that the $5,000 per ton exemption applied to both lean burn and rich burn engines. The state-only provision for rich-burn RICE (which reduces NOx emissions and is codified in Regulation No. 7, Sections XVII.E.3. and 3.a.) is being included as part of the Regional Haze SIP to become federally enforceable upon EPA approval.

For RICE NOx control under the Regional Haze rule, Colorado determines that the installation of NSCR on all rich burn RICE throughout the state satisfies RP requirements. The accompanying benefits of reducing VOCs and CO also support this RP determination. Additional NOx control for lean burn RICE throughout the state is not reasonable for this planning period.

For new and modified RICE of 100 hp or greater, the state is relying on emissions controls that are required by EPA's New Source Performance Standards (NSPS) Subpart JJJJ, 40 CFR Part 60 and EPA's National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart ZZZZ, 40 CFR Part 63. Colorado determines that this federal control program satisfies reasonable progress for these sources in this planning period.

For existing RICE less than 500 hp throughout the state, the state determines that no additional control is necessary for RP in this planning period. Colorado's emission inventory system indicates that in the 2007/2008 timeframe, there were 538 engines less than 500 hp in the state, and these engines emitted 5,464 tons/year of NOx. At an average of about 10 tons of NOx emissions per year, controlling engines of this size is not reasonable. Many of these smaller existing engines will eventually be brought into JJJJ and ZZZZ when modified in the future, so it is reasonable to assume that additional NOx reductions will occur.

The 2018 emissions inventory assumes approximately 16,199 tons of NOx per year from RICE of all sizes in Colorado. The NOx control achieved by controlling rich burn engines in the ozone control area (approximately 7,000 tons/year) is assumed in this number. Controlling the remaining rich burn engines statewide reduces the 2018 RICE

NOx emissions inventory by approximately 5,800 tons/year to approximately 10,400 tons/year. For new RICE subject to the NSPS and NESHAP, NOx emissions reductions have not been estimated. Because the 2018 estimate of 16,199 tons/year of NOx assumed growth in uncontrolled engines and did not account for th NSPS and NESHAP, the 10,400 ton/year emissions in 2018 should be even lower. The remaining NOx from engines is attributed to existing lean burn engines which are uncontrolled for NOx (though they will eventually be brought into JJJJ and ZZZZ when modified in the future), existing rich burn engines after control, small engines, and new RICE after the application of JJJJ and ZZZZ.

A detailed 4-factor analysis for RICE can be found in Appendix D.

### *8.3.3 Combustion Turbines*

Combustion turbines fueled by natural gas or oil are either co-located with coal-fired electric generating units or as stand-alone facilities. These units are primarily used to supplement power supply during peak demand periods when electricity use is highest. Combustion turbine units start quickly and usually operate only for a short time. However, they are capable of operating for extended periods. Combustion turbine units are also capable of operating together or independently.

Information regarding combustion turbine emissions is well recorded in the state's air emissions inventory. Typical emissions for this source type may be significant for NOx, but pipeline quality natural gas is inherently clean and low-emitting for SO2 and PM10 emissions. Combustion turbines are subject to 40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines, which limit sulfur content to 0.8 percent by weight, supported by monitoring and testing. Subpart GG also limits nitrogen oxides to 117.8 percent by volume at 15 percent oxygen on a dry basis (60.332(a)(1)), supported by monitoring and testing. The majority of combustion turbines are installed with Continuous Emissions Monitoring Systems (CEMs).

RP evaluations are triggered for turbines that are co-located at BART or RP sources that have been determined to be significant because they have a Q/d impact of greater than 20 (see section 8.3 below for a description of this "significance" determination). The state analyzed total state-wide combustion turbine emissions averaged over the 2006 – 2008 Reasonable Progress baseline period. There are five Reasonable Progress facilities with combustion turbines – PSCo Valmont Generating Station, PSCo Arapahoe Generating Station, Colorado Springs Utilities Nixon Plant, Platte River Power Authority Rawhide Energy Station, and PSCo Pawnee Generating Station. Of these, only two turbines located at the Nixon Plant emit significant levels of visibility impairing emissions, as defined by the federal Prevention of Significant Deterioration (PSD) significance levels:

- $NO_x$ – 40 tons per year
- $SO_2$ – 40 tons per year
- $PM_{10}$ – 15 tons per year

| Facility – Turbine | Total 2006 – 2008 Averaged NOx Annual Emissions (tpy) | Total 2006 – 2008 Averaged SO2 Annual Emissions (tpy) | Total 2006 – 2008 Averaged PM10 Annual Emissions (tpy) | Greater than *de minimis* levels? |
|---|---|---|---|---|
| Front Range Power Plant – Turbine #1 | 159.6 | 2.9 | 4.9 | Yes – NOx only |
| Front Range Power Plant – Turbine #2 | 147.9 | 2.8 | 4.9 | Yes – NOx only |

The combustion turbines at the Front Range Power Plant were installed with advanced dry-low NOx combustion systems, and based on 2006 – 2008 CEMs data and AP-42 emission factors, are achieving 89.4% and 90.1% NOx reductions, respectively.

There is one feasible emission control technology available for these turbines is adding post combustion technology – selective catalytic reduction (SCR) which, in good working order can achieve removal efficiencies ranging from 65 – 90 percent from uncontrolled levels.

Applying SCR would achieve up to an additional 90% control efficiency to both turbines and could result in about 275 tons of NOx reduced annually with a capital expenditure of at least $15 million. The state estimates that SCR for these turbines will range from approximately $57,000 - $62,000 per ton of NOx reduced annually. In the state's judgment for this planning period for Reasonable Progress, the potential 275 tons per year of NOx reductions are not cost-effective. The state has determined that NOx RP for combustion turbines is existing controls and emission limits.

A detailed 4-factor analysis for combustion turbines can be found in Appendix D.

## 8.4 Determination of Point Sources Subject to Reasonable Progress Evaluation

Colorado refined the RP analysis referred to in Section 8.2 (using the latest WRAP emission inventory data) to select specific point sources to evaluate for RP control[38]. This RP screening methodology involves a calculated ratio called "Q-over-d", that evaluates stationary source emissions (mathematical sum of actual SO2, NOx and PM emissions in tons per year, denoted as "Q") divided by the distance (in kilometers, denoted as "d") of the point source from the nearest Class I area.

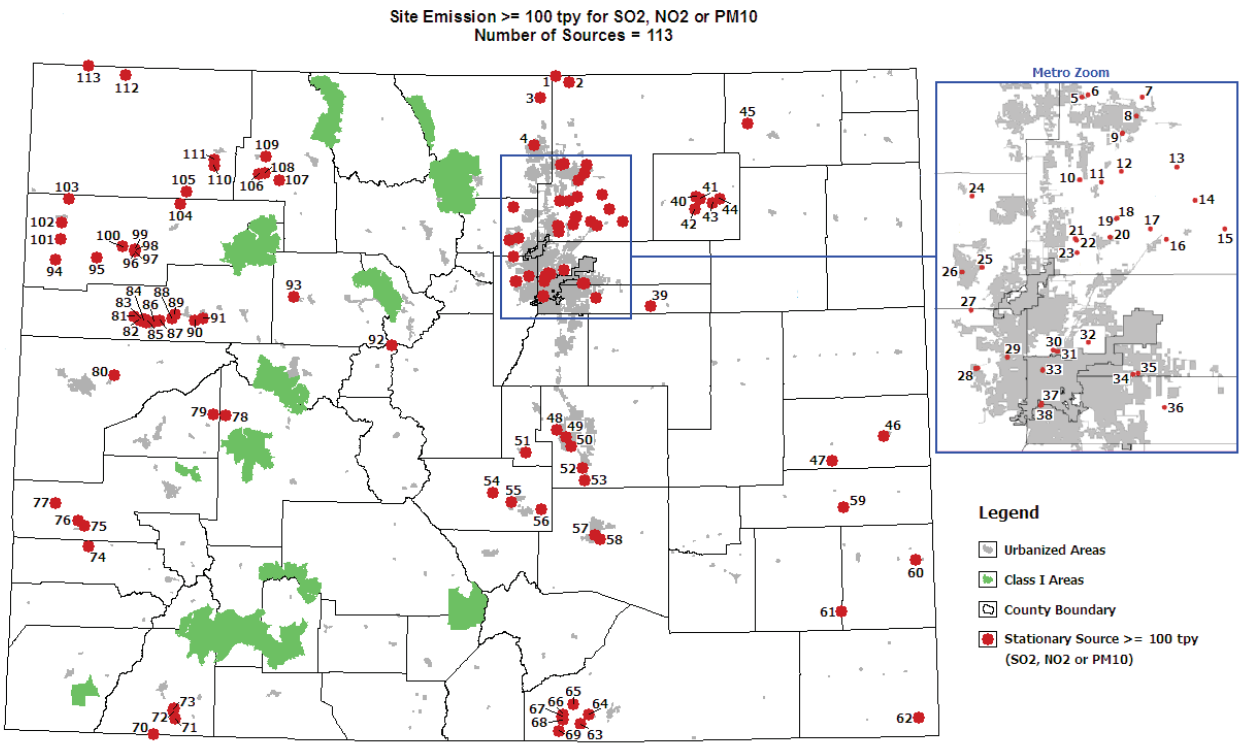
The State evaluated the visibility impact sensitivity of different Q/d thresholds and determined that a Q/d ratio equal to or greater than "20" approximated a delta deciview (Δdv) impact ranging from 0.06 Δdv to 0.56 Δdv. The resultant average of the range is about 0.3 Δdv, which is a more conservative RP threshold than the 0.5 Δdv that was used in determining which sources would be subject-to-BART under the federal BART regulations. The delta deciview impact was determined by evaluating CALPUFF

[38] *Reasonable Progress Analysis of Significant Source Categories Contributing to Regional Haze at Colorado Class I Areas,* March 31, 2010. See the Technical Support Document

modeling, conducted by the state in 2005, for the ten subject-to-BART stationary sources. Since the Q/d methodology involves consideration of PM emissions, the state has added PM (PM-10) emissions to the RP evaluation process.

The evaluation of potential RP sources involved all Colorado stationary sources with actual SO2, NOx or PM10 emissions over 100 tons per year based on Air Pollution Emissions Notice (APEN) reports from 2007. The one-hundred-thirteen (113) sources identified as exceeding the 100 tons/year threshold for any of the three pollutants (see Figure 8-3) were further analyzed, using ArcGIS mapping, to determine the exact distance from the centroid of the source to the nearest Class I area boundary. The Q/d was calculated for each source, and Table 8-1 lists the sixteen (16) point sources that are equal to or greater than the Q/d of 20 threshold. These sixteen sources will be referred to as “significant” sources for purposes of reasonable progress.

**Figure 8-3: Point Sources with >100 TPY of Emissions**



### Table 8-1: Colorado Significant Point Sources with a Q/d ≥ 20

*ArcGIS DATA - Statewide Sources over 100 tpy for SO2, NOx and PM10 (based on 2007 data)*

| Count | FACILITY NAME | SO2 [tpy] | NO2 [tpy] | PM10 [tpy] | Q [tpy] | Closest CIA | d [km] | Q/d |
|---|---|---|---|---|---|---|---|---|
| 1 | PLATTE RIVER POWER AUTHORITY - RAWHIDE | 854 | 1,808 | 134 | 2,796 | Rocky Mnt NP | 56.0 | 49.9 |
| 2 | CEMEX INC. - LYONS CEMENT | 87 | 2,479 | 418 | 2,984 | Rocky Mnt NP | 24.8 | 120.3 |
| 3 | PUBLIC SERVICE CO - VALMONT | 749 | 2,355 | 58 | 3,162 | Rocky Mnt NP | 34.8 | 90.9 |
| 4 | COLORADO ENERGY NATIONS CORPORATION | 2,626 | 1,786 | 42 | 4,453 | Rocky Mnt NP | 54.5 | 81.7 |
| 5 | PUBLIC SERVICE CO - CHEROKEE | 7,116 | 10,205 | 261 | 17,581 | Rocky Mnt NP | 65.3 | 269.2 |
| 6 | PUBLIC SERVICE CO - ARAPAHOE | 2,496 | 2,922 | 178 | 5,595 | Rocky Mnt NP | 73.3 | 76.3 |
| 7 | PUBLIC SERVICE CO - PAWNEE | 13,073 | 4,645 | 193 | 17,911 | Rocky Mnt NP | 155.7 | 115.0 |
| 8 | COLORADO SPRINGS UTILITIES - DRAKE | 8,431 | 3,826 | 251 | 12,507 | Great Sand Dunes NP | 114.0 | 109.7 |
| 9 | COLORADO SPRINGS UTILITIES - NIXON | 3,883 | 2,656 | 129 | 6,668 | Great Sand Dunes NP | 104.4 | 63.9 |
| 10 | AQUILA INC. - W.N. CLARK STATION | 1,480 | 869 | 44 | 2,393 | Great Sand Dunes NP | 58.7 | 40.8 |
| 11 | HOLCIM (US) INC. PORTLAND CEMENT | 372 | 2,589 | 288 | 3,250 | Great Sand Dunes NP | 66.0 | 49.2 |
| 12 | PUBLIC SERVICE CO - COMANCHE | 13,854 | 8,415 | 178 | 22,447 | Great Sand Dunes NP | 84.5 | 265.6 |
| 13 | TRI STATE GENERATION - NUCLA | 1,509 | 1,716 | 101 | 3,327 | Black Canyon NP | 70.6 | 47.1 |
| 14 | PUBLIC SERVICE CO - CAMEO | 2,586 | 1,051 | 112 | 3,750 | Black Canyon NP | 70.5 | 53.2 |
| 15 | PUBLIC SERVICE CO - HAYDEN | 2,657 | 7,694 | 284 | 10,634 | Mt Zirkel WA | 31.6 | 336.5 |
| 16 | TRI STATE GENERATION - CRAIG | 3,586 | 16,807 | 235 | 20,628 | Flat Tops WA | 47.7 | 432.4 |
| | Totals: | 65,358 | 71,821 | 2,906 | | | | |

Note that the APEN reports may not represent actual annual emissions, as Colorado Regulation 3 requires APEN reports to be updated every five years if no significant emissions increases have occurred at the source. Further, sources do not pay APEN emission fees on fugitive dust, thus sources with significant fugitive dust emissions may report potential rather than actual emissions in the APEN. The state contacted sources to ensure that actual emissions were used as much as possible since many sources over-estimate emissions in APENs. This ensures that correct emissions are used for the purposes of Reasonable Progress.

Set forth below are summaries of each of the sixteen significant sources. Many of these are BART sources, and emission control analyses and requirements for those sources are documented in Chapter 6 of this document. The BART determinations represent best available retrofit control and also satisfy RP requirements, and no further assessment of emissions controls for these facilities is necessary for reasonable progress during this planning period. In this regard, the state has already conducted BART analyses for its BART sources that are largely based on an assessment of the same factors to be addressed in establishing RPGs. Thus, Colorado has reasonably concluded that any control requirements imposed in the BART determination also satisfy the RP related requirements in the first planning period. *See* U.S. EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, p. 4-2 (June 2007).

1. The state has determined that Platte River Power Authority's Rawhide Power Plant (unit 1) is a subject-to-RP source and has conducted an emission control analysis for the unit (see below).
2. The CEMEX Portland cement manufacturing facility in Lyons, Colorado, is a subject-to-BART source that the Division reviewed for best available retrofit controls for SO2, NOx and PM emissions. The state has determined that the CEMEX BART determinations for the kiln and the dryer (see Chapter 6) satisfy the SO2, NOx and PM BART/RP requirements in this planning period.
3. The Public Service Company of Colorado (PSCo) Valmont Power Plant (unit 5) is a subject-to-BART source that is included in a better than BART alternative for SO2

and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the state has determined that the facility's closure by 2018 satisfies the PM BART/RP requirements in this planning period.

4. The Colorado Energy Nations Corporation (CENC) operates two subject-to-BART industrial boilers (boilers 4 & 5) that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The CENC BART determination for these two boilers (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period. For boiler 3, the state has determined it to be subject-to-RP and has conducted an emission control analysis for the boiler (see below).
5. The PSCo Cherokee Power Plant has four units (1, 2, 3 & 4); unit 4 is a subject-to-BART source. All of the units are included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the closure of units 1, 2 and 3 by 2018 satisfies the PM RP requirements in this planning period. For unit 4, the BART determination for PM emissions satisfies the PM BART/RP requirements in this planning period.
6. The PSCo Arapahoe Power Plant (units 3 & 4) is a subject-to-RP source that is included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. For PM, the closure of unit 3 by 2018 satisfies the PM RP requirements in this planning period; for unit 4 the conversion to repower from coal to natural gas satisfies the PM RP requirements in this planning period.
7. The PSCo Pawnee Power Plant (unit 1) is a subject-to-BART source that is included in a better than BART alternative for SO2 and NOx (see Chapter 6), which satisfies the SO2 and NOx BART/RP requirements in this planning period. The BART determination for PM emissions satisfies the PM BART/RP requirements in this planning period.
8. The Colorado Springs Utilities (CSU) Drake Power Plant (units 5-7) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Drake BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.
9. The state has determined that the CSU Nixon Plant (unit 1) and the co-located Front Range Power Plant are subject-to-RP sources and has conducted emission control analyses for these sources (see below).
10. The state has determined that the Black Hills Energy Clark Power Plant (units 1 and 2) is a subject-to-RP source and has conducted an emission control analysis for the source (see below).
11. The state has determined that the Holcim Portland cement manufacturing facility (kiln and dryer) is subject-to-RP and has conducted an emission control analysis for the source (see below).
12. The PSCo Comanche Power Plant (units 1 and 2) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Comanche BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.

13. The state has determined that the Tri-State Generation and Transmission Association's Nucla Power Plant is subject-to-RP and has conducted an emission control analysis for the source (see below).
14. The state has determined that the PSCo Cameo Power Plant is subject-to-RP. With the closure of the facility by 2012, the SO2, NOx, and PM RP requirements are satisfied in this planning period. A regulatory closure requirement is contained in this chapter and in Regulation No. 3.
15. The PSCo Hayden Power Plant (units 1 & 2) is a subject-to-BART source that the state reviewed for best available retrofit controls for SO2, NOx and PM emissions. The Hayden BART determination (see Chapter 6) satisfies the SO2, NOx and PM BART/RP requirements in this planning period.
16. The Tri-State Generation and Transmission Association's Craig Power Plant has three units (1, 2, and 3); units 1 & 2 are subject-to-BART that the Division reviewed for best available retrofit controls for SO2, NOx and PM emissions. The BART determinations for units 1 and 2 (see Chapter 6) satisfy the SO2, NOx and PM BART/RP requirements in this planning period. The state has determined that unit 3 is subject-to-RP and has conducted an emission control analysis for the unit (see below).

Consequently, there are seven significant sources identified as subject-to-RP that Colorado has evaluated for controls in the RP analysis process:

- Rawhide Unit 1
- CENC Boiler 3
- Nixon Unit 1
- Clark Units 1, 2
- Holcim Kiln, Dryer
- Nucla
- Craig Unit 3

## 8.5 Evaluation of Point Sources for Reasonable Progress

In identifying an appropriate level of control for RP, Colorado took into consideration the following factors:

(1) The costs of compliance,
(2) The time necessary for compliance,
(3) The energy and non-air quality environmental impacts of compliance, and
(4) The remaining useful life of any potentially affected sources.

Colorado has concluded that it also appropriate to consider a fifth factor: the degree of visibility improvement that may reasonably be anticipated from the use of RP controls. States have flexibility in how they take these factors into consideration, as well as any other factors that the state determines to be relevant. *See* U.S. EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, p. 5-1 (June 2007).

### *8.5.1 Rationale for Point Source RP Determinations*

Similar to the process for determining BART as described in Chapter 6, in making its RP determination for each Colorado source, the state took into consideration the five factors on a case-by case basis, and for significant NOx controls the state also utilized the guidance criteria set forth in Section 6.4.3 consistent with the factors. Summaries of the state's facility-specific consideration of the factors and resulting determinations for each RP source are provided in this Chapter 8. Documentation reflecting the state's analyses and supporting the state's RP determinations, including underlying data and detailed descriptions of the state's analysis for each facility, are provided in Appendix D of this document and the TSD.

***8.5.1.1 The costs of compliance.*** The Division requested, and the companies provided, source-specific cost information for each RP unit. The cost information relates primarily to the installation and operation of new SO2 and NOx control equipment. The cost for each unit is summarized below, and the state's consideration of this factor for each source is presented in detail in Appendix D.

***8.5.1.2 The time necessary for compliance.***

Regulation No 3, Part F, Section VI.B.4. requires facilities subject to RP determinations to submit a compliance plan within 60 days of SIP approval. Based on Colorado facility submittals, the Division anticipates that the time necessary for facilities to complete design, permitting, procurement, and system startup, after SIP approval, would be approximately 3 - 5 years. This timeframe may vary somewhat due to the necessary major maintenance outage with other regionally affected utilities.

***8.5.1.3 The energy and non-air quality environmental impacts of compliance.*** This factor is typically used to identify non-air issues associated with different types of control equipment. The Division requested, and the companies provided, source-specific energy and non-air quality information for each RP unit. The state has particular concerns with respect to potential non-air quality environmental impacts associated with wet scrubber systems for SO2, as further described below.

***8.5.1.4 The remaining useful life of the source.*** For those sources set to retire by 2018, the state established a regulatory closure requirement in this chapter and in Regulation No. 3. For those sources not expected to retire over the next twenty years, this factor did not affect any of the state's RP determinations.

***8.5.1.5 The degree of visibility improvement which may reasonably be anticipated from the use of RP.*** The state took into consideration the degree of visibility improvement which may reasonably be anticipated from the use of RP control, where relevant and the information was available, although degree of visibility improvement is not an express element of four factors to be considered during reasonable progress under EPA's federal regulations and guidelines. Modeling information where relevant and available for each RP determination is presented below and in Appendix D.

***8.5.1.6 Overview of the RP Determinations for Each Source.*** This section presents an overview of the RP determinations for the significant point sources not addressed in Chapter 6.

The regional haze rule gives the states broad latitude on how the four statutory factors, and any other factors a state deems to be relevant, may be considered to determine the appropriate controls for RP. The Regional Haze rule provides little, if any, guidance on specifically how states are to use these factors in making the final determinations regarding what controls are appropriate under the rule, other than to consider the factors in reaching a determination. The manner and method of consideration is left to the state's discretion; states are free to determine the weight and significance to be assigned to each factor.

The Division has reviewed available particulate controls applicable to RP facilities. Based on a review of NSPS, MACT and RACT/BACT/LAER, the state has determined that fabric filter baghouses are the best PM control available. The Portland cement MACT confirms that "a well-performing baghouse represents the best performance for PM". *See,* 74 Fed. Reg. 21136, 21155 (May 6, 2009). The RACT/BACT/LAER Clearinghouse identifies baghouses as the PM control for the newer cement kilns and EGUs. Additional discussion of PM controls, including baghouse controls, is contained in the source specific analyses in Appendix D.

The Division also reviewed various SO2 controls applicable to EGUs and boilers. Two of the primary controls identified in the review are wet scrubbers and dry flue gas desulphurization (FGD). Based upon its experience, and as discussed in detail elsewhere in this Chapter 8, in Appendix D and in the TSD, the state has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including very significant water usage. This is a significant issue in Colorado and the arid West, where water is a costly, precious and scarce resource. There are other costs and environmental impacts that the state also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Moreover, on-site storage of wet ash is an increasing regulatory concern. EPA recognizes that some control technologies can have significant secondary environmental impacts. *See,* 70 Fed. Reg. 39104, 39169 (July 6, 2005). EPA has specifically noted that the limited availability of water can affect the feasibility and costs of wet scrubbers in the arid West. These issues were examined in each source specific analysis in Appendix D.

With respect to NOx controls, the state has assessed pre-combustion and post-combustion controls and upgrades to existing NOx controls, as appropriate.

When determining the emission rates for each source, the state referred to the available literature and considered recent MACT, NSPS and RACT/BACT/LAER determinations to inform emission limits. While relying on source specific information for the final limit, and considering that RP relates to retrofitting sources (vs. new or reconstructed facilities), a review of other BART and RP determinations used to better substantiate the source specific information provided by the source.

For the purposes of the RP review for the three pollutants that the state is assessing for the seven facilities, SO2 and PM have been assessed utilizing the factors on a case by case basis to reach a determination. This is primarily because the top level controls for SO2 and PM are already largely in use on electric generating units in the state, and certain other sources require a case by case review because of their unique nature. For NOx controls on reasonable progress electric generating units, for reasons described below, the state is employing guidance criteria to aid in its RP assessment, largely because significant NOx add-on controls are not the norm for Colorado electric generating units, and to afford a degree of uniformity in the consideration of control for these sources.

With respect to SO2 emissions, there are currently ten flue gas desulphurization lime spray dryer (LSD) SO2 control systems operating at electric generating units in Colorado.[39] There are also two wet limestone systems in use in Colorado. The foregoing systems have been successfully operated and implemented for many years at Colorado sources, in some cases for over twenty years. The LSD has notable advantages in Colorado given the non-air quality consideration of its relatively lower water usage in reducing SO2 emissions in the state and other non-air quality considerations. The state has determined in the past that these systems can be cost-effective for sources in Colorado. With this familiarity and use of the emissions control technology, the state has assessed SO2 emissions control technologies and/or emissions rates for the RP sources on a case by case basis in making its control determinations.

With respect to PM emissions, fabric filter baghouses and appropriate PM emissions rates are in place at all power plants in Colorado. Fabric filter baghouse systems have been successfully operated and implemented for many years at Colorado sources. The state has determined that fabric filter baghouses are cost effective through their use at all coal-fired power plants in Colorado. With this familiarity and use of the emissions control technology, the state has assessed PM emissions control technologies and/or emissions rates for the RP sources on a case by case basis in making its control determinations.

With respect to NOx emissions, post-combustion controls for NOx are generally not employed in Colorado. Accordingly, this requires a direct assessment of the appropriateness of employing such post-combustion technology at these sources for implementation of the Regional Haze rule. There is only one coal-fired electric generating unit in the state that is equipped with a selective catalytic reduction (SCR) system to reduce NOx emissions, and that was employed as new technology designed into a new facility (Public Service Company of Colorado, Comanche Unit #3, operational 2010). There are currently no selective non-catalytic reduction (SNCR) systems in use on coal-fired electric generating units in the state to reduce NOx emissions.

In assessing and determining appropriate NOx controls at significant sources for individual units for visibility improvement under the Regional Haze rule, for reasonable progress, the state has considered the relevant factors in each instance. Based on its authority, discretion and policy judgment to implement the Regional Haze rule, the state has determined that costs and the anticipated degree of visibility improvement are the factors that should be afforded the most weight. In this regard, the state has utilized screening criteria as a means of generally guiding its consideration of these factors.

[39] EGUs with LSD controls include Cherokee Units 3 & 4, Comanche Units 1, 2 & 3, Craig Unit 3, Hayden Units 1 & 2, Rawhide Unit 1, Valmont Unit 5.

More specifically, the state finds most important in its consideration and determinations for individual units: (i) the cost of controls as appropriate to achieve the goals of the regional haze rule (*e.g.*, expressed as annualized control costs for a given technology to remove a ton of Nitrogen Oxides (NOx) from the atmosphere, or $/ton of NOx removed); and, (ii) visibility improvement expected from the control options analyzed (*e.g.*, expressed as visibility improvement in delta deciview (Δdv) from CALPUFF air quality modeling).

Accordingly, as part of its reasonable progress factor consideration the state has elected to generally employ criteria for NOx post-combustion control options to aid in the assessment and determinations for BART – a $/ton of NOx removed cap, and two minimum applicable Δdv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.

- For the highest-performing NOx post-combustion control options (*i.e.*, SCR systems for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit on 0.50 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NOx post-combustion control options (*e.g.*, SNCR technologies for electric generating units) that do not exceed $5,000/ton of pollutant reduced by the state's calculation, and which provide a modeled visibility benefit of 0.20 Δdv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.

The foregoing criteria guide the state's general approach to these policy considerations. They are not binding, and the state is free to deviate from this guidance criteria based upon its consideration of RP control on a case by case basis.

The cost criteria presented above is generally viewed by the state as reasonable based on the state's extensive experience in evaluating industrial sources for emissions controls. For example, the $5,000/ton criterion is consistent with Colorado's retrofit control decisions made in recent years for reciprocating internal combustion engines (RICE) most commonly used in the oil and gas industry.[40] In that case, a $5,000/ton threshold, which was determined by the state Air Quality Control Commission as a not-to-exceed control cost threshold, was deemed reasonable and cost effective for an initiative focused on reducing air emissions to protect and improve public health.[41] The $5,000/ton criterion is also consistent with and within the range of the state's implementation of reasonably achievable control technology (RACT), as well as best achievable control technology (BACT) with respect to new industrial facilities. Control

[40] Air Quality Control Commission Regulation No. 7, 5 C.C.R. 1001-9, Sections XVII.E.3.a.(ii) (statewide RICE engines), and XVI.C.4 (8-Hour Ozone Control Area RICE engines).

[41] The RICE emissions control regulations were promulgated by the Colorado Air Quality Control Commission in order to: (i) reduce ozone precursor emissions from RICE to help keep rapidly growing rural areas in attainment with federal ozone standards; (ii) for reducing transport of ozone precursor emissions from RICE into the Denver Metro Area/North Front Range (DMA/NFR) nonattainment area; and, (iii) for the DMA/NFR nonattainment area, reducing precursor emissions from RICE directly tied to exceedance levels of ozone.

costs for Colorado RACT can be in the range of $5,000/ton (and lower), while control costs for Colorado BACT can be in the range of $5,000/ton (and higher).

In addition, as it considers the pertinent factors for reasonable progress, the state believes that the costs of control should have a relationship to visibility improvement. The highest-performing post-combustion NOx controls, *i.e.*, SCR, have the ability to provide significant NOx reductions, but also have initial capital dollar requirements that can approach or exceed $100 million per unit.[42] The lesser-performing post-combustion NOx controls, *e.g.*, SNCR, reduce less NOx on a percentage basis, but also have substantially lower initial capital requirements, generally less than $10 million.[43] The state finds that the significantly different capital investment required by the different types of control technologies is pertinent to its assessment and determination. Considering costs for the highest-performing add-on NOx controls (*i.e.*, SCR), the state anticipates a direct level of visibility improvement contribution, generally 0.50 Δdv or greater of visibility improvement at the primary affected Class I Area.[44] For the lesser-performing add-on NOx controls (*e.g.*, SNCR), the state anticipates a meaningful and discernible level of visibility improvement that contributes to broader visibility improvement, generally 0.20 Δdv or greater of visibility improvement at the primary affected Class I Area.

Employing the foregoing guidance criteria for post-combustion NOx controls, as part of considering the relevant factors for reasonable progress, promotes a robust evaluation of pertinent control options, including costs and an expectation of visibility benefit, to assist in determining what are appropriate control options for the Regional Haze rule.

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[42] *See, e.g.,* Appendix C, reflecting Public Service of Colorado, Comanche Unit #2, $83MM; Public Service of Colorado, Hayden Unit #2, $72MM; Tri-State Generation and Transmission, Craig Station Unit #1, $210MM.

[43] *See, e.g.*, Appendix C, reflecting CENC (Tri-gen), Unit #4, $1.4MM; Public Service Company of Colorado, Hayden Unit #2, $4.6MM; Tri-State Generation and Transmission, Craig Station Unit #1, $13.1MM

[44] The EPA has determined that BART-eligible sources that affect visibility above 0.50 Δdv are not to be exempted from BART review, on the basis that above that level the source is individually contributing to visibility impairment at a Class I Area. 70 Fed. Reg. at 39161. Colorado is applying these same criteria to RP sources, as a visibility improvement of 0.50 Δdv or greater will also provide significant direct progress towards improving visibility in a Class I Area from that facility.

### *8.5.2 Point Source RP Determinations*

The following summarizes the RP control determinations that will apply to each source.

**Table 8-2 RP Control Determinations for Colorado Sources**

| Emission Unit | Assumed** NOx Control Type | NOx Emission Limit | Assumed** $SO_2$ Control Type | $SO_2$ Emission Limit | Assumed** Particulate Control and Emission Limit |
|---|---|---|---|---|---|
| **Rawhide** Unit 101 | Enhanced Combustion Control* | 0.145 lb/MMBtu (30-day rolling average) | Lime Spray Dryer* | 0.11 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br>0.03 lb/MMBtu |
| **CENC** Unit 3 | No Control | 246 tons per year (12-month rolling total) | No Control | 1.2 lbs/MMBtu | Fabric Filter Baghouse*<br>0.07 lb/MMBtu |
| **Nixon** Unit 1 | Ultra-low NOx burners with Over-Fire Air | 0.21 lb/MMBtu (30-day rolling average) | Lime Spray Dryer | 0.11 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br>0.03 lb/MMBtu |
| **Clark** Units 1 &2 | Shutdown 12/31/2013 | 0 | Shutdown 12/31/2013 | 0 | Shutdown 12/31/2013 |
| **Holcim - Florence** Kiln | SNCR | 2.73 lbs/ton clinker (30-day rolling average)<br>2,086.8 tons/year | Wet Lime Scrubber* | 1.30 lbs/ton clinker (30-day rolling average)<br>721.4 tons/year | Fabric Filter Baghouse* 246.3 tons/year |
| **Nucla** | No Control | 0.5 lb/MMBtu<br>(30-day rolling average) | Limestone Injection* | 0.4 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br>0.03 lb/MMBtu |
| **Craig** Unit 3 | SNCR | 0.28 lb/MMBtu (30-day rolling average) | Lime Spray Dryer* | 0.15 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br>0.013 lb/MMBtu filterable PM<br>0.012 lb/MMBtu PM10 |
| **Cameo** | Shutdown 12/31/2011 | 0 | Shutdown 12/31/2011 | 0 | Shutdown 12/31/2011 |

* Controls are already operating

** Based on the state's RP analysis, the "assumed" technology reflects the control option found to render the RP emission limit achievable. The "assumed" technology listed in the above table is not a requirement.

For all RP determinations, approved in the federal State Implementation Plan, the state affirms that the RP emission limits satisfy Regional Haze requirements for this planning period (through 2017) and that no other Regional Haze analyses or Regional Haze controls will be required by the state during this timeframe.

The following presents an overview of Colorado's RP control determinations:

### *8.5.2.1 RP Determination for Platte River Power Authority - Rawhide Unit 101*

This facility is located in Larimer County approximately 10 miles north of the town of Wellington, Colorado. Unit 101 is a 305 MW boiler and is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$) at a facility with a Q/d impact greater than 20. Platte River Power Authority (PRPA) submitted a "Rawhide NOx Reduction Study" on January 22, 2009 as well as additional relevant information on May 5 and 6, 2010.

#### SO2 RP Determination for PRPA Rawhide Unit 101

*Dry FGD Upgrades* – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing control achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Rawhide Unit 101 operates a lime spray dryer FGD currently achieving over 72 percent SO2 reduction. The state has elected to consider EPA's BART Guidelines as relevant to the RP evaluation of Rawhide Unit 101 and, therefore, the following dry scrubber upgrades were considered.

- *Use of performance additives*: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. PRPA and the Division are not aware of $SO_2$ scrubber performance additives applicable to the Unit 101 SDA system.
- *Use of more reactive sorbent*: Lime quality is critical to achieving the current emission limit. PRPA utilizes premium lime at higher cost to ensure compliance with existing limits. The lime contract requires >92% reactivity (available calcium oxide) lime to ensure adequate scrubber performance. PRPA is already using a highly reactive sorbent, therefore this option is not technically feasible.
- *Increase the pulverization level of sorbent*: The fineness of sorbents used in dry-sorbent injection systems is a consideration and may improve performance for these types of scrubbers. Again, the Unit 101 $SO_2$ scrubber is a semi-dry SDA type scrubber that utilizes feed slurry that is primarily recycle-ash slurry with added lime slurry. PRPA recently completed SDA lime slaking sub-system improvements that are designed to improve the reactivity of the slaked lime-milk slurry.
- *Engineering redesign of atomizer or slurry injection system*: The Unit 101 SDA scrubber utilizes atomizers for slurry injection. The scrubber utilizes three reactor compartments, each with a single atomizer. PRPA maintains a spare atomizer to ensure high scrubber availability. The atomizers utilize the most current wheel-

nozzle design. The state and PRPA concur that PRPA utilizes optimal maintenance and operations; therefore, a lower SO2 emission cannot be achieved with improved maintenance and/or operations.

Fuel switching to natural gas was determined by the source to be a technically feasible option for Rawhide Unit 101, and as provided by PRPA it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

| Rawhide Unit 101 – SO2 Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| Fuel switching – NG | 906 | $237,424,331 | $262,169 |

There are no energy and non-air quality impacts associated with this alternative.

There are no remaining useful life issues for the alternative as the source will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to more stringent SO2 emission limits as a demonstration are as follows:

| SO2 Control Method | SO2 Annual Emission Rate (lb/MMBtu) | $98^{th}$ Percentile Impact ($\Delta$dv) |
|---|---|---|
| Daily Maximum (3-yr) | 0.11 | |
| Existing Dry FGD | 0.09 | 0.01 |
| Dry FGD – tighter limit | 0.07 | 0.03 |
| Fuel switching – NG | 0.00 | 0.87 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that SO2 RP is the following SO2 emission rates:

Rawhide Unit 101: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the installation and operation of lime spray dryers (LSD). The state has determined that these emissions rates are achievable without additional capital investment through the four-factor analysis. Upgrades to the existing SO2 control system were evaluated, and the state determines that meaningful upgrades to the system are not available. Lower SO2 limits would not result in significant visibility improvement (less than 0.02 delta deciview) and would likely result in frequent non-compliance events and, thus, are not reasonable.

**Particulate Matter RP Determination for PRPA Rawhide**

The state has determined that the existing Unit 101 regulatory emissions limit of 0.03 lb/MMBtu (PM/PM10) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for $PM/PM_{10}$.

The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouses.

### NOx RP Determination for PRPA Rawhide

Enhanced combustion control (ECC), selective non-catalytic reduction (SNCR), fuel switching to natural gas (NG), and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Rawhide Unit 101. Fuel switching to natural gas was determined by the source to be a technically feasible option for Rawhide Unit 101, and as provided by PRPA it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

| Rawhide Unit 101 - NOx Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| ECC | 448 | $288,450 | $644 |
| SNCR | 504 | $1,596,000 | $3,168 |
| Fuel switching – NG | 545 | $237,424,331 | $435,681 |
| SCR | 1,185 | $12,103,000 | $10,214 |

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| NOx Control Method | NOx Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact ($\Delta$dv) |
|---|---|---|
| Daily Maximum (3-yr) | 0.302 | |
| ECC | 0.126 | 0.45 |
| SNCR | 0.121 | 0.46 |
| Fuel Switching – NG | 0.118 | 0.47 |
| SCR | 0.061 | 0.59 |

It should be noted that the daily maximum (3-yr) value of 0.302 lb/MMBtu was a substituted value from CAMD. The next highest 24-hour value was 0.222 lb/MMBtu, 26% lower than the modeled value. However, the Division did not conduct revised modeling since it was determined that it would not change the State’s RP determination.

Switching to natural gas was eliminated from consideration due to the excessive cost/effectiveness ratio and degree of visibility improvement less than 0.5 dV.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that NOx RP for Rawhide Unit 101 is the following NOx emission rate:

Rawhide Unit 1: 0.145 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of enhanced combustion control. The dollars per ton control cost, coupled with notable visibility improvements of 0.45 delta dv, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in section 8.4 above. SNCR would achieve similar emissions reductions to enhanced combustion controls and would afford a minimal additional visibility benefit ( 0.01 delta deciview), but at a significantly higher dollar per ton control cost compared to the selected enhanced combustion controls, so SNCR was not determined to be reasonable by the state.

A complete analysis that supports the RP determination for the Rawhide facility can be found in Appendix D.

#### *8.5.2.2 RP Determination for Colorado Energy Nations Company (CENC) Boiler 3*

This facility is located adjacent to the Coors brewery in Golden, Jefferson County. Boiler 3 is considered by the State to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$) at a facility with a Q/d impact greater than 20. CENC submitted a "Reasonable Progress Control Evaluation" on May 7, 2010 as well as additional relevant information on February 8, 2010.

The CENC facility includes five coal-fired boilers that supply steam and electrical power to Coors Brewery. Three of the boilers emit above 40 tons or more of haze forming pollution. Of these three boilers, Units 4 and 5 are subject to BART, and Unit 3 is subject to RP. Unit 3 is rated as follows: 225 MMBtu/hr, which is approximately equivalent to 24 MW, based on the design heat rate.

**SO2 RP Determination for CENC – Boiler 3**

Dry sorbent injection (DSI) and fuel switching to natural gas were determined to be technically feasible for reducing SO2 emissions from Boiler 3. Dry FGD is not technically feasible for Boiler 3 due to space constraints onsite. These options were considered as potentially RP by the state. Fuel switching to natural gas was determined by the source to be a technically feasible option for Boiler 3, and as provided by PRPA it was evaluated by the state.

Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts. Dry FGD controls were determined to be not technically feasible.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| CENC Boiler 3 - SO2 Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| DSI – Trona | 147 | $1,340,661 | $9,114 |
| Fuel Switching – Natural Gas | 245 | $1,428,911 | $5,828 |

DSI – Trona and fuel switching to natural gas were eliminated from consideration due to excessive cost/effectiveness ratio.

Because there are no reasonable alternatives, there are no energy and non-air quality impacts to consider.

There are no remaining useful life issues for the alternatives as the source will remain in service for the 20-year amortization period.

Based on CALPUFF modeling results for subject-to-BART CENC Units 4 and 5, the state determined the further CALPUFF modeling of smaller emission sources at the CENC facility would produce minimal visibility impacts (<<0.10 dv).

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 RP is an emission rate of:

CENC Boiler 3: 1.2 lbs/MMBtu

Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement (<< 0.10 dv) afforded.

**Particulate Matter RP Determination for CENC – Boiler 3**

The state has determined that the existing Boiler 3 regulatory emissions limit of 0.07 lb/MMBtu (PM/PM10) corresponding with the original Industrial Boiler MACT standard represents the most stringent control option. The units are exceeding a PM control efficiency of 90%, and the emission limit is RP for $PM/PM_{10}$. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

**NOx RP Determination for CENC – Boiler 3**

Flue gas recirculation (FGR), selective non-catalytic reduction (SNCR), rotating overfire air (ROFA) fuel switching to natural gas, and three options for selective catalytic reduction (RSCR, HTSCR, and LTSCR) were determined to be technically feasible for reducing NOx emissions at CENC Boiler 3. Fuel switching to natural gas was determined by the source to be a technically feasible option for Boiler 3, and as provided by CENC it was evaluated by the state.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives.

| CENC Boiler 3 - NOx Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| FGR | 33.7 | $1,042,941 | $30,929 |
| SNCR | 50.6 | $513,197 | $10,146 |
| Fuel switching – NG | 84.3 | $1,428,911 | $16,950 |
| ROFA w/ Rotamix | 77 | $978,065 | $9,496 |
| Regenerative SCR | 96.3 | $978,065 | $10,160 |
| High temperature SCR | 125.6 | $1,965,929 | $15,651 |
| Low temperature SCR | 144.5 | $2,772,286 | $19,187 |

Because there are no reasonable alternatives, there are no energy and non-air quality impacts to consider.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Based on CALPUFF modeling results for subject-to-BART CENC Units 4 and 5, the state determined the further CALPUFF modeling of smaller emission sources at the CENC facility would produce visibility impacts below the guidance visibility criteria discussed in section 8.4 above.

All NOx control options were eliminated from consideration due to the excessive cost/effectiveness ratios and small degree of visibility improvement.

Based on review of historical actual load characteristics of this boiler, the state determines to be appropriate an annual NOx ton/year limit based on 50% annual capacity utilization based on the maximum capacity year in the last decade (2000). This annual capacity utilization will then have a 20% contingency factor for a variety of reasons specific to Boiler 3 further explained in Appendix D.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Boiler 3 is the following NOx emission rate

CENC Boiler 3: 246 tons/year (12-month rolling total)

Though other controls achieve better emissions reductions, the expense of these options coupled with predicted minimal visibility improvement (<< 0.10 dv) were determined to be excessive and above the guidance cost criteria discussed in section 8.4 of the Regional Haze SIP, and thus not reasonable

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above BART determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's RP determination because the degree of visibility improvement achieved by SNCR or SCR is likely below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively (as demonstrated in the BART determination for CENC Boiler 4). Moreover, the incremental visibility improvement associated with SNCR or SCR is likely not substantial when compared to the visibility improvement achieved by the selected limits. Thus, it is not warranted to select emission limits associated with either SNCR or SCR for CENC Boiler 3.

A complete analysis that supports the RP determination for the CENC facility can be found in Appendix D.

#### *8.5.2.3 RP Determination for Colorado Springs Utilities' - Nixon Unit 1*

The Nixon plant is located in Fountain, Colorado in El Paso County. Nixon Unit 1 and two combustion turbines at the Front Range Power Plant are considered by the Division to be eligible for the purposes of Reasonable Progress, being industrial sources with the potential to individually emit 40 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$) at a facility with a Q/d impact greater than 20. Colorado Spring Utilities (CSU) provided RP information in "NOx and SO2 Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 and additional relevant information on May 10, 2010.

**SO2 RP Determination for CSU – Nixon**

Dry sorbent injection (DSI) and dry FGD were determined to be technically feasible for reducing SO2 emissions from Nixon. These options were considered as potentially RP by the state. Lime or limestone-based wet FGD is technically feasible, but was determined to not be reasonable due to adverse non-air quality impacts.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Nixon Unit 1 - SO2 Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| DSI – Trona | 2,473 | $9,438,692 | $1,997 |
| Dry FGD @ 78% control (0.10 lb/MMBtu annual average) | 3,215 | $12,036,604 | $3,744 |
| Dry FGD @ 85% control (0.07 lb/MMBtu annual average) | 3,392 | $13,399,590 | $3,950 |

The energy and non-air quality impacts of the remaining alternatives are as follows:

- DSI – reduced mercury capture in the baghouse, fly ash contamination with sodium sulfate, rendering the ash unsalable as replacement for concrete and rendering it landfill material only
- Dry FGD – less mercury removal compared to unscrubbed units, significant water usage

There are no remaining useful life issues for the alternatives as the source will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| SO2 Control Method | Nixon – Unit 1 | |
|---|---|---|
| | SO2 Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Max (3-yr) | 0.45 | |
| DSI | 0.18 | 0.44 |
| Dry FGD (LSD) | 0.10 | 0.46 |
| Dry FGD (LSD) | 0.07 | 0.50 |

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience, 30-day SO2 rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 5% for all SO2 emission rates to determine control efficiencies and annual reductions.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 RP is the following SO2 emission rate:

Nixon Unit 1: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with semi dry FGD (LSD). A lower emissions rate for Unit 1 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.04 delta deciview). Also, stringent retrofit emission limits below 0.10 lb/MMBtu have not been demonstrated in Colorado, and the state determines that a lower emission limit is not reasonable in this planning period.

The LSD control for Unit 1 provides 78% $SO_2$ emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 1: $3,744 per ton $SO_2$ removed; 0.46 deciview of improvement

An alternate control technology that achieves the emissions limits of 0.11 lb/MMBtu, 30-day rolling average, may also be employed.

### Particulate Matter RP Determination for CSU – Nixon

The state determines that the existing Unit 1 regulatory emissions limit of 0.03 lb/MMBtu ($PM/PM_{10}$) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limits is RP for $PM/PM_{10.}$ The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

**NOx RP Determination for CSU – Nixon**

Ultra low NOx burners (ULNB), SNCR, SNCR plus ULNB, and SCR were determined to be technically feasible for reducing NOx emissions at Nixon Unit 1.

The following table lists the emission reductions, annualized costs and cost effectiveness of the control alternatives.

| Nixon Unit 1 - $NO_x$ Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| Ultra-low NOx Burners (ULNBs) | 471 | $567,000 | $1,203 |
| Overfire Air (OFA) | 589 | $403,000 | $684 |
| ULNBs+OFA | 707 | $907,000 | $1,372 |
| Selective Non-Catalytic Reduction (SNCR) | 707 | $3,266,877 | $4,564 |
| ULNB/SCR layered approach | 1,720 | $11,007,000 | $6,398 |
| Selective Catalytic Reduction (SCR) | 1,720 | $11,010,000 | $6,400 |

The energy and non-air quality impacts of the alternatives are as follows:

- OFA and ULNB – not significant
- ULNB – not significant
- SNCR – increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| NOx Control Method | Nixon – Unit 1 | |
|---|---|---|
| | NOx Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Max (3-yr) | 0.26 | |
| ULNB | 0.21 | 0.15 |
| OFA | 0.19 | 0.15 |
| ULNB+OFA | 0.18 | 0.16 |
| SNCR | 0.18 | 0.16 |
| ULNB + SCR | 0.07 | 0.24 |
| SCR | 0.07 | 0.24 |

SCR options were eliminated from consideration due to the excessive cost/effectiveness ratios and degree of visibility improvement.

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Nixon Unit 1 is the following NOx emission rates:

Nixon Unit 1: 0.21 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with ultra-low NOx burners with over fire air control. The Division notes that the ultra-low NOx burners with over-fire air-based emissions limit is the appropriate RP determination for Nixon Unit 1 due to the low cost effectiveness. SNCR would achieve similar emissions reductions at an added expense. Therefore, SNCR was determined to not be reasonable considering the low visibility improvement afforded.

EPA Region 8 notes to the state that a number of control cost studies, such as that by NESCAUM (2005), indicate that costs for SNCR or SCR could be lower than the costs estimated by the Division in the above RP determination. However, assuming such lower costs were relevant to this source, use of such lower costs would not change the state's RP determination because the degree of visibility improvement achieved by SNCR or SCR is below the state's guidance criteria of 0.2 dv and 0.5 dv, respectively. Moreover, the incremental visibility improvement associated with SNCR or SCR is not substantial when compared to the visibility improvement achieved by the selected limits (i.e., 0.01 dv for SNCR and 0.09 dv for SCR). Thus, it is not warranted to select emission limits associated with either SNCR or SCR for Nixon Unit 1.

A complete analysis that supports the RP determination for the Nixon Plant can be found in Appendix D.

#### *8.5.2.4 RP Determination for Black Hills Clark Facility Units 1 and 2*

Black Hills/Colorado Electric Utility Company, LP informed the state that the Clark Station in the Cañon City, Colorado area will be shutdown 12/31/2013, resulting in SO2, NOx and PM reductions of approximately 1,457, 861, and 72 tons per year, respectively. Therefore, a four-factor analysis was not necessary for this facility and the RP determination for the facility is closure.

#### *8.5.2.5 RP Determination for Holcim's Florence Cement Plant*

The Holcim Portland cement plant is located near Florence, Colorado in Fremont County, approximately 20 kilometers southeast of Canon City, and 35 kilometers northwest of Pueblo, Colorado. The plant is located 66 kilometers from Great Sand Dunes National Park.

In May 2002, a newly constructed cement kiln at the Portland Plant commenced operation. This more energy-efficient 5-stage preheater/precalciner kiln replaced three older wet process kilns. As a result, Holcim was able to increase clinker production from approximately 800,000 tons of clinker per year to a permitted level of 1,873,898 tons of clinker per year, while reducing the level of $NO_X$, $SO_2$, and $PM/PM_{10}$ emissions on a pound per ton of clinker produced basis. As a part of this project, Holcim also installed a wet lime scrubber to reduce the emissions of sulfur oxides.

The Portland Plant includes a quarry where major raw materials used to produce Portland cement, such as limestone, translime and sandstone, are mined, crushed and then conveyed to the plant site. The raw materials are further crushed and blended and then directed to the kiln feed bin from where the material is introduced into the kiln.

The dual string 5-stage preheater/precalciner/kiln system features a multi-stage combustion precalciner and a rotary kiln. The kiln system is rated at 950 MMBtu per hour of fuel input with a nominal clinker production rate of 5,950 tons per day. It is permitted to burn the following fuel types and amounts (with nominal fuel heat values, where reported):

- coal (269,262 tons per year [tpy] @ 11,185 Btu/pound);
- tire derived fuel (55,000 tpy @ 14,500 Btu/pound);
- petroleum coke (5,000 tpy @ 14,372 Btu/pound);
- natural gas (6,385 million standard cubic feet @ 1,000 Btu/standard cubic foot);
- dried cellulose (55,000 tpy); and
- oil, including non-hazardous used oil (4,000 tpy @ 12,000 Btu/pound).

The clinker produced by the kiln system is cooled, grounded and blended with additives and the resulting cement product is stored for shipment. The shipment of final product from the plant is made by both truck and rail.

Emissions from the kiln system, raw mill, coal mill, alkali bypass and clinker cooler are all routed through a common main stack for discharge to atmosphere. These emissions are currently controlled by fabric filters (i.e., baghouses) for $PM/PM_{10}$, by the inherent recycling and scrubbing of exhaust gases in the cement manufacturing process and by a tail-pipe wet lime scrubber for $SO_2$, by burning alternative fuels (i.e., tire-derived fuel [TDF]) and using a Low-$NO_X$ precalciner, indirect firing, Low-$NO_X$ burners, staged combustion and a Linkman Expert Control System for $NO_X$, and by the use of good combustion practices for both $NO_X$ and $SO_2$.In addition to the kiln system/main stack emissions, there are two other process points whose $PM/PM_{10}$ emissions exceed the Prevention of Significant Deterioration (PSD) significance level thresholds and were considered as a part of this Reasonable Progress analysis: 1) the raw material extraction and alkali bypass dust disposal operations associated with the quarry, and 2) the cement processing operations associated with the finish mill. Emissions from the quarry are currently controlled through a robust fugitive dust control plan and emissions from the finish mills are controlled by a series of baghouses.

Holcim did not initially complete a detailed four-factor analysis, though it did submit limited information on the feasibility of post-combustion $NO_X$ controls for the kiln system. In late October through early December 2010, Holcim did submit detailed information, including data on baseline emissions, existing controls and additional control options, and visibility modeling to support the reasonable progress determination process. This section has been revised to reflect this additional information.

CALPUFF modeling was conducted by the Division for the kiln system, as a part of our original analysis, using a $SO_2$ emission rate of 99.17 lbs/hour, a $NO_X$ emission rate of

837.96 pounds per hour (lbs/hour), and a $PM_{10}$ emission rate of 19.83 lbs/hour. The modeling indicates a $98^{th}$ percentile visibility impact of 0.435 delta deciview (Δdv) at Great Sand Dunes National Park. Holcim provided additional visibility modeling results in a submittal made in late October 2010.

Because of the high level of existing fugitive dust controls employed at the quarry and the baghouse controls already installed on the finish mill emission points, the state has determined that no meaningful emission reductions (and thus no meaningful visibility improvements) would occur pursuant to any conceivable additional controls on these points. Accordingly, the state has determined that no additional visibility analysis is necessary or appropriate since even the total elimination of the emissions from the quarry and finish mill would not result in any meaningful visibility improvement. For the quarry, the current $PM_{10}$ emission limitation is 47.9 tpy (fugitive) and for the finish mill it is 34.3 tpy (point source). These limitations are included in the existing Holcim Portland Plant construction permit.

### $SO_2$ RP Determination for Holcim Portland Plant – Kiln System

In addition to good combustion practices and the inherent recycling and scrubbing of acid gases by the raw materials, such as limestone, used in the cement manufacturing process, the Portland Plant kiln system has a tail-pipe wet lime scrubber. Holcim has reported that this combination of controls achieves an overall sulfur removal rate of 98.3% for the kiln system, as measured by the total sulfur input in to the system versus the amount of sulfur emitted to atmosphere. Holcim has also reported that they estimate that the wet scrubber at the Portland Plant achieves an overall removal efficiency of over 90% of the $SO_2$ emissions entering the scrubber. This control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

The state did assess the corresponding SO2 emissions rates. The facility is currently permitted to emit 1,006.5 tpy of SO2 from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 1.08 pounds of SO2 per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for SO2). The actual kiln SO2 emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 0.51 pound of SO2 per ton of clinker, with a standard deviation of 0.26 pound per ton. The highest annual emission rate in the baseline years was 0.95 pound per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for $SO_2$. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emissions limit of 1.30 pounds of $SO_2$ per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability. The long-term annual limit was calculated at 721.4 tpy by multiplying the long-term baseline $SO_2$ value of 0.77 lb/ton (the mean of 0.51 pound per ton plus one standard deviation of 0.26 pound per ton) by the annual clinker limit of 1,873,898 tpy, and then dividing by 2,000 pounds per ton.

Because there are no changes to the existing controls for SO2, there are no associated energy and non-air quality impacts for this determination. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

For the kiln system, based upon our consideration and weighing of the four factors, the state has determined that no additional SO2 emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technologies – the inherent recycling and scrubbing effect of the process itself followed by a tail-pipe wet lime scrubber. The RP analysis provides sufficient basis to establish a short-term $SO_2$ emission limit of 1.30 pound per ton of clinker on a 30-day rolling average basis and a long-term annual emission limit of 721.4 tons of $SO_2$ per year (12-month rolling total) for the kiln system. There is no specific visibility improvement associated with this emission limitation.

Finally, on August 9, 2010, EPA finalized changes to the New Source Performance Standards (NSPS) for Portland Cement Plants and to the Maximum Achievable Control Technology standards for the Portland Cement Manufacturing Industry (PC MACT). The NSPS requires, new, modified or reconstructed cement kilns to meet an emission standard of 0.4 pound of SO2 per ton of clinker on a 30-day rolling average or a 90% reduction as measured at the inlet and outlet of the control device. While the new NSPS does not apply to the Holcim Portland Plant because it is an existing facility, it is important to note that the estimated level of control achieved by Holcim's wet scrubber (~90%) is consistent with the level of control prescribed by the NSPS for new sources.

**Particulate Matter RP Determination for Holcim Portland Plant – Kiln System**

The state has determined that the existing fabric filter baghouses installed on the kiln system represent the most stringent control option. Holcim has reported a nominal control efficiency for the kiln system baghouses at 99.5%. The units are exceeding a PM control efficiency of 95% and this control technology represents the highest level of control for Portland cement kilns. As a result, the state did not consider other control technologies as a part of this RP analysis.

The state did assess the corresponding $PM_{10}$ emissions rates. The facility is currently permitted to emit 246.3 tpy of $PM_{10}$ from the kiln system main stack (includes emissions from the clinker cooler). At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 0.26 pound of $PM_{10}$ per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for $PM_{10}$). The actual kiln system $PM_{10}$ emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) average to a rate of 0.16 pound of $PM_{10}$ per ton of clinker (combined emissions from main stack). This value is derived from the limited annual stack test data, which are effectively snapshots in time, and does not take into account the short-term inherent variability in the manufacturing process, raw material and fuel.

Because there are no changes to the existing controls for $PM_{10}$, there are no associated energy and non-air quality impacts for this determination. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

As a part of our original analysis, the state modeled possible visibility improvements associated with two emission rates – the baseline emission rate of 0.08 pound of $PM_{10}$ per ton of clinker (19.83 lbs/hour) and a rate of 0.04 pound of $PM_{10}$ per ton of clinker (9.92 lbs/hour). This analysis assumed the baseline emissions were all attributable to the kiln (i.e., no contribution from the clinker cooler) to assess the impact of a possible reduction of the kiln emission limit. There was no change to the 98th percentile impact deciview value from 19.83 lbs/hour to 9.92 lbs/hour and therefore, no visibility improvement associated with this change. The state's modeling results showed that the most significant contributors to the visibility impairment from the Portland Plant were nitrates ($NO_3$) followed by sulfates ($SO_4$).The contribution of $PM_{10}$ to the total visibility impairment was insignificant in the analysis. The level of $PM_{10}$ emissions evaluated had no discernable impact on visibility.

For the kiln system, based upon our consideration and weighing of the four factors and the very limited impact of $PM_{10}$ emissions from the kiln system on visibility impairment, the state has determined that no additional $PM_{10}$ emissions control is warranted given that the Holcim Portland Plant already is equipped with the top performing control technology – fabric filter baghouses. These baghouses and the current permit limit of 246.3 tpy of $PM_{10}$ (12-month rolling total) from the kiln system main stack (including emissions from the clinker cooler) represent RP for this source. Furthermore, the Portland Plant is subject to the PC MACT and the recent amendments to the PC MACT include new, lower standards for PM emissions. As an existing facility, the Portland Plant kiln system will be subject to this standard once it becomes effective on September 9, 2013. Compliance with the new PC MACT PM emission standards will result in further reductions in the $PM_{10}$ emissions.

### $NO_X$ RP Determination for Holcim Portland Plant – Kiln System

There are a number of technologies available to reduce $NO_X$ emissions from the Portland Plant kiln system below the current baseline emissions level (the current configuration already includes indirect firing, low-$NO_X$ burners, staged combustion, a low-$NO_X$ precalciner, and a Linkman Process Control Expert system). These include water injection (the injection of water or steam into the main flame of a kiln to act as a heat sink to reduce the flame temperature), and selective non-catalytic reduction (SNCR). These technologies were determined to be technically feasible and appropriate for reducing $NO_X$ emissions from Portland cement kilns.

As further discussed in Appendix D, the state has determined that selective catalytic reduction (SCR) is not commercially available for the Portland Plant cement kiln system. Presently, SCR has not been applied to a cement plant of any type in the United States. Holcim notes that the major SCR vendors have either indicated that SCR is not commercially available for cement kilns at this time, or if they are willing to provide a quotation for an SCR system, the associated limitations that are attached with the quote severely undercut the efficacy of the system. The state does not believe that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe constitutes reasonable “available” control technology for purposes of RP at the Holcim Portland Plant. The state believes that commercial demonstration of SCR controls on a cement plant in the United States is appropriate when considering whether a control technology is “available” for purposes of retrofitting such control technology on an existing source.

In the preamble to the recently finalized changes to the Portland Cement MACT/NSPS, EPA stated: “However, although SCR has been demonstrated at a few cement plants in Europe and has been demonstrated on coal-fired power plants in the US, the Agency is not satisfied that it has been sufficiently demonstrated as an off-the-shelf control technology that is readily applicable to cement kilns.” Based on our research and EPA’s analysis for the MACT/NSPS standards, the state has eliminated SCR as an available control technology for purposes of this RP analysis.

The design of the Holcim Portland Plant does allow for the effective use of Selective Non-Catalytic Reduction (SNCR), which requires ammonia-like compounds to be injected into appropriate locations of the preheater/precalciner vessels where temperatures are ideal (between 1600-2000ºF) for reducing $NO_X$ to elemental nitrogen. Holcim has indicated to the state that SNCR is technically and economically feasible for the Portland Plant. In April 2008, Holcim provided information to the state on SNCR systems that was based on trials that were conducted at the plant in the 4$^{th}$ quarter of 2006. Holcim estimated that $NO_X$ emissions could be reduced in the general range of 60 to 80% (based on a 1,000 pound per hour emission rate) at an approximate cost of $1,028 per ton. This was based on a short-term testing and showed considerable ammonia slip which could cause significant environmental, safety and operational issues.

The facility is currently permitted to emit 3,185.7 tpy of NOX from the kiln system main stack. At a permitted clinker production level of 1,873,898 tpy, this equates to an annual average of 3.40 pounds of NOX per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for NOX). The actual kiln NOX emissions divided by the actual clinker production for the five-year baseline period used in this analysis (2004, 2005, 2006, 2007 and 2008) calculate to an overall annual average rate of 3.43 pounds of NOX per ton of clinker, with a standard deviation of 0.21 pound per ton. The highest annual emission rate in the baseline years was 3.67 pounds per ton of clinker.

As a part of their submittals, Holcim analyzed continuous hourly emission data for NOX. The hourly emission data from 2004 to 2008 (baseline years) were used to calculate the daily emission rates. A 30-day rolling average emission rate was calculated by dividing the total emissions from the previous 30 operating days by the total clinker production from the previous 30 operating days. The 99th percentile of the 30-day rolling average data was used to establish the short-term baseline emission rate of 4.47 pounds of NOX per ton of clinker. The 99th percentile accounts for emission changes due to short-term and long-term inherent process, raw material and fuel variability.

Holcim is permitted to burn up to 55,000 tpy of TDF annually and has been using TDF during the baseline years. Use of TDF as a NOX control strategy has been well documented and recognized by EPA. A reduction in NOX emissions of up to 30% to 40% has been reported. Since the TDF market and possible associated TDF-use incentives are unpredictable and TDF's long-term future availability is unknown, the baseline emission rate was adjusted upward by a conservative factor of 10% to account for the NOX reduction in the baseline years as a result of the use of TDF during this baseline period that might not be available in future years. This increased the baseline 30-day rolling average emissions rate from 4.47 to 4.97 pounds of NOX per ton of clinker.

An SNCR control efficiency of 50% is feasible for the Portland Plant kiln that already has number of technologies available to reduce NOX emissions including indirect firing, low-NOX burners, staged combustion, a low-NOX precalciner, and a Linkman Process Control Expert system. However, to achieve the necessary system configuration and temperature profile, SNCR will be applied at the top of the preheater tower and thus the alkali bypass exhaust stream cannot be treated. To achieve the proper cement product specifications, the Portland Plant alkali bypass varies from 0 - 30% of main kiln gas flow. Adjusting by 10%, (conservative estimate) for the alkali bypass to account for the exhaust gas that is not treated (i.e., bypassed) by the SNCR system, the overall SNCR control efficiency for the main stack will be 45%.

Based on the above discussion, the 30-day rolling average short-term limit was calculated at 2.73 pounds of NOX per ton of clinker by adjusting upward the short-term baseline emission rate of 4.47 pounds of NOX per ton clinker by 10% for TDF and then accounting for SNCR 45% overall control efficiency [4.47/0.9*(1-0.45) = 2.73]. The long-term annual limit was calculated at 2,086.8 tpy by adjusting upward the annual baseline emission rate of 3.64 lbs/ton clinker (the mean of 3.43 pounds per ton plus one standard deviation of 0.21 pound per ton) by 10% for TDF and then accounting for SNCR 45% overall control efficiency [3.64/0.9*(1-0.45) = 2.23 lb/ton]. This calculated value of 2.23 pounds per ton was then multiplied by the annual clinker limit of 1,873,898 tpy, and then divided by 2,000 pounds per ton to arrive at the 2,086.8 tpy NOX limit.

Because SNCR with existing LNB is technically and economically feasible, the state did not further consider water injection because the level of control associated with this option is not as high as with SNCR.

The following table lists the most feasible and effective option (SNCR):

| NOx Control Technology | Estimated Control Efficiency | 30-day Rolling Average Emissions (lb/ton of Clinker) | Annual Controlled NOx Emissions (tpy) |
|---|---|---|---|
| Baseline NOx Emissions | - | 4.97 | 3,185.7* |
| SNCR w/ existing LNB | 45%** | 2.73 | 2,086.8 |

* Defaulted to the permit limit since the calculated baseline was higher.

** This is calculated based on the 50% SNCR removal efficiency and 10% bypass

There are no significant associated energy and non-air quality impacts for SNCR in operation on a Portland cement plant. There are no remaining useful life issues for the source, as the state has presumed that the source will remain in service for the 20-year amortization period.

The following table lists the emission reductions, annualized costs and the control cost effectiveness for the feasible controls:

| Holcim Portland Plant – Kiln System | | | | |
|---|---|---|---|---|
| NOx Control Technology | NOx Emission Reduction (tons/yr) | Annualized Cost ($/yr) | Cost Effectiveness ($/ton) | Incremental Cost Effectiveness ($/ton) |
| Baseline NOx Emissions | - | | | |
| SNCR w/existing LNB (45% control) | 1,098.9 | $2,520,000* | $2,293 | - |

* Annualized cost is based on the estimates provided by Holcim. The state believes that the $2,293/ton value is generally representative of control costs for the scenario evaluated in this RP analysis.

As a part of their late October 2010 submittals, Holcim provided modeling data for their proposed $NO_X$ RP limitations. The following table lists the projected visibility improvements for $NO_X$ controls, as identified by Holcim:

| Holcim Portland Plant – Kiln System | | |
|---|---|---|
| NOx Control Method | 98th Percentile Impact (Δdv) | 98th Percentile Improvement (Δdv) |
| Maximum (24-hr max)<br>(based on modeled emission rates of 1,363 lb/hr NOx, 586 lb/hr $SO_2$, 86.4 lb/hr $PM_{10}$) | 0.814 | N/A |
| SNCR w/ existing LNB<br>(45% overall $NO_X$ control efficiency)<br>Limits of **2.73 lb/ton** (30-day rolling average) and **2,086.8 tons per year**<br>(based on modeled emission rates of 750 lb/hr $NO_X$, 586 lb/hr $SO_2$, 86.4 lb/hr $PM_{10}$) | 0.526 | 0.288 |

For the kiln, the state has determined that SNCR w/existing LNB is the best $NO_X$ control system available with $NO_X$ RP emission limits of 2.73 pounds per ton of clinker (30-day rolling average) and 2,086.8 tons per year (12-month rolling total). The emissions rate and the control efficiency reflect the best performance from the control options evaluated. This RP determination affords the most $NO_X$ reduction from the kiln system (1,098.9 tpy) and contributes to significant visibility improvement.

A complete analysis that further supports the RP determination for the Holcim Portland Plant can be found in Appendix D.

### *8.5.2.6 RP Determination for Tri-State Generation and Transmission Association's Nucla Facility*

The Tri-State Nucla Station is located in Montrose County about 3 miles southeast of the town of Nucla, Colorado. The Nucla Station consists of one coal fired steam driven electric generating unit (Unit 4), with a rated electric generating capacity of 110 MW (gross), which was placed into service in 1987. Nucla Unit 4 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

**SO2 RP Determination for Nucla – Unit 4**

Limestone injection improvements, a spray dry absorber (SDA) system (or dry FGD), limestone injection improvements with a SDA, hydrated ash reinjection (HAR), and HAR with limestone injection improvements were determined to be technically feasible for reducing SO2 emissions from Nucla Unit 4. Study-level information for HAR systems at Nucla or any other EGU in the western United States were not available for use in evaluating costs. Since the option to install a dry FGD alone (even without improving limestone injection) provides a better estimated control efficiency than a HAR system plus limestone injection improvements, the HAR system was not considered further in this analysis.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Nucla Unit 4 - SO2 Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| Limestone Injection Improvements | 526 | $914,290 | $4,161 |
| Spray Dry Absorber (dry FGD) | 1,162 | $7,604,627 | $6,547 |
| Limestone Injection Improvements + dry FGD | 1,254 | $9,793,222 | $7,808 |

A dry FGD system, or limestone injection improvements plus dry FGD system, were eliminated from consideration by the state as unreasonable during this planning period due to: 1) the excessive costs, 2) that they would require replacement of an existing system and installation of a completely new system (with attendant new capital costs and facility space considerations), and 3) the lack of modeled visibility affects associated with these particular SO2 reductions.

There is no energy and non-air quality impacts associated with limestone injection improvements. For dry FGD, the energy and non-air quality impacts include less mercury removal compared to unscrubbed units and significant water usage.

There are no remaining useful life issues for alternatives as the source will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis.

Nucla already has a system in place to inject limestone into the boiler as required by current state and federal air permits. This system achieves an approximate 70% SO2 emissions reduction capture efficiency at a permitted emission rate of 0.4 lbs/MMBtu limit. Increased SO2 capture efficiency (85%) with the existing limestone injection as an effective system upgrade, by use of more limestone (termed “limestone injection improvements”) was evaluated and determined to not be feasible under certain operating conditions. The system cannot be ‘run harder’ with more limestone to achieve a more stringent SO2 emission limit; the system would have to be reconstructed or redesigned with attendant issues, or possibly require a new or different SO2 system, to meet an 85% capture efficiency.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that the existing permitted SO2 emission rate for Unit 4 satisfies RP:

Nucla Unit 4: 0.4 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of the existing limestone injection system.

### PM10 RP Determination for Nucla – Unit 4

The state has determined that the existing regulatory emissions limit of 0.03 lb/MMBtu represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/$PM_{10}$. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

### NOx RP Determination for Nucla – Unit 4

Selective non-catalytic reduction (SNCR) was determined to be technically feasible for reducing NOx emissions at Nucla Unit 4. SCR is not technically feasible on a circulating fluidized bed coal-fired boiler, and is otherwise not cost-effective, as discussed in Appendix D. With respect to SNCR, however, there is substantial uncertainty surrounding the potential control efficiency achievable by a full-scale SNCR system at a CFB boiler burning western United States coal. The state and Tri-State’s estimates vary between 10 – 40% NOx reduction potential, which correlates to between $3,000 - $17,000 per ton NOx reduced and may result in between 100 to 400 tons NOx reduced per year.

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis. There are several qualitative reasons that NOx controls may be warranted at Nucla. First, NOx control alternatives may result in between 100 – 400 tons of NOx reduced annually. Second, Nucla is within 100 kilometers in proximity to three Class I areas, depicted in the figure above, and within approximately 115 kilometers to five Class I areas, including Utah's Canyonlands and Arches National Parks. Third, Nucla has a limited, small-scale SNCR system for emissions trimming purposes installed.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that NOx RP for Nucla Unit 4 is no control at the following NOx emission rate:

Nucla Unit 4: 0.5 lb/MMBtu (30-day rolling average)

**Additional Analyses of SO2 and NOx Controls for Nucla**

As state-only requirements of this Reasonable Progress determination, the Commission requires, and Tri-State agrees, that Tri-State conduct a comprehensive four factor analysis of all SO2 and NOx control options for Nucla using site-specific studies and cost information and provide to the state a draft analysis by July 1, 2012. A protocol for the four-factor analysis and studies will be approved by the Division in advance. The analysis will include enhancements or upgrades to the existing limestone injection system for increased SO2 reduction performance, other relevant SO2 control technologies such as lime spray dryers and flue gas desulfurization, and all NOx control options. A final analysis that addresses the state's comments shall be submitted to the state by January 1, 2013. By January 1, 2013, Tri-State shall also conduct appropriate cost analyses, study and, if deemed necessary by the state and the source, testing, as approved by the Division, to inform what performance would be achieved by a full-scale SNCR system at Nucla to determine potential circulating fluidized bed (CFB) boiler-specific NOx control efficiencies. By January 1, 2013, Tri-State shall conduct CALPUFF modeling in compliance with the Division's approved BART-modeling protocol to determine potential visibility impacts the different SO2 and NOx control scenarios for Nucla. Finally, Tri-State shall propose to the state any preferred SO2 and NOx emission control strategies for Nucla by January 1, 2013.

A complete analysis that supports the RP determination for the Nucla facility can be found in Appendix D.

#### *8.5.2.7 RP Determination for Tri-State Generation and Transmission Association's Craig Facility Unit 3*

The Tri-State Craig Station is located in Moffat County about 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively. Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. Craig Units 1 and 2 are subject to BART. Craig Unit 3 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution ($NO_X$, $SO_2$,

$PM_{10}$) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

### SO2 RP Determination for Craig – Unit 3

*Dry FGD Upgrades -* As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Craig Unit 3 operates a [lime spray dryer FGD] currently achieving over 80 percent SO2 reduction. The state considers EPA's BART Guidelines relevant to the RP evaluation of Craig Unit 3 and, therefore, the following dry scrubber upgrades were considered.

- *Use of performance additives*: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. Tri-State and the Division are not aware of $SO_2$ scrubber performance additives applicable or commercially available for the Unit 3 SDA system.

- *Use of more reactive sorbent/Increase the pulverization level of sorbent*: The purchase and installation of two new vertical ball mill slakers improved the ability to supply high quality slaked (hydrated) lime. A higher quality slaked lime slurry means a more reactive sorbent. Typically, slakers are not designed for particle size reduction as part of the slaking process. However, the new vertical ball mill slakers are particularly suited for slaking lime that is a mixture of commercial pebble lime and lime fines. Fines are generated at the Craig facility in the pneumatic lime handling system. Therefore, the Division concurs that TriState cannot use a more reactive sorbent or increase the pulverization level of sorbent.

- *Engineering redesign of atomizer or slurry injection system*: Both the slaked lime slurry and recycled ash slurry preparation and delivery systems were redesigned to improve overall performance and reliability. The improved system allows for slurry pressure control at both the individual reactor level and for each slurry injection header level on each reactor. Tri-State notes that consistent control of slurry parameters (pressure, flow, composition) promotes consistent and reliable SO2 removal performance. The Division concurs that with the recent redesign of the slurry injection system and expansion to two trains of recycled ash slurry preparation, no further redesigns are possible at this time.

Therefore, there are no technically feasible upgrade options for Craig Station Unit 3. However, the state evaluated the option of tightening the emission limit for Craig Unit 3 and determined that a more stringent 30-day rolling $SO_2$ limit of 0.15 lbs/MMBtu represents an appropriate and reasonable level of emissions control for this dry FGD control technology. Upon review of 2009 emissions data from EPA's Clean Air Markets

Division website, the state has determined that this emissions rate is achievable without additional capital investment.

The projected visibility improvements attributed to the alternatives are as follows:

| SO2 Control Method | Craig – Unit 3 | |
|---|---|---|
| | SO2 Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.33 | |
| Dry FGD | 0.15 | 0.26 |
| Dry FGD | 0.07 | 0.38 |

The current SO2 emission limits for Craig 3 are:

- 0.20 lb/MMBtu averaged over a calendar day, to be exceeded no more than once during any calendar month;
- 80% reduction of the potential combustion concentration of SO2, determined on a 30-day rolling average basis
- 2,125 tons/year annual emission limit

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that SO2 BART is the following SO2 emission rates:

Craig Unit 3: 0.15 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of existing dry FGD controls. An SO2 limit lower than 0.15 lbs/MMBtu would not result in significant visibility improvement (less than 0.2 delta deciview) and would likely result in frequent non-compliance events and, thus, is not reasonable.

**PM10 RP Determination for Craig – Unit 3**

The State has determined that the existing Unit 3 regulatory emissions limits of 0.013 (filterable PM) and 0.012 lb/MMBtu (PM10) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for $PM/PM_{10}$. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

**NOx RP Determination for Craig – Unit 3**

Selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Craig Unit 3.

The following table lists the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Craig Unit 3 - NOx Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| SNCR | 853 | $4,173,000 | $4,887 |
| SCR | 4,281 | $29,762,387 | $6,952 |

SCR was eliminated from consideration due to the excessive cost/benefit ratio.

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| NOx Control Method | NOx Annual Emission Rate (lb/MMBtu) | 98$^{th}$ Percentile Impact ($\Delta$dv) |
|---|---|---|
| Daily Maximum (2$^{nd}$ half 2009) | 0.365 | |
| SNCR | 0.240 | 0.32 |
| SCR | 0.070 | 0.79 |

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.
Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Craig Unit 3 is the following NOx emission rates:

Craig Unit 3: 0.28 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of SNCR. To the extent practicable, any technological application Tri-State utilizes to achieve this RP emission limit shall be installed, maintained, and operated in a manner consistent with good air pollution control practice for minimizing emissions. For SNCR-based emission rates at Unit 3, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls with guidance cost criteria discussed in section 8.4 above.

- Unit 3: \$4,887 per ton NOx removed; 0.32 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in section 8.4 above. The state reached this conclusion after considering the associated visibility improvement information and after considering the SCR cost information in the SIP materials and provided during the pre-hearing and hearing process by the company, parties to the hearing, and the FLMs.

A complete analysis that supports the RP determination for the Craig facility can be found in Appendix D.

#### *8.5.2.8 RP Determination for Public Service Company's Cameo Station*

Public Service Company informed the state that the Cameo Station east of Grand Junction, Colorado will be shutdown 12/31/2011, resulting in SO2, NOx and PM reductions of approximately 2,618, 1,140, and 225 tons per year, respectively. Therefore, a four-factor analysis was not necessary for this facility and the RP determination for the facility is closure.

# Chapter 9 Long Term Strategy

The Long-Term Strategy (LTS) is required by both Phase 1 (Reasonably Attributable Visibility Impairment) and Phase 2 (Regional Haze) regulations. The LTS' of both phases are to be coordinated.

This chapter contains:

- LTS requirements;
- An overview of the current Reasonably Attributable Visibility Impairment Long Term Strategies (RAVI LTS), adopted by the Commission in 2004 and subsequently approved by EPA;
- A review of the 2004 RAVI LTS and a SIP revision;
- A Regional Haze LTS; and
- Reasonable Progress Goals for each of the state's 12 mandatory federal Class I areas.

## 9.1 LTS Requirements

The LTS requirements for reasonably attributable visibility impairment, as described in 40 CFR 51.306, are as follows:

- Submittal of an initial RAVI LTS and 3-year periodic review and revision (since revised to 5-year updates per 40 CFR 51.306(g)) for addressing RAVI;
- Submittal of revised LTS within three years of state receipt of any certification of impairment from a federal land manager;
- Review of the impacts from any new or modified stationary source;
- Consultation with federal land managers; and
- A report to the public and EPA on progress toward the national goal.

The LTS requirements for Regional Haze (RH), as described in 40 CFR 51.308(d)(3), are as follows:

- Submittal of 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 Class I areas outside Colorado where Colorado emissions cause or contribute to visibility impairment, or for Class I areas in Colorado 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 Class I area it affects;
- Identify all anthropogenic sources of visibility impairing emissions;
- Consider the following factors when developing the LTS:
  (1) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
  (2) Emission limitations and schedules for compliance to achieve the RP goal;
  (3) Measures to mitigate the impacts of construction activities;

(4) Smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for this purpose;
(5) Source retirement and replacement schedules;
(6) Enforceability of emission limitations and control measures; and
(7) 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.

The following sections 9.2 and 9.3 address these LTS requirements.

## 9.2 2004 RAVI Long-Term Strategy

The RAVI LTS was adopted by the Commission in November 2004. It was subsequently approved by EPA in December 2006 and is summarized below.

### *9.2.1 Existing Impairment*

The LTS must have the capability of addressing current and future existing impairment situations as they face the state. Colorado considers that Commission Regulation No. 3, Part B, 5XIV.D ("Existing Impairment") meets this LTS requirement regarding existing major stationary facilities and provides Federal Land Managers (FLMs) the opportunity to certify whether an existing stationary source(s) is likely reasonably attributable to existing visibility impairment and potentially subject to BART. The state believes existing regulations along with strategies and activities outlined below have together provided for reasonable progress toward the national visibility goal under Phase 1 of the visibility protection program. However, a specific requirement associated with the RH rule is found in 40 CFR § 51.306(c) and is intended to bring into harmony the reasonable attribution requirement in place since 1980 and the RH rule. As such, to meet one part of that requirement, the State of Colorado commits to review the long-term strategy as it applies to reasonably attributable impairment, and make revisions, as appropriate, within three years of state receipt of any certification of reasonably attributable impairment from a Federal Land Manager. This is consistent with the current LTS and State Regulation No. 3 noted above. In addition, Regulation 3, Part D, is amended as part of this SIP action to change the current 3 year review cycle to a 5 year cycle to coordinate the RAVI and RH elements together as intended by the RH rule. Elsewhere in this SIP the state has documented measures to be adopted to address the RH element of the rule including BART determinations and strategies identified in Chapter 8- Reasonable Progress.

In a related action, this 5-year update will satisfy Colorado’s requirement for developing emissions estimates from activities on federal lands (Colorado Revised Statute 25-7-105(1)). The state commits to consult with Federal Land Managers to develop a consolidated emissions inventory, which will be brought to the Air Quality Control Commission as part of the 5-year LTS update and then submitted to EPA. After the 2008 emission inventory data submittal, the Consolidated Emission Reporting Rule will be completely replaced by the Air Emissions Reporting Requirements Rule.

Following is a review of the elements contained in the LTS in a chronological order. During the five-year review required by the RH rule, the State of Colorado will add to or revise this section as needed based on any new findings or actions taken related to RAVI notifications delivered to the state by a FLM.

### *9.2.1.1 Mt. Zirkel Wilderness*

The U.S.D.A. Forest Service (USFS) concluded in its July 1993 certification letter to the State of Colorado that visibility impairment existed in the Mt. Zirkel Wilderness Area (MZWA) and local existing stationary sources, namely the Craig and Hayden power stations, contributed to the problem. In 1996 and again in 2001, settlement agreements between various parties and the Hayden and Craig (Units 1 and 2) Generating Stations, respectively, were completed. The state believes significant emission reductions of SO2 and PM effectively address the RAVI in the MZWA associated with the Hayden and Craig (Units 1 & 2) Generating Stations. The state further believes the Hayden and Craig Consent Decrees effectively resolve the certification of impairment brought by the U.S.D.A. Forest Service. The Forest Service indicated its complaint against Hayden and Craig had been satisfied.

### *9.2.1.2 BART and Emission Limitations*

Although RAVI BART determinations were not made by the state regarding Hayden and Units 1 and 2 of Craig generating stations, emission limitations for the two power plants were incorporated into the LTS SIP in August 1996 (Hayden) and April 2001 (Craig Units 1 and 2) and these SIP revisions remain incorporated into the Colorado SIP. The contents of the August 1996 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for Hayden generating station Units 1 and 2 were incorporated into the 2004 LTS SIP by reference. EPA originally approved this SIP amendment on January 16, 1997. The contents of the April 2001 LTS SIP revision incorporating emission limitations, construction and compliance schedules, and reporting requirements for the Craig generating station Units 1 and 2 were incorporated into the 2004 LTS SIP by reference.

This RH SIP amendment establishes new limits on Hayden Units 1 and 2, and Craig Units 1 and 2, based on a full BART analysis under the current EPA guidelines. Chapter 6 of this SIP (and Appendix C as well as supporting technical support documents) and changes to Regulation No. 3 result in new control requirements for these units to meet BART.

### *9.2.1.3 Monitoring*

It is important to track the effects of the emission changes on visibility and other Air Quality Related Values in and near Mt. Zirkel Wilderness Area and other Class I areas in Colorado. The Division committed in the 2004 LTS SIP amendment to coordinating a monitoring strategy with other agencies and to provide periodic assessments of various monitored parameters in "before" compared to "after" emission reductions periods. Colorado commits to maintain a monitoring strategy and periodically report to the public and the EPA on an annual basis to include trends, current levels and emission changes. In addition periodic emission inventory updates required by the national emissions reporting rule establish a 3-year reporting cycle for emissions updates. Finally, this RH SIP commits to a five year review process established by the RH rule. Through this, the state believes a demonstration of ‘before and after emission reductions’ will be met.

#### 9.2.1.4 Other Stationary Sources and Colorado Class I Areas and Additional Emission Limitations and Schedules for Compliance

There are no outstanding certifications of Phase I visibility impairment in Colorado. For Regional Haze, Chapters 6 and 8 specifically delineate the comprehensive BART analysis and Reasonable Progress analysis of other sources. In these sections specific additional controls of selected stationary sources are detailed and emission reductions from these are reflected in the Appendices and technical support documents. The state believes the coordination of these added control measures meets the requirements of the LTS showing both emission limitations and schedules for compliance. In regard to any future certification of any RAVI, the state is prepared to respond to any future certifications as per AQCC Regulation No. 3 X1V.D in accordance with the five year limit established in 40 CFR § 51.306(c).

#### 9.2.1.5 Ongoing Air Pollution Programs

In the 2004 LTS SIP revision, the state committed to:

- Continue to attain and maintain the PM10 and PM2.5 standards which will have some effect on improving visibility in pristine and scenic areas;
- Continue to provide technical support to efforts to understand and reduce the Brown Cloud in the Front Range of Colorado. Analysis of Brown Cloud data indicates it improved approximately 28% between 1991 and 2006, and data through 2009 indicates this trend continues as demonstrated in the APCD Annual Air Quality Data reports;
- Continue to stay involved and inform the Colorado Air Quality Control Commission about emissions growth in the Four Corners area;
- Continue to participate in any future work of the Rocky Mountain National Park research effort; and,
- Continue to administer and follow existing regulations of point, area and mobile sources as specified in AQCC regulations.

### 9.2.2 Prevention of Future Impairment

The LTS must establish mechanisms to address the prevention of future impairment and outline strategies to ensure progress toward the national goal. The 2004 LTS summarized programs and activities providing reasonable progress toward the national goal under the Phase 1 RAVI program. Generally, Colorado considers its NSR and PSD programs meet the long-term strategy requirements for preventing future impairment from proposed major stationary sources or major modifications to existing facilities.

### 9.2.3 Smoke Management Practices

The LTS requires smoke management practices of prescribed burning be addressed. The 2004 LTS described Colorado’s Regulation No. 9 regarding open burning and wildland fire smoke management. As the level and complexity of burning increases the Division committed to continually evaluate its regulatory program for this source of air pollution and surveyed its current activities in the 2004 LTS review. The addition of the Fire Emissions Tracking System (FETS) by the WRAP, FLMs and states allows Colorado to input fire emission data into the national tracking system thereby adding more precise information for future inventories and studies. The state commits in this SIP to continue administration of Regulation 9 as part of this LTS, and to input data into the FETS as long as it is operational. Colorado will continue as part of Regulation 9 to maintain a database of fire related permits and actions - the basis for data entered into the FETS.

### *9.2.4 Federal Land Manager Consultation and Communication*

The state committed to providing for the plans, goals, and comments of the Federal Land Managers during SIP and LTS revisions. The state will provide, at a minimum, the opportunity for consultation with the FLMs at least 60 days prior to any public hearing on any element of the Class I Visibility SIP including LTS revisions and review. In addition the state will publish as part of the SIP process any formal comments received by the FLMs as a result of their review along with a listing of responses the state made in regard to such comments.

## 9.3 Review of the 2004 RAVI LTS and Revisions

A July 2007 review of the 2004 RAVI LTS concluded that "The Division does not believe extensive and substantive revisions are necessary at this time to ensure reasonable progress toward the national goal under Phase I of the Class I Visibility Protection Program. However, small updates and edits are proposed so this part of the SIP does not become outdated." Appendix A of this SIP document contains this review. The only other changes to this LTS relate to the change in the update period in Regulation 3, as described above in section 9.2.1, and a commitment to utilize the FETS to track fire data as described above in section 9.2.3. The state commits to work with the FLMs to coordinate any changes to the RH/RAVI LTS on the five year cycle required by the regulation. This will include responding to any notification of impairment by the FLMs, providing an opportunity to comment 60 days prior to any public hearing on proposed changes to the RH/RAVI LTS, and to publish the FLM comments and state responses as part of that review process. Appendix B of this document contains the SIP revision for the RAVI LTS.

## 9.4 Regional Haze Long Term Strategy

The following presents Colorado's Long Term Strategy (LTS) for Regional Haze.

### *9.4.1 Impacts on Other States*

Where the state has emissions reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area located in another state or states, the state must consult with the other state(s) in order to develop coordinated emission management strategies. Colorado has analyzed the output of the initial 2006 PSAT product from the WRAP and determined that emissions from the state do not significantly impact other states' Class I areas. The two largest Colorado visibility impacts are at Canyonlands National Park in Utah and Bandelier National Monument in New Mexico, where Colorado's total nitrate and sulfate contribution are only 1.0% and 0.5%, respectively, of total haze at these Class I areas. This is not a meaningful level of contribution, and all other modeled contributions at other Class I areas are of a smaller magnitude.

**Table 9-1 Colorado's Nitrate and Sulfate Impacts at Bandelier and Canyonlands**

| Mandatory Class I Area | Modeled Visibility Improvement by 2018 [deciviews] | Colorado's Contribution to 2018 Nitrate | 2018 Total Nitrate Impacts at CIA | Colorado's Nitrate Contribution to 2018 Haze at CIA | Colorado's Contribution to 2018 Sulfate | 2018 Total Sulfate Impacts at CIA | Colorado's Total Sulfate Contribution to 2018 Haze at CIA | Colorado's Total Nitrate & Sulfate Contribution to 2018 Haze at CIA |
|---|---|---|---|---|---|---|---|---|
| Bandelier National Monument | 0.3 | 5.1% | 6.6% | 0.3% | 1.2% | 15.5% | 0.2% | 0.5% |
| Canyonlands National Park | 0.5 | 6.9% | 9.5% | 0.7% | 2.3% | 14.8% | 0.3% | 1.0% |

*All Colorado Impacts to nearby Class I Areas that exceed 5.0% are shaded in purple. No Colorado 2018 Sulfate Contributions exceeding 5% were indentified.*

### *9.4.2 Impacts from Other States*

Where other states cause or contribute to impairment in a mandatory Class I Federal area, the state must demonstrate it has included in its implementation plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goal for the area. Chapter 7 presents modeling information that describes the contribution to visibility impairment in Colorado's Class I areas from other states. Colorado is establishing reasonable progress goals later in this chapter utilizing modeling results presented in Chapter 7, with supporting information in the technical support documents. This demonstration reflects the emission reductions achieved by the controls committed to by other states.

### *9.4.3 Document Technical Basis for RPGs*

The state must document the technical basis (e.g., modeling) on which the state is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I Federal area. This is addressed in the Technical Support Document, Chapter 7, and later in this Chapter 9.

### *9.4.4 Identify Anthropogenic Sources*

The state must identify all anthropogenic sources of visibility impairment considered by the state in developing its LTS. Colorado presents comprehensive emission inventories in Chapter 5 and the TSD, and presents emissions control evaluations in Chapters 6 and 8. Chapter 7 and the Technical Support Documents present information about source apportionment for each Class I area in Colorado.

### *9.4.5 Emission Reductions Due to Ongoing Air Pollution Control Programs*

Below is a discussion of ongoing air pollution control programs that reduce visibility impairing emissions throughout Colorado.

Numerous emission reduction programs exist for major and minor industrial sources of NOx, SO2 and particulates throughout the state, as well as in the Denver Metro Area/Northern Front Range region for VOCs, NOx, and particulates from mobile, area, stationary and oil/gas sources, and are contained in the following Colorado Air Quality

Control Commission Regulations:

- Regulation Number 1:  Emission Controls for Particulates, Smoke, Carbon Monoxide and Sulfur Oxides
  - In the SIP (includes specific fugitive dust and open burning regulations)
- Regulation Number 3:  Stationary Source Permitting and Air Pollutant Emission Notice Requirements
  - Parts A, B,D, F in the SIP or Submitted to EPA for inclusion in the SIP
  - Part C is the Title V program and is delegated by EPA to the state
- Regulation Number 4:  New Wood Stoves and the Use of Certain Woodburning Appliances on High Pollution Days
  - Regulation Number 4 is in the SIP.  One provision, the Masonry Heater Test Method, is state only.  Colorado is waiting for EPA to develop their own test method – the state will adopt it when EPA goes final
- Regulation Number 6:  Standards of Performance for New Stationary Sources
  - Part A – Federal NSPS's adopted by the state – EPA has delegated authority to the state to implement; Colorado has requested delegation for the most recent adoptions
  - Part B – state-only NSPS regulations
- Regulation Number 7:  Control of Ozone Precursors
  - The majority of Regulation Number 7 for VOC and NOx control is in the SIP or has been submitted for approval into the SIP – these provisions relate to VOC and NOx control measures for the Denver Metro Area/North Front Range 8-hour ozone nonattainment area and are summarized below
- Regulation Number 9:  Open Burning, Prescribed Fire and Permitting – state-only
- Regulation Number 11:  Motor Vehicle Emission Inspection Program – Parts A-F in the SIP
- Regulation Number 16:  Street Sanding Emissions – In the SIP

Some examples of these programs and the visibility-improving emission reductions they achieve are as follows.  It is noted as to whether the program is federally enforceable, submitted by the state in an unrelated submittal for inclusion into the SIP, or state-only enforceable.

- Early reductions from BART sources include approximately 24,000 tpy of SO2 from metro Denver power plants, approximately 6,500 tpy of SO2 from the Comanche power plant, and approximately 18,000 tpy of SO2 from the Craig and Hayden power plants – state-only
- Oil and gas condensate tank control regulations for the Front Range region that have achieved approximately 52,000 tpy of volatile organic compounds (VOC) emission reductions by 2007 - in the SIP - with additional projected reductions of 18,000 tpy by 2010 – Submitted for inclusion in the SIP
- Existing industrial engine control regulations for the Front Range region that have achieved NOx and VOC emissions reductions of approximately 8,900 tpy – In the SIP
- Oil and gas pneumatic actuated device control regulations for the Front Range

region that have achieved VOC emission reductions of approximately 8,400 tpy – state-only
- Mobile source emissions controls for VOCs and NOx through vehicle inspection/maintenance and lower volatility gasoline programs for the Front Range region is estimated to reduce emissions by approximately 8,000 tpy by 2011 – Submitted for inclusion in the SIP
- Statewide condensate tank control regulations that have achieved approximately 5,600 tpy of VOCs emission reductions – state-only
- Statewide existing industrial engine control regulations that are estimated to achieve NOx and VOC emissions reductions of approximately 7,100 tpy by 2010 – state-only
- PM10 emission reduction programs in PM10 maintenance areas throughout the state – In the SIP
- Fugitive dust control programs for construction, mining, vehicular traffic, and industrial sources state-wide – In the SIP
- Smoke management programs for open burning and prescribed fire activities statewide – state-only
- Renewable energy requirements that are driving current and future NOx, SO2 and PM emission reductions from coal-fired power plants - Ballot Initiative 37 – by requiring electricity to be obtained from renewable resources – state-only
- Attaining and maintaining the PM10 and PM2.5 standards throughout the state
- Reducing Colorado Front Range Urban Visibility Impairment (Denver's Brown Cloud) by 28% between 1991 and 2006) – state-only
- Reducing Colorado emissions in the Four Corners area (which is upwind of numerous Class I areas in three states) through oil and gas control measures administered by the CDPHE and the Colorado Oil and Gas Conservation Commission, and by working with the Southern Ute Indian Tribe to develop a Title V permitting program and a minor source permitting program – state-only
- Federal mobile source tailpipe exhaust reductions of approximately 55,000 tpy of VOC and NOx emissions by 2020 – gained through fleet turn-over

(Discussion of state-only measures in this Regional Haze SIP is informational only and not intended to make such measures federally enforceable. However, such measures could be included in future SIP revisions if found necessary to meet National Ambient Air Quality Standards or visibility requirements.)

Another comprehensive review of existing and ongoing programs as well as monitoring data and trends is contained in the Colorado Air Quality Control Commission's 2008-2009 Report to the Public available at the following website:

http://www.cdphe.state.co.us/ap/rttplinks.html

As recently as 1995 Colorado had 12 "non-attainment" areas within the state for carbon monoxide, ozone, and/or PM10 health standards. Generally, all of these areas now maintain good air quality. This progress reflects the effects of local, statewide, regional, and national emission control strategies. This clean-up of Colorado's non-attainment areas also benefited Class I visibility conditions to some unknown degree.

In the summer of 2003, the Denver metropolitan area violated the 8-hour ozone standard. EPA designated all or parts of 9 counties in northeastern Colorado as nonattainment for the 1997 8-hour ozone standard, though the nonattainment designation was deferred with the adoption of the Ozone Action Plan by the Colorado Air Quality Control Commission in March 2004 under EPA's Early Action Compact provisions. High concentrations of ground-level ozone during the 2005-2007 period put the nine-county Denver region in violation of the 1997 standard, and the deferred nonattainment designation became effective in November 2007. A detailed plan to reduce ozone was adopted by the Colorado Air Quality Control Commission in December 2008 and submitted to EPA for approval in 2009. This new plan contains additional VOC and NOx emission reduction measures to support achievement of compliance with the 1997 ozone standard by the end of 2010.

The table below shows the designation status for all current and former non-attainment areas.

**Table 9-1 REDESIGNATION and PLAN AMENDMENT STATUS REPORT**

| PM10 | Redesignations | Plan Amendments |
|---|---|---|
| Aspen | AQCC approved 1/11/01; EPA approved 5/15/03, effective 7/14/03 | 10-year update: AQCC approved 12/16/10 |
| Canon City | AQCC approved 10/17/96; EPA approved 5/30/00, effective 7/31/00 | 10-year update: AQCC approved 11/20/08; Legislature approved 2/15/09; submitted to EPA 6/18/2009 |
| Denver | AQCC approved 4/19/01; EPA approved 9/16/02, effective 10/16/02 | Plan amendment developed with MOBILE6 to remove I/M from SIP; AQCC approved 12/15/05; EPA approved 11/6/07, effective 1/7/08 |
| Lamar | AQCC approved 11/15/01; EPA approved 10/25/05, effective 11/25/05 | None |
| Pagosa Springs | AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01 | 10-year update: AQCC approved 11/19/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010 |
| Steamboat Springs | AQCC approved 11/15/01; EPA approved 10/25/04, effective 11/24/04 | |
| Telluride | AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01 | 10-year update: AQCC approved 11/19/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010 |

| **Carbon Monoxide** | **Redesignations** | **Plan Amendments** |
|---|---|---|
| Colorado Springs | AQCC approved 1/15/98; EPA approved 8/25/99, effective 9/24/99 | - Amendment to drop oxyfuels approved by AQCC 2/17/00; EPA approved 12/22/00, effective 2/20/01<br>- Amendment using MOBILE6 to eliminate I/M from SIP and revise emission budget approved by AQCC 12/18/03; EPA approved 9/07/04, effective 11/08/04<br>- 10-year update: AQCC approved 12/17/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010 |
| Denver | AQCC approved 1/10/00; EPA approved 12/14/01, effective 1/14/02 | - Amendment using MOBILE6 to revise emission budgets approved by AQCC 6/19/03; EPA approved 9/16/04, effective 11/15/04<br>- Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; EPA approved 8/17/07, effective 10/16/08 |
| Ft. Collins | AQCC approved 7/18/02; EPA approved 7/22/03, effective 9/22/03 | 10-year update: AQCC approved 12/16/10 |
| Greeley | AQCC approved 9/19/96; EPA approved 3/10/99, effective 5/10/99 | - Amendment using MOBILE6 to revise emission budget & to eliminate oxyfuels from the regulation/SIP & I/M from the SIP approved by AQCC 12/19/02; EPA approved 8/19/05, effective 9/19/05<br>- 10-year update: AQCC approved 12/17/09; Legislature approved 2/15/10; submitted to EPA 3/31/2010 |
| Longmont | AQCC approved 12/19/97; EPA approved 9/24/99, effective 11/23/99 | - Amendment using MOBILE6 to revise emission budget approved by AQCC 12/18/03; EPA approved 9/30/04, effective 11/29/04<br>- Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; EPA approved 8/17/07, effective 10/16/08 |

| Ozone | Redesignations | Plan Amendments |
|---|---|---|
| Denver/Northern Front Range | AQCC approved 1-hour redesignation request and maintenance plan 1/11/01; EPA approved 9/11/01, effective 10/11/01<br><br>Early Action Compact 8-hour Ozone Action Plan approved by AQCC 3/12/04; EPA approved 8/19/05, effective 9/19/05 | - 8-hour OAP updated to include periodic assessments; AQCC approved 12/15/05; EPA approved //0, effective //0<br>- 8-hour OAP updated 12/17/06 by AQCC to incorporate Reg. 7's 75% oil and gas condensate tank requirements. EPA approved 2/13/08, effective 4/14/08<br>- Due to 2005-2007 ozone values, Front Range has violated the ozone standard and the nonattainment designation became effective 11/20/07; revised attainment plan approved by AQCC 12/11/08; Legislature approved 2/15/09; submitted to EPA 6/18/2009 |
| **Lead** | **Redesignations** | **Plan Amendments** |
| Denver | EPA redesignated Denver attainment in 1984 | |
| **Nitrogen Dioxide** | **Redesignations** | **Plan Amendments** |
| Denver | EPA redesignated Denver attainment in 1984 | |

For larger stationary sources, the state of Colorado considers its New Source Review and Prevention of Significant Deterioration (PSD) programs as being protective of visibility impairment from proposed major stationary sources or major modifications to existing facilities.

### 9.4.6 Measures to Mitigate the Impacts of Construction Activities

Regulations 1 and 3 are currently part of Colorado's EPA-approved SIP and apply statewide. In part, provisions of Regulation 1 address emissions of particulate matter, from construction activities. Provisions of Regulation 3 cover issuance of permits applicable to sources defined in these regulations and air pollution emission notices required of specified sources. Provisions of Regulation 1, sections III.D.2.b apply to new and existing point and area sources. This section of the regulation addresses fugitive particulate emissions from construction activities. As such the state believes these regulations address common construction activities including storage and handling of materials, mining, haul roads and trucks, tailings piles and ponds, demolition and blasting activities, sandblasting, and animal confinement operations.

Colorado believes point and area sources of emissions from these regulated sources are in part contributing to regional haze in Colorado. Colorado relies on the particulate emission controls specified in Regulation 1 to most directly address these sources of fine and course particles known to have a minor, but measured, impact on visibility in Class I areas of the state. Based on Coarse Mass Emissions Trace Analysis, described in Section 8 of the Technical Support Document for each Mandatory Class I Federal Area in Colorado included in this SIP, the greatest impact from coarse mass related construction in the state is expected in Rocky Mountain National Park. In RMNP slightly over 6% of the total impact on visibility on the 20% worst days is attributed to coarse mass particulate matter from construction activities. All other Class I areas have impacts from construction in the 2 to 3 percent range.

This regulatory provision requires applicable new and existing sources to limit emissions and implement a fugitive emission control plan. Various factors are specified in the regulation under which consideration in the control plan encompasses economic and technological reasonability of the control.

### 9.4.7 Smoke Management

For open burning and prescribed fire, Colorado believes its smoke management program reduces smoke emissions through emission reduction techniques and is protective of public health and welfare as well as Class I visibility.

Regulation No. 9 (Open Burning, Prescribed Fire, and Permitting) is the main vehicle in Colorado for addressing smoke management and preventing unacceptable smoke impacts. The rule applies to all open burning activity within Colorado, with certain exceptions. Section III specifically exempts agricultural open burning from the permit requirement[45]. Section III.A of the regulation requires anyone seeking to conduct open burning to obtain a permit from the Division. Regulation No. 9 also contains a number of factors the Division must consider in determining whether and, if so, under what conditions, a permit may be granted. Many of these factors relate to potential visibility impacts in Class I areas. A permit is granted only if the Division is reasonably certain that under the permit's conditions that include the prescribed meteorological conditions for the burn there will be no unacceptable air pollution (including visibility) impacts. Colorado's program also maintains an active compliance assistance and enforcement component. In 2005, the Division certified its smoke management program as consistent with EPA's *Interim Air Quality Policy on Wildland Prescribed Fire*, May 1998.

Factors considered under Regulation No. 9, include, for example,

- the potential contribution of such burning to air pollution in the area;
- the meteorological conditions on the day or days of the proposed burning;
- the location of the proposed burn and smoke-sensitive areas and Class I areas that might be impacted by the smoke and emissions from the burn;

[45] The Division has determined that agricultural burning is not a significant source of emissions related to regional haze impairment. For example, 2004 estimates from the Division are that only 503 tpy of PM10 were generated from agricultural burning in the entire State of Colorado. See TSD "Agricultural Burning in Colorado, 2003 and 2004 Inventories".

- whether the applicant will conduct the burn in accordance with a smoke management plan or narrative that requires:
    - that best smoke management methods will be used to minimize or eliminate smoke impacts at smoke-sensitive receptors (including Class I areas);
    - that the burn will be scheduled outside times of significant visitor use in smoke-sensitive receptor areas that may be impacted by smoke and emissions from the fire; and
- a monitoring plan to allow appropriate evaluation of smoke impacts at smoke-sensitive receptors.

The regulation requires all prescribed fire permitees to submit an application to the Division. A permit is granted only if the Division's assessment demonstrates that under the prescribed meteorological conditions for the burn there will be no unacceptable air pollution (including visibility) impacts. The Division reviews each permit application and determines if the burn can be conducted without causing unacceptable visibility impacts within Class I areas, as well as other smoke sensitive sites. In addition, the regulation provides for the Division to impose "permit conditions necessary to ensure that the burn will be conducted so as to minimize the impacts of the fire on visibility and on public health and welfare."

Permitted sources are also required to report actual activity to the Division. Depending on the size and type of fire, reporting may be a daily requirement. At a minimum, each year all permitted sources must return their permit forms with information indicating whether or not there was any activity in the area covered by the permit and, if so, how many acres were burned. The Division annually prepares a report on prescribed burning activity and estimated emissions. Reports from 1990 through 2009 are available by contacting the Division.

The regulation requires the draft permit for any proposed prescribed fire rated as having a "high" smoke risk rating be subject to a 30-day public comment period. The notice for the public comment period must contain information relating to the potential air quality and visibility impacts at smoke sensitive receptors, including Class I areas.

The Division's web site contains information about various aspects of Colorado's Smoke Management Program, downloadable forms and instructions, and links. It is also used to contain the notices for public comment periods for the draft permits subject to public comment. It is located at: http://www.cdphe.state.co.us/ap/smoke/

The addition of the Fire Emissions Tracking System (FETS) allows Colorado to input fire emission data into the national tracking system thereby adding more precise information for future inventories and studies. The state commits in this SIP to continue administration of Regulation 9 as part of this LTS, and to input data into the FETS as long as it is operational. Colorado will continue as part of Regulation 9 to maintain a data base of fire related permits and actions - the basis for data entered into the FETS.

### 9.4.8 Emission Limitations and Schedules for Compliance to Achieve the Reasonable Progress Goal, and Enforceability of Emission Limitations and Control Measures

The emission limitations and compliance schedules for those sources specifically identified for control in this Regional Haze SIP can be found in Chapters 6 and 8, and Regulation Nos. 3 and 7. Enforceability of the requirements is ensured by codifying these requirements in regulation, inspecting the sources for compliance and initiating enforcement action under EPA-approved compliance regimes, and requiring monitoring, recordkeeping and reporting.

### 9.4.9 Source Retirement and Replacement Schedules

Source retirement and replacement schedules for those sources specifically identified for control in this Regional Haze SIP can be found in Chapters 6 and 8, and in Regulation No. 3. Unless otherwise indicated in those chapters or in Regulation No. 3, the state assumes that all other stationary sources will remain in operation through the end of this planning period. For mobile sources, the turnover of the fleet from older, higher-emitting vehicles to newer, lower-emitting vehicles is captured in the emission inventory presented in Chapter 5 – the fleet turn-over rate was developed utilizing EPA-approved methodologies.

### 9.4.10 Anticipated Net Effect on Visibility

The WRAP has produced extensive analytical results from air quality monitoring, emissions inventories and air quality modeling. These data demonstrate that causes of regional haze in the West are due to emissions from a wide variety of anthropogenic and natural sources, some of which are controllable, some of which are natural, and some of which originate outside the jurisdiction of any state or the federal government and are uncontrollable. Analyses to date consistently show that anthropogenic emissions of haze causing pollutants will decline significantly across the West through 2018, but overall visibility benefits of these reductions will be tempered by emissions from natural, international, and uncontrollable sources.

Colorado in this RH SIP addresses projections to 2018 anticipating growth and all committed to or reasonably expected controls at the time of modeling (emission inventories for Colorado are presented in Chapter 5). Note that at the time of this 2009 WRAP modeling, Colorado had made BART determinations for each subject to BART unit in 2007 and 2008, and the associated emission reductions were included in the modeling. The inventories indicate a total SO2 emission reduction of 58,907 tons per year and a total NOx emission reduction of 123,497 tons per year by 2018. (SO2 and NOx are the primary emissions addressed by Colorado in this Regional Haze SIP.)

For the uniform rate of progress analysis and to establish Reasonable Progress Goal (RPGs), the modeling results from Chapter 7 are utilized. The modeled Uniform Rate of Progress and the progress made towards URP are presented below. Depending on the Class I area, the state has achieved 36 to 76 percent of the visibility improvement necessary to achieve URP. Note that this analysis does not include emission reductions that result from the BART and RP determinations presented in Chapters 6 and 8.

## Figure 9-2 Summary of CMAQ Modeling Progress Towards 2018 URP

**Colorado Mandatory Class I Federal Areas**

**Uniform Progress Summary in Haze Index Metric**

***Based on WRAP CMAQ Modeling using the PRP 2018b***

| Mandatory Class I Federal Area | 20% Worst Days | | | | | 20% Best Days | | |
|---|---|---|---|---|---|---|---|---|
| | Worst Days Baseline Condition [dv] | Uniform Rate of Progress at 2018 [dv] | 2018 URP delta from Baseline [dv] | 2018 Modeling Projection [dv] | CMAQ Modeling % Towards 2018 URP | Best Days Baseline Condition [dv] | 2018 CMAQ Modeling Results [dv] | 2018 CMAQ Modeling Below Baseline? |
| Great Sand Dunes National Park & Preserve | 12.78 | 11.35 | 1.43 | 12.20 | 40.6% | 4.50 | 4.16 | Yes |
| Mesa Verde National Park | 13.03 | 11.58 | 1.45 | 12.50 | 36.6% | 4.32 | 4.10 | Yes |
| Mount Zirkel & Rawah Wilderness Areas | 10.52 | 9.48 | 1.04 | 9.91 | 58.7% | 1.61 | 1.29 | Yes |
| Rocky Mountain National Park | 13.83 | 12.27 | 1.56 | 12.83 | 64.1% | 2.29 | 2.06 | Yes |
| Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas | 10.33 | 9.37 | 0.96 | 9.83 | 52.1% | 3.11 | 2.93 | Yes |
| Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas | 9.61 | 8.78 | 0.83 | 8.98 | 75.9% | 0.70 | 0.53 | Yes |

**Uniform Rate of Progress for 2018**

**Projected Amount of Progress by 2018 Towards URP**

The total tons of visibility impairing pollutants reduced by 2018 due to the BART and RP measures adopted in 2010 are summarized below in Figures 9-4, 9-5 and 9-6.

- 2010 BART: 20,734 tons/year
- 2010 BART alternative: 37,488 tons/year
- 2010 RP: 12,624 tons/year

Total: 70,846 tons/year

The following figures also present "CALPUFF" modeling results that show the visibility benefits of each BART and RP determination. Though not additive to the visibility improvement values presented in Figure 9-2 above because different modeling platforms were used, the CALPUFF modeling illustrates that additional visibility improvement can be anticipated from the BART and RP controls.

## Figure 9-3 Emission Reductions Achieved by 2010 BART Determinations

### BART Emission Control Analysis

**NOx BART - SCR**

| Source | SCR Capital Costs | Annualized SCR Costs | SCR NOx Reduced [tpy] | SCR NOx Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
|---|---|---|---|---|---|---|
| Hayden - Unit 2 | $ 71,780,853 | $ 12,321,491 | 3,032 | $ 4,064 | 0.82 | 23 (Zirkel) |
| Hayden - Unit 1 | $ 61,938,167 | $ 10,560,612 | 3,120 | $ 3,385 | 1.12 | 48 (Zirkel) |
| Craig - Unit 2 (SCR @ 74% Reduction) | $ 209,552,000 | $ 25,036,709 | 3,975 | $ 6,299 | 0.98 | 41 (Mt. Zirkel) |

**NOx BART - SNCR**

| Source | SNCR Capital Costs | Annualized SNCR Costs | SNCR NOx Reduced [tpy] | SNCR NOx Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
|---|---|---|---|---|---|---|
| Craig - Unit 1 (SNCR @ 14% reduction) | $ 13,118,000 | $ 3,797,000 | 727 | $ 5,226 | 0.31 | 15 (Mt. Zirkel) |
| CEMEX - Kiln | $ 600,000 | $ 1,636,636 | 846 | $ 1,934 | 0.40 | 14 (RMNP) |

**NOx BART - Other**

| Source | Capital Costs | Annualized Costs | NOx Reduced [tpy] | NOx Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
|---|---|---|---|---|---|---|
| Drake - Unit 5 (ULNB w/OFA) | $ 2,895,672 | $ 288,844 | 215 | $ 1,342 | 0.08 | > 0 (RMNP) |
| Drake - Unit 6 (ULNB w/OFA) | $ 3,340,318 | $ 337,751 | 509 | $ 664 | 0.20 | > 3 (RMNP) |
| Drake - Unit 7 (ULNB w/OFA) | $ 4,500,232 | $ 461,217 | 749 | $ 616 | 0.26 | > 3 (RMNP) |
| CENC (TriGen) - Unit 4 LNB, w/SOFA | $ 4,284,900 | $ 678,305 | 214 | $ 3,170 | 0.08 | 3 (RMNP) |
| CENC (TriGen) - Unit 5 LNB, w/SOFA and SNCR | $ 6,556,888 | $ 1,739,825 | 354 | $ 4,919 | 0.26 | 14 (RMNP) |
| CEMEX - Dryer T5 Permit Limits | $ - | $ - | 0 | $ - | 0.00 | none |

**SO2 BART**

| Source | Capital or O&M Costs | Annualized Costs | SO2 Reduced [tpy] | SO2 Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
|---|---|---|---|---|---|---|
| Drake - Unit 5: (DSI w/0.26 Emission Limit 30-day) | $ 6,000,000 | $ 1,340,663 | 762 | $ 1,761 | 0.12 | 2 (RMNP) |
| Drake - Unit 6: (FGD w/0.13 Emission Limit 30-day) | $ 38,000,000 | $ 6,665,771 | 2,368 | $ 2,816 | 0.24 | 3 (RMNP) |
| Drake - Unit 7: (FGD w/0.13 Emission Limit 30-day) | $ 44,166,000 | $ 9,577,538 | 3,764 | $ 2,544 | 0.39 | 6 (RMNP) |
| Hayden - Unit 1 Tighten Emission Limit to 0.13 | $165,000 parts & $110,000 O&M | $ 141,150 | 61 | $ 2,318 | 0.01 | >12 (Mt. Zirkel) |
| Hayden - Unit 2 Tighten Emission Limit to 0.13 | $165,000 parts & $110,000 O&M | $ 141,150 | 39 | $ 3,629 | 0.05 | >8 (Mt. Zirkel) |

| | |
|---|---|
| *TOTAL CAPITAL COST* | $ 467,283,031 |
| *TOTAL ANNUALIZED COST* | $ 74,724,662 |

| | | |
|---|---|---|
| **TOTAL NOX REDUCED** | **13,741** | *tons/year* |
| **TOTAL SO2 REDUCED** | **6,993** | *tons/year* |
| **TOTAL COMBINED POLLUTANTS REDUCED** | **20,734** | *tons/year* |

## Figure 9-4 Emission Reductions Achieved by 2010 BART Alternative Determinations

| Facility | NOx Emissions Average 2006-2008 (tpy) | NOx Emissions from Alternative (TPY) | Total NOx Emissions Reduced (TPY) | SO2 Emissions Average 2006 -2008 (tpy) | SO2 Emissions from Alternative (TPY) | Total SO2 Emissions Reduced (TPY) |
|---|---|---|---|---|---|---|
| Arapahoe | | | | | | |
| Unit 3 | 1,770 | 0 | | 925 | 0 | |
| Unit 4 | 1,148 | 900[46] | | 1,765 | 1.28 | |
| Cherokee | | | | | | |
| Unit 1 | 1,556 | 0 | | 2,221 | 0 | |
| Unit 2 | 2,895 | 0 | | 1,888 | 0 | |
| Unit 3 | 1,866 | 0 | | 743 | 0 | |
| Unit 4 | 4,274 | 2,063[47] | | 2,135 | 7.81[48] | |
| Valmont | 2,314 | 0 | | 758 | 0 | |
| Pawnee | 4,538 | 1,403[49] | | 13,472 | 2,406[50] | |
| Totals | 20,361 | 4,366 | 15,995 | 23,908 | 2,415 | 21,493 |

**Total Emission Reductions Achieved: 37,488 tons per year**

[46] Includes 300 tpy NOx for offset or netting purposes and 600 tpy NOx from firing Arapahoe 4 on natural gas as a peaking unit.

[47] Includes 500 NOx tpy for offset or netting purposes and emissions at 0.12 lb NOx/MMBtu

[48] Emissions at 0.0006 lb SO2/MMBtu

[49] Emissions at 0.07 lb NOx/MMBtu

[50] Emissions at 0.12 lb SO2/MMBtu

## Figure 9-5 Emission Reductions Achieved by 2010 RP Determinations

### RP Emission Control Analysis

| NOx RP - SCR | | | | | | |
|---|---|---|---|---|---|---|
| Source | SCR Capital Costs | Annualized SCR Costs | SCR NOx Reduced [tpy] | SCR NOx Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
| | | | | | | |

| NOx RP - SNCR | | | | | | |
|---|---|---|---|---|---|---|
| Source | SNCR Capital Costs | Annualized SNCR Costs | SNCR NOx Reduced [tpy] | SNCR NOx Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
| Craig - Unit 3 (SNCR @ 15% Reduction) | $ 13,139,000 | $ 4,173,000 | 854 | $ 4,886 | 0.32 | 6 (Mt. Zirkel) |
| Holcim Cement (establish limit) | not estimated | $ 2,520,000 | 1,028 | $ 2,451 | 0.23 | 5 (GSDNP) |

| NOx RP- Other | | | | | | |
|---|---|---|---|---|---|---|
| Source | Capital Costs | Annualized Costs | NOx Reduced [tpy] | NOx Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
| Black Hills - Clark Units 1 & 2 (shutdown) | n/a | n/a | 861 | n/a | n/a | n/a |
| Cameo - Unit 1 (Shutdown) | n/a | n/a | 516 | n/a | n/a | n/a |
| Cameo - Unit 2 (Shutdown) | n/a | n/a | 624 | n/a | n/a | n/a |
| CENC - Boiler 3 (none) | n/a | n/a | n/a | n/a | n/a | n/a |
| Nixon - Unit 1 (ULNB w/Overfire Air) | $ 3,822,000 | $ 970,000 | 707 | $ 1,372 | 0.15 | 2 (RMNP) |
| Nucla (none) | n/a | n/a | n/a | n/a | not modeled | not modeled |
| Rawhide - Unit 1 (enchanced combustion control) | $ 1,180,000 | $ 288,450 | 448 | $ 644 | 0.35 | 18 (RMNP) |

| SO2 RP | | | | | | |
|---|---|---|---|---|---|---|
| Source | Capital Costs | Annualized Costs | SO2 Reduced [tpy] | SO2 Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
| Black Hills - Clark Units 1 & 2 (shutdown) | n/a | n/a | 1,457 | n/a | n/a | n/a |
| Cameo - Unit 1 (Shutdown) | n/a | n/a | 849 | n/a | n/a | n/a |
| Cameo - Unit 2 (Shutdown) | n/a | n/a | 1,769 | n/a | n/a | n/a |
| CENC - Boiler 3 (none) | n/a | n/a | n/a | n/a | n/a | n/a |
| Craig - Unit 3 (tighten existing emission limit) | none | none | 0 | n/a | 0.26 | 6 (RMNP) |
| Holcim Cement (establish limit) | not estimated | not estimated | 0 | n/a | - | n/a |
| Nixon - Unit 1 LSD @ 0.10 lb/MMBtu (0.11 lb/MMBtu 30-day rolling) | $ 96,160,000 | $ 12,036,604 | 3,215 | $ 3,744 | 0.46 | 11 (RMNP) |
| Nucla (none) | n/a | n/a | n/a | n/a | not modeled | not modeled |
| Rawhide - Unit 1 (no technically feasible options) | n/a | n/a | n/a | n/a | n/a | n/a |

| PM RP | | | | | | |
|---|---|---|---|---|---|---|
| Source | Capital or O&M Costs | Annualized Costs | PM Reduced [tpy] | PM Control Cost [$/ton] | CALPUFF Δ dv Improvement | # of Days of Improvement |
| Black Hills - Clark Units 1 & 2 (shutdown) | n/a | n/a | 72 | n/a | n/a | n/a |
| Cameo - Units 1 & 2 (Shutdown) | n/a | n/a | 225 | n/a | n/a | n/a |

| | | |
|---|---|---|
| *TOTAL CAPITAL COST* | $ 114,301,000 | |
| *TOTAL ANNUALIZED COST* | $ 19,988,054 | |
| TOTAL NOX REDUCED | 5,038 | *tons/year* |
| TOTAL SO2 REDUCED | 7,290 | *tons/year* |
| TOTAL PM REDUCED | 297 | *tons/year* |
| TOTAL COMBINED POLLUTANTS REDUCED | 12,624 | *tons/year* |

Of these 70,800 tons of SO2 and NOx reduced due to 2010 BART and RP, approximately 44,500 tons per year were not included in the WRAP's 2009 "CMAQ" modeling. Figure 9-6 below presents this analysis for each of the BART and RP sources.

## Figure 9-6 Difference Between the WRAP and Final BART/RP Emissions for NOx and SO2

**Additional NOx and SO2 Reductions**

*Difference between PRP2018b and Proposed BART/RP*

| PLANT | PRP 2018b NOx [tpy] | 2018 BART/RP NOx [tpy] | Difference [tpy] | PRP 2018b SO2 [tpy] | 2018 BART/RP SO2 [tpy] | Difference [tpy] |
|---|---|---|---|---|---|---|
| AQUILA, INC. - W.N. CLARK STATION | 1,090 | - | (1,090) | 1,322 | - | (1,322) |
| CEMEX, INC. - LYONS CEMENT PLANT | 901 | 901 | - | 97 | 95 | (2) |
| COLORADO SPRINGS UTILITIES - NIXON PLT | 2,331 | 1,650 | (681) | 4,073 | 907 | (3,166) |
| COLORADO SPRINGS UTILITIES - DRAKE PLT | 3,669 | 2,789 | (880) | 2,701 | 1,590 | (1,111) |
| HOLCIM (US) INC. PORTLAND PLANT | 1,859 | 2,087 | 228 | 393 | 721 | 328 |
| PLATTE RIVER POWER AUTHORITY - RAWHIDE | 3,912 | 1,418 | (2,494) | 927 | 913 | (14) |
| PUBLIC SERVICE CO - CAMEO (shutdown) | - | - | - | - | - | - |
| PUBLIC SERVICE CO - ARAPAHOE (Unit 3-Shutdown, Unit 4 NG only) | - | 900 | 900 | - | 1 | 1 |
| PUBLIC SERVICE CO - VALMONT | 2,279 | - | (2,279) | 879 | - | (879) |
| PUBLIC SERVICE CO CHEROKEE PLT (Units 3 & 4) | 5,998 | 1,813 | (4,185) | 5,214 | 8 | (5,206) |
| PUBLIC SERVICE CO CHEROKEE PLT (Units 1 & 2) | 4,317 | 250 | (4,067) | 1,750 | - | (1,750) |
| PUBLIC SERVICE CO COMANCHE PLT (Units 1 & 2) | 6,143 | 4,602 | (1,541) | 3,686 | 2,953 | (733) |
| PUBLIC SERVICE CO COMANCHE PLT (Unit 3) | 2,600 | 2,600 | - | 3,250 | 3,250 | - |
| PUBLIC SERVICE CO HAYDEN PLT | 7,307 | 1,341 | (5,966) | 2,898 | 2,541 | (357) |
| PUBLIC SERVICE CO PAWNEE PLT | 3,942 | 1,403 | (2,539) | 2,225 | 2,406 | 181 |
| TRI STATE GENERATION CRAIG (Units 1 & 2) | 10,974 | 5,861 | (5,113) | 2,117 | 1,952 | (165) |
| TRI STATE GENERATION CRAIG (Unit 3) | 5,825 | 4,839 | (986) | 1,823 | 1,863 | 40 |
| TRI STATE GENERATION NUCLA | 1,753 | 2,167 | 414 | 1,325 | 1,325 | 0 |
| TRIGEN - COLORADO ENERGY CORPORATION (Units 4 & 5) | 1,185 | 722 | (463) | 2,624 | 2,762 | 138 |
| TRIGEN - COLORADO ENERGY CORPORATION (Unit 3) | 159 | 222 | 63 | 170 | 379 | 209 |
| | **66,243** | **35,565** | **(30,678)** | **37,473** | **23,666** | **(13,807)** |

**Combined Reductions from NOx and SO2 Controls [tpy]: (44,486)**

These substantial additional emission reductions will further the amount of progress achieved by 2018.

Colorado believes the combination of WRAP's CMAQ modeling and the Division's BART and RP modeling adequately demonstrate the anticipated net positive visibility benefit or improvement for this SIP. Although the state of Colorado makes no commitment to produce comprehensive RH modeling unless resources are available and there is a need for such analysis (e.g., through the WRAP), it is anticipated in the five year review required by the RH rule and committed to in this SIP that additional regional CMAQ modeling will be done to evaluate compliance with the Reasonable Progress Goals for all the western states.

## 9.5 Reasonable Progress Goals

Based on the requirements of the Regional Haze Rule, 40 CFR 51.308(d)(1), the state must establish goals, for each Class I area in Colorado (expressed in deciviews) that provide for Reasonable Progress (RP) towards achieving natural visibility conditions in 2018 and to 2064. The reasonable progress goals (RPGs) must provide for improvement in visibility for the most-impaired (20% worst) days over the period of the State Implementation Plan (SIP) and ensure no degradation in visibility for the least-impaired (20% best) days over the same period.

Colorado is relying on the Western Regional Air Partnership's (WRAP's) CMAQ regional modeling performed in 2009 to establish these goals. As stated throughout this chapter, all western states' reasonably foreseeable control measures at the time of modeling were included in the projections of 2018 visibility levels. Colorado determines that the 2018 projections represent significant visibility improvement and reasonable progress upon the state's consideration of the statutory factors, and are the RPGs for each Class I area. Figure 9-7 presents these RPGs.

**Figure 9-7 Reasonable Progress Goals for Each Class I Area**

**Colorado Mandatory Class I Federal Areas**

**Uniform Progress Summary in Haze Index Metric**

***Based on WRAP CMAQ Modeling using the PRP 2018b***

| *Mandatory Class I Federal Area* | *20% Worst Days* | | | | | *20% Best Days* | | |
|---|---|---|---|---|---|---|---|---|
| | *Worst Days Baseline Condition [dv]* | *Uniform Rate of Progress at 2018 [dv]* | *2018 URP delta from Baseline [dv]* | *2018 Modeling Projection [dv]* | *CMAQ Modeling % Towards 2018 URP* | *Best Days Baseline Condition [dv]* | *2018 CMAQ Modeling Results [dv]* | *2018 CMAQ Modeling Below Baseline?* |
| *Great Sand Dunes National Park & Preserve* | 12.78 | 11.35 | 1.43 | 12.20 | 40.6% | 4.50 | 4.16 | Yes |
| *Mesa Verde National Park* | 13.03 | 11.58 | 1.45 | 12.50 | 36.6% | 4.32 | 4.10 | Yes |
| *Mount Zirkel & Rawah Wilderness Areas* | 10.52 | 9.48 | 1.04 | 9.91 | 58.7% | 1.61 | 1.29 | Yes |
| *Rocky Mountain National Park* | 13.83 | 12.27 | 1.56 | 12.83 | 64.1% | 2.29 | 2.06 | Yes |
| *Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas* | 10.33 | 9.37 | 0.96 | 9.83 | 52.1% | 3.11 | 2.93 | Yes |
| *Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas* | 9.61 | 8.78 | 0.83 | 8.98 | 75.9% | 0.70 | 0.53 | Yes |

**Reasonable Progress Goals for 2018**

**No Degradation of Visibility for the Best Days**

As required, each Class I area must 1) make improvement in visibility for the most-impaired (20% worst) days over the period ending in 2018, and 2) allow no degradation in visibility for the least-impaired (20% best) days. This is demonstrated in Figure 9-5. As stated above in section 9.4.10, these goals reflect the emissions reductions achieved throughout Colorado (as reflected in the Chapter 5 inventories) and the nation. The additional emissions reductions from the BART and RP determinations will increase the amount of progress achieved by 2018.

In establishing the RPGs, the state considered the required four factors as per EPA regulations: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. Colorado describes in Chapter 8 how the four factors were used to select significant sources/source categories not already covered by BART or federal measures for control evaluation. The evaluations resulted in substantial emission reductions that build on the reductions already achieved by other measures.

Although the state used the four factors to determine reasonable and appropriate emission controls for subject facilities, Figure 9-7 illustrates that the RPGs do not achieve URP. The state realizes additional emissions reductions from both within and outside of the state are necessary to achieve URP. The state finds that the RPGs established in this SIP are reasonable for this planning period and that achieving URP in this planning period is not reasonable. In this SIP, Colorado has described, based upon its consideration of the statutory factors, why certain controls for specified BART and RP sources are reasonable, and why additional controls during this planning period are not reasonable. Similarly, the state has described why additional controls for certain area sources (such as oil and gas heater treaters and lean burn RICE engines) are not reasonable in this planning period. The emission reductions needed to achieve URP at each Class I area for this planning period cannot be determined with precision, due to limitations in calculating and modeling all of the visibility-impairing emissions. In the first 5-year assessment, the state commits to begin evaluating this shortfall, first accounting for the degree of additional emission reductions achieved in Colorado and in other states that are not included in the modeling, and then assessing the inventory and modeling technical issues.

Because RPGs are not achieving URP by 2018 and natural conditions by 2064, Colorado is required by the Regional Haze rule to re-calculate and state the length of time necessary to achieve natural conditions, as shown below and presented in Figure 9-8. Instead of achieving natural conditions in 2064 (60 years) at all Class I areas, the year and the length of time is re-calculated as follows:

- Sand Dunes: 2152 (148 years)
- Mesa Verde: 2168 (164 years)
- Zirkel & Rawah: 2106 (102 years)
- Rocky Mountain: 2098 (94 years)
- Black Canyon, Weminuche, & La Garita: 2119 (115 years)
- Eagles Nest, Flat Tops, Maroon Bells & West Elk: 2083 (79 years)

The recalculated natural conditions timeline is based upon progress through 2018, though, as described above, the calculations do not consider the emission control requirements adopted by the state in 2010 and presented in Chapters 6 and 8. The four factors were used to evaluate significant sources of SO2, NOx (and PM from stationary sources) only as the state also determined that it was not reasonable to evaluate sources organic carbon, elemental carbon and particulate matter for control during this planning period. Thus, all reasonable control measures are presented in this SIP and it is acceptable under the Regional Haze rule that natural conditions are projected to be achieved beyond 2064.

## Figure 9-8 Re-Calculation of the Length of Time Necessary to Achieve Natural Conditions

### Colorado Mandatory Class I Federal Areas

**Number of Years to Attain Natural Conditions**

***Based on WRAP CMAQ Modeling using the PRP 2018b***

| Mandatory Class I Federal Area | 20% Worst Days | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Baseline Condition [dv] | Uniform Rate of Progress at 2018 [dv] | 2064 Natural Conditions [dv] | Total Haze Delta (Baseline-2064 NC) [dv] | Haze Program Period [yrs] | Haze Program Reduction Rate [dv/yr] | 2018 Modeling Projection [dv] | 2018 Modeling <= 2018 UPG? | Recast Reduction Rate [dv/yr] | Number of years to NC [yrs] | New NC Goal [year] |
| Great Sand Dunes National Park & Preserve | 12.78 | 11.35 | 6.66 | 6.12 | 60 | 0.102 | 12.20 | No | 0.041 | 148 | 2152 |
| Mesa Verde National Park | 13.03 | 11.58 | 6.81 | 6.22 | 60 | 0.104 | 12.50 | No | 0.038 | 164 | 2168 |
| Mount Zirkel & Rawah Wilderness Areas | 10.52 | 9.48 | 6.08 | 4.44 | 60 | 0.074 | 9.91 | No | 0.044 | 102 | 2106 |
| Rocky Mountain National Park | 13.83 | 12.27 | 7.15 | 6.68 | 60 | 0.111 | 12.83 | No | 0.071 | 94 | 2098 |
| Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas | 10.33 | 9.37 | 6.21 | 4.12 | 60 | 0.069 | 9.83 | No | 0.036 | 115 | 2119 |
| Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas | 9.61 | 8.78 | 6.06 | 3.55 | 60 | 0.059 | 8.98 | No | 0.045 | 79 | 2083 |

The following figures for Mesa Verde National Park illustrate the re-calculations.

**Figure 9-9 Current Uniform Rate of Progress Glidepath for Mesa Verde and the Reasonable Progress Goal for 2018**

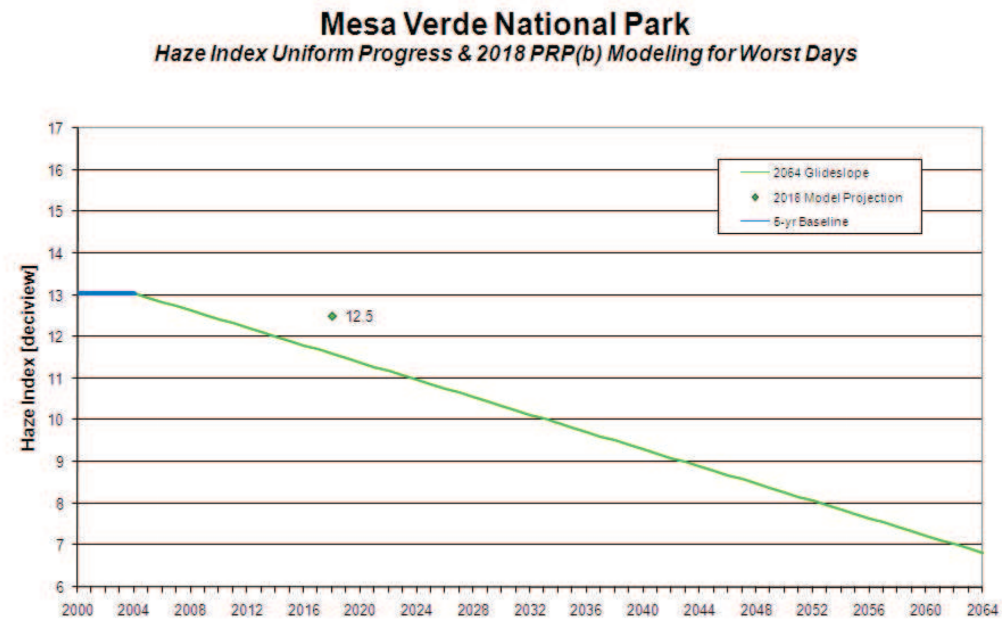
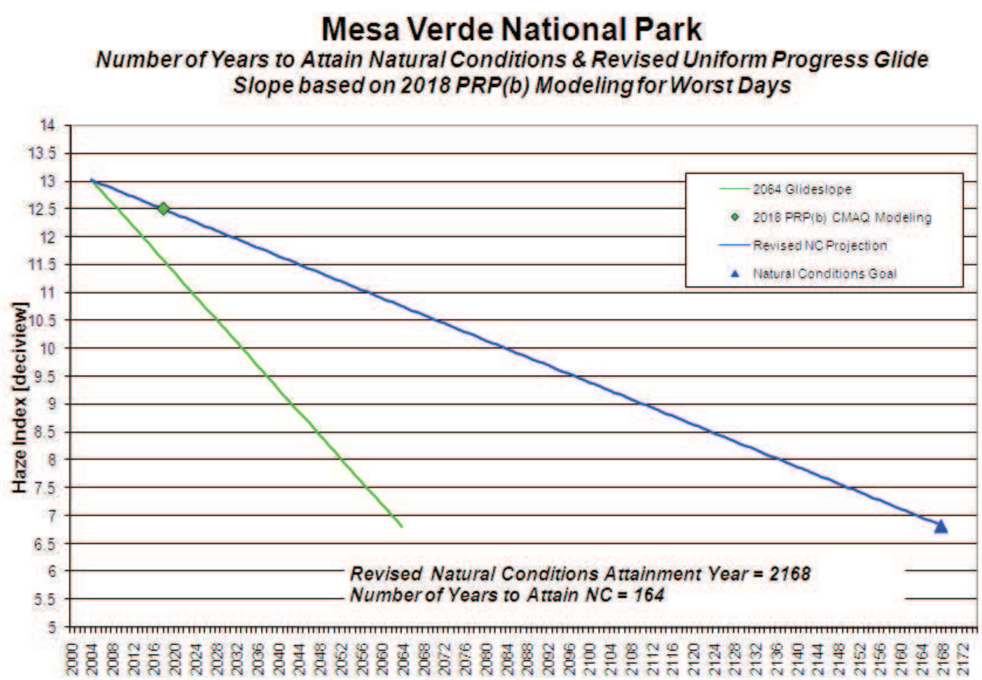



**Figure 9-10 Revised Glidepath for Mesa Verde Illustrating the Number of Years to Achieve Natural Conditions**



# Chapter 10 Commitment to Consultation, Progress Reports, Periodic Evaluations of Plan Adequacy, and Future SIP Revisions

## 10.1 Future Consultation Commitments

### *10.1.1 FLM Consultation*

As required by 40 CFR 51.308(i)(4), Colorado will continue to consult with the FLM on the implementation of the visibility protection program: and the following items

1. Colorado will provide the FLM an opportunity to review and comment on SIP revisions, the five-year progress reports, and other developing programs that may contribute to Class I visibility impairment. This report will include:
    a. Implementation of emission reduction strategies identified in the SIP as contributing to achieving improvement of worst-day visibility;
    b. Summary of major new source permits issued;
    c. Any changes to the monitoring strategy or monitoring stations that may affect tracking reasonable progress;
    d. Work underway in preparing the five and ten year reviews
2. Colorado will afford the FLM with an opportunity for consultation in person and at least 60 days prior to holding any public hearing on a SIP revision. The FLM consultation must include the opportunity to discuss their assessment of visibility impairment in each federal Class I area; and to provide recommendations on the reasonable progress goals and on the development and implementation of the visibility control strategies. Colorado will include a summary of how it addressed the FLM comments in the revised RH SIP.

### *10.1.2 Tribal Consultation*

Colorado will continue to remain in contact with those Tribes which may reasonably be anticipated to cause or contribute to visibility impairment in Colorado mandatory Class I Federal area(s). For those Tribes that adopted a RH TIP, Colorado will consult with them directly. For those Tribes without a RH TIP, Colorado will consult with both the Tribe and EPA. Documentation of the consultation will be maintained.

### *10.1.3 Inter-state Consultation/Coordination*

In accordance with 40 CFR 51.308(d)(1)(iv) and 51.308(d)(3)(i), Colorado commits to continue consultation with Arizona, Nebraska, Kansas, Wyoming, New Mexico, Utah, and California, and any other state which may reasonably be anticipated to cause or contribute to visibility impairment in federal Class I areas located within Colorado. Colorado will also continue consultation with any state for which Colorado's emissions may reasonable be anticipated to cause or contribute to visibility impairment in those state's federal Class I areas.

With regards to the established or updated goal for reasonable progress, should disagreement arise between another state or group of states, Colorado will describe the actions taken to resolve the disagreement in future RH SIP revisions for EPA's consideration. With regards to assessing or updating long-term strategies, Colorado commits to coordinate its emission management strategies with affected states and will continue to include in its future RH SIP revisions all measures necessary to obtain its share of emissions reductions for meeting progress goals.

### *10.1.4 Regional Planning Coordination*

As per the requirements of [51.308(c)(1)(i)],Colorado commits to continued participation with one or more other States in a planning process for the development of future RH SIP revisions. Future plans will include:

1. Showing of inter-state visibility impairment in federal Class I areas based on available inventory, monitoring, or modeling information as per the requirements of [51.308(c)(1)(ii)].
2. Description of the regional planning process, including the list of states, which have agreed to work with Colorado to address regional haze, the goals, objectives, management, decision making structure for the regional planning group, deadlines for completing significant technical analyses and developing emission management strategies, and a schedule for State review and adoption of regulations implementing the recommendations of the regional group as per the requirements of ; [51.308(c)(1)(iii)].
4. Address fully the recommendations of WRAP, including Colorado's apportionment of emission reduction obligations as agreed upon through WRAP and the resulting control measures required [51.308(c)(1)(iv) and 51.308(d)(3)(ii)].

## 10.2 Commitment to Progress Reports

40 CFR 51.308(g), requires a State/Tribe to submit a progress report to EPA every five years evaluating progress towards the reasonable progress goal(s). The first progress report is due five years from the submittal of the initial implementation plan and must be in the form of an implementation plan revision that complies with Sections 51.102 and 51.103. At a minimum, the progress reports must contain the elements in paragraphs 51.308(g)(1) through (7) for each Class I area as summarized below.

1. Status of implementation of the RFP SIP measures for CIAs in Colorado and those outside the State identified as being impacted by emissions from within the state
2. Summary of emissions reductions in Colorado adopted or identified as part of the RFP strategy

3. A five year annual average assessment of the most and least impaired days for each CIA in Colorado including the current visibility conditions, difference between current conditions and baseline and change in visibility impairment over the five year period
4. Analysis, by type of source or activity of pollutant emission changes or activities over the five year period from all sources contributing to visibility impairment in Colorado, based on the most recent EI with estimates projected forward as necessary to account for changes in the applicable five year period
5. Assessment of significant changes in anthropogenic emissions in or out of Colorado in the applicable five years which limited or impeded RFP;
6. Assessment of the current SIP sufficiency to meet reasonable progress goals both in Colorado and other States CIA identified as being significantly impacted by Colorado emissions
7. Assessment of Colorado's visibility monitoring strategy and modifications of the strategy as necessary.

In accordance with the requirements listed in Section 51.308(g) of the federal regional haze rule, Colorado commits to submitting a report on reasonable progress to EPA every five years following the initial submittal of the SIP. That report will be in the form of an implementation plan revision. The reasonable progress report will evaluate the progress made towards the reasonable progress goal for each mandatory Class I area located within Colorado and in each mandatory Class I area located outside Colorado, which have been identified as being affected by emissions from Colorado.

The State will also evaluate the monitoring strategy adequacy in assessing reasonable progress goals.

## 10.3 Determination of Current Plan Adequacy

Based on the findings of the five-year progress report, 40 CFR 51.308(h) requires a State to make a determination of adequacy of the current implementation plan. The State must take one or more of the actions listed in 40 CFR 51. 308(h)(1) through (4) that are applicable. These actions are described below and must be taken at the same time the State is required to submit a five-year progress report.

1. If the State finds that no substantive SIP revisions are required to meet established visibility goals and emissions reductions, the State will provide a negative declaration that no implementation plan revision is needed.
2. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from outside the State, the State shall notify EPA and the other contributing state(s) or tribe(s). The plan deficiency shall be addressed through a regional planning process in developing additional strategies with the planning efforts described in the progress report(s).
3. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from another country, the State shall notify EPA and provide the available supporting information.

4. If the State finds the implementation plan is, or may be, inadequate to ensure reasonable progress due to emissions from within the State, the State shall revise the plan to address the deficiency within a year.

Colorado commits, in accordance with 40 CFR 51.308(h), to make an adequacy determination of the current SIP at the same time a five-year progress report is due.

## 10.4 Commitment to Comprehensive SIP Revisions

In addition to SIP revisions made for plan adequacy as specified in Section 10.3 of this plan, 40 CFR 51.308(f)(1-3)requires a State to revise and submit its regional haze implementation plan to EPA by July 31, 2018, and every ten years thereafter. Colorado commits to providing this revision and to evaluate and reassess elements under 40 CFR 51.308(d) taking into account improvements in monitoring data collection and analysis, and control technologies. Elements of the future plans are summarized below.

### *10.4.1 Current Visibility Conditions*

Colorado commits to determine and report current visibility conditions for the most and least impaired days using themost recent five year period for which data is available and to determine the actual progress made towards natural conditions. Current visibility conditions will be calculated based on the annual average level of visibility impairment.

### *10.4.2 Long Term Strategy Effectiveness*

Colorado commits to determine the effectiveness of the long-term strategy for achieving reasonable progress goals over the prior implementation period(s) and to affirm or revise the RPG and monitoring strategy as specified in 10.4.3 and 10.4.4 of this section.

### *10.4.3 Affirmation of or Revisions to Reasonable Progress Goals*

As part of this comprehensive SIP update and future ten year revisions, Colorado commits to affirm or revise the reasonable progress goals in accordance with the procedures set forth in 40 CFR 51.308(d)(1). For any goal which provided a slower rate of progress than needed to attain natural conditions by the year 2064, Colorado will perform the analysis of additional measures that could be adopted to achieve the degree of visibility improvement projected by the analysis contained in the initial implementation plan. This analysis of additional measures will be performed in accordance with the procedures set forth in 40 CFR 51.308(d)(1)(A) to include a consideration of the costs of compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and a demonstration showing how these factors were taken into consideration in selecting the goal.

1. Colorado commits, in accordance with 40 CFR 51.308(d)(1)(B), to analyze and determine the rate of progress needed to attain natural conditions by the year 2064 comparing baseline visibility to natural visibility conditions in each CIA considering the uniform rate of improvement and emission reduction measures needed to achieve RFP.

2. As per 40 CFR 51.308(d)(1)(B)(ii) if Colorado establishes a RPG with a slower rate of progress than needed to attain natural conditions by 2064, Colorado will demonstrate, based on the factors listed in this section 10.4.3, the rate of progress is unreasonable and the established goal is reasonable. Colorado will provide for a public review, as part of the implementation plan revision in 2018, an assessment of the number of years it will take to attain natural conditions based on the RPG.
3. As per 40 CFR 51.308(d)(1(B)(iv) Colorado will consult with States reasonably anticipated to cause or contribute to visibility impairment in the mandatory Class I Federal areas and where Colorado or another State cannot agree a RPG is appropriate, Colorado will describe, in the SIP submittal of 2018, actions taken to resolve disagreements.

# Chapter 11 Resource and Reference Documents

There are a substantial number of documents that are referenced in this SIP and form the detailed technical basis for the proceeding Chapters. This Chapter is not the full Technical Support Document. It is a catalog of references used in the preparation of this SIP revision. The full Technical Support Document will be on the Air Pollution Control Division web site at http://www.cdphe.state.co.us/ap/regionalhaze.html

**11.1 Class I Area Technical Support Documents (TSDs)** TSDs are a comprehensive technical summary for each Class I area in Colorado. The individual Class I area TSDs includes sections describing the Class I area; visibility monitoring; visibility conditions; haze impacting particles; emission source characterization; regional modeling; and PM source apportionment. Included in each TSD is the PSAT Modeling showing estimated source category impacts on Class I areas. Titles include:

*Colorado State Implementation Plan for Regional Haze Technical Support Document – Black Canyon of the Gunnison National Park,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Eagles Nest Wilderness Area,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Flat Tops Wilderness Area,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –La Garita Wilderness Area,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document – Maroon Bells Wilderness Area,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Mesa Verde National Park,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Mount Zirkel Wilderness Area,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Rocky Mountain National Park,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Rawah Wilderness Area,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Sand Dunes National Park,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document – Weminuche Wilderness Area,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –West Elk Wilderness Area,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, October 2007

**11.2 Other Technical Support Documents** In addition to the Class I area-specific TSDs, two other technical support documents have been developed. One for the IMPROVE look-alike monitors at Douglas Pass and Ripple Creek and another for agricultural burning in Colorado. Titles are:

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Douglas Pass and Ripple Creek Pass Sites,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, June 2007

*Colorado State Implementation Plan for Regional Haze Technical Support Document –Agricultural Burning in Colorado 2003-4 Inventory,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, July 2007

*Colorado State Implementation Plan for Regional Haze. Technical Support Document, Analysis of Colorado Visibility Impacts on Nearby Class I Areas,* Colorado Dept. of Public Health and Environment, Air Pollution Control Division, March 2007

**11.3 Long-Term Strategy Review Update** In 2004, the State adopted this SIP revision in order to update the LTS. This SIP revision is intended to amend the 2002 LTS portion of the Class I Visibility SIP. This document is titled:

*Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part II Revision of the Long-Term Strategy*, Colorado Department of Public Health and Environment, Air Pollution Control Division, November 2004

## List of Appendices –

**Appendix A – Periodic Review of Colorado RAVI Long Term Strategy**

**Appendix B – SIP Revision for RAVI Long Term Strategy**

**Appendix C – Technical Support for the BART Determinations**

**Appendix D – Technical Support for the Reasonable Progress Determinations**