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
Adopted by the Colorado Air Quality Control Commission on December 15, 2016

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	01/07/2011
Third Revision	11/20/2014
Fourth Revision	12/15/2016

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 31, 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 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.

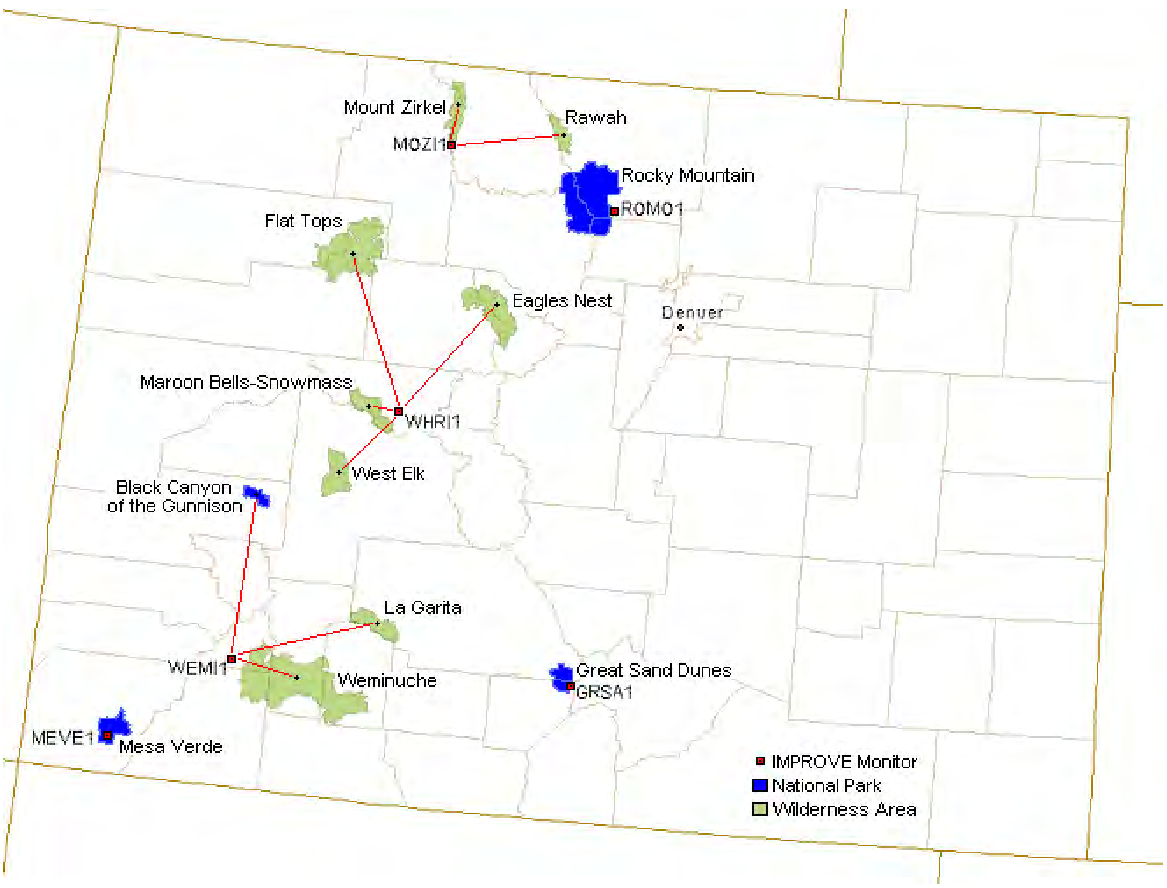
1.3 Description of Colorado's Class I Areas

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, 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 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, 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:

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 satisfy 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

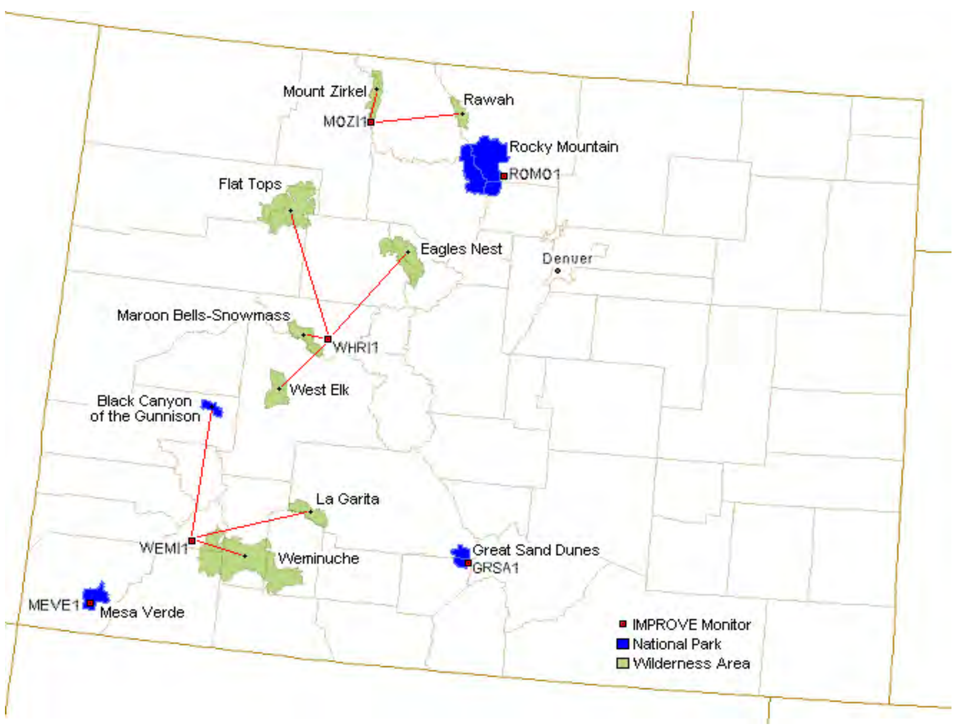


Figure 3-2 includes summary information for each IMPROVE monitor. The National Park Service (NPS) and the U.S. Forest Service (USFS) each operate and maintain three IMPROVE monitors in the State.

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.

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

Colorado will continue to work with EPA in refining monitoring 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.

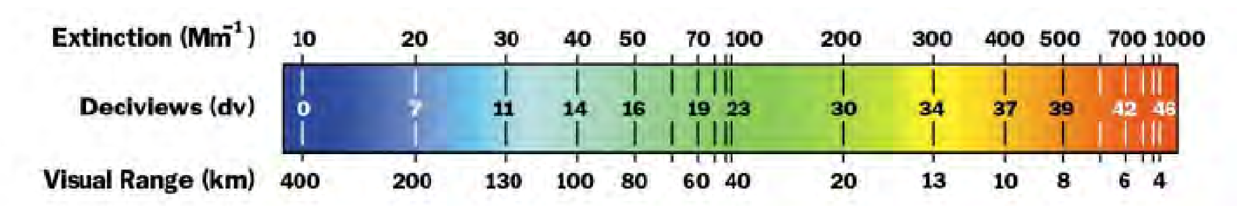
[3] http://www.wrapfets.org/
[4] http://pah.cert.ucr.edu/aqm/308/

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 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)

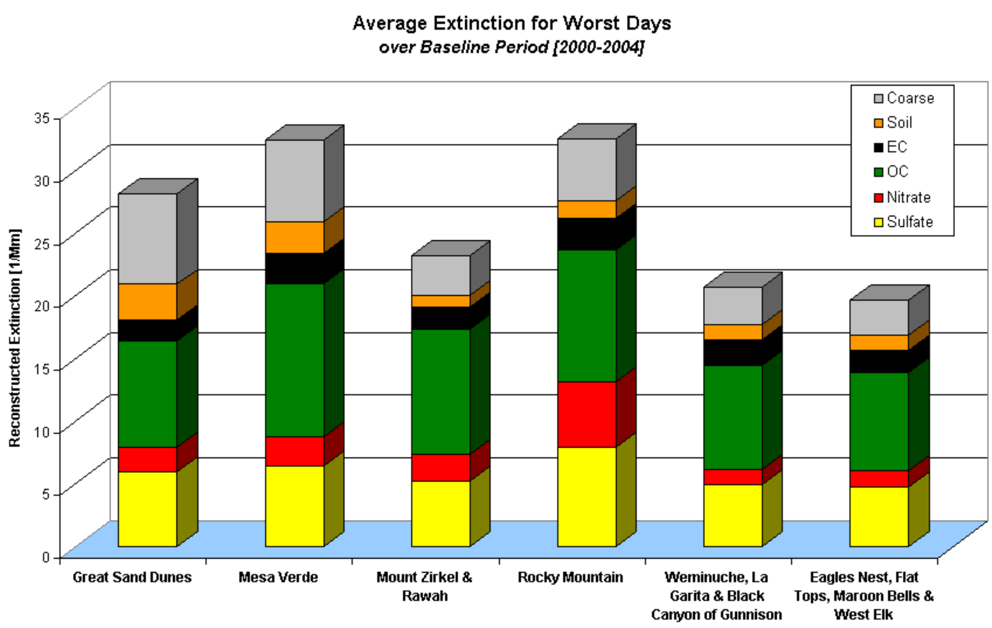
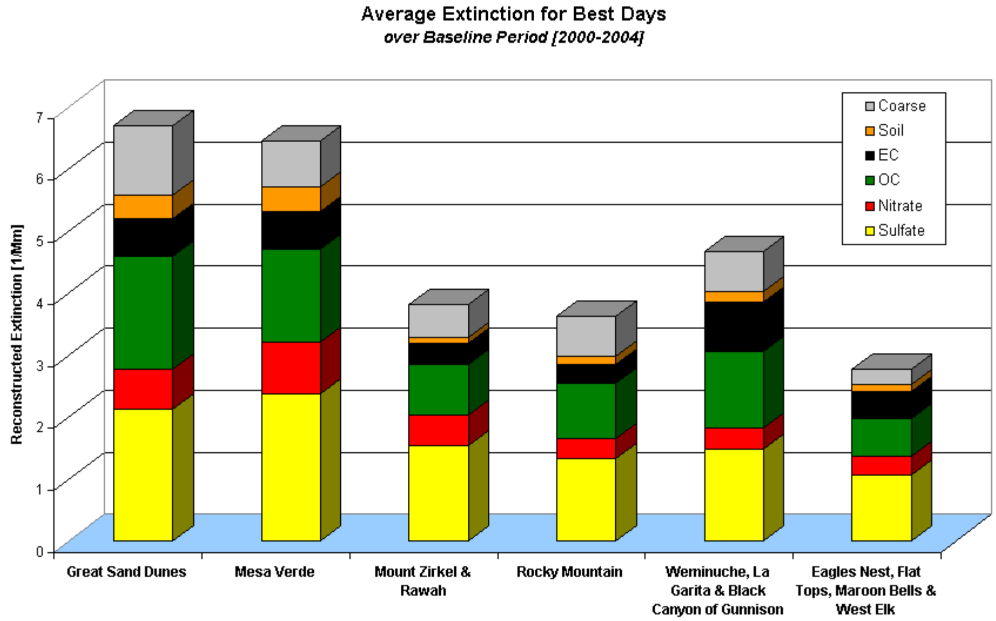


Figure 4-2 Reconstructed Aerosol Components for 20% Best Days (2000-2004)



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 1st 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

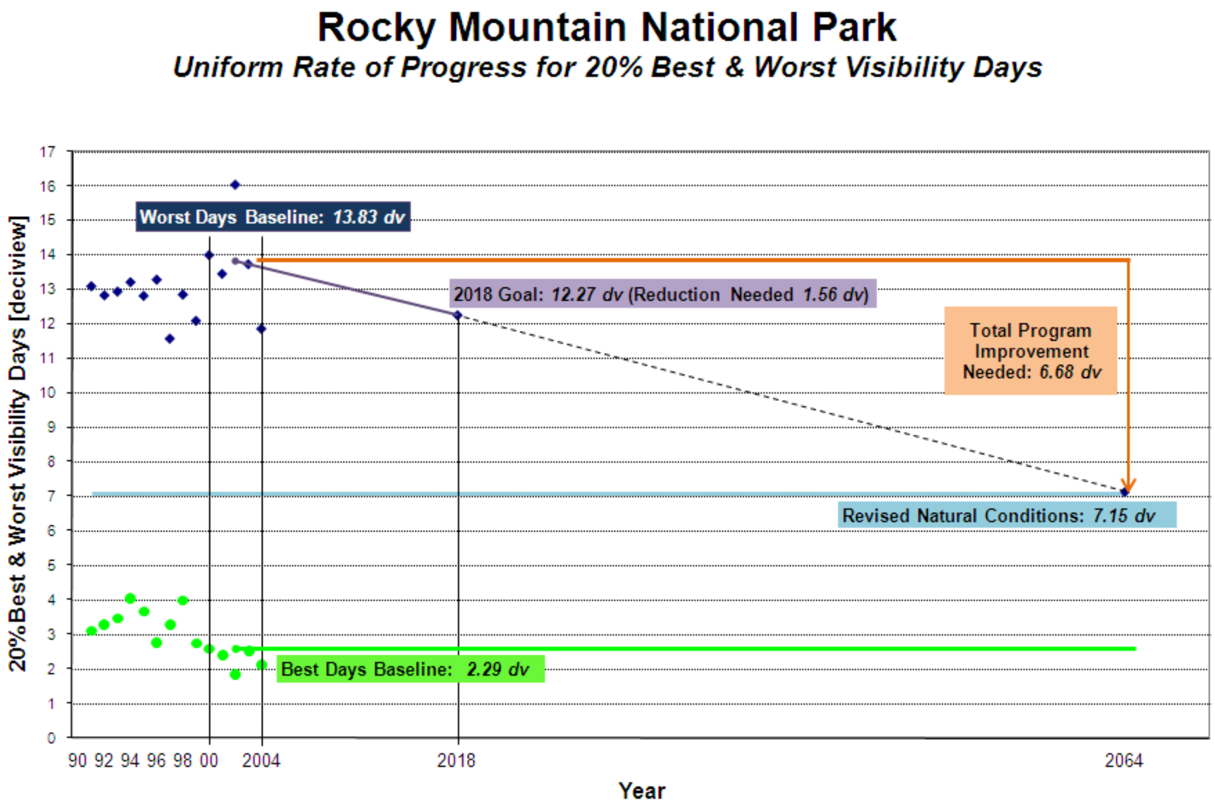
Baseline Summary of Best & Worst Days in Haze Index Metric

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 day's 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			
	Statewide NOx Emissions		
Source Category	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			
	Statewide POA Emissions		
Source Category	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 Number 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 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.

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, 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) 901.0 tons/yr (12-month rolling average)	None	25.3 lbs/hr (12-month rolling average) 95.0 tons/yr (12-month rolling average)	Fabric Filter Baghouse * 0.275 lb/ton of dry feed 20% opacity
Cemex - Lyons Dryer	None	13.9 tons/yr	None	36.7 tons/yr	Fabric Filter Baghouse* 22.8 tons/yr 10% opacity
CENC Unit 4	Low NOx Burners with Separated Over-Fire Air	0.37 lb/MMBtu (30-day rolling average) Or 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* 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) Or 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* 0.07 lb/MMBtu
Comanche Unit 1	Low NOx Burners*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime Spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Comanche Unit 2	Low NOx Burners*	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	Lime Spray Dryer*	0.12 lb/MMBtu (30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	Fabric Filter Baghouse* 0.03 lb/MMBtu
Craig Unit 1	Selective Catalytic Reduction System	***	Wet Limestone scrubber*	0.11 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 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**
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* 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* 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* 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* 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* 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* 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 table is not a requirement.

*** Craig Unit 1 will either close on or before December 31, 2025 ***or*** cease burning coal no later than August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu will be effective after August 31, 2021. Effective January 1, 2017 (first compliance date January 31, 2017), Craig Unit 1 will be subject to a NOx emission limit of 0.28 lb/MMBtu 30-day rolling average until closing or converting to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1. The Division shall be notified in writing by the owner-operator no later than February 28, 2021 whether Craig Unit 1 will close or convert to gas.

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* 0.03 lbs/MMBtu 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* 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* 0.03 lbs/MMBtu 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 table is not a requirement.

[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.

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 Number 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 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.

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" *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 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 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 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

Table 6 - 4 Colorado's BART Eligible Sources

Plant Name	Source Owner	Rating, Heat Input or Source type	Start Year	Current Status
Craig Unit 1	Tri-State Generation and Transmission, Inc.	446 MW	1979	Subject-to-BART
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 shut down; 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	Pharmaceutic al 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.

(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 Number 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 Number 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, 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.

[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, and Valmont Unit 5.

Each of these systems will meet EPA's presumptive limits, and in some cases surpass those limits.[11] The 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.

[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*, 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.

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 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 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]

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

[13] Air Quality Control Commission Regulation Number 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).

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 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.

[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.

[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 Number 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.

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 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 98th percentile visibility impact of 0.78 delta deciview (Δdv) at Rocky Mountain National Park. The modeled 98th 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
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 (tons/yr)	Annualized Cost ($/yr)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/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 (Δdv)	98th Percentile Improvement (from 24-hr Max) (Δdv)
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 (>1500ºF) is significantly higher at the exit than a more typical preheater precalciner kiln (650ºF). 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 98th 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 overfired 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 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, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria discussed 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 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 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:* Tri-State determined that installation of perforated trays, as described, 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	4,048	$25,036,709	$6,184

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	$6,298

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	0.08	0.94

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 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: 0.070 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.080 lb/MMBtu (30-day rolling average)

The 0.08 lb/MMbtu limit for Unit 2 was based upon evidence before the AQCC in 2010, and took into consideration both cost and feasibility. Significant progress towards installation of SCR at Unit 2 has been made, and the vendor has guaranteed performance at the 0.08 lb/MMBtu 30-day rolling average NOx limit. Both vendor performance and equipment performance can improve over time, and the Division has determined, and Tri-State has agreed, that Tri-State can achieve a 0.07 lb/MMBtu NOx limit at Unit 1. The state assumes that the BART emission limits can be achieved through the operation of SCR. For SCR at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls above the guidance criteria presented earlier in Chapter 6. The criteria guide the state's general approach to these policy considerations, but are not binding. Therefore, the state deviates from the guidance criteria in this case due to the fact that Tri-State has agreed to achieve the proposed emission rates at Craig Units 1 and 2 and the notable visibility improvements.

- Unit 1: $6,184 per ton NOx removed; 1.01 deciview of improvement
- Unit 2: $6,298 per ton NOx removed; 0.94 deciview of improvement

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. Once EPA approves this revision to the Regional Haze SIP, Tri-State will be required to meet the 0.07 lb/MMBtu NOx emission limit by August 31, 2021. Once the revised emission limit is approved, Tri-State will begin the design and development of bid documents, engage in a process to review bids and select a contractor for the multi-year construction project. Based on Tri-State's experience at Unit 2 (where construction and installation of SCR is already underway), and taking into consideration such factors as the weather in Craig, Colorado, the coordination necessary between the various owners of Unit 1, electric utilities and regional entities responsible for the bulk electric system, and compliance deadlines for other similar types of facilities in Colorado, Arizona and Wyoming, the Division has determined that the compliance deadline of August 31, 2021 is as expeditiously as practicable as SCR can be installed at Unit 1.

This BART determination is the result of an agreement between Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state to resolve an appeal of EPA's approval of Craig Station –related elements of Colorado's Regional Haze Plan. This BART determination is consistent with the information provided by the FLMs and is supported by the associated visibility improvement information as well as the SCR cost information provided in the SIP materials and otherwise reflected in the hearing 2014 record. In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a BART reassessment for Craig Unit 1. This reassessment evaluates the additional scenarios:

Scenario 1 (Close by December 31, 2025): The first table assumes an amortization period of four years and four months of operation from the projected compliance date to the date of retirement (December 31, 2025) and that control technology could be installed by August 31, 2021, consistent with the 2014 BART determination. In the second table, an assumed amortization period of eight years of operation[18] is used since a projected compliance date could occur earlier depending on the alternative selected. Both of these assumed amortization periods change the remaining useful life for the alternatives as Craig Unit 1 will no longer remain in service for the 20-year amortization period used in the 2014 BART determination, depending on the alternative selected[19].

[18] Operation period begins calendar year 2018 (December 31, 2017).
[19] EPA finalized revisions of the Air Pollution Cost Control Manual (Chapters 1 and 2) in May 2016; these revisions change the amortization period for SCR from 20 years to 30 years. The amortization period for SNCR remains 20 years.

Both of these reduced timeframes change the cost effectiveness for the alternatives as follows:

Craig Unit 1 - NO_x Cost Comparisons (assuming four years, four months of operation)			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$6,172,522	$7,928
SCR	4,048	$64,106,699	$15,835

Craig Unit 1 - NO_x Cost Comparisons (assuming eight years of operation)			
Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$4,755,842	$6,109
SCR	4,048	$41,476,535	$10,245

Based on this assessment, regardless of the amortization period used, both SNCR and SCR are not cost effective when the remaining useful life is shortened, and when considering the remaining BART factors as discussed in Appendix C. For Craig Unit 1, a NOx emission limit of 0.07 lb/MMBtu (2014 BART determination) is BART under a 20 or 30 year remaining useful life.

Or;

Scenario 2: A cease coal burning date of August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu applies after August 31, 2021. This scenario (without the inclusions) is equivalent to the 2014 BART determination.

Both of these scenarios include a 30-day rolling average NOx emission limit of 0.28 lb/MMBtu that will commence on January 1, 2017 (first compliance date January 31, 2017) and be effective until either closure or conversion to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1.

The scenario options under this BART reassessment are the result of an agreement. This reassessment relies on the 2014 BART determination for Craig Unit 1 and supplements that determination to reflect the terms of the agreement. This agreement achieves greater air quality benefits than the 2011 Regional Haze SIP. Both of these scenarios achieve greater NOx reductions and other environmental co-benefits compared to the 2014 BART determination. Consistent with the agreement, Craig Unit 1 will either close on or before December 31, 2025 ***or*** cease burning coal by August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023.

In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu will apply after August 31, 2021. Effective January 1, 2017 (first compliance date January 31, 2017), Craig Unit 1 will be subject to a NOx emission limit of 0.28 lb/MMBtu 30-day rolling average until closure or conversion to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective on December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1. A complete analysis that supports the BART determination for Craig Station Units 1 and 2 and the BART reassessment for Unit 1, 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.

- 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 98^{th} 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
Overfired 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
Overfired 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
Overfired 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 (*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 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 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 & 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.

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, 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.

<u>Analysis under 40 CFR Part 51, § 308(e)</u>

(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 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.[20] 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.

[20] 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.

(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. With respect to SO2 emissions, the PSCo BART Alternative will reduce SO2 emissions from these units by 21,493 tons per 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 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 Number 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 Number 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 Regulation Number 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.

Technical Analysis of the PSCo Alternative Emissions Reductions with Respect to the Section 308(e) Alternative Measure Demonstration

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

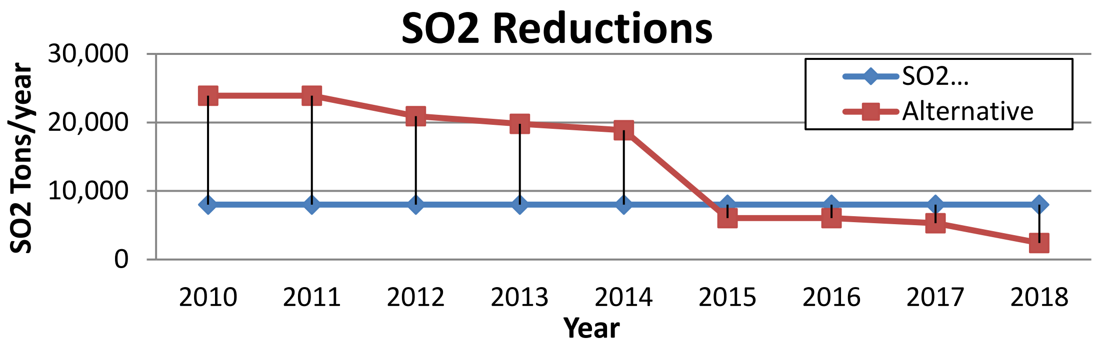
Facility	MMBtu Average 2006 to 2008	SO2 TPY Average 2006 to 2008	SO2 TPY at 0.15 lb/MMBtu Presumptive	SO2 TPY under PSCo Alternative in 2018	% Reduction Beyond Presumptive BART
Arapahoe					
Unit 3	4,380,121	924.97	328.51	0.00	100.00%
Unit 4	8,545,791	1,764.70	640.93	1.28[21]	99.8%
Cherokee					
Unit 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.

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

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



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

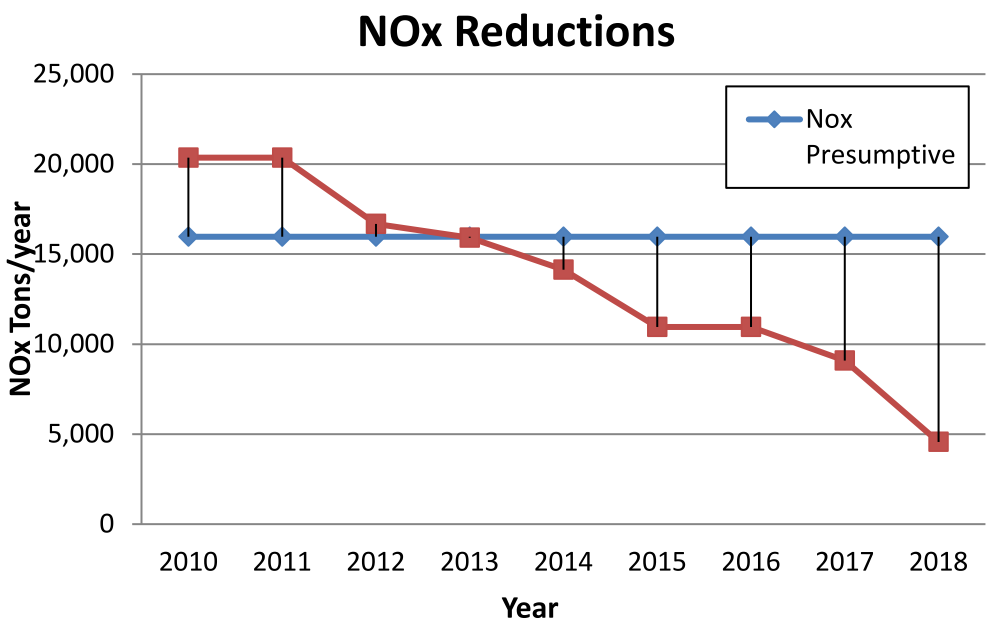
Facility	MMBtu Average 2006 to 2008	NOx TPY Average 2006 to 2008	NOx lb/MMBtu Standard	TPY NOx at Standard	TPY NOx Under PSCo Alternative in 2018	% Reduction Beyond Presumptive BART
Arapahoe						
Unit 3	4,380,121	1,770.47	0.23	503.71	0.00	100.00%
Unit 4	8,545,791	1,147.67	0.23	982.77	900.00[22]	8.42%
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[23]	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%

[22] 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.

[23] 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 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.

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 NH3 slip and 54% reduction with a 10ppm NH4 slip.[24] 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.[25]

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

[25] 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 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.

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

Facility	SCR $/ton	SNCR $/ton	SNCR TPY at 50%[26]	PSCo Alternative TPY	% Reduction from SNCR at 50% Control
Arapahoe					
Unit 3			885.23	0	100.00%
Unit 4			573.83	900[27]	-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[28]	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.[29]

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

[27] 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.

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

[29] 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

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 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

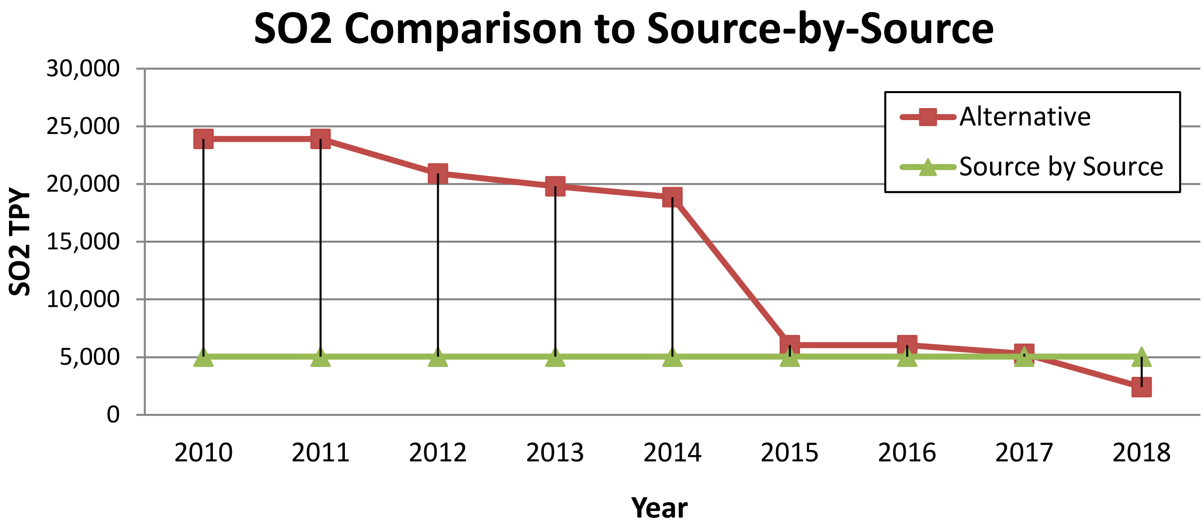
Facility	SO2 TPY from AP-42	Source-by-Source	SO2 TPY from PSCo Alternative	% Reduction Beyond Source-by-Source
Arapahoe				
Unit 3	1,076.53	53.82	0.00	100.00%
Unit 4	2,322.21	1.28	1.28	0.00%
Cherokee				
Unit 1	2,803.67	140.18	0.00	100.00%
Unit 2	2,662.17	133.10	0.00	100.00%
Unit 3	3,438.79	171.93	0.00	100.00%
Unit 4	9,779.27	1,953.57[30]	7.81	99.6%
Valmont	3,822.73	191.13	0.00	100.00%
Pawnee	8,342.36	2,405.62[31]	2,405.63	0.00%
Total	34,248	5,051	2,415	52.19%

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.

[30] 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.

[31] 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.

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



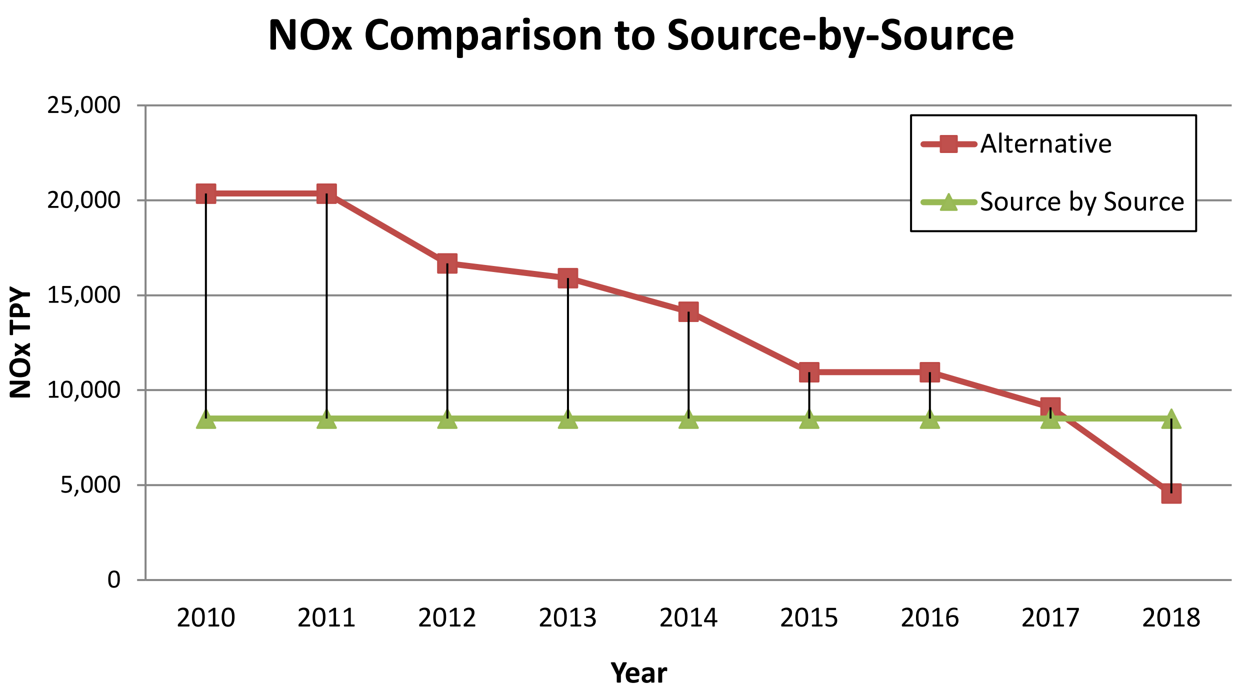
For NOx the state looked at a source by source analysis for Arapahoe Unit 4, Cherokee Unit 4 and Pawnee. For the remainder of the sources, for demonstration purposes, the state applied an aggressive 90% control level assumption to the sources. The 90% was taken from emissions calculated using AP-42.[32] 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.

[32] 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.

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[33]	-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[34]	2,062.86[35]	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%

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



[33] 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.

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

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

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[36,37,38]

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* 0.03 lbs/MMBtu 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* 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* 0.03 lbs/MMBtu 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.

[36] 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.

[37] 500 tpy NOx will be reserved from Cherokee Station for netting or offsets.

[38] 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.

8.2 Visibility Impairing Pollutants Subject to Evaluation

The state conducted a detailed evaluation[39] 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.

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

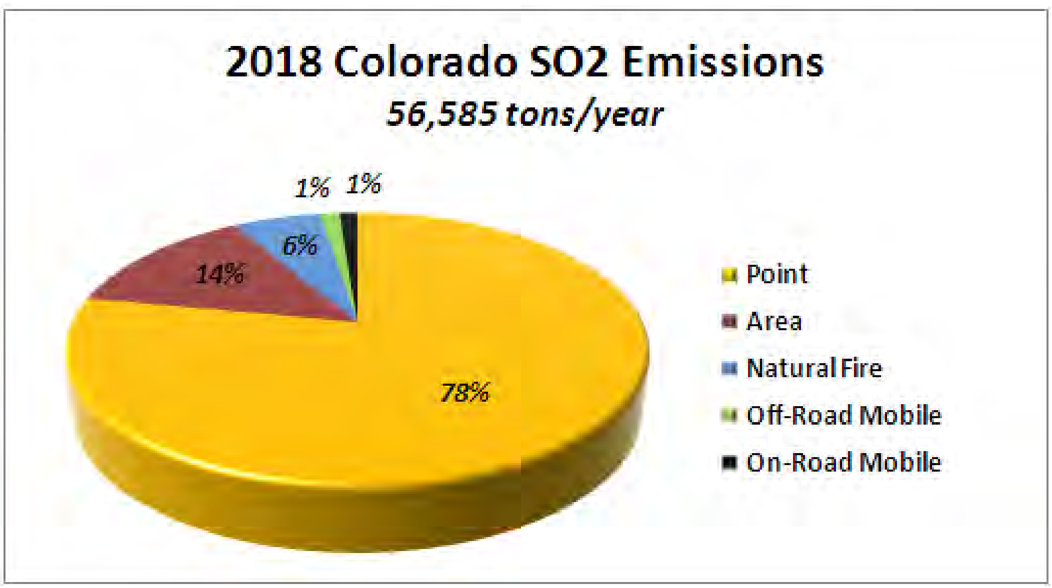
This determination is based on the well documented point source emission inventories for SO2 and NOx, and the Regional Model performance for sulfate and nitrate was determined to be acceptable. Significant point source PM emissions are also evaluated because of the Q/d screening methodology (Q = total 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.

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

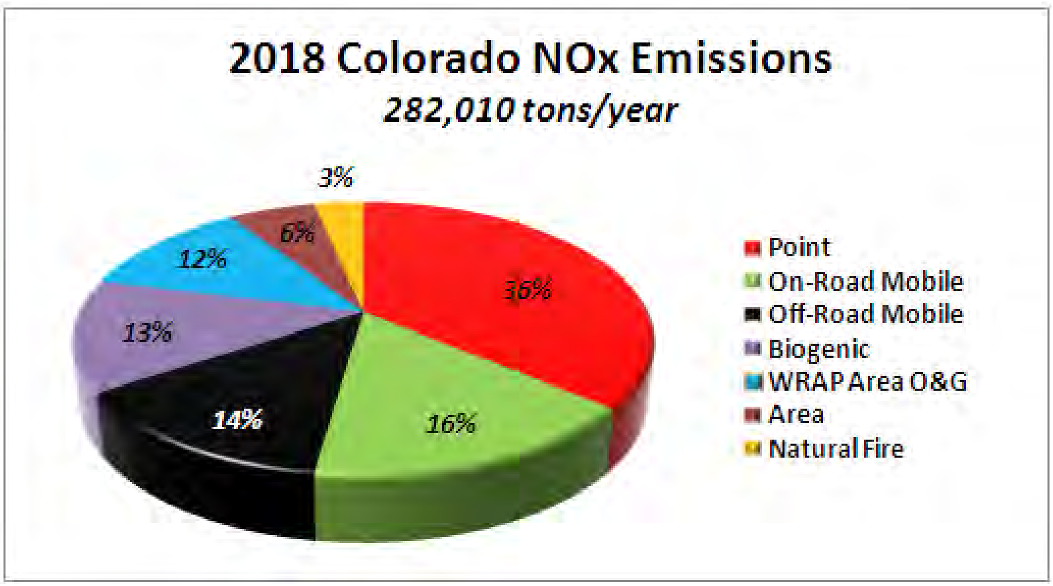


As indicated, 78% of total statewide SO2 emissions are from point sources – largely coal-fired boilers. Area source SO2 emissions (14%) are dominated by thousands of boilers and internal combustion engines statewide that burn distillate fuel. Depending on use and fuel grade, the maximum sulfur content 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 Number 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 Number 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, 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 Number 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 the 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 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[40].

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

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 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

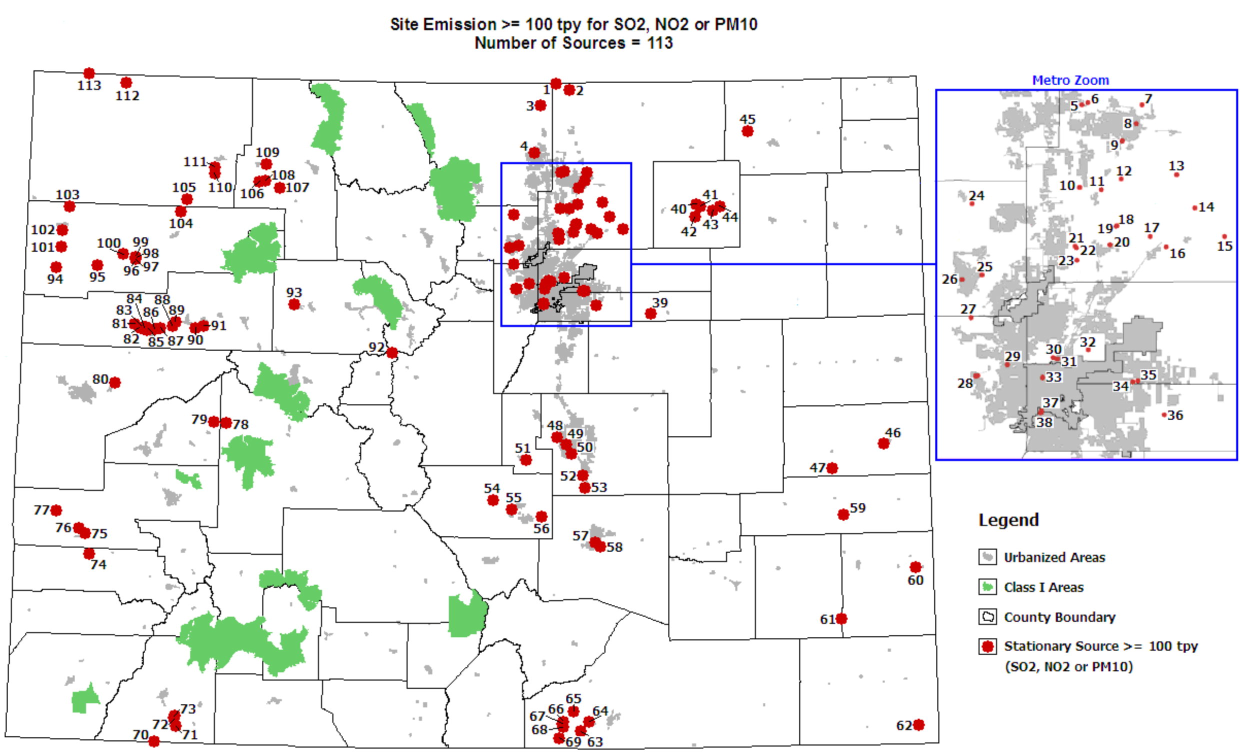


Table 8-1: Colorado Significant Point Sources with a Q/d ≥ 20

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	1,061	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 Number 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 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.
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.
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.
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.
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.
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.
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 Number 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.

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 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 Number 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.

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 Number 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 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, 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.[41] 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.

[41] 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.

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. 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 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.[42]

[42] Air Quality Control Commission Regulation Number 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).

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.[43] 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 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.[44] 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.[45] 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.[46] 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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[43] 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.

[44] *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.

[45] *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

[46] 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* 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* 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* 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) 2,086.8 tons/year	Wet Lime Scrubber*	1.30 lbs/ton clinker (30-day rolling average) 721.4 tons/year	Fabric Filter Baghouse* 246.3 tons/year
Nucla	No Control	0.5 lb/MMBtu (30-day rolling average) ***	Limestone Injection*	0.4 lb/MMBtu (30-day rolling average)	Fabric Filter Baghouse* 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* 0.013 lb/MMBtu filterable PM 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 table is not a requirement.

*** Nucla Station will close on or before December 31, 2022. Additionally, an annual NOx limit of 952 tons per year will be effective on January 1, 2020 beginning in 2020 on a calendar year basis for Nucla Station.

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 (Δdv)
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 (Δdv)
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. 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 overfired 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. 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 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
Overfired 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 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 shut down 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 98th 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 1600-2000°F) 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 4th 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 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) (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 (45% overall NO_X control efficiency) Limits of **2.73 lb/ton** (30-day rolling average) and **2,086.8 tons per year** (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, 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. On December 26, 2012, Tri-State submitted an updated four-factor analysis and visibility modeling to the Division, with the conclusion that limestone for SO2 control and existing SNCR for NOx reduction remained the preferred strategy.

Requirements for Nucla Station

On December 31, 2012, EPA approved Colorado's Regional Haze SIP, including Colorado's Reasonable Progress determination for Nucla Unit 4 (0.5 lb/MMBtu (30-day rolling average)). In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a Reasonable Progress review of Nucla. This review adds a requirement of a closure date on or before December 31, 2022 for Nucla Station. Additionally, an annual NO_x limit of 952 tons per year will be effective January 1, 2020 on a calendar year basis beginning in 2020.

These requirements are the result of an agreement. The 2022 closure achieves further NOx reductions and other environmental co-benefits than the 2011 RP determination. Consistent with the agreement and in lieu of being subject to stringent requirements as part of the long term strategy for the second implementation period of Regional Haze, Nucla Station will close by December 31, 2022. Additionally, an annual NOx limit of 952 tons per year will be effective on January 1, 2020 on a calendar year basis beginning in 2020. Nucla Unit 4 will still comply with the 2011 RP determination of 0.5 lb/MMBtu (30-day rolling average) until closure. A complete analysis that supports the RP determination and review 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 Tri-State 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)	98th Percentile Impact (Δdv)
Daily Maximum (2nd 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.

- 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. 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.

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 Number 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 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 Number 3. In addition, Regulation Number 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 Number 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 Number 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. Colorado considers it's 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 Number 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 Number 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 Number 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 Number 3, as described in Section 9.2.1, and a commitment to utilize the FETS to track fire data as described 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 9-1Colorado'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

Following 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.
- 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:

https://www.colorado.gov/cdphe/aqccAs 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.

Table 9-1 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 - 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 - 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 - 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 - 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 - 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 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 - 8-hour OAP updated 12/17/06 by AQCC to incorporate Regulation Number 7's 75% oil and gas condensate tank requirements. EPA approved 2/13/08, effective 4/14/08 - 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

Regulation Numbers 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 Number 3 cover issuance of permits applicable to sources defined in these regulations and air pollution emission notices required of specified sources. Provisions of Regulation Number 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 Number 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 Number 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[47]. Section III.A of the regulation requires anyone seeking to conduct open burning to obtain a permit from the Division. Regulation Number 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.

[47] 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".

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 Number 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;
- 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: https://www.colorado.gov/cdphe/smoke-management-permits

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 Number 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 Number 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 Numbers 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 Number 3. Unless otherwise indicated in those chapters or in Regulation Number 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. 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 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

Also, 3,321 tons of additional NOx reductions will occur by 2021 due to a more stringent emission limit at Craig Unit 1 adopted in 2014. The revised total is 74,167 tons/year of visibility impairing pollutants reduced (due to BART and RP measures).

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 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 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 1 (SCR @ 78% reduction)	$ 209,548,000	$ 25,036,709	4,048	$ 6,184	1.01	41 (Mt. Zirkel)
Craig - Unit 2 (SCR @ 74% Reduction)	$ 209,552,000	$ 25,036,709	3,975	$ 6,299	0.94	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
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	$ 1,082,813,031	
TOTAL ANNUALIZED COST	$ 146,037,789	
TOTAL NOX REDUCED	**25,085**	*tons/year*
TOTAL SO2 REDUCED	**6,993**	*tons/year*
TOTAL COMBINED POLLUTANTS REDUCED	**32,079**	*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[48]		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[49]		2,135	7.81[50]	
Valmont	2,314	0		758	0	
Pawnee	4,538	1,403[51]		13,472	2,406[52]	
Totals	20,361	4,366	15,995	23,908	2,415	21,493

Total Emission Reductions Achieved: 37,488 tons per year

[48] Includes 300 tpy NOx for offset or netting purposes and 600 tpy NOx from firing Arapahoe 4 on natural gas as a peaking unit.

[49] Includes 500 NOx tpy for offset or netting purposes and emissions at 0.12 lb NOx/MMBtu

[50] Emissions at 0.0006 lb SO2/MMBtu

[51] Emissions at 0.07 lb NOx/MMBtu

[52] 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 74,121 tons of SO2 and NOx reduced due to BART and RP, approximately 47,821 tons per year were not included in the WRAP's 2009 "CMAQ" modeling. Figure 9-6 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	2,539	(8,435)	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	**32,243**	**(34,000)**	**37,473**	**23,666**	**(13,807)**

Combined Reductions from NOx and SO2 Controls [tpy]: (47,808)

These substantial additional emission reductions will further the amount of progress achieved. 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 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 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, 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

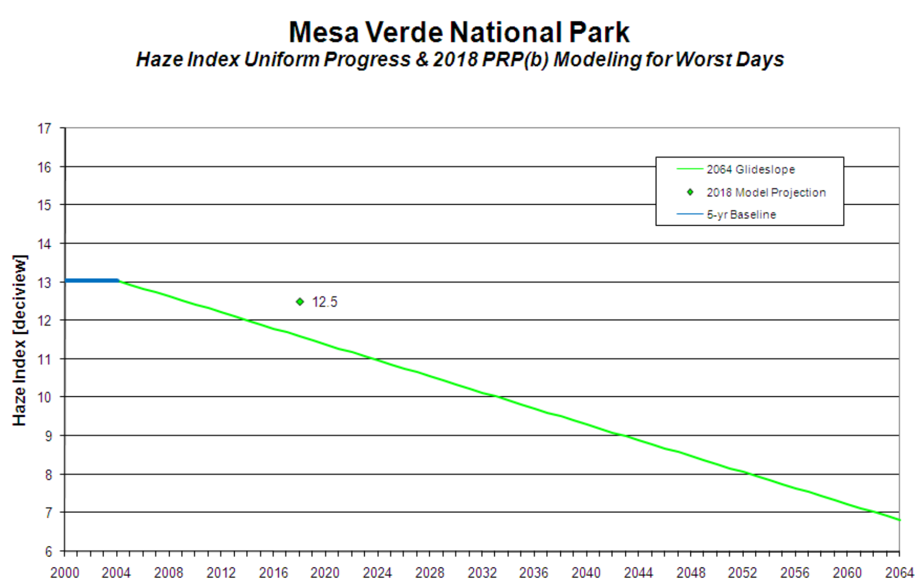
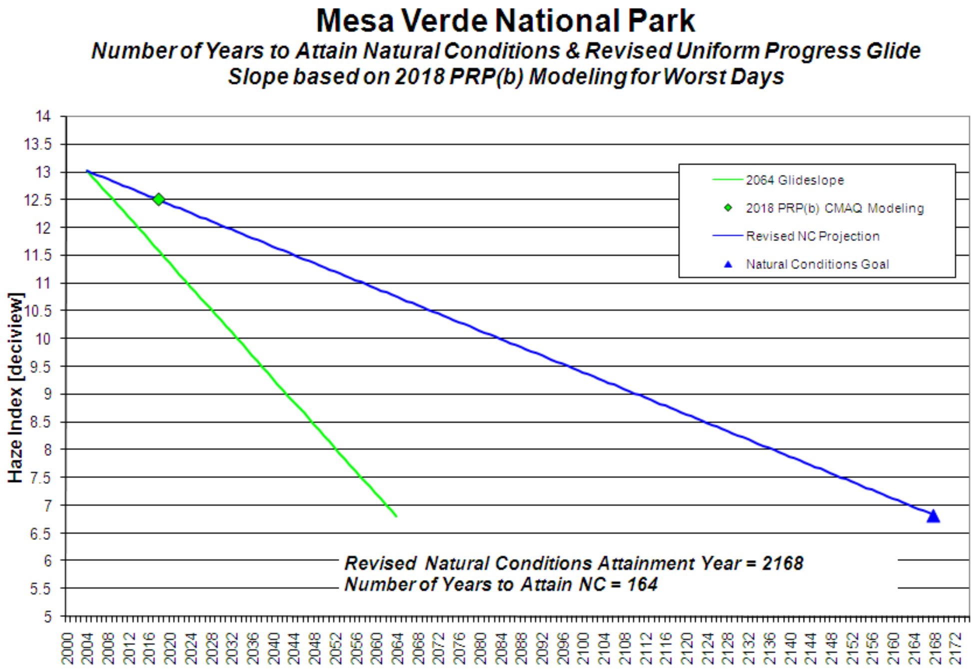


Figure 9-10 Revised Glidepath for Mesa Verde Illustrating the Number of Years to Achieve Natural Conditions



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)].
3. 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.

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 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.

10.4.1 Current Visibility Conditions

Colorado commits to determine and report current visibility conditions for the most and least impaired days using the most 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

APPENDIX A

Regional Haze State Implementation Plan

Periodic Review of Colorado RAVI Long Term Strategy

LONG-TERM STRATEGY REVIEW

OF

COLORADO'S STATE IMPLEMENTATION PLAN FOR CLASS I AREA VISIBILITY PROTECTION ADDRESSING REASONABLY ATTRIBUTABLE IMPAIRMENT

July 2007
(updated October 2007)

I. STATE OF COLORADO'S PHASE I STATE IMPLEMENTATION PLAN FOR CLASS I VISIBILITY PROTECTION ADDRESSING REASONABLY ATTRIBUTABLE IMPAIRMENT

The various elements of Phase I of Colorado's Class I Visibility State Implementation Plan are spread throughout Colorado Air Quality Control Commission Regulation No. 3. All of the components of the Visibility SIP are important to long-term visibility protection of Class I areas in the State and are integrated in varying degrees into the LTS review and revision protocol. Therefore, each of the components is briefly discussed in this section.

A. Existing Impairment.

The AQCC's Regulation No. 3, *Stationary Source Permitting and Air Pollution Emission Notice Requirements*, includes provisions to address impairment within Class I areas reasonably attributable to existing major sources.

Regulation No. 3 Part D §XIV.D provides for an affected FLM or the Division to certify visibility impairment in a Class I area due to an existing stationary source. Existing sources regulated under this program are those that were not in operation prior to August 7, 1962 nor for which construction was commenced on or after August 7, 1977, which have the potential to emit 250 tons or more of an air pollutant regulated by the Division.

The FLM or the Division may certify at any time that impairment exists in any Class I area. If the Division reasonably attributes the impairment to an existing source, the Division must conduct a BART analysis and determine if additional emission limitations are required. If so, the source must apply for a BART permit from the Division. Once the permit is granted, the source must limit its emissions on a schedule not to exceed five years. At the time of Colorado's Visibility SIP development, the FLMs did not indicate that potentially reasonably attributable types of visibility impairment were present in any of Colorado's Class I areas. The Division concurred with the finding. However, in 1993 the USFS certified visibility impairment in the Mt. Zirkel Wilderness in northwest Colorado.[1] The certification has subsequently been resolved and is discussed below in section II.B.1.a.

B. New Source Review.

Applicants for permits to operate as a major source must demonstrate that the proposed source will not have an adverse impact on visibility in any Class I area. Regulation 3 Part D §XIII.A sets forth a schedule for the participation of affected FLMs and consultation with the Division in the review process of such an analysis as part of the Prevention of Significant Deterioration (PSD) permitting application process.

The Division is required to consider any FLM determinations that the proposed source would have an adverse impact on visibility in the Class I area (Regulation 3 Part D §V.A.6 and XIII.C). The Division may independently make its own determination. If the Division does determine that its own or the FLM's analysis demonstrates that an adverse impact would occur, the Division shall not issue the permit.

In addition to the analysis, a source may be required to conduct monitoring to establish the condition of, and impact on, air quality related values (AQRVs) in the Class I area that may be affected. Monitoring can be required both before completing a permit application to construct and during the construction and operation of the source (Regulation 3 Part D §VI.A.3, §VI.A.4, §XIII.B).

C. Consultation With Federal Land Managers.

Regulation No. 3 provides for participation by the FLMs in the new source review process. The FLMs may also make recommendations to the Division concerning integral vistas, identify impairment in any Class I area, and provide consultation concerning elements considered for inclusion in the monitoring strategy. The Division also is required to consult with the FLMs during development and review of the Phase I Long-Term Strategy (Regulation 3 Part D §XIV.F.1.a).

D. Monitoring Strategy.

The monitoring strategy in the SIP is based on 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 effects from the operation of new major 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 sources must conduct visibility analyses utilizing existing visibility data. If data are adequate and/or representative of the potentially impacted Class I area(s), the permitees 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 FLMs or the Division certify existing impairment in a Class I area, the Division will determine if the documented visibility impairment can be reasonably attributed to emissions from an existing local stationary source. 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 not sufficient to make a decision regarding "reasonable attribution" of visibility impairment from an existing source(s), the Division will initiate cooperative studies. Such studies could involve the FLMs, the potentially affected source(s), the EPA, and others.

E. Phase I Long-Term Strategy.

The Phase I LTS is that portion of the Visibility SIP that is the State's long-term strategy for making reasonable progress toward remedying existing and preventing future visibility impairment within the context of the Phase I program.

EPA regulations require the State to: (1) develop a long-term strategy; (2) coordinate its LTS with existing plans and goals, including those of federal land managers, that may affect impairment in any Class I area; (3) demonstrate why the LTS is adequate for making reasonable progress toward the national goal and state why the minimum factors (listed in the next paragraph) were or were not addressed in developing the LTS; (4) consider the time necessary for compliance as well as the economic, energy, and non-air quality environmental impacts of compliance, the remaining useful life of any affected existing source, as well as the effect of new sources; (5) review its strategy no less frequently than every 5 years and consult with federal land managers during this process; and (6) report to EPA and the public on progress achieved toward the national visibility goal.

During development of the LTS the State must consider, at a minimum, the following six factors:

- *Emission reductions due to ongoing air pollution control programs*. For example, the attainment and maintenance of National Ambient Air Quality Standards in the Denver metropolitan area and other non-attainment areas throughout Colorado may reduce visibility impairment in a number of Class I areas in the State. If this is the case, the State should explain how this would contribute to reasonable progress.

- *Additional emission limitations and schedules for compliance*. For example, states may have to control other sources causing impairment not covered by BART to make reasonable progress toward the national goal.

- *Measures to mitigate the impacts of construction activities*. This recognizes that nearby construction activities can contribute to impairment in Class I areas. If this appears to be a problem in Colorado, then the State should explain in its LTS what measures it will take to mitigate these impacts.

- *Source retirement and replacement schedules*. The construction of new sources, which will ensure the early or scheduled retirement of older, less well-controlled sources, can greatly aid progress toward the national visibility goal over the long term.

- *Smoke management techniques for agricultural and forestry management purposes including such plans as currently exist within the State for this purpose.* The LTS should discuss measures that would constitute reasonable progress in relation to this issue.

- *Enforceability of emission limitations and control measures*. In some situations the enforceability of proposed or actual emission limitations and control measures on sources causing existing impairment may be an issue.

F. Colorado's LTS History and the Current Review and Revision.

Since the time the Colorado Visibility SIP was adopted by the AQCC in 1987, the LTS has been amended and/or reviewed on eight occasions:

- The original 1987 LTS was reviewed and revised in August 1992.

- After the 1993 certification of impairment at the Mt. Zirkel Wilderness Area, the EPA requested an informal LTS status report, which was supplied in December 1993.

- The 1996-97 LTS was completed in two stages:

    - August 1996 -- focusing entirely on the Mt. Zirkel Wilderness Area certification of impairment and the incorporation of emission limitations for the Hayden Generating Station; and

    - April 1997 -- addressing all other issues.

- The LTS was comprehensively reviewed again in January 1999, but a SIP revision was not found to be necessary.

- Following the Craig Consent Decree in early 2001, the LTS was again amended in April 2001 incorporating emission limitations, schedules, and reporting requirements for Craig Units 1 and 2. The State, the USFS, and EPA concluded that the 1993 certification of visibility impairment involving Mt. Zirkel Wilderness Area was resolved.[2,3]

- The February 2002 LTS was comprehensively reviewed and the LTS portion of the SIP was updated and reorganized into a more readable format.

- The November 2004 LTS was also a comprehensive review and minor SIP revision update.

Past LTS reviews and SIP revisions are available from the Division.

This current review is a report on the activities, actions, processes, and progress made with respect to the seven review categories within the context of the existing Phase I LTS, adopted by the Commission in November 2004. Colorado believes, based on an assessment of the State's achievements with respect to these seven categories, that the current Reasonably Attributable Class I visibility program of the State of Colorado achieves reasonable progress toward the national visibility goal under Phase I of the visibility protection program.

In a separate document is a SIP revision to the reasonably attributable part of the LTS. The revision is a relatively small series of amendments intended to reflect current conditions and plans.

II. REVIEW OF COLORADO'S LONG-TERM STRATEGY

A. STATE AND EPA REQUIREMENTS

State regulations require the Division to periodically report to the AQCC on the progress made toward the national visibility goal via the Phase I SIP. This report to the AQCC and the public is being submitted to fulfill these requirements. A SIP revision is contained in a separate document.

EPA regulations require that the State provide this report to the public and the Administrator of EPA. Both EPA and State regulations require the report to include an assessment of:

1. The progress achieved in remedying existing impairment of visibility in any Class I area.

2. The ability of the long-term strategy to prevent future impairment of visibility in any Class I area.

3. Any change in visibility since the last such report, or in the case of the first report, since plan approval, including an assessment of existing conditions.

4. Additional measures, including the need for SIP revisions that may be necessary to ensure reasonable progress toward the national visibility goal.

5. The progress achieved in implementing BART and meeting other schedules set forth in the long-term strategy.

6. The impact of any exemption from BART granted to any facility.

7. The need for BART to remedy existing impairment in an integral vista declared since plan approval.

B. STEP-BY-STEP REVIEW

Each element of the review is presented in detail below.

1. PROGRESS IN REMEDYING EXISTING IMPAIRMENT OF VISIBILITY IN ANY CLASS I AREA.

The Phase I Class I Visibility SIP is focused on source-specific or plume-type impairment from single or small groups of stationary sources, consistent with Phase I of the implementation of EPA's visibility program.

a. Visibility Impacts in the Mt. Zirkel Wilderness.

In July 1993, the USFS certified visibility impairment in the Mt. Zirkel Wilderness Area and named the Hayden and Craig power stations as suspected sources.[1] As noted, upon certification by a federal land manager of visibility impairment in a Class I area, the Division must determine if it can "reasonably attribute" the visibility impairment to one or more existing stationary sources. If so, the Division must conduct a BART analysis and as a result may order emission limitations for each pollutant at the facilities.

The Division considered existing information available at the time of the USFS certification of impairment to determine if it could make a decision to reasonably attribute visibility impairment within the MZWA to the Hayden and/or Craig generating stations. The Division concluded that existing information was insufficient to reasonably attribute. The Division's response was to collaboratively develop with other stakeholders the $3.5 million Mt. Zirkel Visibility Study (MZVS) in order to collect additional information. The MZVS was concluded in July 1996.[4]

For a complete review of the activities, studies, and events that have occurred in relation to this environmental matter, see the April 1997 and January 1999 LTS reviews (available from the Division). Below is a summary of the how the certification of impairment has been resolved.

(i). Hayden Station.

The certification of impairment made by the USFS regarding the Hayden Station was resolved through a settlement process that began in late 1995. On May 21, 1996, the Sierra Club, State of Colorado, owners of Hayden Station, and Environmental Protection Agency/Department of Justice executed an agreement -- the Hayden Consent Decree.[5] On May 22, 1996, the Decree was filed in federal district court. The court approved it on August 19, 1996. The Decree was intended to resolve a number of issues, including a successful Sierra Club lawsuit against the Hayden Station, the needs of the State's visibility regulatory program in relation to Hayden, and an EPA complaint against the facility. In addition, the Decree was intended to make progress toward reducing acid deposition in the Mt. Zirkel Wilderness.

Emission limitations, construction schedules, and reporting requirements taken from the Hayden Consent Decree were incorporated into the Visibility SIP by the AQCC on August 15, 1996. The State believes that these significant emission reductions effectively eliminate the sulfate and primary plume related visibility impairment in the MZWA that could be associated with the Hayden Station. The State further believes that the Hayden Consent Decree effectively resolves the certification of impairment brought by the USFS against the Hayden Station. The Forest Service has concluded that its complaint against Hayden has been satisfied. EPA approved this SIP amendment on January 16, 1997.[6]

The construction of Hayden's control equipment progressed ahead of schedule. All compliance dates in the SIP and Consent Decree were met and the emission limitations for NOx, SO_2, opacity, and particulate matter have been consistently achieved in actual operation. The relevant emission limitations and monitoring requirements have been moved into the facility's Title V operating permit and the permit has been issued and the Consent Decree has been terminated.

(ii). Craig Generating Station (Yampa Project).

The certification of impairment made by the USFS regarding the Craig Station Units 1 and 2 was also resolved through a settlement process that began in Fall 1999. After Hayden was resolved in August 1996, attention turned to Craig Station Units 1 and 2. The Mt. Zirkel Visibility Study (MZVS) indicated to the Division that sulfate haze from Yampa Valley power plants occasionally entered the MZWA and along with regional haze contributed to visibility impairment. Thus, the focus to resolving the Craig Station portion of the certification was on reducing SO_2, the precursor pollutant of sulfate, from Craig Station Units 1 and 2. The State preferred to resolve the visibility certification through negotiated settlement. If settlement seemed unlikely, the State was prepared to resolve the certification using the available regulatory tools. At a meeting in late 1996 between the State, Craig Owners, and EPA, the State agreed to temporarily delay pursuing regulatory action in order to foster the collaboration needed to jointly develop additional information on various SO_2 emission reduction options and associated cost. Craig Station Units 1 and 2 at the time achieved 65% SO_2 control; both EPA and the State believed that an improvement in the degree of control would resolve the certification. A joint study, known as the Craig Station Flue Gas Desulfurization Study (Craig FGD Study), became the focus for a negotiated settlement. The information could also be used as part of a BART determination if needed. The study was completed in August 1999.[7]

There were other issues involved and parties concerned with emissions from Craig Station Units 1 and 2. The USFS has strong concerns about local emissions of SO_2 and NOx that may be associated with acid deposition and aquatic and terrestrial ecosystem effects in the MZWA. A 1996 Colorado statute provides FLMs with an opportunity to assert impairment to Class I areas by air pollution adversely affecting non-visibility related qualities of the area, such as the aquatic ecosystem.[8] The USFS did not trigger the law with an assertion related to MZWA and was awaiting the outcome of the resolution of the visibility certification and/or global settlement of all issues. In addition, the Sierra Club initiated a citizen lawsuit under the Clean Air Act in late 1996 directed against Craig Station Units 1 and 2 regarding opacity issues.

In Fall 1999, the Sierra Club, Craig Owners, EPA, the State, and the USFS began global settlement talks with an independent mediator. On September 22, 1999, EPA issued a SIP call to Colorado indicating the State had twelve months to resolve the certification regarding Craig Station Units 1 and 2.[9] The Craig Owners and Sierra Club concluded a Consent Decree and filed it with the federal district court on January 10, 2001. The court approved the agreement on March 19, 2001. The State resolved the certification of impairment for Units 1 and 2 of Craig Station by adopting emission limitations, schedules, and reporting requirements from the Craig Consent Decree into the Visibility SIP. The USFS concluded that, "the proposed reductions of both sulfur dioxide and nitrogen oxides will resolve all Forest Service issues relative to the Craig Stations and our 1993 Certification of Impairment."[10] The SIP was amended by the AQCC on April 19, 2001[2] and EPA published final approval of the SIP amendment after a public comment period.[3] Work was completed on Unit 1 during 2003 and on Unit 2 in 2004. All compliance dates in the SIP and Consent Decree were met and the emission limitations for NOx, SO_2, opacity, and particulate matter have been consistently achieved in actual operation. The relevant emission limitations and monitoring requirements have been moved into the facility's Title V operating permit. The permit has been issued and the Consent Decree terminated.

(iii). Other Stationary Sources and the MZWA.

The Division has found no evidence that other stationary sources potentially subject to

BART may reasonably be attributed to cause or contribute to visibility impairment at MZWA under Phase I of the EPA visibility program. The USFS certification of visibility impairment, related to the Phase I program, has been completely resolved. Regional haze that impacts any Colorado Class I areas, including MZWA, are addressed in the regional haze SIP.

(iv). Monitoring and the MZWA.

It is important to track the effect of the emission reductions at Hayden and Craig generating stations on visibility impairment near the Wilderness as well as on acid levels in sensitive lakes and the snowpack. Funding for and the collection of these data are provided variously by the USFS, U.S. Geological Survey, EPA, and the Division. Table 1 below provides a brief overview of monitoring activities in and around MZWA.

Table 1
Long-Term Visibility and Non-Visibility Air Quality Related Value Measurements In and Near the Mt. Zirkel Wilderness Area

Instrument, Measurement, or Sampler	1. Sponsor 2. Funding 3. History	Purpose
Continuous SO_2 monitor at Buffalo Pass Tower*	1. Colorado Air Pollution Control Division 2. \$9,800/year by CAPCD 3. 9/97 through present.	Measures frequency and magnitude of SO_2 “hits” at Buffalo Pass as an indicator of the presence of Craig and Hayden emissions and potential impacts at the Mt. Zirkel Wilderness Area. The monitor provides hourly average SO_2. The purpose of the monitor is to determine whether trends are occurring as emissions change at Hayden and Craig 20 and 40 miles away, respectively, in the Yampa Valley.
Continuous ambient nephelometer at Buffalo Pass Tower*	1. US Forest Service 2. \$9,600/year by USFS 3. 1994 through present.	Measures frequency and magnitude of visibility episodes (the nephelometer measures light scattering, a component of visibility) at Buffalo Pass. This measurement provides hourly average light scattering but is subject to significant weather interferences.
Automatic camera system	1. US Forest Service 2. \$5,280/year by USFS 3. 10/90 through present	Three 35mm slides are taken each day and archived. The visual information can be used to document various types of visibility conditions and matched/collated with instrumental measurements.
IMPROVE aerosol monitor at Buffalo Pass Tower*	1. Initially USFS, now EPA, as part of the national IMPROVE visibility monitoring network. 2. \$14,000/year by EPA (for supplies and analysis) \$33,000/year by USFS (for support of all Buffalo Pass Tower monitoring operations)	Measurements include 1-in-3 day sampling, 24-hour filter based PM2.5 (chemically speciated) and PM10 (mass only). Light extinction reconstruction is calculated from the various aerosol constituents. Measurement of overall reconstructed light extinction is used for episode identification as well as trends. These reconstructed extinction data will be compared between the before and after periods. While this measure is not as prone to weather interferences as the nephelometer, other challenges in analyzing these data include changes in regional emissions, climatic variation, wildfire, and the nature

Instrument, Measurement, or Sampler	1. Sponsor 2. Funding 3. History	Purpose
	3. 1994 through present	of trying to distinguish episodic change in a 24-hour average.
National Acid Deposition Program (NADP) sampler at Buffalo Pass Tower*.	1. USFS 2. $12,288/year by USFS 3. 1984 through present	Measurement of acid precipitation-related chemical constituents. The network collects data on the chemistry of precipitation for monitoring of geographical and temporal long-term trends. The precipitation at each station is collected weekly. It is then sent to the Central Analytical Laboratory where it is analyzed for hydrogen (acidity as pH), sulfate, nitrate, ammonium, chloride, and base cations (such as calcium, magnesium, potassium and sodium).
Mercury deposition sampler at Buffalo Pass Tower*	1. USFS 2. $12,000/year by USFS 3. 1997 through present	Mercury deposition sampling is done through the NADP program. This site is sponsored and funded by USFS. The purpose is to measure mercury deposition. The sample is collected weekly and sent to the NADP's Central Analytical Laboratory.
Snowpack chemistry sampling in March or April of each year prior to spring snowmelt.	1. USGS, NPS, USFS 2. $115,000/year 3. 1990 through present	Annual measurement of snowpack chemistry prior to spring snowmelt and the release of acids during the "spring acid pulse." The U.S. Geological Survey has been monitoring snowpack chemistry at more than 50 locations throughout the Rocky Mountain region, extending from northern New Mexico to northern Montana, annually since 1993. There are 20 sites in Colorado, including several in and near the Mt. Zirkel Wilderness. Some sites in Colorado have been monitored since 1990. The purpose of the monitoring is to: 1) have an integrated measurement of acid deposition and snow chemistry over the snow accumulation months in high altitude areas associated with sensitive high altitude aquatic ecosystems; 2) determine whether trends are occurring in the snowpack chemistry; and 3) provide indicators of regional and/or local source emission changes.
Lake sampling in Mt. Zirkel Wilderness (and 2 other wilderness areas) during summer and fall.	1. USFS/CDPHE/ USGS 2. $62,000 3. 1983 through present	Measurements of acid precipitation-related chemical constituents as well as overall measures such as hydrogen ion, pH, and buffering capacity of 3 lakes in the Mt. Zirkel Wilderness. The purpose of the long-term monitoring of these lakes is to: 1) determine the natural variance in chemistry of the lakes; 2) determine whether trends are occurring in the chemistry of lakes in the Mt. Zirkel Wilderness, and 3) provide information on the ambient chemistry of lakes in the Wilderness.

*Buffalo Pass monitoring tower is at the southern end of the Mt. Zirkel Wilderness.

The measurements provide a reasonably comprehensive network to track the emission changes through different parts of key environmental systems, including atmospheric emissions, visibility, precipitation, acid deposition, mercury deposition, snowpack and aquatic ecosystems.

(v). Analysis of the Effects of the Hayden Generating Station Emission Reductions. Using the data collected from the network described above, the Division and the USGS completed an analysis during 2004-2005 of the effects of the emission reductions at the Hayden Generating Station. At that time, Craig had just completed its emission capture upgrade and there were insufficient data to analyze to assess the additional effects of the Craig project. Therefore, the analysis focused on the reductions at the Hayden Generating Station. A final report will be completed during 2009 on the effects of the reductions at Craig as well as an assessment of the combined effect of the decreases in emissions from both facilities.

Study Design. Environmental data were compared between a period "before" Hayden was controlled versus a period "after" Hayden was controlled**.**

The period before controls were installed at Hayden is defined as 1995 through 9/24/98. 1995 is chosen as the beginning of the before period even though data extends earlier for a number of data sets. The before period is purposely constrained to limit the influence of regional emission changes over time as well as climate variation.

Unit 1's boiler was brought down on 9/25/98 to begin the tieing-in and integration of its various air pollution control systems. Unit 1 was re-started with emission controls on December 21, 1998. Unit 2's boiler was brought down on 3/7/99. It was re-started on May 20, 1999. However, intermittent problems with the SO_2 controls could not be fixed until November 16, 1999. The Craig Generating Station (Yampa Project) began its upgrades on September 13, 2003. The three periods (i.e., before, during, after) are summarized in Table 2 below. Only the before and after periods were analyzed and compared.

Table 2
The Before, During and After Periods

Period	**Dates**	**What**
Before	1995 through 9/24/98	This is the period before Hayden's pollution controls began operating
During (not analyzed)	9/25/98 through 11/16/99	Pollution control equipment was being tied-in, integrated and de-bugged.
After	11/17/99 through 9/12/03	Hayden's equipment in routine operation and Craig had not yet begun its tie-in period.

Confounding Factors. Because the collection of environmental data occurs in the real world, rather than in a laboratory where other changes can be held constant, there are several influences the data analysts were aware might confound or mask the signal of Hayden's emission change. All of the factors below contribute to make it more difficult to find and attribute the changes due solely to Hayden.

- Climate
  - The before period was wetter than average and the after period was drier than average. There was a 30-40% decrease in precipitation between the two periods depending on measurement location.
- Regional Haze
  - The after period was 17% more hazy. This is largely due to the decrease in precipitation and associated drought. Chemical analyses showed that almost all of the change between the two periods was due to particles from wildfires and increased dust.
- Overall Yampa Valley Emissions
  - Hayden and Craig are in the same valley, therefore, emissions from both must be considered together since analysis techniques can't identify the pollutants from one plant versus the other. Given Hayden's specific reduction and the ongoing operation at Craig (before its upgrade), SO_2 decreased in the Yampa Valley by 48% and NOx increased 7%.
- Regional Emission Changes
  - Not only was there an emission change at Hayden, but large emission reductions of SO_2 also occurred in the southwestern part of the U.S. For example: Arizona/39%, New Mexico/27%, Wyoming/18%, Texas/15%.
- Atmospheric Chemistry
  - The atmospheric chemistry converting invisible SO_2 gas to visible sulfate particles is not linear. That is, a one unit decrease in SO_2 may not lead to a one unit decrease in sulfate.

Results.

- Emissions
  - Sulfur dioxide (SO_2) removal at Hayden has always been at least 85% over 30 and 90 day rolling averages since the compliance period began. Nitrogen oxides (NOx) have decreased approximately 50% annually. The new particulate control system has completely eliminated the occasional black smoke-plume episodes that previously occurred.
- Ambient SO_2 as measured at Mt. Zirkel Wilderness Area
  - Decreased 40% due to the reductions at Hayden.
- Haze at Mt. Zirkel Wilderness Area
  - Increased 17% due to the drought and increases in regional haze. This would have been worse without the reductions at Hayden.
- Sulfate Particulate Haze
  - Overall decrease of 20% at Mt. Zirkel Wilderness Area.
  - Peak sulfate episodes were eliminated in the after data. This is a very important finding because it is the worst days that hamper enjoyment of clear visibility.

        - It is estimated that approximately half of the overall decrease is due to Hayden's reductions. The other half is due to the regional scale reductions in SO_2.
- Acid Deposition Measurements
    - Decrease in sulfuric acid deposition of approximately 20%.
        - Looking at other measurement sites, this decrease in sulfuric acid *only* occurred at acid deposition sites downwind of Hayden.
    - Overall decrease in acid deposition at all sites, however, most of this is drought related due to an increase in dust elements in the rain and snow that buffer acids.
- Snowpits
    - Small decrease in sulfuric acid at pits downwind from Hayden.
    - Overall decrease in acidity, again due to more dust elements in the snowpack.
- Lakes
    - No change due to emission reductions in before versus after periods. This is expected because response time to an emission reduction of SO_2 in a watershed is several years. Effects of drought were also visible in lake acidity (i.e., less acid due to increased dust elements).

In spite of the big challenges nature and other anthropogenic changes piled onto the study design, the USGS and the APCD see a strong signal decrease in episodic visibility impairing sulfate and acidic wet sulfate in and near the Mt. Zirkel Wilderness Area from the emission reductions at Hayden Generating Station.

b. Regional haze.

EPA published its final regional haze rule in July 1999.[11] This review of the Phase I SIP is not related formally to the regional haze program. Nevertheless, such haze exists at all Colorado Class I areas and is the subject of the larger regional haze SIP document within which this LTS review is embedded and coordinated.

c. Ongoing Air Pollution Control Programs.

Since the November 2004 LTS review/report several activities in ongoing air pollution control programs have occurred that are relevant to this review.

(i). Rocky Mountain National Park Initiative.

The National Park Service (NPS), other federal agencies, and academic researchers have actively pursued ecosystem and air quality monitoring and data collection programs in and near the Park for over twenty years. Through these efforts significant amounts of data have been collected. Findings from these data published in over 80 peer reviewed research articles document ecosystem changes from nitrogen (N) deposition on the east side of the Continental Divide including changes in the type and abundance of aquatic plant species, elevated levels of nitrate in surface waters, elevated levels of N in spruce tree chemistry, long-term accumulation of N in forest soils, and a shift in alpine tundra plant communities favoring sedges and grasses over the natural wildflower flora.

Two-thirds of the Park is near or above treeline with shallow soils and granitic bedrock that are indicative of a fragile ecosystem environment. This environment is highly susceptible to changes induced by chemical contributions to soils and waters through atmospheric deposition. The Park's enabling legislation and other key Congressional statutes mandate that natural resources at RMNP are to remain unimpaired for future generations. Thus, the Rocky Mountain National Park Initiative was created to study and promote action to remedy air quality issues facing the Park, primarily the adverse ecosystem impacts from increasing nitrogen deposition. Other air quality issues are being addressed by other means: visibility impairment by the regional haze program development and ozone by the Early Action Compact and SIP development process.

Using a collaborative approach, the participating agencies -- the Colorado Department of Public Health and Environment (CDPHE), the U.S. Environmental Protection Agency Region 8 (EPA), and the NPS -- have worked effectively to develop a Nitrogen Deposition Reduction Plan (Plan or NDRP). A public participation process facilitated by a Colorado Air Quality Control Commission (AQCC) Subcommittee has helped to involve the public, and a memorandum of understanding (MOU) has been used by the involved agencies to guide the Initiative's progress leading to development of the Plan.

The agencies have initially focused their efforts in developing the Plan on voluntary approaches first, together with programs that are pending or under way, in lieu of developing a new regulatory program to achieve nitrogen deposition reductions. The agencies believe this strategy has the potential to provide benefits in the near term to reducing nitrogen deposition. However, the agencies support a process to require regulatory measures specific to reducing nitrogen deposition if voluntary and anticipated reductions prove insufficient in making planned progress goals under this Plan. Development and implementation of a contingency plan is one mechanism supported by the agencies to ensure reduction of adverse ecosystem impacts in RMNP.

The NDRP works to: (1) consider all available emission reduction options and programs for nitrogen-related emissions (primarily nitrogen oxides (NOx) and ammonia (NH3)); (2) provide a technical assessment of the state-of-knowledge of deposition components and trends, the emission sources, source areas, and atmospheric transport; (3) determine implementation measures for making progress and mechanisms to evaluate effectiveness of, and incorporation of new, control measures; (4) make recommendations for future needs as necessary to assure continued progress and achievement of Park goals; and (5) incorporate adaptive management principals for the consideration and use of new data and analyses as they become available.

The Plan includes a critical load determination for nitrogen affecting the high alpine ecosystems in the Park that was established prior to the development of this Plan. The critical load for wet nitrogen deposition, set at 1.5 kg/ha/yr, is a threshold value above which significant harmful effects to sensitive ecosystem components occur. The critical load for wet nitrogen deposition east of the Continental Divide in RMNP represents an estimation of the concentration at which excess nitrogen deposition began causing harmful impacts on RMNP ecosystems. The Plan relies on a "glidepath" management approach to achieve the critical load goal in the Park by the year 2032 with interim milestones to be measured at five-year intervals. The first milestone, set for 2012, works to achieve a reduction that is consistent with an average rate of deposition reduction that will achieve the critical load by the year 2032 and reflects the potential benefit from planned state and federal emission reduction programs.

The NDRP was approved by the AQCC in April 2007. Implementation of the Plan will likely benefit visibility at RMNP to an unknown degree. The Division maintains a website that is a clearinghouse for information related to the Initiative. The full NDRP and other technical documents may be found at
http://www.cdphe.state.co.us/ap/rmnp.html

(ii). The Four Corners Task Force.
After many years of concern about emissions growth in the Four Corners area and impacts on nearby Class I areas, the States of New Mexico and Colorado have convened an Air Quality Task Force to work on the air quality issues and challenges facing the Four Corners region. The Four Corners region is rich in coal and oil & gas reserves. Oil & gas production and coal-fired power plants result in large emissions of air pollution that may be degrading air quality. Specific concerns include National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) increment compliance, degradation of visibility, and increased deposition.

The U.S. Department of Interior - Bureau of Land Management (BLM) and the U.S. Department of Agriculture - Forest Service (USFS) are currently responding to industry proposals for expanded development of oil and gas production in the region. There are two proposed coal-fired power plants: a 1,500 megawatt plant proposed on Navajo Nation lands and a 300 megawatt plant proposed north of Grants, New Mexico. Additionally, the population in the Four Corners region likely will continue to grow in coming years, resulting in even more air pollution and, specifically, more nitrogen oxide emissions.

In response to these challenges, the affected states, tribes and federal land managers in the region have come together to begin to plan for control strategies for future air quality impacts from development. The concept of a Task Force emerged that would allow for a broad and inclusive collaborative process to regional air quality planning.

The Task Force work groups are:

- Oil and Gas,
- Power Plants,
- Other Sources,
- Cumulative Effects, and
- Monitoring.

These workgroups are studying issues and creating lists of options to the Task Force about how to proceed. An executive/steering committee that includes representatives from the states of

Colorado, New Mexico, and Utah, the U.S. Environmental Protection Agency, the U.S. Department of Agriculture - Forest Service, and the U.S. Department of the Interior - National Park Service and the Bureau of Land Management has been formed to help guide the Task Force's progress. Timelines for workgroup deliverables are being developed to ensure that all options developed are timely. The task force will work over a two-year period and deliver a final report by December 2007.

The Task Force's website is
http://www.nmenv.state.nm.us/aqb/4C/index.html

(iii). New Oil and Gas Controls.

On December 17, 2006, the Colorado Air Quality Control Commission (AQCC) adopted changes to oil & gas industry regulations to reduce emissions of volatile organic compounds (VOCs) from condensate tanks. VOCs are a precursor to ozone formation and secondary organic carbon particulate – a component of visibility degradation.

New control requirements were established for condensate tanks in both the Front Range Early Action Compact Area and statewide. New reporting and recordkeeping requirements were also established. The new requirements are summarized below:

Control Requirements: Front Range Ozone Early Action Compact (EAC) Area

- Commencing May 1, 2007, companies in the EAC region must increase the control of VOCs from current 47.5 percent level to 75 percent for the summertime ozone season.
- In addition, there are new reporting and recordkeeping requirements.

Control Requirements: Statewide

- Tanks standards: New and existing condensate tanks emitting 20 tons per year or more of VOCs required to control emissions by 95 percent commencing May 1, 2008.
- Glycol Dehydrator controls: New and existing glycol dehydrators emitting more than 15 tons per year of VOCs are required to control emissions by 90 percent commencing May 1, 2008.
- Table 3 contains engine standards for new or relocated engines from out-of-state commencing July 1, 2007.

Table 3
Engine Standards

Maximum engine horsepower	Construction or relocation date	NOx g/hp-hr	CO g/hp-hr	NMHC g/hp-hr
100 - 500 hp	January 1, 2008 January 1, 2011	2.0 1.0	4.0 2.0	1.0 0.7
Greater than 500 hp	July 1, 2007 July 1, 2010	2.0 1.0	4.0 2.0	1.0 0.7

Additional information about the new emission controls can be found at http://www.cdphe.state.co.us/ap/oilgas.html

(iv). Review of Ongoing Programs and Status of Redesignations.

The most comprehensive review of existing and ongoing programs as well as monitoring data and trends is contained in the Colorado Air Quality Control Commission's 2006-2007 Report to the Public. This report in its entirety is included as Attachment 1.

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 has 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 has designated all or parts of 9 counties in northeastern Colorado as nonattainment for the 8-hour ozone, though the nonattainment designation has been 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 on Friday, July 20, 2007 appear to have put the nine-county Denver region in violation of the federal health-based, eight-hour standard for ozone. If monitoring results are verified, the region will likely be designated as "nonattainment" for ozone by the U.S. Environmental Protection Agency. A detailed plan to reduce ozone will be developed for submission to the EPA in 2008 by the Colorado Air Pollution Control Division, along with the Regional Air Quality Council and the North Front Range Metropolitan Planning Organization. This new plan, a federally -required State Implementation Plan for ozone, will require further reductions in ozone levels beyond what was required through an earlier Ozone Early Action Compact.

The table below shows the designation status for Colorado non-attainment areas as of April 2007.

Table 4
REDESIGNATION and PLAN AMENDMENT STATUS REPORT – 4/2/07

	Redesignations	**Plan Amendments**
PM10		
Aspen	AQCC approved 1/11/01; EPA approved 5/15/03, effective 7/14/03	None
Canon City	AQCC approved 10/17/96; EPA approved 5/30/00, effective 7/31/00	None
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

	Redesignations	Plan Amendments
		12/15/05; Governor submitted to EPA 9/25/06
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	None
Steamboat Springs	AQCC approved 11/15/01; EPA approved 10/25/04, effective 11/24/04	None
Telluride	AQCC approved 3/16/00; EPA approved 6/15/01, effective 8/14/01	None

Carbon Monoxide		
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 - 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
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 - Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; Governor submitted to EPA 9/25/06
Ft. Collins	AQCC approved 7/18/02; EPA approved 7/22/03, effective 9/22/03	
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
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 - Amendment developed with MOBILE6 to remove I/M & oxyfuels from SIP; AQCC approved 12/15/05; Governor submitted to EPA 9/25/06

Ozone		
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 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; Governor submitted to EPA 10/06 - 8-hour OAP updated 12/17/06 by AQCC to incorporate Reg 7 oil and gas condensate tank and engine requirements. Governor's submittal anticipated -Additional exceedances in 2007. SIP preparation in 2008.
Lead		
Denver	EPA redesignated Denver attainment in 1984	
Nitrogen Dioxide		
Denver	EPA redesignated Denver attainment in 1984	

2. THE ABILITY OF THE LONG-TERM STRATEGY TO PREVENT FUTURE IMPAIRMENT OF VISIBILITY IN ANY CLASS I AREA.

Generally, the State of Colorado considers its New Source Review and Prevention of Significant Deterioration (PSD) programs as meeting the long-term strategy requirements for preventing future impairment from proposed major stationary sources or major modifications to existing facilities. In addition, there are specific activities the Division has undertaken.

a. Modeling Guidance.

The Division has published modeling guidance that presents methods for estimating impacts from stationary sources of air pollution. The guidance is intended to help permit applicants, air quality specialists, and others understand the Division's expectations for the ambient air impact analysis and to prevent unnecessary delays in the permit process. It provides a starting point for modeling, but allows the use of professional judgment. The guidance contains sections on visibility modeling. In 2001, a technical peer review of the guidance was completed. A more general public review process was finished toward the end of that year. The finalized and updated (as of December 27, 2005) guidance document is available via the Air Pollution Control Division's web site at: http://apcd.state.co.us/permits/cmg.html

b. Smoke Management.

Colorado believes its smoke management program is protective of public health and welfare as well as Class I visibility. In 2005, the Division certified its smoke management program as consistent with EPA's *Interim Air Quality Policy on Wildland Prescribed Fire*, May 1998. The program is described below.

(i). Regulation No. 9.

Regulation No. 9 (Open Burning, Prescribed Fire, and Permitting) is the main vehicle in Colorado for addressing smoke management and preventing unacceptable smoke impacts. In addition to its permitting requirements, it implements Colorado Senate Bill 01-214 ("Concerning the Application of State Air Quality Standards to the Use of Prescribed Fire for Management Activities Within the State and Making an Appropriation Therefor") that became law in 2001. The regulation also incorporates permitting and reporting requirements for all users of prescribed fire similar to those in the State's past Smoke Management Memorandum of Understanding (MOU). The AQCC adopted the regulation on January 17, 2002.

Regulation No. 9 is in eight sections:

I. Scope
II. Definitions
III. Open Burning Permit Requirement
IV. General Open Burning Permits
V. Planned Ignition Fire Permits
VI. Unplanned Ignition Fire Permits
VII. Additional Requirements for Significant Users of Prescribed Fire
VIII. Fees

The rule applies to all open burning activity within Colorado, with certain exceptions. Section III specifically exempts agricultural open burning from the permit requirement.

After the scope and definitions sections, the rule has several sections regarding permitting and other requirements applicable to open burning of various types. Section IV contains requirements for a general open burning permit and associated permit conditions. Sections V and VI contain the permitting, information, modeling and reporting requirements, as well as a smoke risk categorization, and permit conditions for planned ignition prescribed fires to insure that prescribed fires neither violate National Ambient Air Quality Standards nor have unacceptable visibility impacts. These provisions are similar to the past voluntary agreements among signatories of the expired Colorado Smoke Management MOU for prescribed fire. The regulation, however, applies to <u>all</u> users of prescribed fire above a de minimus level project. The rule also specifies requirements regarding suppression of prescribed fire if monitoring and/or air pollution levels indicate that permit conditions, the burn prescription, and/or air quality standards have been or will be exceeded. The Division's draft permits for large burns with a high smoke-risk are subject to a 30-day public comment period and the opportunity for a public comment hearing before the Commission. The Division will disclose potential visibility impacts of these proposed fires and must consider comments when determining whether to grant, conditionally grant, or deny the final permit.

Sections VII and VIII are the elements of the regulation that implement SB01-214. Section VII addresses how significant users of prescribed fire (i.e., those that own or manage 10,000 acres and generate at least 10 tons of PM_{10} annually from use of prescribed fire) must submit planning documents to the Commission. The regulation identifies the contents of the planning documents. The rule further requires that all such prescribed fire activities of significant users shall conform to the State standard to "minimize emissions using all available, practicable methods that are technologically feasible and economically reasonable." SB 01-214 directs the Commission to hold a public hearing regarding each planning document and to develop any necessary comments and recommendations to bring the plans into consistency with the State goal. After July 1, 2002 the Division cannot issue open burning permits to significant users for lands whose planning documents and fuel management decision-making are inconsistent with Commission recommendations and comments. The Commission has had hearings on the planning documents of the U.S.D.A. Forest Service, U.S.D.I. Bureau of Land Management, Colorado Division of Wildlife, U.S.D.I. National Park Service, U.S.D.O.D. Fort Carson, U.S.D.I. Fish and Wildlife Service, U.S.D.O.D. Air Force Academy, Jefferson County, Banded Peak Area Ranches, Colorado State Parks, Colorado State Land Board, the Forbes/Trinchera Ranch, and the Denver Water Board.

Fees are discussed in section VIII. No fees are charged for general permits (local authorities may charge fees under their own authority). Significant users of prescribed fire pay fees of $59.98/hour to the Division for review of planning documents. Prescribed fire permitees pay for the cost of the prescribed fire program based on a cost distribution methodology. The Division's Fiscal Officer calculated the cost of the program at the outset of the program beginning in calendar year 2002. The Statement of Basis, Specific Statutory Authority and Purpose of the regulation also specifies the Commission's intent that the Division annually calculate the cost to administer the program and report to the Commission each August on program costs, projections, and revenues. If the cumulative cost varies more than 5% from the total fee amount in regulation, the Division will seek a fee change before the Commission in a properly noticed public hearing. In addition, the Statement indicates that any deficits not be funded by stationary source fees. The current cost of the program as stated in Regulation No. 9 is $174,585.08.

While not included in the rule, it is important to note that the statute also finds the prescribed fires of significant users conducted on lands the primary purpose of which is nonagricultural to be for "commercial purposes". The effect is to subject any such activity conducted without a permit to significantly higher fines than previously (i.e., up to $100/day for "noncommercial purposes" and up to $10,000/day for "commercial purposes").

In March 2004, the Commission approved changes to Regulation No. 9 allowing the permitting of Air Curtain Destructors (ACD) to be used for the narrow purpose of burning wildland fuels generated as a result of projects to reduce the risk of wildfire. The use of ACDs in lieu of pile burning will significantly reduce emissions from defensible space and other types of wildfire risk reduction projects.

(ii). The Regulation and Visibility Protection.

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. 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;
- 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. Proposed planned ignition burns are compared to computer model output that indicates the air pollution (including visibility) impacts. A permit is granted only if the modeling run 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 that the Division may 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."

Permitees 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 permitees must indicate 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 2006 are available by contacting the Division.

As mentioned above, the regulation requires that 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 the 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. The web site underwent a major revision and updating during 2005. It is located at: http://www.cdphe.state.co.us/ap/smoke/

3. CHANGES IN VISIBILITY SINCE SIP APPROVAL AND ASSESSMENT OF EXISTING CONDITIONS

Visibility monitoring is being performed in or near a number of Colorado's Class I areas.

The specific purposes of monitoring may vary, but generally include assessing existing conditions and trends as well as learning more about the sources of visibility impairment in Colorado's Class I areas.

The routine visibility monitoring performed in Colorado's Class I areas are at IMPROVE, IMPROVE Protocol or IMPROVE Look Alike sites. IMPROVE is an acronym that stands for Interagency Monitoring of PROtected Visual Environments. IMPROVE is a cooperative visibility monitoring effort of the EPA, NPS, USF&WS, BLM, USFS, Western States Air Resources Council (WESTAR), Mid-Atlantic Regional Air Management Association (MARAMA), North Eastern States for Coordinated Air Use Management (NESCAUM), and the National Association of Clean Air Agencies (NAACA). IMPROVE Protocol sites are operated using the same equipment, procedures and analytical labs as other sites in the IMPROVE network across the country, allowing comparisons of data from all these sites. IMPROVE Look Alike sites are operated using the same equipment and procedures but may utilize different labs. IMPROVE sites are funded by EPA. IMPROVE Protocol sites are funded by a sponsoring federal land management agency or state. IMPROVE Look Alike sites may be funded by private industry or other entity. IMPROVE and IMPROVE Protocol sites are operated by the NPS, BLM, or the USFS. The State of Colorado has funded a short-term IMPROVE Look Alike site but does not fund other IMPROVE or IMPROVE Protocol sites. IMPROVE has an extensive web site at: http://vista.cira.colostate.edu/improve. Graphically processed IMPROVE data as well as links to photographic images of various haze levels at Class I areas and meteorological data are found on the Visibility Information Exchange Web System (VIEWS) at: http://vista.cira.colostate.edu/views/

The types of visibility monitoring being performed in Colorado's Class I areas and some of the results of this monitoring are summarized later in this section of the LTS review. The section is divided into three major parts:

a. Monitoring Methods and Network -- a very brief discussion of each of the types of routine visibility monitoring performed in Colorado and a description of the monitoring network in place as of December 2006.

b. Site-By-Site Data Summaries -- summaries of the routine data available as of April 2007 collected by these methods, a short discussion of the data, and of possible data trends of each site (park or wilderness area).

c. Overall Conclusions from the Routine Monitoring -- statements about visibility levels, sources, and trends in Colorado's Class I areas.

a. Monitoring Methods and the Network.

Routine visibility monitoring consists of three general components. The first, view monitoring, is used to document the visual quality of a scene. The second component, atmospheric optical monitoring, measures basic optical properties of the atmosphere (e.g., atmospheric extinction, light scattering) that relate to the atmosphere's ability to cause visibility impairment. In some of Colorado's Class I areas atmospheric extinction has been directly measured with a transmissometer. At one of the monitoring sites, a nephelometer monitors the scattering coefficient of ambient air. The third component of most routine visibility monitoring systems, particle monitoring, measures fine atmospheric particles that are responsible for visibility impairment. This third component is considered the core method for IMPROVE and at each site, at a minimum, is a chemically speciated fine particle monitor. Each general component of monitoring is described in more detail below.

(i). View Monitoring.

Camera systems are used to document visibility in a view from a fixed location. A specially constructed camera system automatically takes slides or digital images of a view at regularly scheduled times each day (usually three times per day). The images provide a qualitative record of visibility conditions that exist at a site.

Automated camera systems are in place at the following sites to monitor visibility conditions in or near the following Class I areas (the letters in parentheses below are how each site is referenced within the FLM and IMPROVE data and image management systems):

- Shamrock Mines (SHMI) near the Weminuche Wilderness;
- Maroon Bells-Snowmass Wilderness site in the White River National Forest (MABE); and
- Mt. Zirkel Wilderness (ZIRK).

In the past automated camera systems operated at the following sites (the letters in parentheses below are how each site is referenced within the IMPROVE data management system):

- Colorado National Monument (COLM);
- Dinosaur National Monument (DINO);
- Great Sand Dunes National Park (GRSA);
- Mesa Verde National Park (MEVE);
- Rocky Mountain National Park (ROMO);
- West Elk Wilderness (WEEL);
- La Garita Wilderness (LAGA);
- Eagles Nest Wilderness (EANE); and
- Weminuche Wilderness (WEMI).

In addition, camera systems have monitored at the following Class II wilderness areas:

- Lost Creek Wilderness (at the Devil's Head Fire Tower) (DEHE); and
- Mount Massive Wilderness (MOMA).

Once a multi-year visual record of site conditions is collected, the camera systems are removed and installed to document conditions at another site. A spectrum of various visibility conditions seen on the slides taken at a given site and relationship to other monitoring if

available are archived onto a photo CD and/or uploaded to web sites. Images are available at:
http://www.fsvisimages.com/
and
http://vista.cira.colostate.edu/views/Web/IMPROVE/Data_IMPRPhot.htm

(ii). Atmospheric Optical Monitoring.

Atmospheric extinction describes the ability of particles and gases in the atmosphere to attenuate light over a given distance (e.g., per kilometer). Extinction occurs due to the scattering and absorption of light from gaseous and aerosol constituents of the atmosphere. A transmissometer is an optical visibility monitoring device, which can continuously measure atmospheric extinction. The instrument accomplishes the measurement by sending a light beam of known intensity to a distant receiver and measuring the resulting loss of light. A nephelometer directly measures the scattering component of atmospheric extinction.

High relative humidity, rain and fog events reduce visibility. Data collected during periods experiencing such events are often excluded from transmissometer and nephelometer data in order that it reflect anthropogenic influences. Transmissometer data were collected at the following IMPROVE sites (the letters in parentheses below are how each site is referenced within the IMPROVE data management system):

- Mesa Verde National Park (MEVE), through May 1993; and
- Rocky Mountain National Park (ROMO), through October 2006.

Nephelometer data are collected at:

- Mt. Zirkel Wilderness (MOZI).

(iii). Particle Monitoring.

Atmospheric particle monitoring is accomplished by a combination of particle sampling and sample analysis. Simultaneous particulate samples are collected in the four channels of the IMPROVE Particle Sampler: three $PM_{2.5}$ samples (particles less than 2.5 microns in diameter) on different filter types (Teflon, nylon, and quartz) and one PM_{10} sample (particles less than 10 microns in diameter) on a Teflon filter. The filters are subsequently analyzed for total mass, elements, organic and light absorbing carbon, ions, and optical absorption. Particulate monitoring is used to quantify and identify the air pollutants responsible for visibility degradation. Atmospheric extinction can be mathematically reconstructed from these chemically speciated aerosol samples – this is the core method EPA has selected for monitoring haze. Typically, an IMPROVE Sampler takes a 24-hour sample once every three days. The IMPROVE web site contains literature that indicates[12] the overall uncertainty (defined as the ratio of the mean precision from all sources divided by the mean concentration) is 4% to 7% for most variables and >15% for organic carbon. These numbers reflect precision; accuracy is unknown.

Particulate monitoring with an IMPROVE Sampler is performed in or near the following

Colorado Class I areas (the letters in parentheses below are how each site is referenced within the IMPROVE data management system):

- Great Sand Dunes National Monument (GRSA).
- Mesa Verde National Park (MEVE).
- Weminuche Wilderness Area (WEMI).
    - This monitoring site also represents visibility conditions in La Garita Wilderness and Black Canyon of the Gunnison Wilderness.
- Shamrock Mines (SHMI).
    - This site was installed in 2005 and is a supplemental site for assessing impacts to the Weminuche Wilderness Area from emissions activity in the Four Corners Area.
- Snowmass/Maroon Bells Wilderness site in the White River National Forest (WHRI).
    - This monitoring site also represents visibility conditions in West Elk Wilderness, Eagles Nest Wilderness, and Flat Tops Wilderness.
- Mount Zirkel Wilderness Area (MOZI).
    - This site also represents visibility conditions in the Rawah Wilderness.
- Rocky Mountain National Park (ROMO).
- Ripple Creek Pass (RICR).
    - This site is to the north of the Flat Tops Wilderness. It is funded privately by Shell Oil Company and operated by Air Sciences, Incorporated.
- Douglas Pass (DOPA).
    - This site operated at the top of Douglas Pass near the Utah border for over 2 years. It was funded by the Colorado Governor's Office of Energy Management and Conservation and operated by Air Sciences, Incorporated.

b. Routine Monitoring Data Summary.

A number of the visibility monitoring sites in Colorado's Class I areas have been in operation for several years. Table 5 below is a summary of the types of monitoring and the dates when monitoring has occurred at each of the sites.

Table 5
Routine Visibility Monitoring

SITE	CAMERA	TRANSMIS-SOMETER	NEPHELO-METER	IMPROVE PARTICULATE MONITORING	SITE TYPE[1]
BLCA Black Canyon NP	2/85-11/93				BLM - IMPROVE PROTOCOL
COLM Colorado NM	7/81-9/91				NPS – IMPROVE PROTOCOL
COLP Louisiana-Pacific	7/92-1/97				NPS - IMPROVE PROTOCOL
DEHE Devil's Head Fire Tower Lost Creek WA	5/94-1/02				USFS-IMPROVE PROTOCOL
DINO Dinosaur NM	9/79-2/81 6/85-9/91				NPS-IMPROVE PROTOCOL
DOPA Douglas Pass				9/03-1/06	Colorado-IMPROVE Look Alike
EANE Eagle's Nest WA	6/93-9/00				USFS-IMPROVE PROTOCOL
GRSA Great Sand Dunes NP	7/87-4/95			5/88-present	NPS - IMPROVE
LAGA La Garita WA	9/97-10/01				USFS-IMPROVE PROTOCOL

1 IMPROVE Protocol sites are operated using the same equipment and procedures as other sites in the IMPROVE network across the country, allowing comparisons of data from all these sites. IMPROVE sites are funded by EPA. IMPROVE Protocol sites are funded by the sponsoring federal land management agency or state. Sites are operated by the NPS, BLM, or the USFS.

SITE	CAMERA	TRANSMIS-SOMETER	NEPHELO-METER	IMPROVE PARTICULATE MONITORING	SITE TYPE[1]
MEVE Mesa Verde NP	9/79-4/95	9/88-7/93		3/88-present	NPS - IMPROVE
MOMA Mt. Massive WA	7/97-11/01				USFS - IMPROVE PROTOCOL
MOZI Mt. Zirkel WA	10/90-present (on Storm Peak)		12/93-present	12/93-present	USFS - IMPROVE
RICR Ripple Creek Pass Flat Tops WA				12/02-present	Shell Oil-IMPROVE Look Alike
ROMO Rocky Mtn. NP	10/85-1/95	12/87-10/06		10/87-present	NPS - IMPROVE
SHMI Shamrock Mines Weminuche WA	11/05-present				USFS – IMPROVE PROTOCOL
WEEL West Elk WA	7/92-11/96				USFS - IMPROVE PROTOCOL
WEMI Weminuche WA	7/86-8/93			3/88-present	USFS - IMPROVE
WHRI/ MABE Maroon Bells/ Snowmass WA	12/91-present			7/93-9/99 (channel A only) 9/99- (full IMPROVE)	USFS – IMPROVE PROTOCOL USFS – IMPROVE

In 2003, two temporary sites were installed in Western Colorado. The sites use IMPROVE protocols and equipment but are unable to utilize one of the analytical laboratories under contract to the long-term sites. As such, these temporary sites are known as IMPROVE Look Alike sites. One is at the north end of the Flat Tops Wilderness at Ripple Creek Pass and is funded by Shell Exploration and Production Company. The other was to the west of the first site nearly on the border with Utah at Douglas Pass. It has been discontinued. This site was funded by the Colorado Governor's Office of Energy Management and Conservation. The sites were installed and operated by a consulting firm, Air Sciences, Incorporated. The Division has provided technical support and advice as needed. As data are processed from these sites, they are uploaded to the VIEWS site annually. Data analysis from these sites are included in the Regional Haze SIP Technical Support Documents (TSDs).

A new IMPROVE protocol site has recently (Fall 2005) been added to the network within Colorado by the USFS. The Shamrock Mines site near Vallecito and the Weminuche Wilderness is intended to supplement the existing Weminuche Wilderness site. Shamrock Mines is at a much lower altitude than the current site. NOx and ozone are also monitored at the new site. The USFS is concerned with the cumulative impacts of oil and gas development in the 4-corners region and believes the new location will better capture pollutants in the area.

For IMPROVE and IMPROVE Protocol sites in Colorado the camera, transmissometer, and nephelometer based data are collected, analyzed, and archived by Air Resource Specialists, Inc. (ARS), the contractor to IMPROVE, NPS, USFS and BLM for optical data. The particle data are collected, analyzed and archived by the University of California at Davis, the contractor to IMPROVE, NPS, USFS and BLM for particle measurements. For the IMPROVE Look Alike sites, Air Sciences, Inc. operates the sites and uses the same lab except for the University of California at Davis. Instead, RTI, Inc. is utilized. For all sites, the raw data may be downloaded from the IMPROVE or VIEWS web sites.

c. Site-By-Site Data Summaries.

Due to the extensive data analyses and displays within the Technical Support Documents and other sections of the Regional Haze SIP submittal, this LTS Review's focus is solely on trends at sites with more than 3 years of data. Trends in the haze index, known as deciview (dv) are provided for both the Best 20% days each year and Worst 20% days each year. These plots have been copied from the VIEWS web site. An additional focus is on the data since the last LTS Review in 2004.

(i). Mesa Verde National Park.

Processed IMPROVE Sampler data are available beginning in 1989 through 2004 at Mesa Verde National Park. Figure 1 presents annual average deciview for the best and worst days for each year of available data at the Park.

The Best Days show no particular trend but are not degrading. The Worst Days appear to have an overall steady increase in impairment beginning in 1992 through 2000. 2001 is the lowest year on record and 2002/2003 are the worst years on record. 2004 again returns to low values similar to 2001. To explore these trends and the recent extreme variability further, Figure 2 contains a speciated look at the Worst Days from 1989 through 2004. A qualitative summary of Figure 2 by pollutant shows that:

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and a minor contributor to visibility impairment at Mesa Verde. Nitrate shows an increasing trend beginning around 1999 and continuing through 2004.
- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a major contributor at the Park. Sulfate shows an overall decreasing trend over the years.
- CM_bext (coarse mass extinction) is a moderate contributor and mostly consists of natural sources (e.g., wind blown dust). Coarse mass shows a lot of variability early in the record and again after 1999 likely corresponding to dust events and overall dry conditions.
- ECf_bext (elemental carbon extinction) is both an anthropogenic and naturally occurring (e.g., wildfire) pollutant. It is a minor contributor at Mesa Verde with no particular trend but demonstrates more variability beginning in 2000.

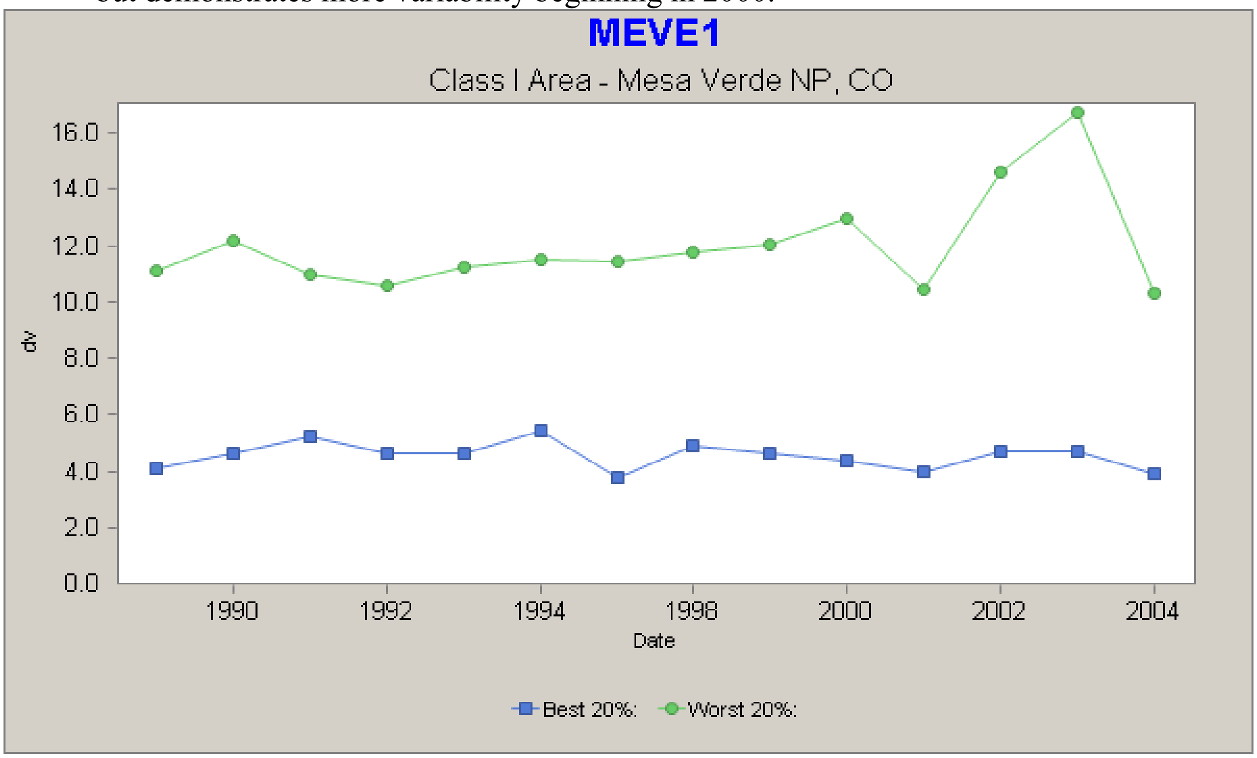


Figure 1: Mesa Verde National Park, Best and Worst Days, 1989 through 2004

- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire). Over the period of monitoring at Mesa Verde, it starts fairly high early in the record then drops and begins a slow increase until 2000. Beginning in 2000, there is a period of "ups and downs" corresponding to the period of drought and wildfire in the West. Organic carbon emerges in recent years as the most important contributor to impairment and variability in impairment at Mesa Verde NP.
- SOILf_bext (fine soil extinction) is largely natural (e.g., dust) with very low values early in the record at the Park with increases corresponding to the drought period.

The influence of drought and related emissions from wildfire and dust events is evident. Figure 3 examines precipitation at Mesa Verde National Park from 1990-1997 versus 1998-2004. Average precipitation is around 6 inches lower in the more recent period and several years (1999-2002) have annual averages between 11.6 and 13.8 inches, reflecting the profound drought in the area.

(ii). Weminuche Wilderness Area.

Processed IMPROVE Sampler data are available beginning in 1989 through 2004 at Weminuche Wilderness Area. Figure 5 presents annual average deciview for the best and worst days for each year of available data at the Wilderness.

The Best Days show no degradation and a steady trend toward less impairment. The Worst Days appear to have a slight increase in impairment beginning in 1993 through 2000. 2001 is the lowest year on record and 2002/2003 are the 3rd and 4th worst years on record. 2004 again returns to low values similar to 2001. To explore these trends and the recent extreme variability further, Figure 6 contains a speciated look at the Worst Days from 1989 through 2004. A qualitative summary of Figure 6 by pollutant shows that:

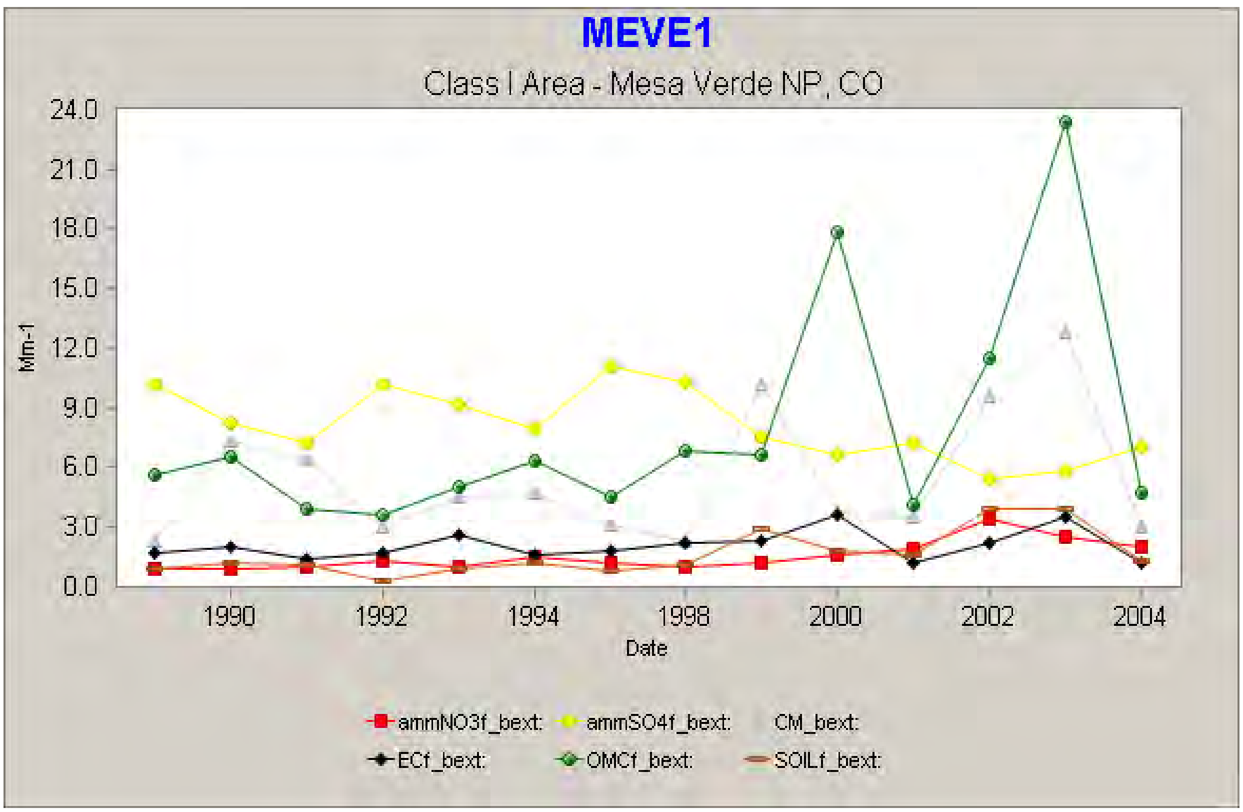


Figure 2: Mesa Verde National Park, Annual Extinction Values by Aerosol Species, Worst Days 1989 through 2004

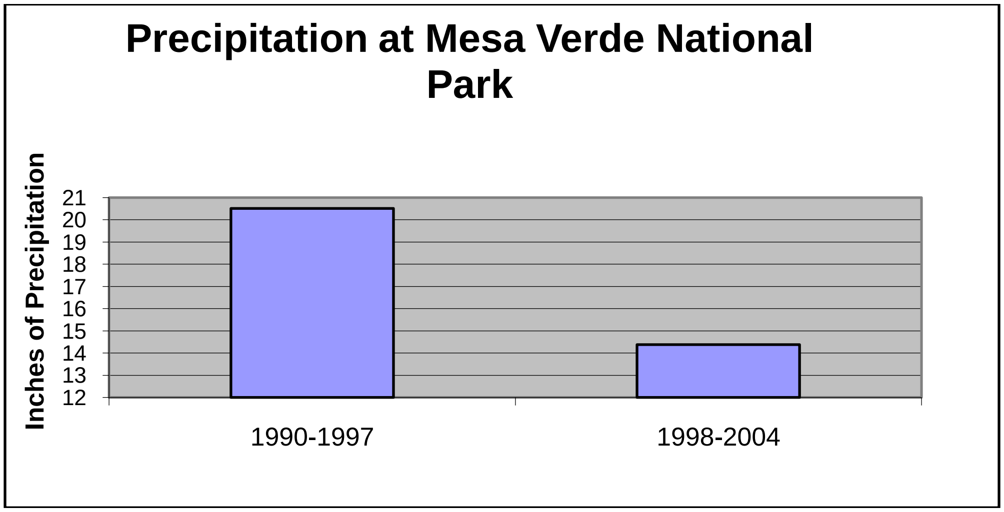


Figure 3: Precipitation At Mesa Verde National Park, 1990-1997 vs 1998-2004

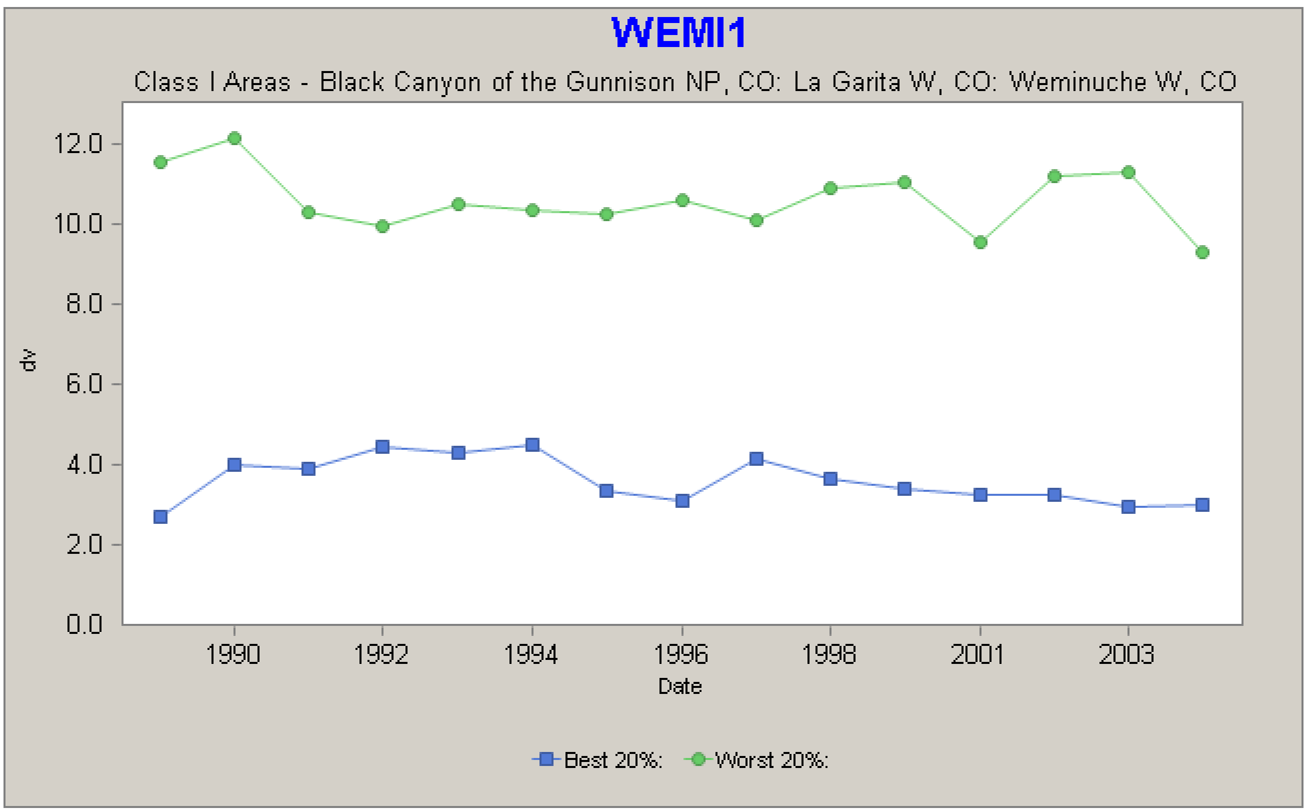


Figure 5: Weminuche Wilderness Area, Best and Worst Days 1989 through 2004

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and a minor contributor to visibility impairment at Weminuche. Nitrate shows an increasing trend beginning around 1997 and continuing through 2003. The 2004 value is less than recent years and is similar to what was measured in 2001.

- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a major contributor at the Park. Sulfate shows an overall decreasing trend since 1998.
- CM_bext (coarse mass extinction) is a moderate contributor and mostly consists of natural sources (e.g., wind blown dust). Coarse mass shows a lot of variability early in the record and again after 1999 likely corresponding to dust events and overall dry conditions.
- ECf_bext (elemental carbon extinction) is both an anthropogenic and naturally occurring (e.g., wildfire) pollutant. It is a moderate contributor at Weminuche with a slight shift to lower values beginning in 1997.
- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire). Over the period of monitoring at Weminuche, it starts fairly high early in the record then drops and begins a slow increase until 2001. Beginning in 2001, there is a period of large variability corresponding to the period of drought and wildfire in the West and particular fires near and in the Weminuche Wilderness. Organic carbon emerges in recent years as the most important contributor to impairment and variability in impairment at Weminuche.
- SOILf_bext (fine soil extinction) is largely natural (e.g., dust) with very low values (similar to nitrate) early in the record at the Park with increases corresponding to the drought period.

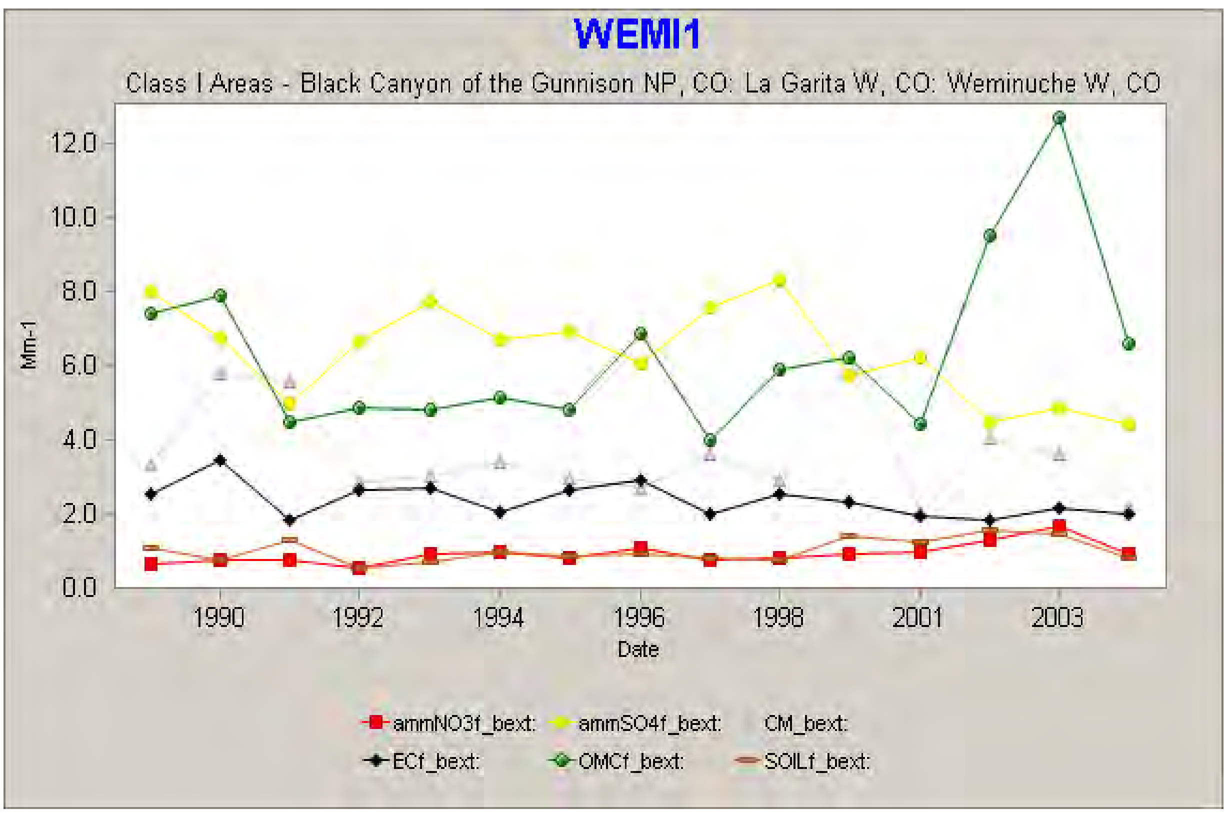


Figure 6: Weminuche Wilderness Area, Annual Extinction Values by Aerosol Species, Worst Days 1989 through 2004

(iii). Great Sand Dunes National Park.

Processed IMPROVE Sampler data are available beginning in 1989 through 2004 at Great Sand Dunes National Park. Figure 7 presents annual average deciview for the best and worst days for each year of available data at the Park.

The Best Days show a little change and overall no degradation since 1999. The Worst Days appear to have a slight increase in impairment beginning in 1996 through 2000. 2001 is among the lowest years on record, followed by 2002: the highest on record. 2003 is the 4th worst and 2004 again returns to low values similar to 2001 and among the lowest on record. To explore these trends and the recent extreme variability further, Figure 8 contains a speciated look at the Worst Days from 1989 through 2004. A qualitative summary of Figure 8 by pollutant shows that:

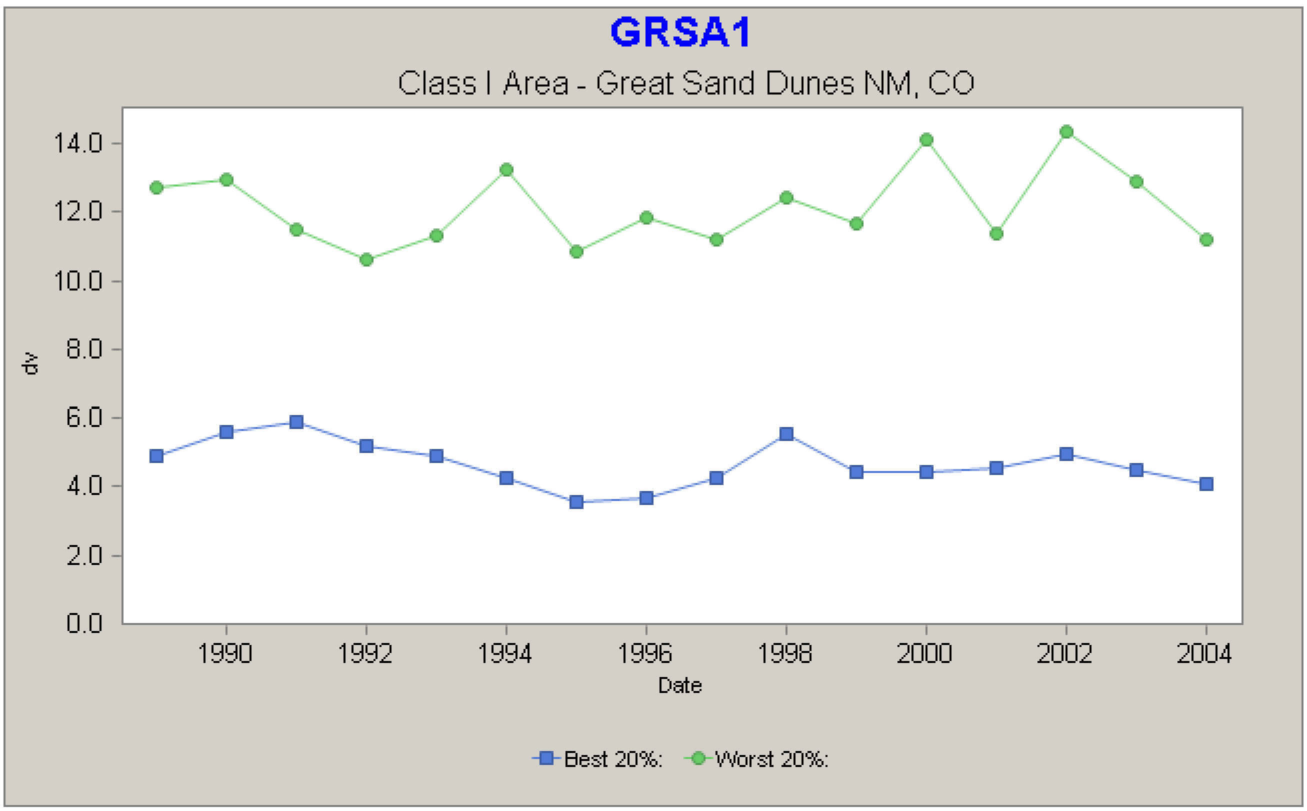


Figure 7: Great Sand Dunes National Park, Best and Worst Days 1989 through 2004

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and a minor contributor to visibility impairment at Great Sand Dunes. Nitrate shows a slight increasing trend beginning around 2000 and continuing through 2004, with a dramatic exception in 2003 (among the lowest values on record). The 2004 value is the highest on record.
- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a major contributor at the Park. Sulfate shows an overall decreasing trend since 1998.
- CM_bext (coarse mass extinction) is a major contributor and mostly consists of natural sources (e.g., wind blown sand/dust). Coarse mass shows a huge amount of variability

over its record with the "ups and downs" tracking closely with Organic Carbon in recent years.

- ECf_bext (elemental carbon extinction) is both an anthropogenic and naturally occurring (e.g., wildfire) pollutant. It is a minor contributor at Great Sand Dunes NP with no discernable trend.
- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire). Over the period of monitoring at Great Sand Dunes, it begins an "up and down" pattern in 1995 thru 2003. The pattern is broken by 2004 as its value continues in 2003's declining direction.
- SOILf_bext (fine soil extinction) is largely natural (e.g., sand/dust) with very low values (similar to nitrate) early in the record at the Park with increases corresponding to the drought period. Fine soil, coarse mass and organic carbon emerge in recent years as the most important contributors to impairment and variability in impairment at Sand Dunes.

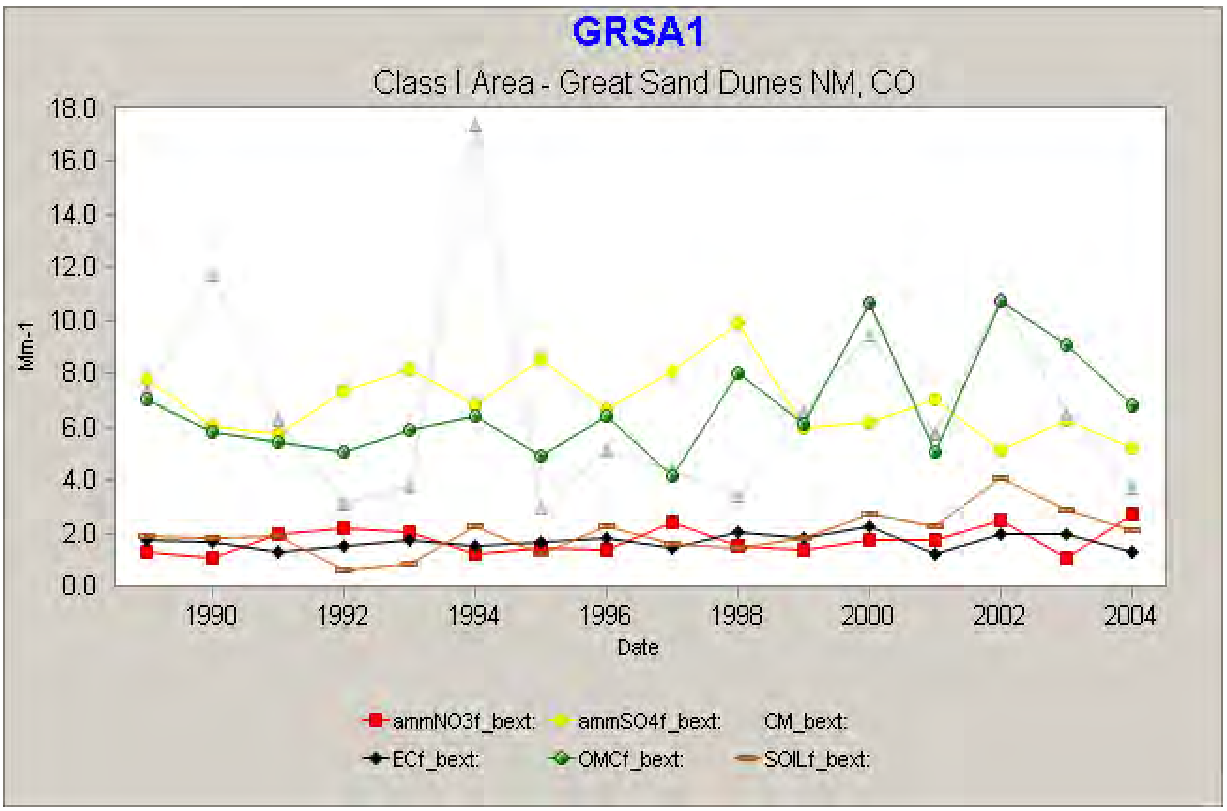


Figure 8: Great Sand Dunes National Park, Annual Extinction Values by Aerosol Species, Worst Days 1989 through 2004

(iv). White River National Forest - Maroon Bells/Snowmass Wilderness.

Processed IMPROVE Sampler data are available beginning in 2001 through 2004 at the White River site. Figure 9 presents annual average deciview for the best and worst days for each year of available data at the site. All other IMPROVE sites in Colorado have much longer data records, in most cases over 15 years. However, the White River site was installed during 2000, with the first complete data year in 2001. Based on the four years of processed data, White River is Colorado's least impaired site compared to other IMPROVE locations in the state.

The Best Days show a no degradation trend over the four years of data. The Worst Days spike-up in 2002 but return to the 2001 value in 2003 and decline further in 2004. To explore these trends, Figure 10 contains a speciated look at the Worst Days from 1981 through 2004. A qualitative summary of Figure 10 by pollutant shows that:

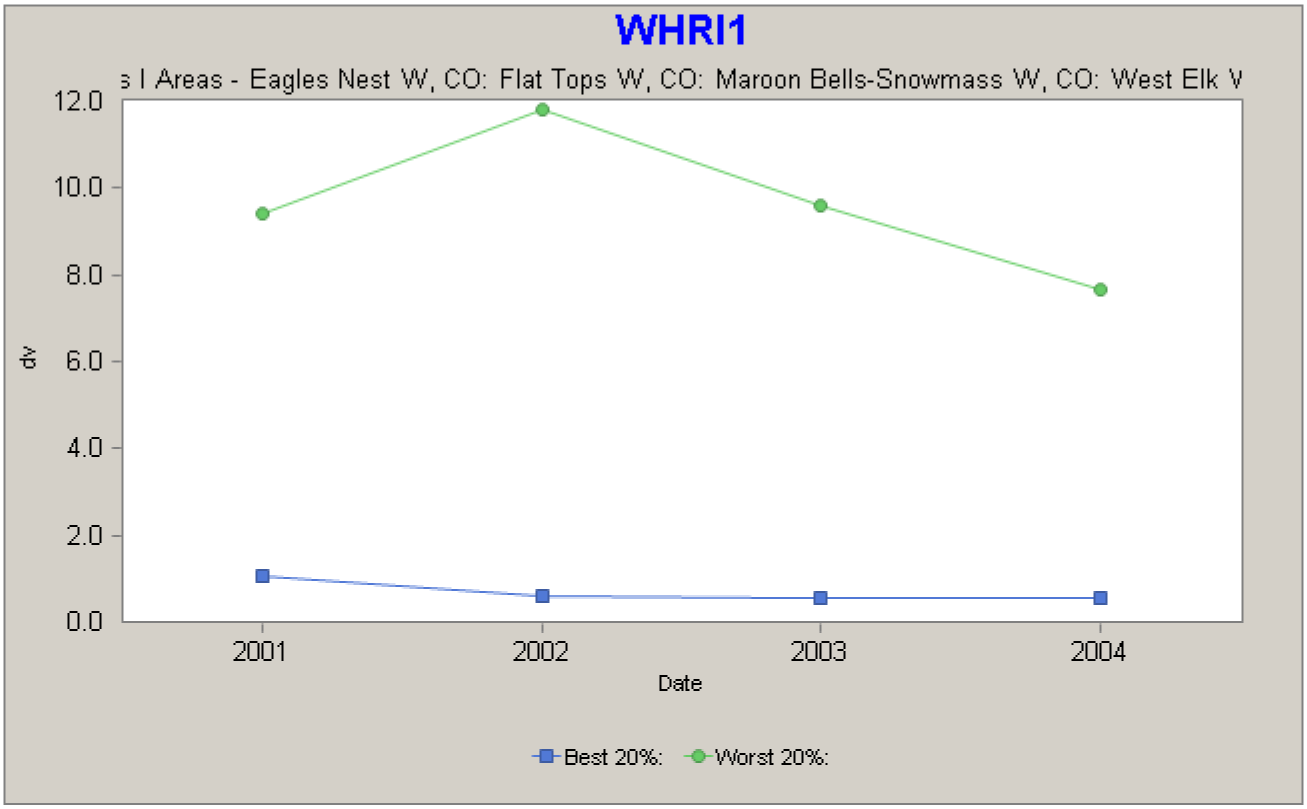


Figure 9: White River National Forest, Best and Worst Days 2001 through 2004

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and a minor contributor to visibility impairment at the White River site. Nitrate shows a slight decreasing trend through 2004.
- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a moderate contributor at the White River site. Sulfate shows an overall decreasing trend.
- CM_bext (coarse mass extinction) is fairly moderate contributor and mostly consists of natural sources (e.g., wind blown sand/dust). Compared to other sites in Colorado examined previously, there has been little relative variability in course mass and it declined in 2003 and 2004.
- ECf_bext (elemental carbon extinction) is both an anthropogenic and naturally occurring (e.g., wildfire) pollutant. It is a minor contributor at the wilderness areas represented by the White River site and has had only a small amount of variability in the four years monitored.

- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire). Organic carbon is a moderate contributor at White River, with the exception of 2002 when it spiked (likely due to upwind wildfire) and influenced impairment at the site more than the sum of the other pollutants combined.
- SOILf_bext (fine soil extinction) is largely natural (e.g., sand/dust) with very low values (similar to nitrate).

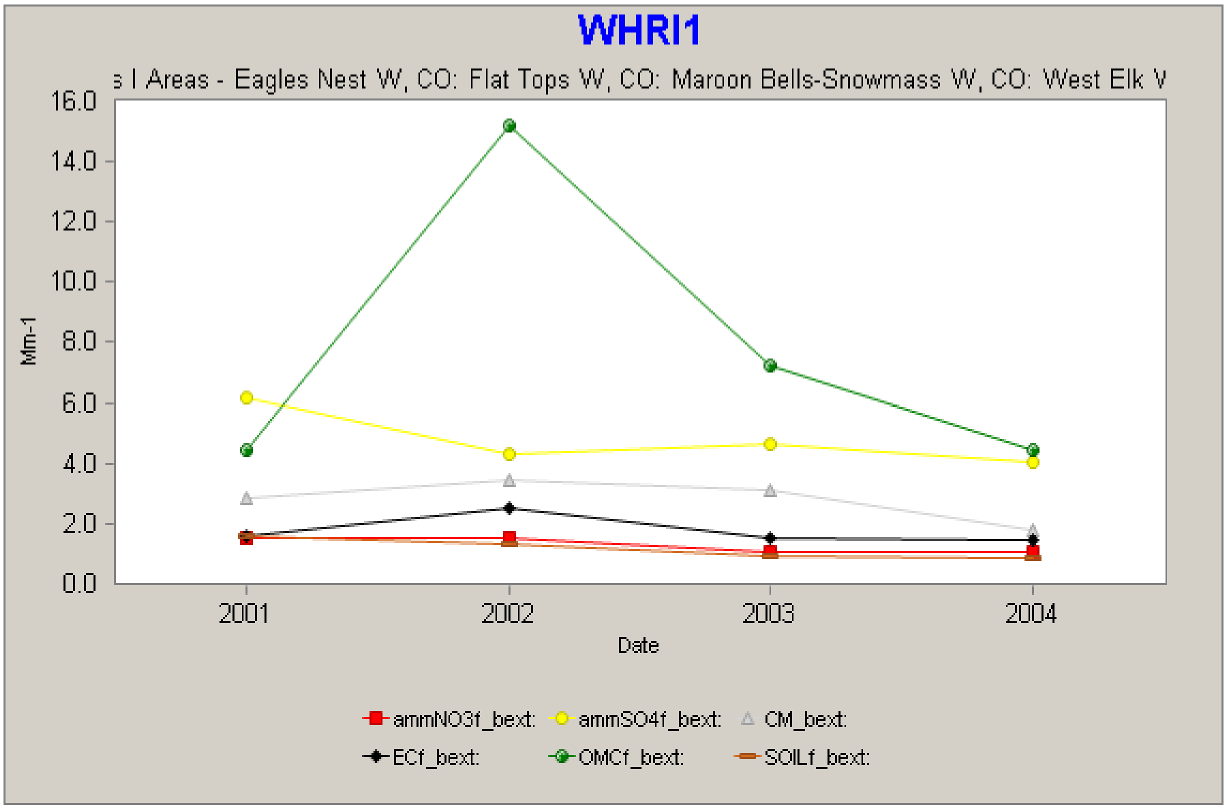


Figure 10: White River National Forest, Annual Extinction Values by Aerosol Species, Worst Days 2001 through 2004

(v). Mt Zirkel Wilderness Area.

Processed IMPROVE Sampler data are available beginning in 1995 through 2004 at Mt. Zirkel Wilderness Area. Figure 11 presents annual average deciview for the best and worst days for each year of available data at the Wilderness.

The Best Days show a no degradation trend over the 9 years of data (2000 was incomplete) with a fairly dramatic decline in impairment in recent years. The Worst Days do not exhibit any obvious trend; however, 2004 was the lowest on record. To explore these data further, Figure 12 contains a speciated look at the Worst Days from 1995 through 2004. A qualitative summary of Figure 12 by pollutant shows that:

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and a minor contributor to visibility impairment at Mt. Zirkel Wilderness Area. In recent years nitrate has increased and appears to be a moderate level contributor.

- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a major contributor at the Park. Sulfate shows an overall decreasing trend since 1998.
- CM_bext (coarse mass extinction) is a moderate contributor and mostly consists of natural sources (e.g., wind blown sand/dust). Compared to the more southern sites, coarse mass at Mt. Zirkel shows little variability over its record and an overall declining trend.

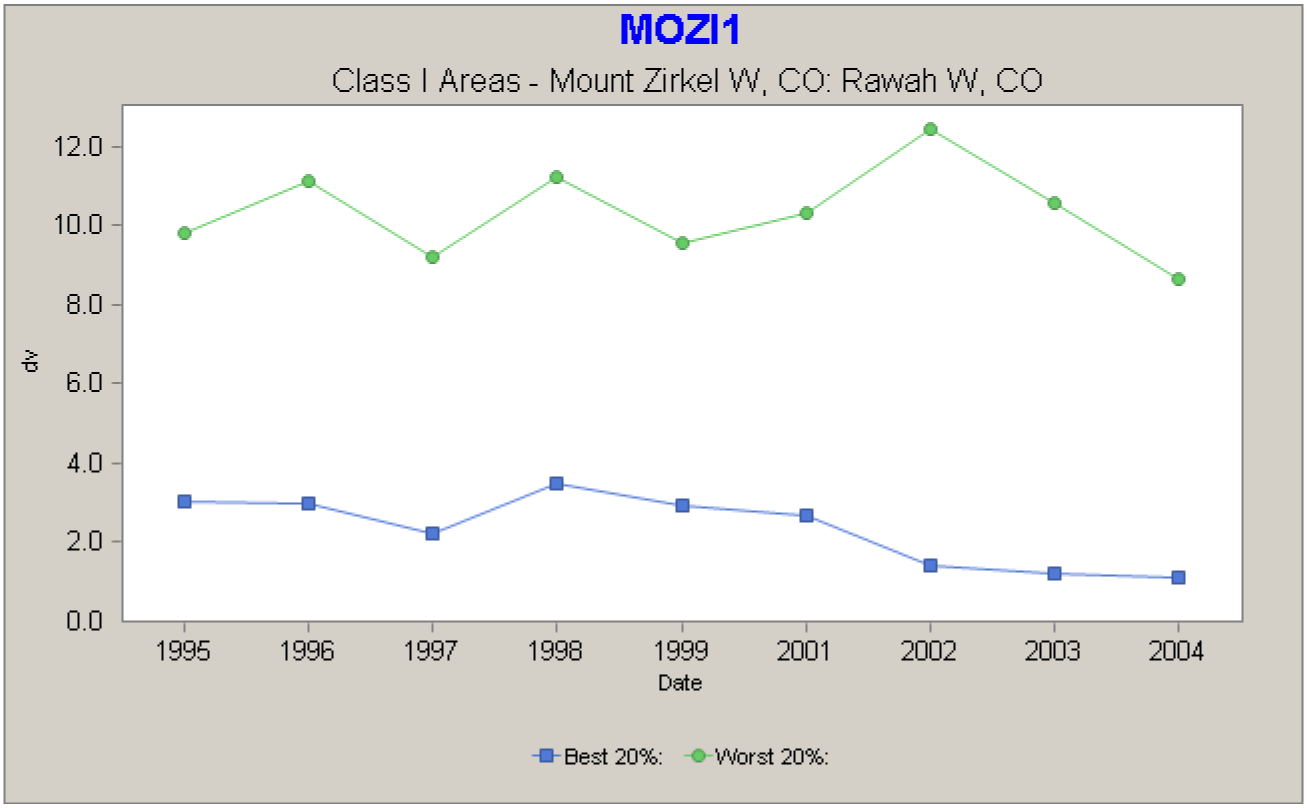


Figure 11: Mt. Zirkel Wilderness Area, Best and Worst Days 1995 through 2004

- ECf_bext (elemental carbon extinction) is both an anthropogenic and naturally occurring (e.g., wildfire) pollutant. It is a minor contributor at Mt. Zirkel Wilderness Area with no discernable trend.
- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire) and a major contributor to impairment at this site. Over the period of monitoring at Mt. Zirkel Wilderness, organic carbon exhibits considerable variability and, similar to most other Colorado sites, had large annual worst day values for 2002 and 2003.
- SOILf_bext (fine soil extinction) is largely natural (e.g., sand/dust) with very low values (similar to nitrate).

(vi). Rocky Mountain National Park.

Processed IMPROVE Sampler data are available beginning in 1991 through 2004 at Rocky Mountain National Park. Figure 13 presents annual average deciview for the best and worst days for each year of available data at the Park.

The Best Days show no degradation over time and a trend toward less impairment. The most recent years are the cleanest on record. The Worst Days reflect the drought and shift up from 2000 through 2003. To explore these trends and the recent increase on the Worst Days further, Figure 14 contains a speciated look at the Worst Days from 1991 through 2004. A qualitative

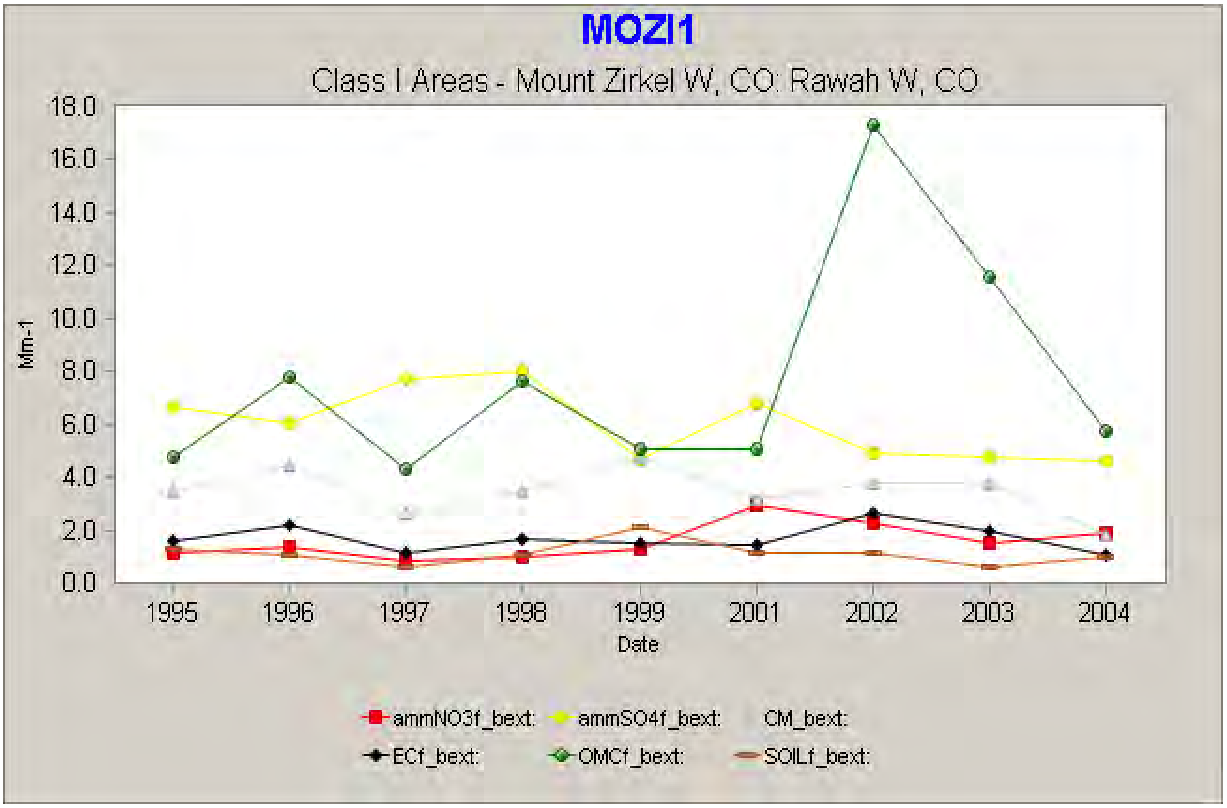


Figure 12: Mt. Zirkel Wilderness Area, Annual Extinction Values by Aerosol Species, Worst Days 1995 through 2004

summary of Figure 14 by pollutant shows that:

- ammNO3f_bext (ammonium nitrate extinction) is an anthropogenic pollutant and shifts from a moderate contributor to visibility impairment at Rocky to a major contributor in 2001 and 2002. Values for 2003 and 2004 drop to more typical levels. Nitrate shows a decreasing trend from the beginning of the record through 2000 then the two-year spike occurs. Rocky Mountain National Park's nitrate levels are higher overall than other IMPROVE sites in Colorado. The two-year spike is unusual given that nitrate is largely an anthropogenic pollutant.
- ammSO4f_bext (ammonium sulfate extinction) is an anthropogenic pollutant and a major contributor at the Park. In contrast with other IMPROVE sites in Colorado, sulfate does not demonstrate an obvious declining trend over the data record. However, considering the period 1999 through 2004, there are 4 of the 5 lowest values in the data record. Similar to what was seen for nitrate, the sulfate spike in 2001 and 2002 may need further exploration.

- CM_bext (coarse mass extinction) is a moderate contributor. In 2000, it spiked and for that single year it was a major contributor, along with organic carbon. Coarse mass emissions mostly consist of natural sources (e.g., wind blown dust). Coarse mass does not reveal an obvious trend over the record and there is a lesser reflection, compared to

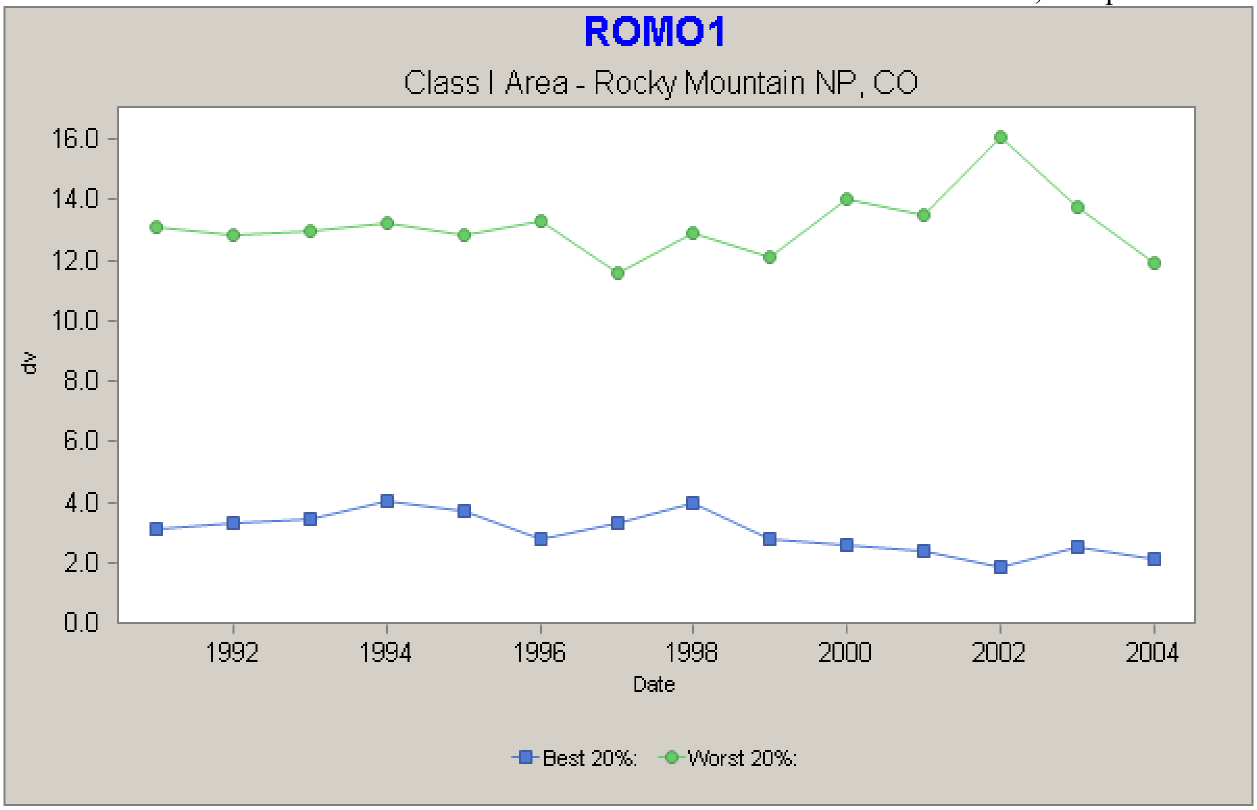


Figure 13: Rocky Mountain National Park, Best and Worst Days 1991 through 2004

many other sites in Colorado, of the drought in recent years.
- ECf_bext (elemental carbon extinction) is a both an anthropogenic (e.g., diesel emissions) and naturally occurring (e.g., wildfire) pollutant. It is a minor contributor at Rocky Mountain NP with no particular trend.
- OMCf_bext (organic carbon extinction) is largely a naturally occurring pollutant (e.g., wildfire). Over the period of monitoring at Rocky Mountain National Park, the "ups and downs" seen at other sites also have occurred at Rocky as well as the large values during the peak drought years.
- SOILf_bext (fine soil extinction) is largely natural (e.g., dust) with low values throughout the record at the Park.

In order to explore further the unusual nitrate and sulfate levels in 2001 and 2002, additional plots are presented below from the VIEWS website. They are the 2000, 2001 and 2002 annual composition plots for Rocky Mountain National Park. Each stacked bar represents a 24-hour sample. Each bar component is one of the species listed on the plot legend. The "W" over a bar means that sample is among the worst 20% impaired during that year. A "B" over a bar indicates that sample is in the 20% best visibility days during that year. Figure 15 is 2000 data.

This is a fairly typical year for sulfate and nitrate at Rocky. There are no combined sulfate and nitrate episodes above 20/Mm-1 of extinction. Figure 16 is 2001 data. There are 9 sample days with combined sulfate and nitrate above 20/Mm-1. Figure 17 is 2002 data. There appear to be 7 or 8

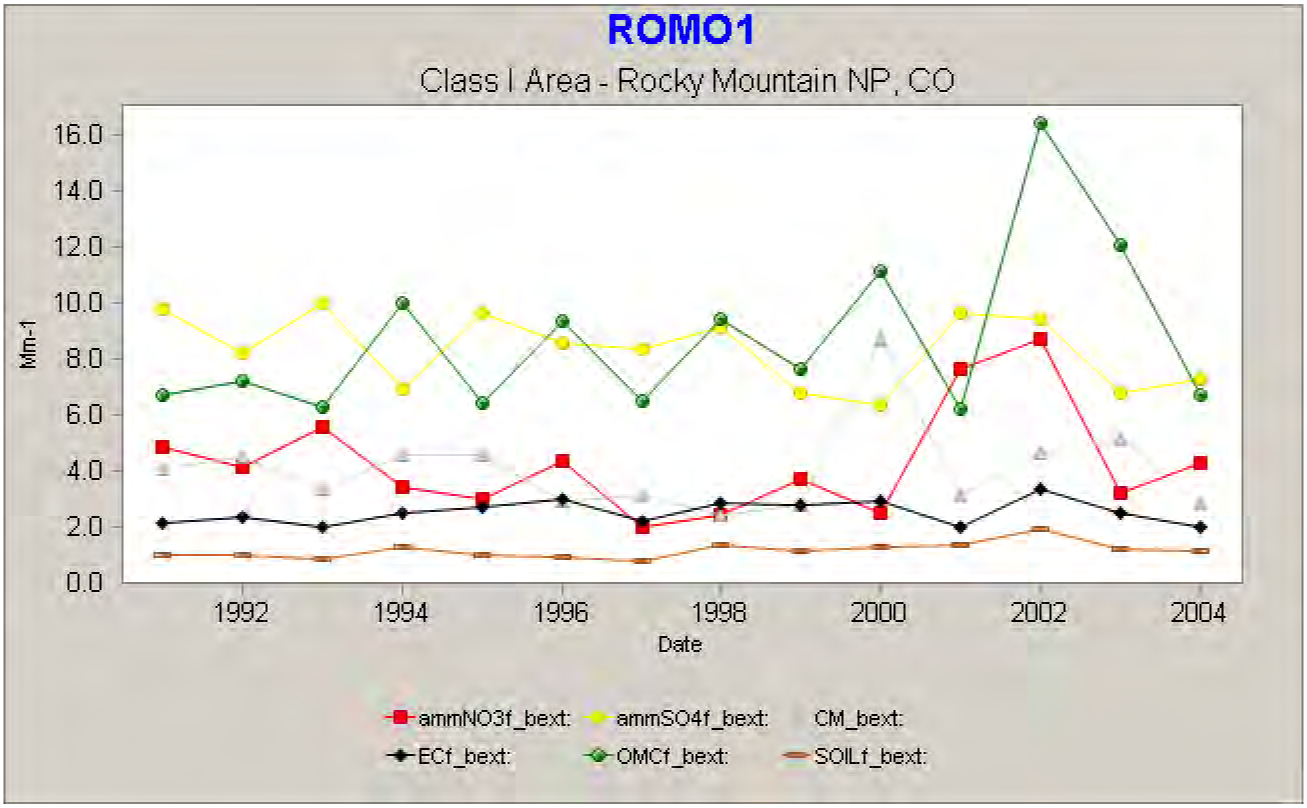


Figure 14: Rocky Mountain National Park, Annual Extinction Values by Aerosol Species, Worst Days 1991 through 2004

such days in 2002. It is important to note that these episodes, with 1 or 2 minor exceptions, do not occur when other pollutants are also peaking. The Division is hopeful that results from the ROMANS study, conducted by the National Park Service to examine nitrogen and sulfate emissions and precursors at Rocky Mountain National Park, will provide some insight about the sources and meteorological conditions that occurred in 2001 and 2002 that led to the 7-9 peaks of sulfate and nitrate per year. For more information about the ROMANS study see **http://www.cira.colostate.edu/publications/newsletter/fall2006.pdf**

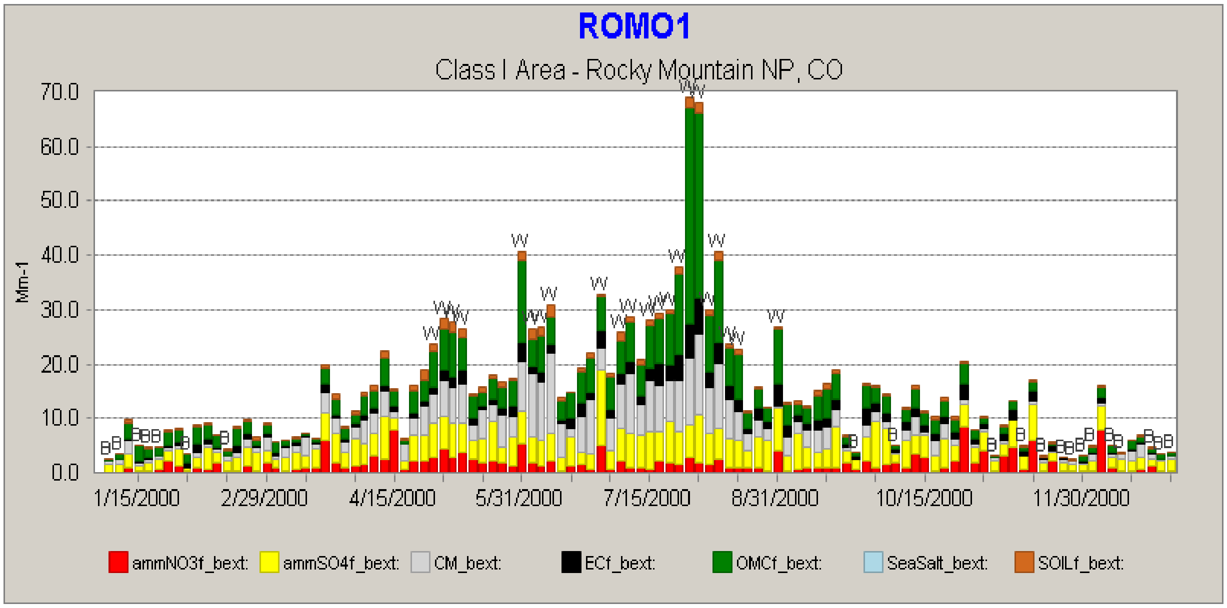


Figure 15: Rocky Mountain National Park, Composition Plot by Aerosol Species for Each Sample in 2000

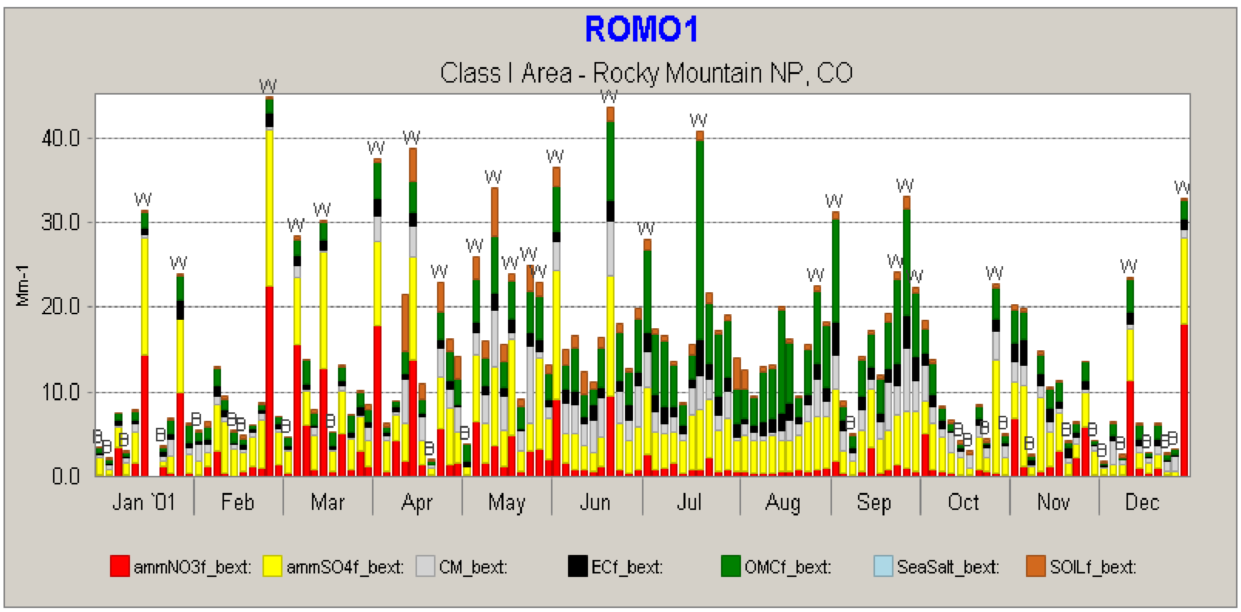


Figure 16: Rocky Mountain National Park, Composition Plot by Aerosol Species for Each Sample in 2001

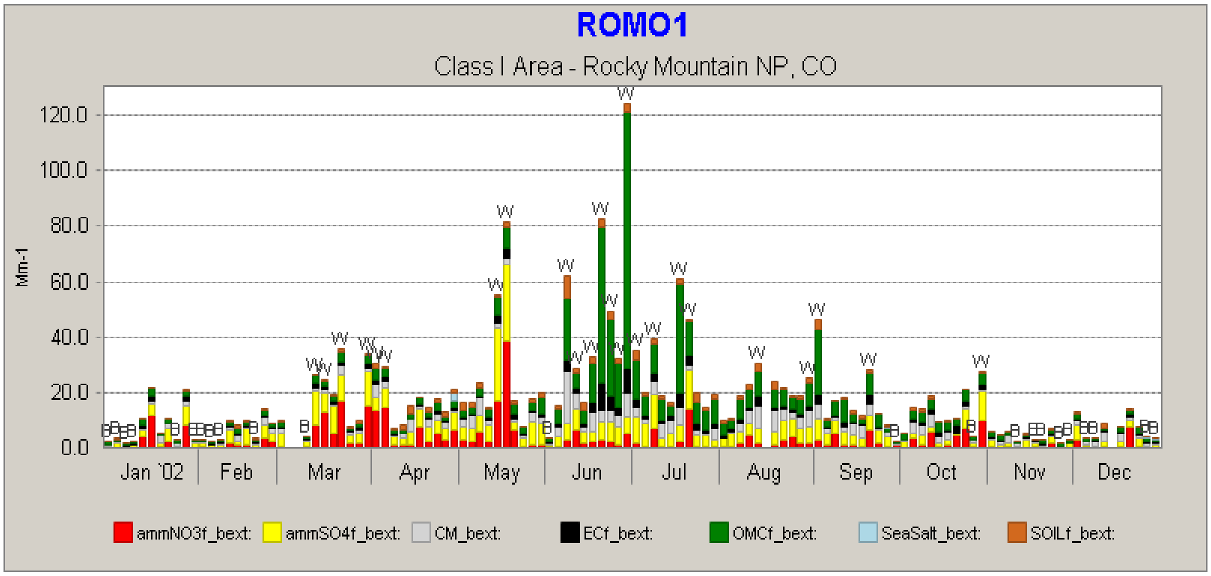


Figure 17: Rocky Mountain National Park, Composition Plot by Aerosol Species for Each Sample in 2002

d. Overall Conclusions.

Colorado has among the best visibility in the country at its Class I areas and throughout other scenic and pristine parts of the State. However, on an episodic basis visibility can become impaired at all sites monitored.

Visibility on the best days is not degrading over time at any site in Colorado. This is good and important news as protecting the cleanest days is a critical aspect of the Class I visibility protection program.

Visibility on the worst days is a more complex assessment. Mesa Verde NP shows a slow and steady increase in impairment over time. Weminuche and Great Sand Dunes show a very slight increase in impairment. Rocky Mountain and Mt. Zirkel show little apparent trend. At all these sites the most recent years of complete data have large variation from year-to-year driven largely by the sustained drought in the West. In addition to direct impacts from the drought, fewer precipitation events equate to less of a potential for natural removal mechanisms (i.e., rain and snow storms) scrubbing particles out of the air. The data record for White River is too short to draw conclusions at this time regarding trends.

4. ADDITIONAL MEASURES, INCLUDING SIP REVISIONS, THAT MAY BE NECESSARY TO ENSURE REASONABLE PROGRESS TOWARD THE NATIONAL GOAL.

Substantive LTS SIP revisions occurred in August 1996, April 1997, and April 2001. The 2002 SIP revision was to update outdated language and create a better overall organization of the LTS portion of the SIP. A minor update occurred in 2004. 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, once again, small updates and edits are proposed in order that this part of the SIP does not become outdated.

5. THE PROGRESS ACHIEVED IN IMPLEMENTING BART AND MEETING OTHER SCHEDULES SET FORTH IN THE LONG-TERM STRATEGY.

Hayden. Emission limitations and schedules for Hayden Generating Station were adopted into the SIP on August 15, 1996 based on the Hayden Consent Decree. By terms of the Decree, Hayden Station must provide progress reports to the State concerning construction of new equipment and compliance with new emission limitations. The particulate and SO_2 control equipment for Units 1 & 2 have been installed and are operating. All schedules in both the Decree and in the SIP regarding Hayden were met, some up to six months ahead of deadlines in the SIP and Consent Decree. Both units were in compliance for all pollutants by November 16, 1999. The emission limits and reporting requirements have been integrated into Hayden's Title V permit, as envisioned by the Consent Decree. As such, the court terminated the Decree in late-2001. Since then Hayden has continued to operate the facility within its emission limits and has remained in compliance.

Craig. Emission limitations and schedules for Units 1 and 2 of the Craig Station were adopted into the SIP on April 19, 2001 based on the Craig Consent Decree. By the terms of the SIP, progress reports must be provided to the State.

Unit 1's tie-in with its new equipment began on September 13, 2003 and completion of PM, NOx and SO_2 upgrades were finished by December 19, 2003. Testing of the NOx upgrades continued through the end of 4th quarter 2003. SO_2 removal has consistently been above 90% since mid-December 2003 (limit is 90%). The NOx limit is 0.30 lbs/Mmbtu annual average and the end of 2005 actual average was 0.279 lbs/Mmbtu.

Unit 2's tie-in began on March 13, 2004. The compliance period began on October 1, 2004 for all subject pollutants. SO_2 emissions from Unit 2 have also consistently achieved better than 90% removal and the NOx annual average has been below the required 0.30 lbs/Mmbtu.

The emission limits and reporting requirements have been integrated into Craig's Title V permit, as envisioned by the Consent Decree. As such, the court terminated the Decree in late-2005. Since then Craig has continued to operate the facility within its emission limits and has remained in compliance.

6. THE IMPACT OF ANY EXEMPTION FROM BART.

The Division has not made a reasonable attribution decision. The need for a BART analysis has not been triggered, therefore, exemptions were neither requested nor granted.

7. THE NEED FOR BART TO REMEDY EXISTING IMPAIRMENT IN AN INTEGRAL VISTA DECLARED SINCE PLAN APPROVAL.

There have been no integral vistas listed by either the federal land managers or the State since the plan was approved. Therefore, a discussion on the need for BART in such integral vistas is not necessary.

IV. CONSULTATION WITH FEDERAL LAND MANAGERS

The Division is required by federal and state law to provide at least 60 days to consult with the federal land managers during periodic reviews of the LTS. The Division is sending this report to the USFS and NPS at the time of the request for hearing before the Air Quality Control Commission. These agencies are the managers of all of Colorado's Class I areas.

V. ENDNOTES AND REFERENCES

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1. Letter to Honorable Roy Romer, Governor of Colorado, from Elizabeth Estill, Regional Forester, U.S. Forest Service Rocky Mountain Region, July 14, 1993.

2. "Revision of Colorado's State Implementation Plan for Class I Visibility Protection, Craig Station Units 1 and 2 Requirements," adopted by the Colorado Air Quality Control Commission, April 19, 2001.

3. "Clean Air Act Approval and Promulgation of Air Quality Implementation Plan Revision for Colorado; Long-Term Strategy of State Implementation Plan for Class I Visibility Protection: Craig Station Requirements," 66 Federal Register, 35374.

4. Watson, J.G. and D. Blumenthal 1996*, Mt. Zirkel Wilderness Area, Reasonable Attribution Study of Visibility Impairment; Volume II: Results of Data Analysis and Modeling, Part 1 of 2 -- Final Report*; July 1, 1996. Desert Research Institute, University and Community College System of Nevada, 5625 Fox Avenue, Reno, Nevada 89506.

5. In the United States District Court for the District of Colorado, Civil Action No. 93-B-1749, Sierra Club, Plaintiff, vs. Public Service Company of Colorado, Inc., Salt River Project Agricultural Improvement and Power District, and PacifiCorp, Defendants, United States of America and State of Colorado, Plaintiff-Intervenors, Consent Decree, date lodged in Court, May 22, 1996, date entered in Court, August 19, 1996.

6. "Clean Air Act Approval and Promulgation of Air Quality Implementation Plan Revision for Colorado; Long-Term Strategy of State Implementation Plan for Class I Visibility Protection, Part I: Hayden Station Requirements," January 16, 1997, 62 Federal Register, 2305.

7. "Craig Station FGD System Modifications – Analyses of Potential Alternatives, Project Design Basis and Cost Estimates", EPA Contract #'s 68-D7-0001 – Phase # 1-005 & 9X-0264-NALX, dated August 31, 1999.

8. C.R.S. 25-7 Part 10, "Air Quality Related Values – Class I Federal Areas."

9. Letter to Honorable Bill Owens, Governor of Colorado from William P. Yellowtail,

Regional Administrator, EPA Region 8; September, 22, 1999.

10. Letter from Tom L. Thompson, Acting Regional Forester, U.S.D.A. Forest Service, Rocky Mountain Region to Margie Perkins, Director, Colorado Air Pollution Control Division, December 14, 2000.

11. "Regional Haze Regulations," July 1, 1999, 64 Federal Register 35714, (codified at Part 40 Code of Federal Regulations sections 51.308 and 309).

12 . "IMPROVE Data Guide: A Guide to Interpret Data", University of California Davis, August 1995.

APPENDIX B

Regional Haze State Implementation Plan

SIP Revision for RAVI Long Term Strategy

LONG-TERM STRATEGY REVISION

OF

COLORADO'S STATE IMPLEMENTATION PLAN

FOR CLASS I AREA VISIBILITY PROTECTION

ADDRESSING REASONABLY ATTRIBUTABLE

IMPAIRMENT

January 2011

This document is the Phase I Long-Term Strategy (LTS) revision of the State Implementation Plan (SIP) of Colorado‟s Class I Visibility Protection Program addressing reasonably attributable visibility impairment (RAVI). The Phase I RAVI LTS review is a separate document and contains background information and the review/report sections as required by EPA and State law.

The state adopted this SIP revision in order to update the LTS. The state adopted an LTS SIP revision in 2007, which was submitted to EPA in 2008 as part of the Regional Haze SIP. For various reasons this submittal was not acted on by EPA. Because of substantial revisions to the Regional Haze SIP in 2010, the state updated, amended and re-adopted this RAVI LTS in 2010. This SIP revision is intended to amend the 2004 LTS portion of the Class I Visibility SIP.

References in this SIP revision to Colorado Air Quality Control Commission Regulation No. 9 (Open Burning, Prescribed Fire, and Permits) are intended only to provide information about the location of various aspects of Colorado‟s smoke management program. Regulation No. 9 is neither being submitted for EPA approval nor incorporated into the SIP by reference. It implements Colorado‟s program and is not federally required. The State is precluded from submitting this Regulation No. 9 for incorporation into this SIP by C.R.S. 25-7-105.1.

The State of Colorado believes the strategies, activities, and plans outlined below in sections for Existing Impairment, Prevention of Future Impairment, Smoke Management, and Consultation and Communication with Federal Land Managers constitute reasonable progress toward the national visibility goal under Phase I. The following Long-Term Strategy addresses the visibility issues that currently face the State of Colorado‟s Class I units within the framework of EPA‟s Phase I of the visibility protection program. The six factors required by the EPA to be considered in a LTS are embedded within the strategies below and marked with an asterisk for reference.

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I. EXISTING IMPAIRMENT.

The LTS must have the capability of addressing current and future existing impairment situations as they face the State. Generally, Colorado considers that its Air Quality Control Commission, Regulation No. 3, Part B, §XIV.D ("Existing Impairment") meets this long-term strategy requirement regarding existing major stationary facilities. The State believes that its existing regulations along with the strategies and activities outlined below have together provided for reasonable progress toward the national visibility goal.

A. Existing Impairment and the Mt. Zirkel Wilderness.

1. The Certification.

The U.S.D.A. Forest Service (USFS) concluded in its July 1993 certification letter to the State of Colorado that it was reasonable to believe that visibility impairment existed in the Mt. Zirkel Wilderness Area (MZWA) and that local existing stationary sources - the Craig and Hayden power stations - contributed to the problem.

2. Reasonable Progress for the Mt. Zirkel Wilderness.

a. Hayden.

The certification of impairment made by the USFS regarding the Hayden Station was resolved through a settlement process that began in late 1995. An agreement, the Hayden Consent Decree, was approved by the federal district court on August 19, 1996. The agreement was between the Sierra Club, State of Colorado, owners of Hayden Station, and Environmental Protection Agency/Department of Justice. The Decree was intended to resolve a number of issues, including a Sierra Club lawsuit against the Hayden Station, the needs of the State‟s visibility regulatory program in relation to Hayden, and an EPA complaint against the facility. In addition, the Decree was intended to make progress toward reducing acid deposition in the Mt. Zirkel Wilderness.

Emission limitations, construction schedules, and reporting requirements taken from the Hayden Consent Decree were incorporated into the Visibility SIP by the AQCC. The State believes that these significant emission reductions will effectively eliminate the visibility impairment in the MZWA that could be associated with the Hayden Station. The State further believes that the Hayden Consent Decree effectively resolves the certification of impairment brought by the USFS against the Hayden Station. The Forest Service has indicated that its complaint against Hayden has been satisfied. EPA approved this SIP amendment on January 16, 1997.

The construction of Hayden‟s control equipment progressed ahead of schedule. All compliance dates in the SIP and Consent Decree were met and emission limitations for NOx, SO_2, opacity, and particulate matter are being achieved. The relevant emission limitations and monitoring requirements have been moved into the facility‟s Title V operating permit and the permit has been issued. As a result, the Consent Decree has been terminated by the court.

b. Craig Generating Station (Yampa Project).

The certification of impairment made by the USFS regarding the Craig Station Units 1 and 2 was also resolved through a settlement process that began in Fall 1999.

After Hayden was resolved in August 1996, the State"s attention turned to Craig Station Units 1 and 2. In addition to the State and the USFS visibility certification, there are other issues concerning the emissions from Yampa Valley power plants. The USFS has strong concerns about local emissions of SO_2 and NOx that may be associated with acid deposition and aquatic and terrestrial ecosystem effects in the MZWA. As well, a citizen lawsuit under the Clean Air Act by the Sierra Club directed against Craig Station Units 1 and 2 regarding opacity issues was initiated in late 1996.

After several years of preliminary efforts, studies and workshops, in Fall 1999 the Sierra Club, Craig Owners, EPA, the State, and the USFS began global settlement talks with an independent mediator. The Craig owners and Sierra Club concluded a Consent Decree and filed it with the federal district court on January 10, 2001. It was approved by the court on March 19, 2001. The State resolved the certification of impairment in relation to Units 1 and 2 of Craig Station by the AQCC adopting emission limitations, schedules, and reporting requirements from the Craig Consent Decree into the Visibility SIP. The Forest Service concluded that all of its concerns related to the Craig Station and the 1993 Certification of Impairment are now resolved. Work was completed on Unit 1 during 2003 and on Unit 2 in 2004. All compliance dates in the SIP and Consent Decree were met and the emission limitations for NOx, SO_2, opacity, and particulate matter have been consistently achieved in actual operation. The relevant emission limitations and monitoring requirements have been moved into the facility"s Title V operating permit and the permit has been issued. As a result, the Consent Decree has been terminated by the court.

3. BART and Emission Limitations.

Although 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. These SIP amendments also address the enforceability of Hayden"s and Craig"s emission limitations* (the dates when the facilities must comply with emission limitations and the enforcement structure have been previously adopted into this LTS). Source retirement and replacement* and construction activities* are not required in the SIP or LTS at this time as the Division is unaware of any relevant issues triggering such a necessity. Note that BART determinations under the Regional haze regulations are described in Chapter 6 of the Regional Haze SIP.

a. Hayden's Emission Limitations.

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 are incorporated into this LTS SIP by reference.[1] EPA approved this SIP amendment on January 16, 1997.[2]

∗ A factor that must be considered in a LTS SIP revision according to EPA regulation.

b. Craig's Emission Limitations.

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 are incorporated into this LTS SIP by reference. The SIP revision was adopted by the AQCC on April 19, 2001[3] and EPA published final approval of the SIP amendment after a public comment period on July 5, 2001.[4]

4. 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. The Division commits to coordinating a monitoring strategy with other agencies and providing periodic assessments of various monitored parameters in "before" compared to "after" emission reductions periods. The Division worked collaboratively in 2005 with the U. S. Geological Survey to assess the effects of Hayden"s emission reductions. The Division plans on conducting a more comprehensive evaluation of both Craig"s and Hayden"s effects combined. This work should be completed in 2011 after a suitable period of data has been collected.

B. Other Stationary Sources and Colorado Class I Areas and Additional Emission Limitations and Schedules for Compliance*.

There are no outstanding certifications of visibility impairment in Colorado. In addition, the Division has found no evidence that other stationary sources potentially subject to BART may reasonably be attributed to cause or contribute to visibility impairment at MZWA or any other Class I area in Colorado under Phase I of EPA"s visibility program. The USFS certification of visibility impairment at Mt. Zirkel Wilderness Area has been completely resolved. The Division recognizes that regional haze impacts all of Colorado"s Class I areas, including MZWA. The State is prepared to respond to any future certifications as per AQCC Regulation No. 3 § XIV.D.

C. Ongoing Air Pollution Programs*.

1. PM_{10}.

The State of Colorado has attained and maintained the PM_{10} standard in its non-attainment areas throughout the State. PM_{10} attainment and maintenance plans have been approved by EPA for Aspen, Canon City, Denver, Lamar, Pagosa Springs, Steamboat Springs, and Telluride. These various plans contain numerous air pollution control programs that are effectively reducing emissions. The attainment and maintenance of the PM_{10} standard will likely have some small effect (since the standard is only rarely exceeded) on improving visibility in pristine and scenic areas. The Division is committed to maintaining the PM_{10} standard throughout the State.

2. Urban Haze -- Brown Cloud.

There is a concern about urban haze in the eastern Front Range urban corridor from the Denver metropolitan area to Fort Collins. This Front Range area is approximately 25-50 miles from Rocky Mountain National Park, a Class I area. The National Park Service, the federal land manager of the Park, has not certified visibility impairment in the Park. Analysis of urban Brown Cloud data in Denver indicates it has improved approximately 28% between 1991 and 2006. The Division will provide periodic trend analysis of the urban Brown Cloud as data

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* A factor that must be considered in a LTS SIP revision according to EPA regulation.

permits and continue to provide technical support to efforts to understand and reduce the Brown Cloud.

3. Emissions in the Four Corners Area.

The cumulative growth of many minor sources of air pollution, including mobile, area and stationary sources, can slowly lead to degradation of air quality and have visibility impacts. Federal land managers have commented in previous Phase I LTS review/revision cycles regarding concerns about the cumulative emissions and their possible impacts on Class I areas in the southwest portion of Colorado.

In response to these challenges, the affected states, tribes and federal land managers in the region have come together to plan for control strategies for future air quality impacts from development. The concept of a Task Force emerged that would allow for a broad and inclusive collaborative process to regional air quality planning. An executive/steering committee of the Four Corners Task Force that includes representatives from the states of Colorado, New Mexico, and Utah, the U.S. Environmental Protection Agency, the U.S. Department of Agriculture - Forest Service, and the U.S. Department of the Interior - National Park Service and the Bureau of Land Management has been formed to help guide the Task Force's progress. Timelines for workgroup deliverables were developed to ensure that all options developed are timely and a final report was issued in November 2007. The report contains analyses of over 100 emission mitigation options that could be utilized in future discussions on reducing emissions in that region.

4. Plan for Rocky Mountain National Park.

The National Park Service (NPS), other federal agencies, and academic researchers have actively pursued ecosystem and air quality monitoring and data collection programs in and near the Park for over twenty years. Findings from these data published in over 80 peer reviewed research articles document ecosystem changes from nitrogen (N) deposition on the east side of the Continental Divide including changes in the type and abundance of aquatic plant species, elevated levels of nitrate in surface waters, elevated levels of N in spruce tree chemistry, long-term accumulation of N in forest soils, and a shift in alpine tundra plant communities favoring sedges and grasses over the natural wildflower flora.

The Rocky Mountain National Park Initiative was created to study and promote action to remedy air quality issues facing the Park, primarily the adverse ecosystem impacts from increasing nitrogen deposition. Other air quality issues are being addressed by other means: visibility impairment by the regional haze program development and Early Action Compact/SIP preparation for ozone.

Using a collaborative approach, the participating agencies -- the Colorado Department of Public Health and Environment (CDPHE), the U.S. Environmental Protection Agency Region 8 (EPA), and the NPS -- have worked effectively to develop a Nitrogen Deposition Reduction Plan (Plan or NDRP). A public participation process facilitated by a Colorado Air Quality Control Commission (AQCC) Subcommittee has helped to involve the public, and a memorandum of understanding (MOU) has been used by the involved agencies to guide the Initiative"s progress leading to development of the Plan.

The agencies have initially focused their efforts in developing the Plan on voluntary approaches first, together with programs that are pending or under way, in lieu of developing a new regulatory program to achieve nitrogen deposition reductions. The agencies believe this strategy has the potential to provide benefits in the near term to reducing nitrogen deposition. However, the agencies support a process to require regulatory measures specific to reducing nitrogen deposition if voluntary and anticipated reductions prove insufficient in making planned progress goals under this Plan. Development and implementation of a contingency plan is one mechanism supported by the agencies to ensure reduction of adverse ecosystem impacts in RMNP.

The NDRP was approved by the AQCC in April 2007. This plan documented the science of nitrogen deposition and the ecological impacts, presented long-term deposition reduction goals, documented current and potential NOx and ammonia emission reduction options, and established a path for future activities. The plan acknowledges that emission reductions measure targeted at reducing N deposition will likely benefit visibility at RMNP. Colorado intends on analyzing the visibility improvement benefit of any deposition-targeted measure.

One of the commitments made in the 2007 NDRP was to develop a contingency plan that would put in place corrective measures in the event that initial and any subsequent interim deposition goals are not realized. Such a plan was adopted by the Colorado Air Quality Control Commission in June 2010. This contingency plan does not automatically require the implementation of additional emission control measures designed to reduce the deposition of nitrogen in RMNP. Instead, a focused process to develop appropriate responses if and when nitrogen deposition goals are not achieved was adopted.

The Division maintains a website that is a clearinghouse for information related to the Initiative and contains the 2007 NDRP and the 2010 Contingency Plan. Please see:

http://www.cdphe.state.co.us/ap/rmnp.html

II. 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.

A. Ongoing Air Pollution Programs∗.

1. PSD and NSR.

Generally, Colorado considers that 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. The State believes that its existing regulations along with the efforts outlined below have together provided for reasonable progress toward the national visibility goal.

∗ A factor that must be considered in a LTS SIP revision according to EPA regulation.

a. Modeling.

The Division has published modeling guidance that presents methods for estimating impacts from stationary sources of air pollution. The guidance is intended to help permit applicants, air quality specialists, and others understand the Division"s expectations for the ambient air impact analysis and to prevent unnecessary delays in the permit process. It provides a starting point for modeling, but allows the use of professional judgment. The guidance contains sections on visibility modeling. In 2001, a technical peer review of the guidance was completed. A more general public review process was finished toward the end of that year. The finalized and updated (as of December 27, 2005) guidance document is available via the Air Pollution Control Division"s web site at: http://www.colorado.gov/airquality/permits.aspx The Division will continue to update its modeling guidance as needed to insure estimated impacts are projected in as technically sound a manner as reasonably possible.

III. SMOKE MANAGEMENT PRACTICES∗.

The LTS requires that smoke management practices of prescribed burning be addressed.

A. The Colorado Smoke Management Memorandum of Understanding and AQCC Regulation No 9.

Until 2002, Colorado"s open burning regulation did not specifically address wildland prescribed fire. In this absence, operational understandings evolved over many years between the Division and the users of prescribed fire for grassland and forestland management. Until January 2002, these understandings regarding the details of permitting and reporting of prescribed fire activity were contained in the Colorado Smoke Management Plan and Memorandum of Understanding (MOU). The Colorado Department of Public Health and Environment, the Forest Service, National Park Service, Bureau of Land Management, Fish and Wildlife Service, Air Force Academy, U.S. Army (Fort Carson), U.S. D.O.E. Rocky Flats Field Office, City of Boulder Wildland Fire Department, Colorado Division of Wildlife, and the Colorado State Forest Service were voluntary signatories to the MOU. The AQCC adopted Regulation No. 9 (Open Burning, Prescribed Fire and Permitting) on January 17, 2002. Adopting this regulation includes the voluntary requirements contained in the MOU and applies them to all users of prescribed fire. In addition, the regulation implements Senate Bill 01-214. Overall, Regulation No. 9 is the main vehicle in Colorado for addressing smoke management from general open burning as well as prescribed wildland burning.

B. SB01-214 and Smoke Management Program Development.

Colorado Senate Bill 01-214 ("Concerning the Application of State Air Quality Standards to the Use of Prescribed Fire for Management Activities Within the State and Making an Appropriation Thereof") became law in 2001. Regulations implementing it were adopted as part of Regulation No. 9. The statute and implementing regulations require significant users of prescribed fire for grassland and forestland management to conform to the State standard to "minimize emissions using all available, practicable methods that are technologically feasible and economically reasonable in order to minimize the impact or reduce the potential for such impact on both the attainment and maintenance of national ambient air quality standards and achievement of federal and state visibility goals." All significant users are to submit planning documents to the Commission. The regulation asks that planning documents explain the

∗ A factor that must be considered in a LTS SIP revision according to EPA regulation.

decision process and criteria the significant user applies to making choices about fuel treatment alternatives to achieve various land management goals and must demonstrate how the significant user will comply with the State standard. Each planning document will have a public hearing before the AQCC. The AQCC is to review and make recommendations and comments for each planning document. Starting in July 2002, the Division cannot issue burning permits to any significant user of prescribed fire if their plan for an area is not consistent with Commission comments and recommendations. The Commission has had hearings on the planning documents of the U.S.D.A. Forest Service, U.S.D.I. Bureau of Land Management, Colorado Division of Wildlife, U.S.D.I. National Park Service, U.S.D.O.D. Fort Carson, U.S.D.I. Fish and Wildlife Service, U.S.D.O.D. Air Force Academy, Jefferson County, Banded Peak Area Ranches, Colorado State Parks, Colorado State Land Board, Trinchera Ranch, Denver Water Board, Blue Valley Ranch, and Larimer County.

The statute also requires fees. Regulation No. 9 specifies that significant users shall pay fees of $59.98/hour to the Division for review of planning documents. Prescribed fire permitees also pay for the cost of the prescribed fire program based on a cost distribution methodology described in the regulation. The cost of the program is currently about $199,000 annually.

It is the State"s intention that through this processes described above, the plans and practices of significant users will continue to consider air quality and visibility concerns into their fuel management decision making.

The Division will also continue to annually produce a report on prescribed burning activity and estimated emissions. The report will contain estimates of acres burned, piles burned, and estimated resulting emissions. The Division has annually prepared such reports since 1990.

The regulation, encompassing the new permitting regulation and the implementation of SB01-214, embodies a comprehensive smoke management program with elements relating to review and approval of wildland fuel management planning documents, permitting of specific fires, reporting actual activity, and a fee program regarding open burning. During 2005, the Division certified its program as consistent with EPA"s *Interim Air Quality Policy on Wildland Prescribed Fire*, May 1998. Each prescribed fire project is reviewed by Division staff consistent with Regulation No. 9 in the course of establishing smoke permit conditions. Approximately 300-350 wildland fire permit applications are processed each year.

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.

IV. FEDERAL LAND MANAGER CONSULTATION AND COMMUNICATION.

The plans, goals, and comments of the federal land managers are to be addressed during SIP and LTS revisions. Good communication with the federal land managers is important to implementing the LTS and making reasonable progress toward the national goal.

A. Consultation.

The federal land managers (FLMs) with Class I areas in Colorado will be given opportunities to comment and provide input during the LTS review and revision process. The Division 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 and to publish the FLM comments and state responses. In accordance with the Regional Haze regulation, the schedule for reviewing and updating this RAVI LTS has been changed from an every three-year period to an every five-year period. The state commits to consult with the FLMs as described above during each five-year review of the LTS.

B. Monitoring Plan.

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 have indicated that they have developed, adopted, and implemented a monitoring plan through the Class I visibility monitoring collaborative known as IMPROVE. EPA"s Regional Haze Rule (40CFR51.308(d)(4)) indicates, "The State must submit with the implementation plan a monitoring strategy for measuring, characterizing, and reporting of regional haze visibility impairment that is 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 network." The federal agencies" monitoring plan relies on this network and ensures that each Class I area in Colorado will have an on-site monitor or an off-site monitor that is representative of visibility in the Class I area. In the 2004 LTS revision, the Division provided letters from the federal land managers and approval letters from the Division. This information is repeated in the 2010 revision and is included here to conform to the requirements of state law to incorporate the monitoring plans in this manner into the SIP.

V. ENDNOTES AND REFERENCES

1. "Long-Term Strategy Review and Revision of Colorado's State Implementation Plan For Class I Visibility Protection, Part I: Hayden Station Requirements, Section VI. C „Enforceable Parts of the SIP Revision: Definitions, Emission Controls and Limitations, Continuous Emission Monitors, Construction Schedule, Emission Limitation Compliance Deadlines, and Reporting‟", August 15, 1996, Colorado Department of Public Health and Environment, Air Pollution Control Division, adopted August 19, 1996 by the Colorado Air Quality Control Commission.

2. "Clean Air Act Approval and Promulgation of Air Quality Implementation Plan Revision for Colorado; Long-Term Strategy of State Implementation Plan for Class I Visibility Protection, Part I: Hayden Station Requirements," January 16, 1997, 62 Federal Register, 2305.

3. "Revision of Colorado‟s State Implementation Plan for Class I Visibility Protection, Craig Station Units 1 and 2 Requirements, Section III „Enforceable Portion of the SIP Revision, Definitions, Emission Controls and Limitations, Continuous Emission Monitors, Construction Schedule, Emission Limitation Compliance Deadlines, and Reporting‟, March 13, 2001, Colorado Department of Public Health and Environment, Air Pollution Control Division, adopted April 19, 2001 by the Colorado Air Quality Control Commission.

4. "Clean Air Act Approval and Promulgation of Air Quality Implementation Plan Revision for Colorado; Long-Term Strategy of State Implementation Plan for Class I Visibility Protection: Craig Station Requirements," 66 Federal Register, 35374.

APPENDIX C

Regional Haze State Implementation Plan

Technical Support for the BART Determinations

Best Available Retrofit Technology (BART) Analysis of Control Options For CEMEX Inc. – Lyons Cement Plant

I. Source Description

Owner/Operator: Cemex
Source Type: Portland Cement Manufacturing
Kiln Type: Modified Long-dry Kiln
Review: Best Available Retrofit Technology (BART)

History:

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 potential 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.

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 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.

Process Description:

Limestone and other raw materials extracted from the quarry are processed through a primary crusher at the Dowe Flats quarry. The crushed material is transported to the plant on a 2.0 mile belt conveyor system and discharged to a stockpile. The stockpiled material is placed on a belt by means of a front end loader to be processed through a primary crusher, the dryer, and a secondary crusher. The material from the secondary crusher is stored in raw material storage silos.

These storage silos contain silica and iron ore and various quarried raw materials. Material from these storage silos is discharged to weigh belts for the formulation of a desired product. The weigh belts discharge to the raw mill. The raw mill mixes and crushes the blended materials and delivers the homogenized material to storage silos. The homogenized material from the storage silos is delivered to the calciner portion of the kiln. Pulverized coal from the coal mill is fired at the bottom of the flash calciner. The partially calcined material from the calciner then enters the 14 foot 3 inch diameter - 245 foot long rotary kiln, which is located at a slight incline along its horizontal axis. The Cemex kiln process-type is best categorized as a modified long dry kiln. The material travels towards the clinker discharge end where additional pulverized coal is fired for the clinkering process. The clinker is discharged from the kiln into the clinker cooler where it is cooled by air forced through the clinker bed by under grate fans. The cooled clinker is then moved to internal storage in an A-Frame building, or outside storage stockpiles. The stored clinker is the raw material for the finish mill. In the finish mill the clinker is combined with gypsum and other additives, ground to a fine material and stored in product silos. The material in the product silos can be loaded for bulk transport, or sent to a packaging system.

From an overall perspective, the manufacturing process may be viewed as two segments -- clinker production and cement production. The clinker storage allows the two processes to operate at different production rates. During periods of low demand for cement, clinker is accumulated. If cement is in high demand, the clinker production can be supplemented by purchase of clinker from other sources. The overall result is the clinker production can operate at a rather steady rate, while the cement production can operate in response to the current or projected demands.

II. Source Emissions

There are two BART eligible units at the Cemex facility, the dryer (point 003) and the kiln (point 007). Regulation Number 3 requires sources to submit an Air Pollution Emission Notice (APEN) on each emission point at least every five years. Typically, emission points with low emissions are updated every five years whereas points with higher emissions are updated annually, since fees are assessed on these emissions.

Table 1 lists the APEN reported emissions from the dryer and emission inventory records collected during routine inspections. The 1999 APEN is based on emission factors, whereas the 2003, 2008 and 2009 APENs are based on a stack test. The Division has determined that the 2008 emissions best represents baseline emissions for the dryer since stack test data is considered more reliable then emission factors. Furthermore, the 2008 clinker production is representative of typical operations because it falls within the normal range of the historical average (please see Table 3 below). Consequently, for purposes of this analysis the dryer has baseline emissions of NOx = 10.41 tpy; SO2= 0.89 tpy; and PM10 = 5.12 tpy; based on a recent stack test.

Table 1: Dryer Emissions

Dryer SCC - 30500620				
Pollutant	SO2	NOx	PM10	CO
Allowable Emissions* [tpy]	36.70	13.90	22.80	57.30
1999 APEN Emissions [tpy]	31.10	13.30	22.20	55.40
2003 APEN Emissions [tpy]	0.64	1.83	1.89	3.83
2008 APEN Emissions [tpy]	**0.89**	**10.41**	**5.12**	**2.97**
2009 APEN Emissions [tpy]	0.37	4.27	2.10	1.22
Baseline [tpy]	**0.89**	**10.41**	**5.12**	**2.97**
% Baseline is below Allowable Emissions	-97.8%	-25.1%	-77.5%	-94.8%
Baseline Emissions [lbs/ton of Clinker]	0.004	0.04	0.02	0.01

** Current emission limitations are contained in operating permit (95OPBO082)*

Table 2 below lists the emissions from the kiln. The APEN reported SO2, NOx and CO emissions are based on continuous emission monitoring systems (CEMS) and the PM10 emissions are based on periodic stack tests. The Division has determined that the 2002 emissions best represent baseline emissions for the kiln because it corresponds to the high range for SO2 emissions (which can vary significantly due to pyrites in the limestone) and NOx emissions are within the normal historical range along with clinker production which is near the historical average. There is an increase in kiln PM10 emissions starting in 2007 because of a change in CDPHE's APEN reporting policy, which allows for the grouping of common stacks associated with kiln (process group P007) and a change to reporting PM10 emissions based on periodic stack tests rather than the use of emission factors. Consequently, the 2002 PM10 emissions are not the most realistic depiction of anticipated baghouse controls and actual emissions that are listed in more recent kiln (P007) APEN reports.

The EPA BART guidelines suggest that *"the baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." See [70 FR 39167]*. There is some variation in the short-term and long-term SO2 emissions depending on the raw material mix, type of clinker produced, and fuel used. Thus, historically there was some flexibility provided in developing the original permit limits to allow of the use of alternative fuels and raw materials, as well as longer averaging periods. The 10-year period (2000-2009) may represent a different kiln operation condition when compared to earlier periods because no petroleum coke was burned in the kiln despite being permitted to burn such fuel. The Division determined that looking back at kiln operations prior to the year 2000 were not reasonable for purposes of BART. Consequently, the selection of 2002 as the kiln emissions baseline essentially precludes the use of petroleum coke since the use of such fuel would result in SO2 emissions far above 95 tons per year.

The justification for selecting the highest SO2 emission rate over a baseline period is associated with the fact that cement kiln SO2 emissions are not as predictable as a coal-fired boiler (power plant). The sulfur in the coal is sole source of SO2 at a power plant, whereas a cement kiln has two sources, the coal fuel and the sulfide impurities (iron pyrite) in the limestone and other raw materials added to the kiln. Consequently, it is much easier, although still a challenge, to maintain compliance with SO2 limits at coal-fired power plants through careful blending of various coals, or purchasing compliant coal to achieve more consistent sulfur content. Conversely, coal blending for cement kilns only addresses one source of SO2, the other source (the raw materials) varies depending on impurities in the mining deposit and other additives used in clinker production.

Table 2: Kiln Emissions

Kiln SCC – 30500606 (120 tons/hour maximum feed rate – 967,680 tons/year dry basis)				
Pollutant	SO2	NOx	PM10	CO
Allowable Emissions [tpy]	1,340.0	2,649.0	133.0	396.0
2000 APEN Emissions [tpy]	14.4	1,729.6		
2001 APEN Emissions [tpy]	18.7	1,858.9	8.7	233.2
2002 APEN Emissions [tpy]	**95.0**	**1,747.1**	**8.5**	**235.3**
2003 APEN Emissions [tpy]	48.0	1,835.0	9.6	210.0
2004 APEN Emissions [tpy]	26.3	1,708.9	9.1	209.0
2005 APEN Emissions [tpy]	27.2	1,591.3	8.5	156.0
2006 APEN Emissions [tpy]	44.7	2,011.7	8.5	239.2
2007 APEN Emissions [tpy]	65.0	1,689.0	56.0	311.0
2008 APEN Emissions [tpy]	55.8	1,295.5	42.0	345.1
2009 APEN Emissions [tpy]	15.5	495.5	17.5	102.4
Baseline [tpy]	**95.0**	**1,747.1**	**8.5**	**235.3**
% Baseline is below Allowable Emissions	-92.9%	-34.0%	-93.6%	-40.6%
Baseline Emissions [lbs/ton of Clinker]	0.402	7.388	0.036	0.995

The average clinker production over the period (2000 – 2008) is 486,031 tons. The year 2009 was excluded from the average as clinker production was well below the average production level.

Table 3: Kiln-Flash Calciner – Historical Emissions

Year	Actual Clinker Production [tpy]	SO2 [tpy]	SO2 [lbs/ton of Clinker]	NOx [tpy]	NOx [lbs/ton of Clinker]
2000	539,992	14.4	0.053	1,729.6	6.42
2001	508,733	18.7	0.074	1,858.9	7.31
2002	**472,945**	**95.0**	**0.402**	**1,747.1**	**7.39**
2003	516,251	48.0	0.186	1,835.0	7.11
2004	472,053	26.3	0.111	1,708.9	7.24
2005	440,384	27.2	0.123	1,591.3	7.23
2006	466,173	44.7	0.192	2,011.7	8.63
2007	479,225	65.0	0.271	1,689.0	7.05
2008	478,520	55.8	0.233	1,295.5	5.41
2009	185,076	15.5	0.167	495.5	5.35

III. BART Evaluation

There are two BART eligible units at the Cemex facility, the dryer and the kiln. The dryer is natural gas-fired with actual emissions of NOx = 10.41 tpy; SO2= 0.89 tpy; and PM10 = 5.12 tpy; based on a recent stack test. CALPUFF modeling[1], of the dryer and kiln combined indicates a 98th percentile visibility impact (at Rocky Mountain National Park) of 0.78 delta deciview[2] (Δdv) and 98th percentile visibility impact at of only the kiln is 0.76 Δdv[3]. 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 Division 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 Division 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 measurable visibility improvement which is a fundamental factor in the BART evaluation. Consequently, the current SO2, NOx and PM10 emission limits (see Table 1 –Dryer Allowable Emissions) established in the Cemex – Lyons Operating Permit (95OPBO082) have been determined to satisfy the requirements for BART.

III.A. Review of Sulfur Dioxide Controls on the Kiln

Step 1: Identify All Available Technologies

Cemex originally identified four available technologies for the removal of sulfur dioxide from Portland cement kilns. A copy of Cemex's BART analysis is included with this analysis as an attachment, and provides further support and documentation for the conclusions reached herein. The Division added Dry Sorbent Injection (DSI) as another option that is available for control of

[1] Cemex Inc., Lyons Colorado - BART Five Factor Analysis; dated August 29, 2008
[2] Table 3-6 of the Cemex BART Five Factor Analysis
[3] Table 4-7 of the Cemex BART Five Factor Analysis

SO2 emissions. The Division also reviewed the RACT/BACT/LAER clearinghouse and other BART analyses develop the following list of available technologies:

1. Fuel Substitution
2. Raw Material Substitution
3. Lime Addition to Kiln Feed
4. Dry Sorbent Injection
5. Wet Lime Scrubbing

Step 2: Eliminate Technically Infeasible Options

Cemex concluded that fuel substitution and raw material substitution are not technically feasible at the plant. Because of the physical, chemical and engineering principles involved in manufacturing Portland cement, technical difficulties would arguably preclude the successful use of these control options at the plant. Nonetheless, the Division has determined that each of the foregoing technologies is "technically feasible" for the facility, as that term is discussed in EPA's BART guidelines.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Step 4: Evaluate Impacts and Document Results

1. Fuel Substitution:

Cemex is authorized to burn coal, coke and tire derived fuel (TDF) at the facility, although coal is the primary fuel. The coal used in the kiln typically has a sulfur content of less than 1.5%, whereas the sulfur content of coke can be as high as 6% sulfur. Removal of SO2 is inherent to the cement manufacturing process as the hot combustion gases come in contact with the limestone generating free lime, which then reacts with the SO2 in the free gas stream resulting in removal of sulfur in the clinker product. Removal efficiencies in rotary kiln systems can range between 38% and 99% of sulfur input. Cemex estimates the SO2 removal efficiency of about 80%. Based on the low level of SO2 emissions (based on CEMS) emitted from the kiln, it is apparent that a high level of SO2 control is achieved through the inherent removal process within the kiln. Since inherent removal accounts for at least 80% reduction in kiln SO2 emissions, any further lowering of the sulfur content of the fuel results in about a 20% reduction in directly emitted SO2.

In November 2002, a preliminary performance (stack) test was conducted on the kiln that compared fossil fuel (coal & natural gas) with coal supplemented with TDF (coal & tires) which indicated about a 40% reduction in SOx in the exhaust stream. The stack tests show that TDF can be burned without exceeding applicable emission limits for either criteria pollutants or hazardous air pollutants. Both the Division and Cemex continue to believe that firing TDF is a viable emission control strategy under appropriate conditions along with consideration of the stack tests results and the fact that TDF is widely used as an alternative fuel. Nevertheless, some in the Lyons community have expressed reservations about the tire burning, and requested a moratorium on using TDF. In response to concerns, and in consideration of a Division issued Compliance Order on Consent (Case No. 2005-049), Cemex agreed not to use TDF as an alternative fuel in the kiln for a period that expired on December 31, 2007. Presently, Cemex may commence using TDF as permitted in accordance with the terms and conditions of Permit No. 95OPBO082, unless TDF is prohibited by another legally enforceable requirement.

Cost of Compliance:

Cemex provided limited TDF cost information because of ongoing community concerns associated with burning tires. The annualized costs are about $172,179 per year; however the costs of acquiring TDF and the transportation costs were not included. Assuming the above annual cost and the estimated 40% SO2 reduction, the control cost is estimated at about $4,531 per ton of SO2 reduced.

Energy Impacts and Non Air-Quality Impacts:

There is community concern associated with fuel switching to TDF.

Existing Controls in Use at Source:

The source uses low sulfur coal and inherent removal of SO2 emissions through contact with the clinker results in about 80% control.

Remaining Useful Life:

No impact

2. Raw Material Substitution:

Sulfide sulfur in the raw materials (primarily limestone), usually in the form of iron pyrite, is thermally decomposed and oxidized or "roasted" to form SO2. The pyritic sulfur reacts with oxygen according to the following reaction:

$$4FeS_2 + 11O_2 \rightarrow 2Fe_2O_3 + 8SO_2$$

Using raw materials with lower pyritic sulfur content would reduce the potential for SO2 emissions from the kiln system. However, while pyrites are present in the limestone and other raw materials used at the plant, concentrations of sulfide sulfur in these materials is typically low. On average, the sulfide content of the raw materials is less than 2%. It is uncertain that lower sulfur content materials are available. Since the raw materials and fuel used at the plant already have very low sulfide sulfur, raw material substitution is not likely to produce significant sulfur reductions.

Similar to most cement plants, the Cemex facility is built near the mine source of limestone, the primary raw material for cement manufacture. To require transport of materials with lower sulfide concentrations from elsewhere would impose an economic penalty that would cause most plants to be economically infeasible. During the production of cement clinker, the limestone loses about one-third of its weight as CO2. The shipping costs for the "lost" weight in the limestone can be economically prohibitive.

The Division has determined that raw material substitution with a different source of limestone is not a practical control option as SO2 emissions vary depending on the level of pyrite contamination which is inherently difficult to predict. Consequently, raw material substitution has been eliminated from further review and consideration.

3. Lime Addition to Kiln Feed:

Lime Addition to Kiln Feed at the Lyons plant would consist of mixing lime (CaO) with the raw Kiln feed. The CaO would react with SO2 driven off in the kiln to form calcium sulfite (CaSO3) and calcium sulfate (CaSO4) according to the following reactions:

$$CaO + SO_2 \rightarrow CaSO_3$$

$$CaSO_3 + \tfrac{1}{2} O_2 \rightarrow CaSO_4$$

These reactions can occur in the calciner, throughout the rotary kiln, and in the lower stages of the flash calciner (i.e., at any location in the system at which CaO and SO2 are present simultaneously and are mixed adequately). The amount of SO2 absorbed through this mechanism at any location in the pyroprocess is dependent on the site-specific temperature and other factors such as the time of contact between the reactants. Once sulfur is absorbed as CaSO4 in the materials in the pyroprocess, it is unlikely to be released again as SO2. CaSO4 would be retained in the raw mix and ultimately be converted into clinker. Cemex anticipates that Lime Addition to Kiln Feed could achieve 25% control of the SO2 emitted from the system. Considering the length of the kiln and the corresponding amount of contact time, it appears that 25% control of SO2 is possible depending on the amount of lime that is fed into the kiln.

Cost of Compliance:

The cost of Lime Addition to Kiln Feed was determined by calculating the cost of the CaO needed to react with the SO2 in the system. In an exhaust gas stream, the molar ratio of CaO needed to react with a mole of SO2 (to achieve a near 90% reaction) is on the order of 1:1. However in the situation of Cemex – Lyons, adding the CaO directly to the feed would result in a diminished effectiveness because of the lower SO2 concentrations. Cemex has indicated that, based on data from Cemex's Wampum, PA plant, an addition of 2-3 ton/hr of CaO to a similar Kiln feed stream resulted in approximately a 25% reduction in the SO2 concentration (from 600 ppm down to 450 ppm). The concentration of SO2 in the gas stream at the Lyons plant is significantly lower (a typical 24-hr average is in the 6 ppm range) and it is unknown how much more CaO is needed to achieve the desired reduction. Since the typical emission range at Cemex-Lyons is 100 times lower than the tested levels at Cemex-Wampum, it is expected that more CaO would be needed to achieve adequate contact time with the lower concentrations of sulfur in the exhaust stream. Moreover, the effectiveness of CaO addition is further limited by the alkali byproducts associated with the use of more CaO. Consequently, Cemex has conservatively estimated that it could take about 4 tons per hour of CaO addition to achieve a 25% SO2 reduction.

Cemex – Lyons kiln is limited to 8,064 hours per year of operation based on a permit limit in the Operating Permit (95OPBO082), thus the resulting annual CaO usage is 32,256 tons (4*8064). Cemex's 2007 BART application identified the CaO cost at $60/ton, but this was for raw CaO (un-calcined) which has different properties. The appropriate material is the use of calcined CaO (lime or quick lime) which cost about $143/ton. Therefore, the annual operating cost would be 32,256 tons x $143/ton = $4,612,608. The lime (CaO) addition would yield approximately 90% conversion to clinker, or 29,030 tpy of clinker, which has a value of $1,161,216 @ $40/ton. Therefore, the actual operating cost would be approximately $4,612,608 - $1,161,216 = $3,451,392. At 25 % control effectiveness, the annual SO2 emissions would be lowered from the proposed permit limit of 95.0 tpy to 71.25 tons/year. The cost effectiveness would be approximately $153,271per ton of SO2 removed.

Energy Impacts and Non Air-Quality Impacts:

Alkali impurities in the CaO could result in additional wasting of kiln dust to meet low alkali limits. Additional fugitive PM10 emission may result from handling of the CaO.

Existing Controls in Use at Source:

The source uses low sulfur coal and inherent removal of SO2 emissions through contact with the clinker results in about 80% control.

Remaining Useful Life:

The remaining useful life of the kiln does not impact the annualized costs for lime addition to kiln feed.

4. Dry Sorbent Injection:

Dry Sorbent Injection (DSI) utilizes finely ground sorbent which is injected in the gas stream of the kiln. The sorbent typically used is a hydrated lime, sodium bicarbonate or Trona (soda ash). Water may be injected separately from the sorbent either downstream or upstream of the dry sorbent injection point to humidify the flue gas. The relative position of the dry sorbent and water injection is optimized to maximally promote droplet scavenging or impacts between sorbent particles and water droplets, both suspended in gas stream. Fly ash, reaction products, and any unreacted sorbent are collected in the particulate control device.

Cost of Compliance:

Cemex did not provide any DSI costs specific to the Lyons kiln.

Energy Impacts and Non Air-Quality Impacts:

There are no energy or non-air quality impacts associated with dry sorbent injection.

Existing Controls in Use at Source:

The source uses low sulfur coal and inherent removal of SO2 emissions through contact with the clinker which results in about 80% control.

Remaining Useful Life:

The remaining useful life of the kiln does not impact the annualized costs for dry sorbent injection.

5. Wet Lime Scrubbing:

Wet lime scrubbing (WLS) is the term used for a traditional tailpipe wet scrubber. This process involves passing the flue gas from the main PMCD through a sprayed aqueous suspension of Ca(OH)2 or CaCO3 (limestone) that is contained in an appropriate scrubbing device. In WLS the SO2 reacts with the scrubbing reagent to form CaSO3 that is collected and retained as aqueous sludge. Typically, the sludge is dewatered and disposed in an on-site landfill. In some cases involving cement plants, the CaSO3 sludge could be oxidized to CaSO4 and used in the finish mills as a substitute for purchased gypsum for regulation of the setting time of the cement product. Typically, WLS is considered to have a scrubbing efficiency of up to 90 percent of the SO2 in the flue gas treated by the scrubber. *See* Cemex BART submittal at 4-4, *citing* “EPA Fact Sheet – Flue Gas Desulfurization (FGD) Wet, Spray Dry, and Dry Scrubbers.”

Cost of Compliance:

Cemex performed an economic analysis to determine the annualized cost for WLS based on a recent vendor bid for a cement plant with a similar exhaust flow rate. The “annual tons reduced” were determined by subtracting the estimated controlled annual emissions from the Division proposed annual permit limit of 95 tpy SO2. The estimated controlled annual emissions, 9.5 tpy, were calculated by applying 90 percent control efficiency to the 95 tpy of SO2. Utilizing this methodology and correcting a math error on the amount of sludge generated, the estimated annualized cost[4] is $2,529,018 for WLS, the projected SO2 control cost per ton is $29,579/ton. A detailed cost analysis is included in Table 4-5 of Cemex's BART submittal, which was corrected by the Division to account for the longer amortization period.

Energy and Non Air-Quality Impacts: Wet Lime Scrubbing (WLS)

Based upon its experience, the Division has determined that wet scrubbing has several negative energy and non air quality environmental impacts, including significant water usage which is a precious commodity in the arid West. Cemex estimates that an appropriately sized wet scrubber would consume approximately 16 million gallons of water per year. Most of this water would be emitted as a steam vapor with a small portion in the sludge that would be generated by the control device. A wet scrubber would also require an additional fan of considerable horsepower to move the flue gas through the scrubber.

Wet scrubbing may also lead to an increase in PM emissions at the Cemex facility, because some particles of limestone or CaSO4 will be entrained in the flue gas and subsequently be emitted from the scrubber. Wet scrubbing is also known to increase emissions of sulfuric acid mist.

Existing Controls in Use at Source:

The source uses low sulfur coal and inherent removal of SO2 emissions through contact with the clinker results in about 80% control.

Remaining Useful Life:

The remaining useful life of the kiln is impacted by the remaining life of the quarry, which Cemex has estimated to be approximately 8 years from the date that a BART control would be required based on the expiration of Boulder County SUP 93-14 for quarry operations. The continued viability of the cement production operation relies on finding additional limestone feedstock of very similar composition within a distance that allows for economic operation. The Division is not aware that Cemex has successfully secured additional limestone supplies that would provide additional useful life to the facility. Presently, Cemex is unwilling to consent to closure date in the operating permit therefore the Division has used 20 years as the capital recovery period.

[4] Capital Recovery based on an assumed 20 year life and 7% interest rate

Table 4 below lists the most feasible and effective options, ranked by control effectiveness.

Table 4: Kiln SO2 Control Options

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%	19.0	71.3	0.30
Fuel Substitution (coal supplemented with TDF)	40%	15.2	57.0	0.24
Dry Sorbent Injection	50%	12.7	47.5	0.20
Wet Lime Scrubbing (Tailpipe scrubber)	90%	2.5	9.5	0.04

Table 5 below lists the SO2 emission reduction, annualized costs and the control cost effectiveness for the feasible controls, ranked by control effectiveness.

Table 5: Summary of Cost Effectiveness of SO2 Control Technologies for the Kiln

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

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control scenarios. Cemex also conducted refined CALMET modeling which indicates that Rocky Mountain National Park is the only Class I Area where the Lyons plant causes or contributes to visibility impairment. Cemex's refined modeling is discussed in detail in the attached Cemex BART 5-Factor Analysis which was reviewed by the Division and found to meet all required performance requirements.

The amount of visibility improvement associated with various SO2 control scenarios using CALPUFF modeling are listed in Table 6.

Table 6: Visibility improvement for SO2 Controls – Kiln Only

Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (from 24-hr Max) (Δdv)	Cost Effectiveness ($/Δdv)
24-hr Maximum (≈ 104 lbs/hr)	0.760	-	
Baseline (≈ 25.3 lbs/hr)*	0.730	0.030	
Lime Addition to Kiln (≈ 19.0 lbs/hr)*	0.727	0.033	$110,308,420
Fuel Substitution (≈ 15.2 lbs/hr)*	0.726	0.034	$5,064,088
Dry Sorbent Injection (≈ 12.7 lbs/hr)*	0.724	0.036	
Wet Lime Scrubbing (≈ 2.5 lbs/hr)	0.720	0.040	$63,225,462

** - Visibility impacts interpolated from original BART modeling*

The SO2 baseline of 95 tons/year is based on 2002 APEN report which results in a 0.03 Δdv of visibility improvement over the 24-hour maximum emission rate of 104 lb/hour (419 tons/year). The SO2 reduction from lime addition to kiln feed is estimated at 25% and the anticipated degree visibility improvement (from 24-hr Maximum) is about 0.033 Δdv at a cost of $110.3 million dollars per Δdv. The control efficiency of fuel substitution could be as high as 40% (about 38 tons/year) based on very limited testing and the anticipated degree of visibility improvement (from 24-hr Maximum) is about 0.034 Δdv at a cost of $5 million dollars per Δdv. Dry sorbent injection has a visibility improvement of 0.036 Δdv, based on an estimated 47.5 tpy reduction in SO2 emissions. Wet lime scrubbing reduces SO2 emissions by about 85.5 tpy with 0.04 Δdv visibility improvement at a cost of $63 million dollars per Δdv. The visibility projections for the below listed emission levels are based on scaling the existing BART modeling.

Step 6: Select BART Control

The Division reviewed the Cemex data on raw material substitution. Since the raw materials (mostly limestone) consumed at the plant typically have low sulfide sulfur content, material substitution would not result in a significant reduction in SO2 in the Kiln. The Division agrees that raw material substitution is not an appropriate or realistic SO2 control technology for the Kiln.

The Division has eliminated the Lime Addition to Kiln Feed SO2 control option from consideration based on excessive cost ($153,271 per ton) and minimal visibility improvement (0.033 Δdv). Despite not having cost information on Dry Sorbent Injection, the Division has determined that the minimal visibility improvement of 0.036 Δdv does not justify further consideration of this control technology.

The Division has eliminated the Wet Lime Scrubbing SO2 control option from consideration based on excessive cost ($29,579 per ton) and minimal visibility improvement (0.04 Δdv improvement). Moreover, wet scrubbing has a number of adverse energy and environmental impacts as described above.

The Division has considered the five factors and has thoroughly reviewed the data supplied by Cemex to determine that process control (inherent removal in the kiln) from the 2002 baseline period represents Best Available Retrofit Technology for control of SO2 emissions in the kiln. Table 7 specifies the Division SO2 BART determination of 25.3 pounds per hour and 95.0 tons per year that are 12-month rolling averages. The Division considered establishing an SO2 emissions limit based on clinker production, however, the Cemex-Lyons facility does not have the capability to weigh clinker product upon exiting the kiln. Consequently, compliance with the SO2 BART limits will be determined by a continuous emissions monitor system (CEMS).

Table 7: SO2 Emission Limits on the Kiln

Subject Unit	SO2 Control Technology	SO2 Emission Limits
Kiln System	Inherent Removal	25.3 lbs/hr (12-month rolling average)
		95.0 tons/yr (12-month rolling average)

The federal BART rule requires that emission limits must be enforceable and specify a reasonable averaging time consistent with established reference methods. The Division finds that in consideration of the potential for variability in SO2 emissions associated with pyrites in the limestone and other raw materials used at the plant, an annual averaging period provides long-term compliance with the low levels of SO2 emitted from the kiln while allowing for short-term variability in SO2 emissions. Shorter term averaging periods are not practical as the sources of the sulfur impurities are not readily detectable in the quarry materials. The type of cement produced also potentially impacts the variability of SO2 emissions in the kiln feed mix which necessitates longer averaging periods.

In consideration of establishing the SO2 emission limit, the Division reviewed not only the 5 factor analysis, but also looked at emission limits from the RACT/BACT/LAER clearinghouse to determine SO2 emission limits for other cement kilns across the nation. The Division was unable to find an operationally similar kiln to the Cemex - Lyons kiln, but the SO2 emission limits for newer higher efficiency kilns do establish a reasonable range to consider. Table 8 identifies SO2 limits ranging from 0.2 to 12.0 lb per ton of clinker. In comparing the Division proposed SO2 BART limit (approximately equal to 0.40 lb per ton of clinker) to the values approved for new Portland cement kilns in the RACT/BACT/LAER clearinghouse, it is well below the higher limits established in Missouri, and is slightly higher than those established in Florida.

Table 8: RACT/BACT/LAER data for Cement Kilns

RBLC ID	SO2 Control	SO2 Limit	Units	Year
FL 0297	Process	0.2	lb/ton clinker	2007
MO-0072	Process	1.93	lb/ton clinker	2006
FL-0271	Process	0.2	lb/ton clinker	2006
FL-0268	Process	0.23	lb/ton clinker	2004
FL-0267	Process	0.28	lb/ton clinker	2004
SD-003	Process	632	ton/hr	2003
MO-0059	Wet Scrubber	12	lb/ton clinker	2002
IA-0052	Process	4850	ton/year	2002
TX-0355	Process	20	lb/hr	2001
FL-0139	Process	0.27	lb/ton clinker	2000

The Division also evaluated a recent local BACT determination (2007) on Grupo Cementos de Chihuahua (GCC) Rio Grande Pueblo Portland cement plant that establishes a SO2 emission limit of 1.99 lb/ton of clinker. In considering the RBL clearinghouse ranges and a recent Colorado BACT determination, the Division finds that the proposed SO2 BART limits (approximately equal to 0.40 lb/ton of clinker) to be a reasonable limit for such a relatively small SO2 emission source.

Accordingly, based upon its consideration and weighing of the five factors, the Division has determined that the use of low sulfur coal and the inherent control resulting from the Portland cement process provides sufficient basis to establish annual SO2 emission limits of 25.3 lbs/hour and 95.0 tpy (approximately equal to 0.40 lb per ton of clinker) as SO2 BART for the kiln at this facility. No additional controls are warranted because about 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.

III.B. Review of Nitrogen Oxide Controls on the Kiln

As explained above, in Section III, no evaluation of the dryer is warranted because of extremely low emissions. Based on actual 2008 data, the NOx emissions from the kiln are 1295.5 tpy and the raw material dryer are 10.41 tpy. Since the average emissions from the dryer (about 2.8 pounds per hour) are very small compared to the kiln (about 343.9 pounds per hour); the following BART evaluation focuses only on the kiln.

Step 1: Identify All Available Technologies

The primary pollutant of concern for regional haze from the Lyons plant is the NOx generated from the kiln system. Cemex's current allowable NOx emission rate is 2,649 tpy NOx, which equates to an average allowable emission rate of 667 pounds NOx per hour based on the permit limit of 8064 hours of operation per year. Using 2002 as the baseline, the annual average NOx emission rate is 464.3 lbs/hr (1,747.1 tpy) or about 4.73 lbs/ton of dry kiln feed.

Variations in kiln NOx emissions occur with the composition of the raw materials used to produce different types of cement, which depends on market demand. Also, changes in the raw materials (natural rock composition) and seasonal temperature variations occur, as indicated in the following excerpt from a study[5], *"The results of these changes range from zero emissions of NOx during a complete outage of the system to significantly higher than normal NOx emissions when the fuel input is increased to restore the process equilibrium and a normal production rate. More subtle changes in the process, e.g. variations in ambient temperature (short-term and seasonal), variations in the feed rates or fuel or raw materials, demand operator responses that also serve to vary NOx emissions. For a variety of factors, the operation of some pre-calciner kiln systems is more stable than others. Almost invariability, however, pre-calciner kiln systems exhibit more stable operation than the three other types of kiln systems, and experience the least variability in NOx emissions."* The Cemex - Lyons kiln is a modified long dry kiln, thus some consideration of a longer averaging period is appropriate to account for variation in NOx emissions depending on cement product produced and variations in raw materials.

[5] See "Variability of NOx Emissions from Precalciner Cement Kiln Systems", Walter L. Greer, Curtis D. Lesslie

Cemex identified six available technologies for the removal of NOx from Portland cement kilns. The Division reviewed the RACT/BACT/LAER Clearinghouse and other BART analyses and agrees with CEMEX's identification of available technologies. The available technologies are the following:

1. Water Injection
2. CKD Insufflation
3. Firing Tire-Derived Fuel
4. Indirect Firing with Low NOx Burners (LNB)
5. Selective Non Catalytic Reduction (SNCR)
6. LNB with SNCR
7. Selective Catalytic Reduction (SCR)

Step 2: Eliminate Technically Infeasible Options

Cemex has concluded that water injection and kiln dust insufflation are not technically feasible at the plant. Because of the physical, chemical and engineering principles involved in manufacturing Portland cement, technical difficulties would arguably preclude the successful use of these control options at the plant. Nonetheless, the Division has determined that these technologies are "technically feasible" for the facility, as that term is discussed in EPA's BART guidelines. As further discussed below, however, the Division has also determined that water injection and kiln dust insufflation are not appropriate NOx controls for purposes of BART at the facility.

7. Selective Catalytic Reduction (SCR):

Selective catalytic reduction (SCR) refers to the reduction of NOx in the presence of ammonia to water and elemental nitrogen in the presence of a catalyst. The term "selective" refers to the unique ability of ammonia to react selectively with NOx. The EPA released a NOx control technology update for new cement kilns entitled "Alternative Control Techniques Document Update – NOx Emissions from New Cement Kilns," EPA-453/R-07-006, November 2007 that discusses SCR control for cement kilns. The following discussion is excerpted from the EPA report:

> *SCR is the process of adding ammonia or urea in the presence of a catalyst to selectively reduce NO_x emissions from exhaust gases. The SCR process has been used extensively on gas turbines, internal combustion (IC) engines, and fossil fuel-fired utility boilers. In the SCR system, anhydrous ammonia, usually diluted with air or steam or aqueous ammonia solution, is injected through a catalyst bed to reduce NO_x emissions. A number of catalyst materials have been used, such as titanium dioxide, vanadium pentoxide, and zeolite-based materials. The catalyst is typically supported on ceramic materials (e.g., alumina in a honeycomb monolith form) and promotes the NO_x reduction reactions by providing a site for these reactions to occur. The catalyst is not consumed in the process, but allows the reactions to occur at a lower temperature. The optimum temperature for the catalyst reactions depends on the specific catalyst used. Several different catalysts are available for use at different exhaust gas temperatures. Base metal catalysts are useful between 450 °F and 800 °F (232 °C and 427 °C). For high temperature operations (675 °F [357 °C] to over 1100 °F [593 °C]), zeolite catalysts containing precious metals such as platinum and palladium are useful. The two principal reactions in the SCR process at cement plants using SCR are the following:*

4 NH3+ 4 NO + O2 → 4 N2 + 6 H2O
and
4 NH3 + 2 NO2 + O2 → 3 N2 + 6 H2O

The first equation is the predominant reaction because 90-95% of NO_x in flue gas is NO. It is important to note that the desired chemical reactions are identical with SNCR and SCR. The only difference is that a catalyst is present with SCR, which allows the reactions to occur at a lower temperature. In an SCR system, ammonia is typically injected to produce a NH_3: NO_x molar ratio of 1.05–1.1:1 to achieve a NO_x conversion of 80–90% with an ammonia slip of about 10 ppm of unreacted ammonia in gases leaving the reactor. The NO_x removal efficiency depends on the flue gas temperature, the molar ratio of ammonia to NO_x, and the flue gas residence time in the catalyst bed. All these factors must be considered in designing the desired NO_x reduction, the appropriate reagent ratios, the catalyst bed volume, and the operating conditions. As with SNCR, the appropriate temperature window must be maintained to assure that ammonia slip does not result in a visible plume. SCR can be installed at a cement kiln at two possible locations:

After the PM control device – a "low-dust" system
After the last cyclone without ducting – a "high-dust" system.

The advantages of a "low-dust" system are longer catalyst life and lower danger of blockage. The disadvantage is the additional energy costs required to heat the cooled exhaust to achieve proper reaction temperatures in the catalyst. On a worldwide basis, three cement kilns have used SCR: Solnhofen Zementwerkes in Germany and Cementeria di Monselice and Italcementi Sarche di Calavino in Italy. The SCR system was operated at the Solnhofen plant from 2001 to January 2006, at which time the plant began using SNCR to compare the operational costs of the two systems to evaluate which technology is better and more economical. Both Solnhofen and Cementeria di Monselice have preheater kilns. The Italcementi plant operates a small Polysius Lepol technology kiln, which is a traveling grate preheater kiln. Both plants use a 25% aqueous ammonia solution, have 6 catalyst layers but only use 3 layers. Both plants have similar designs and facilities that are similar in size and raw materials. At Solnhofen, 200 mg/m^3 (~ 0.8 lb/t) of NO_x is typically achieved from an inlet of 1,050 mg/Nm^3 (4.2 lb/t) or 80% control. Also, ammonia slip was less than 1 mg/m^3. Greater than 80% control is frequently achieved. At the end of 2003, the catalyst had logged 20,000–25,000 hours with no discernable problems. The catalyst was guaranteed for 16,000 hrs, with an expected catalyst life of 3–4 yrs.

The SCR system at Cementeria di Monselice in Bergamo, Italy began operation in June 2006. Catalyst activity remains high after 3,500 hours of operation. Following startup in June 2006, continuous testing was conducted for six weeks.

The design of a SCR system is expected to be site specific. According to Schreiber[6], the technology transfer of SCR systems from the power plant industry to the Portland cement industry requires substantial research and pilot testing before the technology could be considered commercially available. Figure 1, from Granger[7] shows the performance of a typical catalyst under different conditions of temperature and gas composition. The highest NOx reduction

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[6] See Schreiber, R, *et al* "Evaluation of Suitability of Selective Catalytic Reduction and Selective Non-Catalytic Reduction for use in Portland Cement Industry", (2006)
[7] See Granger, P. Elsevier, "Past and Present in DeNOx Catalysis: From Molecular Modeling to Chemical Engineering", (2007)

efficiencies for this particular catalyst (vanadium pentoxide with titanium dioxide substrate) were achieved at a temperature range of 350°C to 450°C. At a particular temperature, as denoted by the sweeping arcs, small incremental increases in ammonia result in an increase in the NOx reduction until the optimal rate is achieved beyond which a rapid increase in ammonia slip results. This also provides evidence of the narrow temperature window for effective SCR performance.

Figure 1: Catalyst Performance for NOx Control and Ammonia slip at Various Temperatures

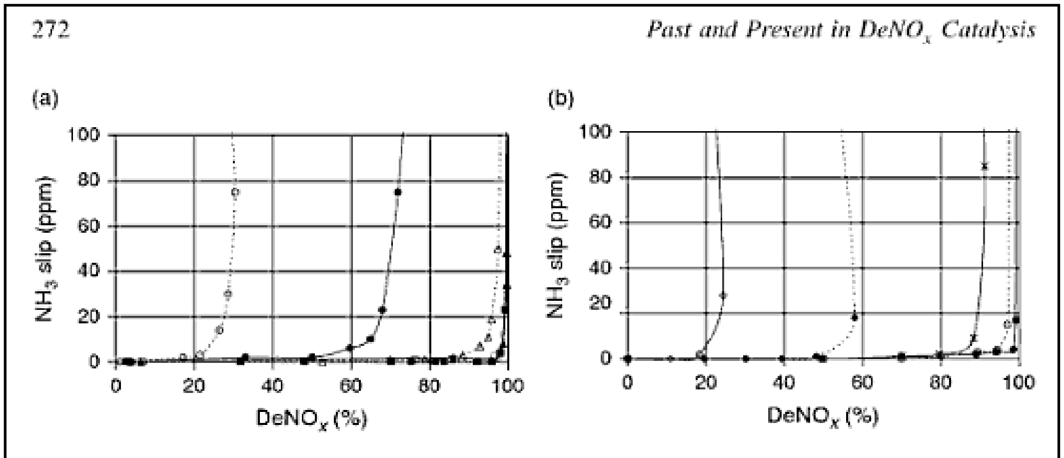

Figure 9.9. Performance of a coated V_2O_5/WO_3-TiO_2 SCR catalyst developed in our laboratory (Table 9.1) with (a) pure NO and with (b) $NO:NO_2 = 1:1$. (◇) 120°C, (♦) 150°C, (*) 180°C, (○) 200°C, (•) 250°C, (▲) 300°C, (Δ) 350°C, (□) 400°C, and (■) 450°C. Cell density: ≈400 cpsi. $V_{cat} = 7.5\ cm^3$. Model gas investigation with 10% O_2, 5% H_2O, 1000 ppm NO or 500 ppm NO + 500 ppm NO_2, 0–1500 ppm NH_3, and balance N_2 in a laboratory test unit [13]. High Resolution FTIR gas analysis [13]. GHSV = 52 000 h^{-1}.

Additionally, multiple challenges exist to achieve SCR effectiveness: selection of catalyst type, positioning of the catalyst, management of catalyst life, catalyst poisoning and ammonia slip. Each challenge presents additional confounding issues related to the application at the Cemex – Lyons facility due to the unique design of the modified long dry kiln. A good catalyst must ensure high activity and selectivity for NOx reduction and low activity in the oxidation of SO2 to SO4. Because of the high selectivity, the catalyst will have a specific temperature window at which the NOx reduction is optimal (Granger 2007). Specific to the Cemex – Lyons kiln, the exit temperature, after the baghouse, will require reheating of the exhaust gases to reach the optimal temperature for effective NOx control. If post NOx control cooling is required, additional water usage would be necessary along with the challenges of the resultant high moisture (20-25%) exhaust gas stream.

There is limited information regarding the geometry and optimal positioning of the catalyst to allow for effective NOx reduction and low pressure loss. Further, engineering analysis on overall efficiency during the catalyst life-cycle would be required to ascertain effectiveness. According to Benson[8], alkali and alkaline-earth rich oxides (sodium, magnesium, calcium and potassium) have strong influence on catalyst deactivation (*See also* Nicosia *et al.,* 2008, and Strege *et al.,* 2008). Figure 2 shows evidence of catalyst poisoning by both sulfur and alkalies[9].

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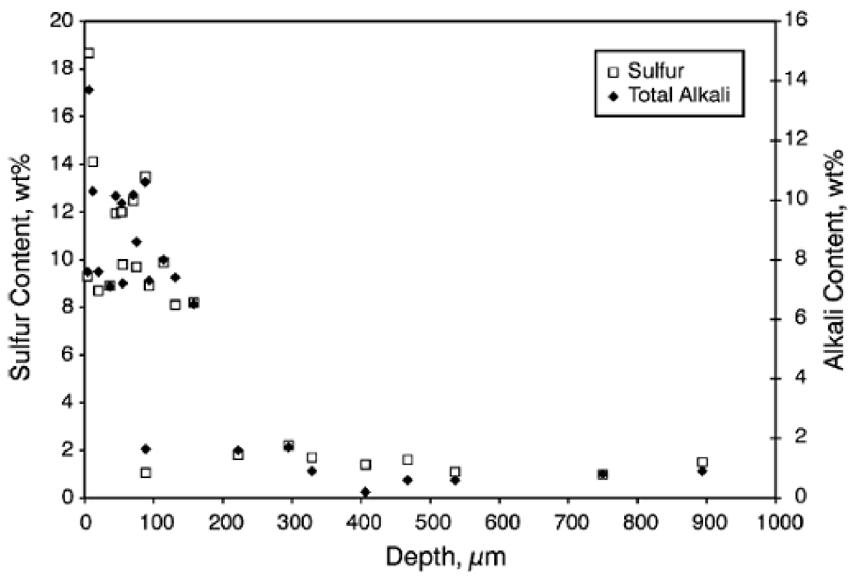
[8] See Benson, S. *et al.* "SCR catalyst performance in flue gases derived from subbituminous and lignite coals, Fuel Processing Technology, Vol. 86" (2005)

[9] See Strege, J. et al., "SCR deactivation in a full-scale cofired utility boiler, Fuel 87" (2008)

The contaminants occupy active sites that otherwise would be available for ammonia storage thus reducing the reactivity and selectivity of the catalyst resulting in lower NOx control effectiveness. Also, particulates from the calcining process would likely combine with available ammonia to form a sticky dust that may adhere to the active sites on the catalyst thereby further reducing the effectiveness of the NOx reduction. Particulate scouring of the catalyst surface has been identified as another mechanism that reduces the effectiveness of the catalyst. The exit gas of the Cemex – Lyons kiln presents additional specific issues including moisture in the exhaust stream and alkali dust. The combination of both could result in rapid loss of catalyst activity depending on the type of catalyst materials used.

Figure 2: Sulfur and Alkali Penetration into the pores of the catalyst

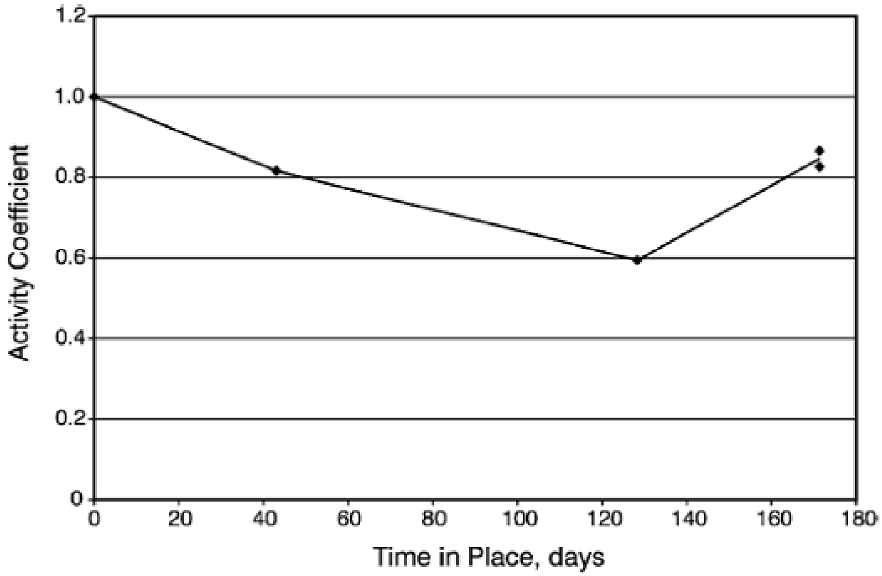


Total alkali (Na + K) and sulfur content with depth beneath catalyst surface.

The above figure indicates that sulfur and alkali compounds penetrate into the catalyst surface resulting in a reduction in the number of active sites thereby reducing the activity and selectivity toward NOx reduction (see Strege *et al.*, 2008).

Figure 3: Bench Scale Test Results of Catalyst Deactivation over a Period of Time

J.R. Strege et al. / Fuel



Bench-scale test results of catalyst deactivation with time.

The above figure provides evidence of catalyst deactivation. If the catalyst life is assumed to end when activity coefficient is around 0.6, then the catalyst life is about 130 days or 3,100 hours, which is much lower than the ~23,000 hour catalyst life cited in the report on the Solnhofen Zementwerkes in Germany.

Ammonia slip is also an issue of concern as it readily reacts to form secondary particulates. A catalyst must combine high NOx conversions to elemental nitrogen and water along with low ammonia slip. In principle, the catalyst has acidic surfaces that retain unreacted ammonia; the storage capacity of these acidic sites depends on temperature. According to Barbaro[10], a good flow distribution is needed to ensure minimal ammonia slip. The Cemex – Lyons kiln has neither the temperature nor the flow characteristics necessary for optimal catalyst performance. Another concern for the Cemex – Lyons kiln, is the potential for ammonia slip to create visibility impairment that is readily transported into nearby Rocky Mountain National Park.

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.

Of the four major vendors contacted, two, Lurgi PSI Inc. (Lurgi) and Babcock & Wilcox, did not provide any proposal, with Lurgi stating that their technology was not yet ready for commercial release. A third with relevant experience from the Solnhofen demonstration plant, KWH, indicated that technical uncertainties prevented them from designing an SCR system. Only Alstom provided a proposal that suggested SCR could be supplied to a cement kiln system.

[10] See Barbaro, P.; Bianxhini, C. Wiley-VCH, Catalysis for Sustainable Energy Production (2009)

However, careful review of the Alstom proposal indicated that the Alstom proposal did not identify a commercial SCR system that would be viable for a cement kiln system application.

The Division finds that a limited use - trial basis application of an SCR control technology on three modern kilns in Europe that differ significantly from the Cemex – Lyons kiln design does not constitute "available" control technology for purposes of BART. The Division notes that very specific temperature and dust content parameters must be achieved prior to the catalyst reactor elements to preclude plugging issues. As mentioned in the EPA report, *"The advantages to the low dust configuration are longer catalyst life and lower danger of blockage. The disadvantage is the additional energy costs required to heat the cooled exhaust to achieve proper reaction temperatures in the catalyst*." Cement kilns are inherently very dusty environments; consequently for many cement kilns, the catalyst reactor must be installed after the baghouse as would be required for the Cemex - Lyons kiln, which is a modified long-dry kiln design. The Division believes that commercial demonstration of SCR controls on a cement plant in the United States is necessary for a control technology to be "available" for purposes of retrofitting such control technology on an existing source. BART should not be a forum to test new experimental controls to see if they work, particularly when ideal design parameters are constrained in retrofit situations. Therefore, the Division has eliminated SCR as an available control technology for purposes of BART.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Step 4: Evaluate Impacts and Document Results

1. Water Injection:

The injection of water or steam into the main flame of a kiln can act as a heat sink to reduce the flame temperature. Since NOx formation is a function of the flame temperature and residence time at that temperature, water injection reduces the generation of thermal NOx. Cemex - Lyons has stated that its own experience indicates that water injection can reduce the thermal NOx by approximately 7%. The Division anticipates some reduction in thermal NOx formation when water is injected into the area where the flame temperature is the highest. Aside from actual testing in the kiln, a 7% reduction seems reasonable.

Cost of Compliance:

Based on information from Cemex – Lyons, the Division estimates the annualized costs of water injection at about $43,598 with minimal annual operating costs. Assuming a 7% NOx reduction, the control cost is about $356 per ton of NOx reduced.

Energy Impacts and Non Air-Quality Impacts:

The only non-air quality impacts associated with water injection is the use of a precious resource in limited supply in the arid west.

Existing Controls in Use at Source:

None.

Remaining Useful Life:

The remaining useful life of the kiln does not impact the annualized costs for water injection.

2. Cement Kiln Dust Insufflation:

Cement Kiln Dust (CKD) is a residual byproduct that can be produced by any of the four basic types of cement kiln systems. CKD is most often treated as a waste even though there are some beneficial uses. However, as a means of recycling usable CKD to the cement pyroprocess, CKD sometimes is injected or insufflated into the burning zone of the rotary kiln in or near the main flame. The presence of these cold solids within or in close proximity to the flame has the effect of cooling the flame and/or the burning zone thereby reducing the formation of thermal NOx. The insufflation process is somewhat counterintuitive because a basic requirement of a cement kiln is a very hot flame to heat the clinkering raw materials to about 2700°F in as short a time as possible. Because of the thermal inefficiency associated with the practice, CKD insufflation is not an attractive control option for NOx. While the Division does not agree that the thermal inefficiency makes kiln dust insufflation technically infeasible, the Division has determined that that inefficiency, coupled with the much greater reduction achieved through SNCR (discussed below), render insufflation inappropriate for the Cemex plant. Cemex provided additional information that indicates that CKD insufflation is not typically done because of operational issues including ring formation in the kiln. Consequently, the Division is not evaluating this control option further because of operational issues and the greater reduction achieved through SNCR.

3. Firing Tire-Derived Fuel:

Secondary combustion is defined as follows: a portion of the fuel is fired in a location other than the burning zone. This reduces thermal NOx generation because the temperature in the secondary combustion zone is less than 2100 °F. Firing of solid fuels, such as used tires, is an example of secondary combustion. The Cemex – Lyons kiln has conducted testing of tire derived fuel (TDF) which can be introduced at the kiln feed shelf, creating a secondary combustion zone in the riser between the kiln and the combustion chamber.

In November 2002, a preliminary performance (stack) test was conducted to compare fossil fuel (coal & natural gas) with coal supplemented with TDF (coal & tires) which indicated about a 24.4 % reduction in NOx in the exhaust stream. Cemex estimates that firing TDF can reduce NOx by 10% on a long term basis if utilized. The stack tests show that TDF can be burned without exceeding applicable emission limits for either criteria pollutants or hazardous air pollutants. Both the Division and Cemex continue to believe that firing TDF is a viable NOx reduction control strategy under appropriate conditions along with consideration of the stack tests results and the fact that TDF is widely used as an alternative fuel. Nevertheless, some in the Lyons community have expressed reservations about the tire burning, and requested a moratorium on using TDF. In response to concerns, and in consideration of a Division issued Compliance Order on Consent (Case No. 2005-049), Cemex agreed not to use TDF as an alternative fuel in the kiln for a period that expired on December 31, 2007. Presently, Cemex may commence using TDF as permitted in accordance with the terms and conditions of Permit No. 95OPBO082, unless TDF is prohibited by another legally enforceable requirement. Potentially, TDF could be used in combination with other control technologies, such as SNCR to meet additional BART NOx reduction objectives.

<u>Cost of Compliance:</u>

Cemex provided limited TDF cost information because of ongoing community concerns associated with burning tires. The annualized costs are about $172,179 per year; however the costs of acquiring TDF and the transportation costs were not included. Assuming the above annual cost and the estimated 10% NOx reduction, the control cost is estimated at about $986 per ton of NOx reduced.

Energy Impacts and Non Air-Quality Impacts:

There is community concern associated with fuel switching to TDF.

Existing Controls in Use at Source:

None.

Remaining Useful Life:

No impact

4. Indirect Firing with Low-NOx Burners:

Low NOx burners (LNBs) reduce the amount of NOx formed at the flame. The principle of all LNBs is the same: stepwise or staged combustion and localized exhaust gas recirculation (i.e., at the flame). As applied to the rotary cement Kiln, the low-NOx burner creates primary and secondary combustion zones at the end of the main burner pipe to reduce the amount of NOx initially formed at the flame. In the high-temperature primary zone, combustion is initiated in a fuel-rich environment in the presence of a less than stoichiometric oxygen concentration. The oxygen-deficient condition at the primary combustion site minimizes thermal and fuel NOx formation and produces free radicals that chemically reduce some of the NOx that is being generated in the flame.

In the secondary zone, combustion is completed in an oxygen-rich environment. The temperature in the secondary combustion zone is much lower than in the first; therefore, lower NOx formation is achieved as combustion is completed. CO that has been generated in the primary combustion zone as an artifact of the sub-stoichiometric combustion is fully oxidized in the secondary combustion zone.

The EPA has indicated that a 14% reduction in NOx emissions may be anticipated in switching from a direct-fired standard burner to an indirect-fired LNB. This is based on a study conducted on an indirect-fired LNB at the Dragon Product Company cement kiln at the plant located in Thomaston, Maine. However, the EPA has also determined that the emission reduction contribution of the LNB itself and of the firing system conversion direct to indirect cannot be isolated from the limited data available. The terms direct and indirect firing have unique meaning in the context of Kiln firing (unlike the more general meanings where direct firing implies that the products of combustion contact the process materials whereas indirect firing involves a heat transfer medium). In Kiln firing, direct and indirect firing describes the manner in which pulverized fuel is conveyed from the fuel grinding mill to the burner. Cemex has estimated that a LNB would lower NOx by 20% at the Lyons plant.

Cost of Compliance:

Cemex also provided information from a NESCAUM report (Dec 2000) that indicates 20-30% NOx reduction can be achieved through the use of indirect firing with LNBs. Cost data was included from a study of California Portland Cement (Colton, CA) that evaluated TDF along with indirect firing w/LNBs that indicates $7 million capital cost and $350,000 annual O&M costs. This study includes TDF firing and does not separate out the actual cost associated with the indirect firing with LNBs. The Division has estimated the annualized cost at about $710,750 with a result control cost of about $2,034 per ton of NOx reduced.

Energy Impacts and Non Air-Quality Impacts:
None.

Existing Controls in Use at Source:
None.

Remaining Useful Life:
No impact

5. Selective Non-Catalytic Reduction (SNCR):

In the relatively narrow temperature window of 1600 to 1995°F, ammonia (NH3) reacts with NOx without the need for a catalyst to form water and molecular nitrogen in accordance with the following simplified reactions.

$$4NO + 4NH3 + O2 \rightarrow 4N2 + 6H2O$$

$$2NO2 + 4NH3 + O2 \rightarrow 3N2 + 6H2O$$

As applied to NOx control from cement kilns and other combustion sources, this technology is called Selective Non-Catalytic Reduction (SNCR). Above this temperature range, the NH3 is oxidized to NOx, thereby increasing NOx emissions. Below this temperature range, the reaction rate is too slow for completion and unreacted NH3 may be emitted from the pyroprocess. This temperature window generally is available at some location within rotary kiln systems. The NH3 could be delivered to the kiln system through the use of anhydrous NH3, or an aqueous solution of NH3 (ammonium hydroxide) or urea [(NH2)2CO]. A concern about application of SNCR technology is the breakthrough of unreacted NH3 as "ammonia slip" and its subsequent reaction in the atmosphere with SO2, sulfur trioxide (SO3), hydrogen chloride (HCl) and/or chlorine (Cl2) to form a detached plume of PM10 –PM2.5.

SNCR is being evaluated at 45 to 50% control efficiency depending on the averaging period. The Cemex kiln/flash calciner configuration is best described as a modified long dry kiln. The Division has conducted extensive research and has not found any documentation on similar kiln types. EPA's Alternative Control Techniques Document Update – NOx Emissions from New Cement Kilns (November 2007) addresses only new cement kilns. These new kilns are multi-stage (4 or 5 stage) preheater/precalciner kilns and are not comparable to Cemex – Lyons unusual modified long dry kiln. The Division has also considered the Cemex Brooksville plant in Florida, but it is a multi stage preheater design and is not comparable to the Lyons facility. The Division's evaluation reveals that the Solnhofen facility achieved only 50% reduction with SCR. Significantly, the Division is concerned that requiring a higher reduction through SNCR (beyond 45% on a 30 day rolling average) could cause excessive ammonia slip that would exacerbate the nitrogen deposition concerns at Rocky Mountain National Park. Considering the close proximity of Cemex to RMNP, any unreacted ammonia (slip) is available to react with oxides of nitrogen or sulfur to form particulates (nitrate or sulfate) a potentially significant contributor to visibility impairment.

It is important to note, that all kilns are not created equal. Modern 5-stage preheater/calciner kilns are not an appropriate comparison to the unusual and modified configuration of the Cemex

– Lyons 40-year old kiln. Consequently, it is difficult to assert what amount of NOx reduction can be achieved with SNCR controls on this older modified long dry kiln. It is important to realize that a higher SNCR control efficiency in a long type kiln necessitates the injection of more ammonia (higher molar ratio) to increase the opportunity for reacting with oxides of nitrogen. This is particularly important to understand with older kilns where operating parameters are often less than the engineering ideal. Often residence time and temperature limit the effectiveness of the reaction. Any excess ammonia (slip) that fails to react, largely because the temperature is too low, is exhausted out the stack to eventually form particulates which counteracts the original basis for the emissions control –visibility. Thus, if EPA desires higher control efficiency, the penalty is more visibility impairment downwind of the source. Therefore, the engineering evaluation must consider the balance between high control efficiency and ammonia slip.

Cost of Compliance:

Based on information provided by Cemex – Lyons, the Division estimates the annual costs at about $1,636,636 per year. Assuming a 48.43% NOx reduction, the control cost is about $1,934 per ton of NOx reduced.

Energy Impacts and Non Air-Quality Impacts:

None.

Existing Controls in Use at Source:

None.

Remaining Useful Life:

No impact.

6. Selective Non-Catalytic Reduction with Low NOx Burners (LNB):

Cemex conducted a BART analysis for the kiln located in Lyons, Colorado and concluded that SNCR could reduce nitrogen oxides (NOx) emissions on a long-term basis by about 50 percent. Various entities have suggested that Cemex provide an analysis combining low NOx burners and SNCR with the goal of achieving a higher NOx reduction, perhaps as high as 60 percent. Accordingly, this analysis has been revised to evaluate the combination of low NOx burners and SNCR.

In the cement manufacturing industry, it is well known that thermal NOx represents the majority of the NOx formation in cement kiln systems. Thermal NOx is a side effect of the high temperatures necessary in the cement kiln to produce a quality clinker product. One effort to combat the thermal NOx formation in the cement industry has been the installation and use of LNB. LNB have been used to a limited degree in the cement industry for over 30 years. The concept of LNB is to minimize primary air as a source of nitrogen, reduce flame turbulence, delay air and fuel mixing, and establish a fuel rich zone for initial combustion. The resulting longer, less intense flame from the staging of combustion in this manner reduces flame temperatures and is therefore thought to reduce thermal NOx formation.

In practice, LNB create two distinct combustion zones: the primary and the secondary combustion zones. In the primary, or initial, combustion zone flame turbulence and air and fuel mixing are suppressed by decreasing the amount of primary air supplied to the burning zone. It is well understood that the higher the primary air, the higher the NOx from the kiln system.[11] Typical primary air for LNB ranges from 5 to 7 percent.[12] The result is a fuel-rich, oxygen-lean, high temperature combustion zone created by reducing the amount of primary air and delaying the combustion of all of the fuel. The peak flame temperatures in the primary combustion zone must be maintained high to initiate the clinkering reactions. However, thermal NOx formation is thought to be suppressed due to the oxygen-lean environment in the primary combustion zone which generates excess CO and other radicals known to react with NOx.

The primary combustion zone is followed by an oxygen-rich secondary combustion zone where fuel combustion is completed. Lower temperature secondary combustion air is mixed into the secondary combustion zone, thereby lowering the peak combustion temperatures. Although excess oxygen is available, NO_x formation is suppressed in the secondary combustion zone because the temperatures are insufficient for significant thermal NOx formation.

The Lyons Plant is currently equipped with a two channel, straight pipe burner with one channel for coal and a second channel for air used to adjust the momentum of the flame. The burner configuration is closer to a mono-channel than to a multi-channel burner definition. The measured primary air at the Lyons Plant ranges from 40 to 65 percent accordingly to the amount of momentum air used, with most of the primary air coming from the coal mill's minimum air evacuation requirements. The application of LNB at the Lyons Plant would primarily consist of replacing the existing main kiln burner.

The level of NOx reduction reported in the literature for LNB applications on cement kiln systems vary considerably. Factors affecting the variability include, but are not limited to the specific type of LNB, pre-installation NOx emission levels, kiln type, and fuels used. According to EPA's "Alternative Control Techniques Document Update – NOx Emissions from Cement Manufacturing," EPA-453/R-94-004, March 2004, the NOx reduction achievable with LNB ranges from 20 to 30% for typical kiln systems. The level of control achieved is generally greater for newer kiln systems. Many older kiln systems may achieve lower NOx reductions due to the specific operating characteristics of the kiln systems. There are also a few non-typical kiln systems in the US, with one being the Lyons Plant. Considering the unique design and age of the Lyons Plant cement kiln system, it is uncertain whether meaningful NOx reductions would be expected from the installation of LNB in combination with SNCR.

Cemex has proposed the installation and use of SNCR to achieve about a 50% NOx reduction (long term) at the Lyons Plant. This level of NOx reduction has been demonstrated on several cement kiln systems in the US, is recognized in the recently EPA proposed New Source Performance Standards as the demonstrable control efficiency for SNCR, and represents a high level of control with little risk of the known side effects to ammonia injection. The main risk for SNCR is the formation of a detached plume attributable to excessive ammonia slip due to injecting at too high of a normalized stoichiometric ratio (NSR) (i.e., pushing the SNCR technology too far to achieve higher levels of NOx reduction leads to the formation of a detached ammonia plume, called ammonia slip). Ammonia slip from SNCR is non-existent to minimal when the reagent is injected at or below an NSR of about 0.7. Operating SNCR above this NSR significantly increases the ammonia slip to the point where conditions are favorable for the

[11] Battye, R., Walsh, S., and Greco, J. 2000. NOx control technologies for the cement industry. Final report. Pages 30-31. EPA contract No. 68-D98-026.
[12] Battye, R., Walsh, S., and Greco, J. 2000. NOx control technologies for the cement industry. Final report. Page 59. EPA contract No. 68-D98-026.

formation of a detached plume containing ammonium chloride and ammonium sulfide compounds. These compounds, as well as any unreacted ammonia, would result in visibility degradation which is counter to the intent of BART.

Therefore, the Division concludes that given the reasonable uncertainty in the benefits of LNB, the existing proposal to utilize the existing burner along with SNCR remains the best control option for the Lyons Plant kiln.

Cost of Compliance:

Based on information provided by Cemex – Lyons, the Division estimates the annual costs at about $1,686,395 per year. Cemex provided an estimated 55% NOx reduction resulting in an estimated control cost of about $1,755 per ton of NOx reduced.

Energy Impacts and Non Air-Quality Impacts:

None.

Existing Controls in Use at Source:

None.

Remaining Useful Life:

No impact.

Table 10 below contains a ranking by control effectiveness of the remaining control technologies.

Table 10: Kiln NOx Control Options

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%	431.8	1,624.8	6.87
Firing TDF	10%	417.8	1,572.3	6.65
Indirect Firing with LNB	20%	371.4	1,397.6	5.91
SNCR	45%	255.3	960.9	4.06
SNCR	48.43%	239.4	901.0	3.81
SNCR w/LNB	55%	208.9	786.2	3.33
SCR	Not technically feasible			

Table 11 below lists the NOx emission reduction, annualized costs and the control cost effectiveness for the feasible controls, ranked by control effectiveness.

Table 11: Summary of Cost Effectiveness of NOx Control Technologies for the Kiln

Control Technology	NOx Emission Reduction [tons/yr]	Annualized Cost [$/yr]	Cost Effectiveness [$/ton]	Incremental Cost Effectiveness [$/ton]
Baseline NOx Emissions	-			
Water Injection	122.3	$43,598	$356	
Firing TDF	174.7	$172,179	$986	$2,453
Indirect Firing with LNB	349.4	$710,750	$2,034	$3,083
SNCR (45% control)	786.2	$1,636,636	$2,082	$2,120
SNCR (48.43% control)	846.1	$1,636,636	$1,934	$1,864
SNCR w/LNB (55% control w/uncertainty)	960.9	$1,686,395	$1,755	$434

Based on the above discussion, the combination of SNCR with LNB has an uncertain level of control due to the unique nature of the Lyons kiln. The Division has determined that SNCR is the best available NOx control option for the Cemex – Lyons modified long dry kiln. Because Cemex has proposed SNCR as the preferred control option, it is not necessary or appropriate to further evaluate the lesser control options, including relative costs.

SNCR requires injection of the reagents in the kiln at a temperature between 870 to 1,090°C (1,600 to 2,000°F). In principle, any of a number of nitrogen compounds may be used as SNCR reagents (e.g., cyanuric acid, pyridine, and ammonium acetate). However, for reasons of cost, safety, simplicity, and by-product formation, ammonia and urea have been used in most of the SNCR applications. The selection of reagents is process and temperature specific. At higher temperatures, urea decomposes to produce ammonia, which is responsible for NO_x reduction. In cement kiln applications, ammonia typically has performed best as the reducing reagent. Because no catalyst is used to increase the reaction rate, the temperature window is critical for conducting this reaction. At higher temperatures, the rate of a competing reaction for the direct oxidation of ammonia, which actually forms additional NO_x, becomes significant. At lower temperatures, the rates of NO_x reduction reactions become too slow resulting in too much unreacted ammonia being released to the atmosphere (i.e., ammonia slip). The effective temperature window range can be lowered to about 700°C (1,300°F) by the addition of hydrogen along with the reducing agent.

The NO_x reduction efficiency of SNCR depends upon the temperature, oxygen, carbon monoxide, and residence time, as well as the ammonia and NO_x concentrations in the flue gas. Injection of ammonia at a NH_3:3 NO_x proportion of 1 to 1.5 will reduce NO_x emissions between 60 to 80 percent. Using a molar ratio of 0.5 will give NO_x reductions of approximately 40 percent. Work done by the German equipment supplier Polysius has shown that the optimum temperature for reduction of NO_x by ammonia is about 950ºC (1,740ºF), while for urea, the temperature increases to about 1,000ºC (1,830ºF).

Operating experience has identified several concerns with both ammonia and urea-based SNCR processes. The most frequently reported is the buildup of ammonium bisulfite or bisulfate scale, which is significant for sulfur-containing fuels. SNCR processes also appear to convert some NO_x to N_2O. The rate of N_2O formation is a weak function of both the reactant and the NO concentration. However, N_2O formation seems to be inherently more prevalent in systems using urea than those using ammonia.

The NO_x destruction efficiency also depends upon the flue gas residence time in the appropriate temperature window. Unlike an SCR system where the reaction temperature is controlled in a dedicated reactor, an SNCR system relies on the existing gas temperature profile to provide an adequate residence time for a desired NO_x destruction. Maximum achievable NO_x reduction in a cement kiln may thus depend upon the gas temperature profile.

Based on the foregoing discussion and the potential for ammonia slip, the Division concludes that an assumed 45% NOx reduction (30-day rolling average) and 48.43% NOx reduction (annual average) from 2002 baseline is reasonable.

Step 5: Evaluate Visibility Results

An impact analysis was conducted to assess potential visibility improvements associated with SNCR. CALPUFF modeling was used as part of this analysis. The visibility improvement associated with various scenarios was calculated as the difference between the existing visibility impairment and the visibility impairment for the controlled emission rates as measured by the 98th percentile modeled visibility impact. Based upon the modeling, the addition of SNCR is projected to result in a 0.41 dv improvement.

Table 12: Visibility improvement for NOx Controls – Kiln Only

Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (from 24-hr Max) (Δdv)	Cost Effectiveness ($/Δdv)
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	$198,174
Firing TDF (≈417.9 lbs/hr)*	0.526	0.234	$735,807
Indirect Firing with LNB (≈ 371.4 lbs/hr)*	0.481	0.279	$2,547,493
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	$4,175,091
Proposed BART Limit (annual) – SNCR (≈ 239.0 lbs/hr)**	0.352	0.408	$4,011,363
SNCR w/LNB (≈208.9 lbs/hr) **	0.322	0.438	$3,850,217

** - Visibility impacts interpolated from original BART CALPUFF modeling*
*** - Visibility impacts extrapolated from original BART CALPUFF modeling*

Step 6: Select BART Control

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. As discussed above, 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.

The Division has considered the five factors and has thoroughly reviewed the data supplied by Cemex to determine that SNCR represents Best Available Retrofit Technology for control of NOx emissions from the kiln. Table 13 specifies the Division NOx BART determination of 255.3 pounds per hour (30-day rolling average) and 901.0 tons per year (12-month rolling average). The Division considered establishing a NOx emissions limit based on clinker production, however, the Cemex-Lyons facility does not have the capability to weigh clinker product upon exiting the kiln. Consequently, compliance with the NOx BART limits will be determined by a continuous emissions monitor system (CEMS).

Table 13: NOx Emission Limits on the Kiln

Subject Unit	NOx Control Technology	NOx Emission Limits
Kiln System	Selective Non-Catalytic Reduction (SNCR)	255.3 lbs/hour (30-day rolling average)
		901.0 tons/year (12-month rolling average)

The Division has reviewed the analysis provided by Cemex and agrees that SNCR is the appropriate NOx control technology. In reviewing the proposed emission rate of 255.3 lbs/hour (approximately equal to 4.06 lb/ton of clinker), the Division also looked at the RACT/BACT/LAER clearing house (see Table 14 below). The NOx rate of 4.06 lb/ton clinker is consistent with determinations made in Iowa and Missouri, but is about double the proposed limits for the newer Florida kilns. The Cemex – Lyons facility is an older modified long dry kiln and does not have the precalciner systems developed for newer facilities specifically to reduce the temperatures for clinker formation. The use of lower temperatures also reduces the formation of thermal NOx.

Table 14: RACT/BACT/LAER data for NOx emissions from Portland Cement Kilns

RBLC ID	NOx Control	NOx Limit	Units	Year
FL 0297	SNCR	1.5	lb/ton clinker	2007
FL-0271	SNCR	1.95	lb/ton clinker	2006
FL-0268	SNCR	1.95	lb/ton clinker	2004
FL-0267	SNCR	1.95	lb/ton clinker	2004
SD-003	Preheater/calciner	2267	tons/yr	2003
MO-0059	SNCR	8	lb/ton clinker	2002
IA-0052	Process	4	lb/ton clinker	2002
TX-0355	Process	660	lb/hr	2001
FL-0139	Process	2.9	lb/ton clinker	2000

The Division also reviewed the *U.S. v. Lafarge* Consent Decree, dated January 21, 2010. In that recent action, the NOx reduction requirements established under the kiln retrofit options require

SNCR with a 12-month rolling emission limit of 4.89 lbs NOx/ton of clinker. The BART Regulations do not require the demolition and reconstruction of any facility that is subject-to-BART. The proposed Cemex BART limit compares favorably to similar units addressed by the *Lafarge* Consent Decree and the RACT/BACT/LAER clearinghouse. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Because the Cemex kiln is a modified long dry kiln and is not directly comparable to the reported limits listed in the RACT/BACT/LAER clearinghouse, the Division finds that requiring an emission rate that falls into the range for modern sources that are more thermodynamically efficient (produce less NOx) helps to further validate the stringency of the NOx emissions rate selection.

The Division is aware that Cemex may be able to do better than a 45% reduction, and will require that 48.43% reduction on an annual basis (901.0 tons per year, 12-month rolling average). This limit results in reductions that are 68% lower than the current allowable NOx limit (2,649 tpy) contained in the operating permit.

The Division also notes that the flash vessel at Cemex - Lyons is unique and may affect how well SNCR will perform at the plant. Because of this uncertainty the Division will not specify the ammonia injection or slip rate but will allow Cemex - Lyons to meet the NOx limits through SNCR technology and process controls. Improving process controls may allow Cemex - Lyons to limit formation of NOx in the kiln and thus meet the NOx limits while reducing ammonia use. By requiring a 48.43% reduction on an annual basis, the Cemex BART determination almost matches the reductions achieved for both SCR and SNCR at the Solnhofen facility.

Accordingly, based upon its analysis and consideration of the five factors, the Division has determined that the higher NOx emission rate is reasonable for the older cement kiln process, and that SNCR control at 255.3 lb/hr NOx on a 30-day rolling average (which is about 4.06 lbs of NOx per ton of clinker) is NOx BART for the Cemex – Lyons facility. This BART determination will remove 45% of the NOx emissions averaged over 30 days, and is projected to result in about 0.39 Δ dv in visibility improvement.

III.C. Review of Particulate Matter Controls on the Kiln and Dryer

PM emissions from the kiln are currently controlled by fabric filter baghouse and wet dust suppression techniques. Emission testing from the kiln has demonstrated compliance with the National Emission Standards for Hazardous Air Pollutants for Source Categories; Portland Cement Manufacturing Industry, 40 CFR Part 63 Subpart LLL. The NESHAP standard applies the kiln and establishes PM emissions limits.

During development of the NESHAP standard, EPA was not able to identify any technologies for existing or new kilns that would consistently achieve lower emissions than the New Source Performance Standards (NSPS). Consequently, the level of the NESHAP standard is the same as NSPS and requires compliance with certain particulate emission limits and opacity limits. The NESHAP standard also includes emission limits for HCl and other hazardous pollutants; however these are not considered for their impact on visibility. The provisions of the NESHAP standard are already contained in the operating permit issued to Cemex – Lyons. For sources already regulated by a NESHAP standard, EPA stated the following in the BART guidelines:

> *"We believe that, in many cases, it will be unlikely that States will identify emission controls more stringent than the MACT standards without identifying control options that would cost many thousands of dollars per ton. Unless there are new technologies subsequent to the*

MACT standards which would lead to cost effective increases in the level of control, you may rely on the MACT standards for purposes of BART.” [70 FR 39163]

The Division has reviewed the requirements of the NESHAP (MACT) for Portland cement production and evaluated the RACT/BACT/LAER clearinghouse database for other available particulate control options (see Table 15). The Division has determined that no new particulate control methodologies are identified that would improve upon the PM controls required in the NESHAP.

Table 15: RACT/BACT/LAER data for PM emissions from Portland Cement Kilns

RBLC ID	PM Control	PM Limit	Units	Year
FL 0297	Fabric Filter	0.1	lb/ton clinker	2007
MO-0072	Baghouse	0.516	lb/ton clinker	2006
FL-0271	Baghouse	0.1	lb/ton clinker	2006
FL-0268	Baghouse	0.2	lb/ton clinker	2004
FL-0267	ESP	0.2	lb/ton clinker	2004
SD-003	Fabric Filter	0.13	lb/ton	2003
MO-0059	Fabric Filter	99%		2002
IA-0052	Baghouse	0.5160	lb/ton clinker	2002
TX-0355	ESP	40	lb/hr	2001
FL-0139	Baghouse	0.11	lb/ton clinker	2000

Therefore, the Division is establishing the following PM and opacity limits as BART for particulate matter control that is based on the NESHAP 40 CFR Part 63 Subpart LLL:

Table 16: Particulate Matter Emission Limits on the Kiln and Dryer

Subject Unit	Control Technology	PM Limits from 40 CFR Part 63 Subpart LLL	BART PM Emission Limits
Kiln System	Fabric Filter Baghouse	0.30 lb/ton of dry feed 20% opacity	0.275 lb/ton of dry feed 20% opacity
Dryer	Fabric Filter Baghouse	10% opacity	22.8 tons/year* 10% opacity

** Current emission limitation from Operating Permit (95OPBO082)*

The Division has established a PM limit on the kiln system that is more stringent than the NESHAP, which is already in the Cemex – Lyons Operating Permit. Because the current NESHAP limits constitute the most stringent level of control, the State does not need to provide a five-factor analysis for PM for these units.

Best Available Retrofit Technology (BART) Analysis of Control Options For Colorado Energy Nations, Golden, Colorado

I. Source Description

Owner/Operator: Colorado Energy Nations Company (CENC) (formerly Trigen Colorado Energy Corporation)
Source Type: Steam Generating Unit
Boiler Type(s): Boiler 4 – Pulverized Coal Dry-Bottom Tangentially-Fired (SCC: 10200222 for coal)
Boiler 5 – Pulverized Coal Dry-Bottom Tangentially-Fired (SCC: 10200222 for coal)

The CENC facility is located in Jefferson County on 10th Street in the town of Golden, Colorado. Figure 1 below provides an aerial perspective of the CENC site. The two large buildings are separated by Clear Creek to the south and US Highway 58 borders the northern side of the CENC site. The large building to the north of CENC and south of Highway 58 is the Coors Brewery.

Figure 1: CENC facility Aerial Perspective

The CENC facility consists of five (5) boilers and the associated equipment for coal and ash handling. The boilers provide steam for one (1) 20 MW generator, two (2) 10 MW generators, and for industrial use. The boilers are rated at 228 MMBtu/hr (Boilers 1 and 2), 225 MMBtu/hr (Boiler 3), 360 MMBtu/hr (Boiler 4) and 650 MMBtu/hr (Boiler 5). Boilers 1 and 2 normally operated in hot standby mode or when one of the coal boilers (Boilers 3, 4, or 5) is down. Boilers 3, 4, and 5 are controlled for PM/PM_{10} by separate fabric filter baghouses, which were installed at the time of construction for each boiler. The boilers were installed as follows:

- Boiler 1 – 1962
- Boiler 2 – 1962
- Boiler 3 – 1962 – updated to coal in 1981
- Boiler 4 – 1974 – last modification in 1975
- Boiler 5 – 1979 – reached full capacity in 1980

No coal processing is performed on-site. The coal is received ready for feed to the boilers. Boilers 4 and 5 are equipped with pulverizers that process the coal directly into the fire zone. The ash and flyash from the boilers may be sold or transported off-site for disposal. Therefore, all fugitive dust sources at the facility are related to coal conveying or ash handling. There is also one Detroit Diesel engine (<100 HP) at the facility for maintenance of equipment and/or backup operation of air compressors that was installed prior to 1970. This engine is tested weekly. The Coors Brewery currently contracts for the purchase of the total electricity and steam output.

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 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 98th 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 "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. These documents are all provided as "CENC BART Submittals". Table 1 depicts technical information for each BART-subject boiler at the CENC facility.

Table 1: CENC Facility BART-eligible Emission Controls and Reduction (%)

	Unit B004	Unit B005
Placed in Service	1975	1979
Boiler Rating, MMBtu/Hr for coal	360	650
Electrical Power Rating, Gross Megawatts	35	65
Description	Combustion Engineering Model CE-VU40 360 MMBtu/hr (coal), tangential fired, firing coal, natural gas, #2 fuel oil, ethanol, on-site generated on-spec used oil and sludge from WWTP	Combustion Engineering Model CE-VU40 650 MMBtu/hr (coal), tangential fired, firing coal, natural gas, #2 fuel oil, ethanol, on-site generated on-spec used oil and sludge from WWTP
Air Pollution Control Equipment	Wheelabrator-Frye Model 264 fabric filter baghouse with 8 compartments	Carter Day fabric filter baghouse with 12 modules
Monitoring Equipment	COM CEMs for SO_2, NO_x, CO_2, and stack gas	COM CEMs for SO_2, NO_x, CO_2, and stack gas

Emissions Reduction (%)	NO_x – None SO_2 – None PM/PM_{10} – 99+%	NO_x – None SO_2 – None PM/PM_{10} – 99+%

II. Source Emissions

CENC estimated that a realistic depiction of anticipated annual emissions for Boilers 4 and 5, or "Baseline Emissions", to be conservative, was the maximum historical (2000 – 2005) 12-month (rolling) emissions experienced in the July 31, 2006 analysis. CENC also provided 2-year annual average emissions for comparison purposes.

Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses. Therefore, the Division used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The baseline emissions are used as the basis for estimating annual emission reductions for the various control technologies evaluated and determining the annualized costs to achieve those reductions. . The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database as applicable. These emissions are summarized in Table 2.

Table 2: CENC Boilers 4 and 5 Baseline Emissions

Pollutant	Boiler 4		Boiler 5	
	Annual Emissions* (tpy)	30-day rolling average emissions** (lb/MMBtu)	Annual Emissions* (tpy)	30-day rolling average emissions** (lb/MMBtu)
NO_x	600	0.50	691	0.34
SO_2	781	0.64	1,406	0.71
PM_{10}	11	0.003***	18	0.01***

*Using most recent three calendar years (CEMs data).
**The Division calculated 30-day rolling average rate (lb/MMBtu) from the most recent three calendar years (CEMs data) based on maximum daily reported data for each unit for NO_x and SO_2 emissions. Days with zero emissions/heat input were not included in these averages.
***The PM_{10} emission rate is determined from calculating the maximum heat input and annual operating hours.

Boiler 4 is mainly fired on coal and can be fired on natural gas. Fuel oil may be used as a backup fuel, but has not been used in recent years. Boiler 5 is fired on coal, with backup oil firing. Either boiler also may fire ethanol or sludge from the Coors Brewery. Both units are subject to Colorado Regulation 6 Part A and NSPS 40 CFR Subpart D.

III. Units Evaluated for Control

As documented by CENC, these boilers fire low sulfur, high heating value bituminous coal from western Colorado. The specifications for the coal are listed in Table 3.

Table 3: Coal Specifications (2006 – 2008 Averaged APEN data)

	Specifications		
Emission Unit	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
B004	11,703	0.42	9.14
B005	11,833	0.42	9.17

Table 1 lists the units at the CENC facility that the Division examined for control to meet BART-eligible requirements. Controlled and uncontrolled emission factors and CEMs data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal.

Table 4: Uncontrolled emission factors for CENC BART-eligible sources

Emission Unit	Pollutant	Fuel		
		Natural Gas (lb/MMscf)	Coal (bituminous) (lb/ton)	#2 Fuel Oil (lb/Mgallons)
Boiler 4 & Boiler 5	NO_x	280	8.4	24
	SO_2	0.6	35 x %S = 14.7*	157 x %S = 67.5*
	PM/PM_{10}	7.6	PM – 10 x %A = 91.4** PM_{10} – 2.3 x %A = 21.0**	PM – 2 PM_{10} – 1

*%S = % of sulfur present in coal supply. For example, 35 x 0.42 = 14.7
**%A = % of ash present in coal supply. For example, 10 x 9.14 = 91.4

IV. BART Evaluation of Boiler 4 and Boiler 5

A. Sulfur Dioxide (SO_2)

Step 1: Identify All Available Technologies

CENC identified four SO_2 control options:
- Flue gas desulfurization (FGD):
  - Lime spray dry absorber (SDA or dry FGD)
- Dry sorbent injection – Trona (DSI)
- SO_2 emission management

The Division also identified and examined additional control options for these units:
- Lime or limestone-based (wet FGD)
- Emission limit tightening (no control)

Step 2: Eliminate Technically Infeasible Options

FGD: Flue gas desulfurization removes SO_2 from flue gases by a variety of methods. Wet scrubbing uses a slurry of alkaline sorbent, either limestone or lime, to scrub the gases. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

Wet FGD: Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar "foot print" area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney.

Dry FGD: Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants[1]. SDA systems are typically utilized at smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. Additionally, Controlling SO_2 Emissions: A Review of Technologies[2] evaluates various SO_2 control technologies and shows that for low-sulfur coal applications, LSDs can meet comparable emission rates to wet systems.

A SDA system must be located before the boiler flue gases enter the baghouse. Each reactor vessel requires a "foot print" area comprising about 2,000 to 4,000 square feet (depending on volume of flue gas treated) along with additional space for support equipment access, slurry preparation, mixing and associated tanks.

The plant is bounded to the north by US Highway 58 and Coors Brewery buildings, to the west by 12th street and a small parking, to the east by Coors rail yard lots, and the south by Clear Creek and the Coors Brewery. Train tracks also bound the facility to the north and east. Figure 1 illustrates these boundaries. Figure 2, depicting a detailed view of the boilers, respective baghouses, and available spaces for FGD systems, indicates that available physical space is severely constrained at the CENC facility, due to locations as well as pollution control retrofits for particulate matter. The entire site is very congested, with limited access and limited room for major retrofits of new capital equipment. CENC asserts that in order to allow sufficient residence time for evaporation and reaction with SO_2, the design gas residence time in a SDA is approximately 10 seconds. For Boilers 4 and 5, a SDA vessel for each boiler, not including other associated equipment, would be approximately 35 feet in diameter by 60 feet high. In addition, in order to provide high reagent utilization, the unreacted lime mixed with ash form the baghouse must be recycled. This would increase solids loading in each baghouse by a factor of 3 and require extra baghouse capacity and a complete reconstruction of the ash handling system. Subsequently, CENC determined that it is not technically feasible to install dry FGD systems on either Boilers 4 or 5 (B004/B005).

In 2007, the Division conducted an on-site visit to determine the technical feasibility of potential SO_2 controls on Units 4 and 5. The Division noted:

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[1] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

[2] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

- CENC determined dry FGD controls are not technically feasible as discussed above, therefore control effectiveness and impacts are not evaluated in this analysis. After the site visit, the Division concurred with this conclusion.
- Traditional wet FGD controls are possible considering that there is adequate space near the baghouse to allow for the installation of controls, but are eliminated based on other considerations within the five factors (i.e. energy and non-air quality impacts). Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Boilers 4 and 5.

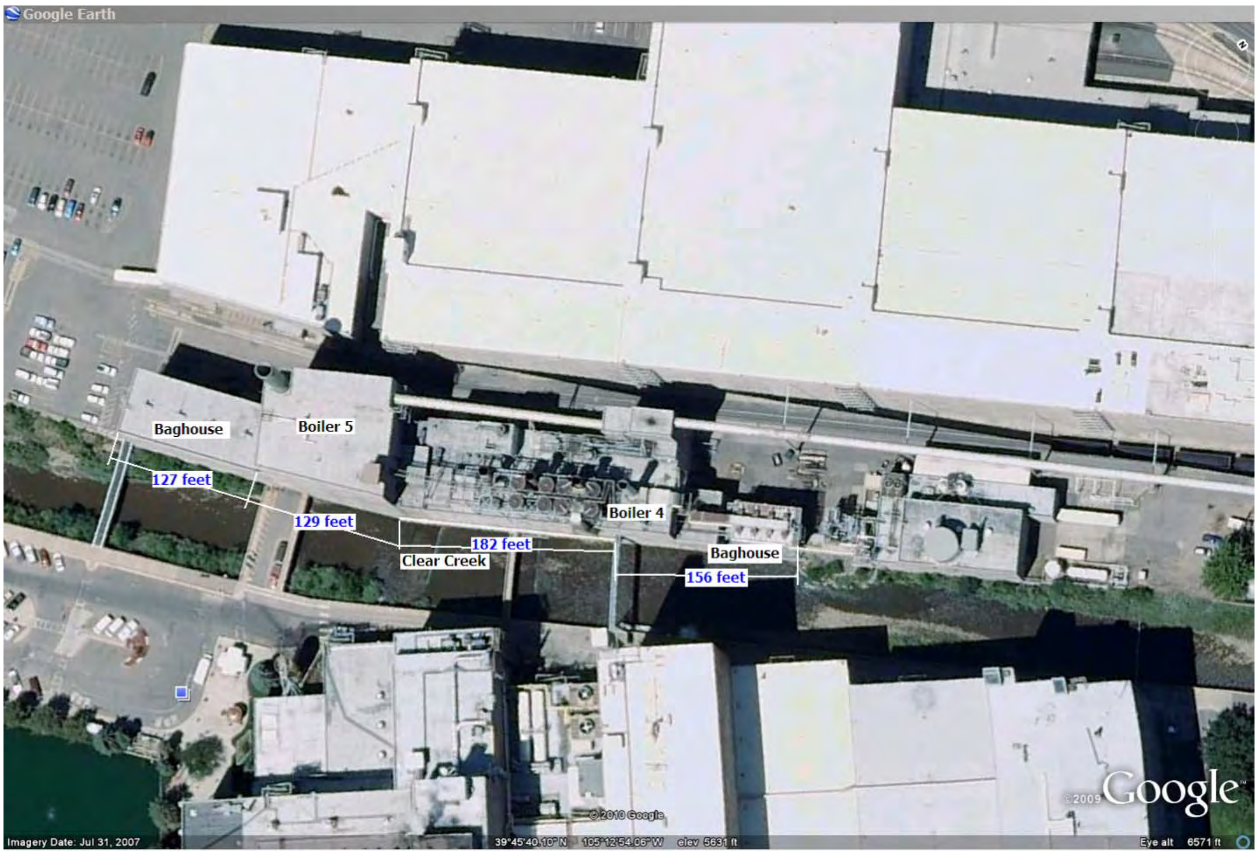

Figure 2: Aerial Zoom of CENC Facility

DSI: Dry sorbent injection involves the injection of typically a sodium based reagent, either the mineral trona (sodium sesquicarbonate) or refined sodium bicarbonate, into the flue gas. The injected reagent reacts with the SO_2 present in the flue gas to create sodium sulfate, which is then collected in the particulate control device, in the case of CENC. CENC asserts that the flue gas temperatures present upstream of the boiler airheaters are in the appropriate range to allow for DSI application. A very important factor in DSI application is the ability for the boiler's particulate control device to accommodate the added particulate loading of the DSI reagent in addition to the flyash loading. CENC's preliminary review indicates that even with the added loading of DSI reagent, the CENC baghouses would be operating within the design specification for particulate loading, but the ash collection system(s) would require modifications. The flue gas is not cooled nor saturated with water, so reheating of desulfurized flue gas is not required. No gas-sorbent contacting vessel is required to be installed. DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system.

However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Lime, soda ash, and Trona (sodium sesquicarbonate) are possible. Lime is the least reactive reagent resulting in low efficiencies even at high injection rates. Trona is a very reactive reagent that can be used to achieve a range of efficiencies depending on the amount of sorbent injected, and would likely be the chosen reagent.

Due to variability of boiler configurations, coal composition, NO_x to SO_2 ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum SO_2 removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CENC estimated the maximum SO_2 removal rate that can be achieved while minimizing the creation of the brown plume condition to be 65% SO_2 removal. In practical application, a higher SO_2 removal rate may be possible, while it is also possible that a lower SO_2 removal rate may be necessary to limit the brown plume formation. This determination would require actual SO_2 removal real-time testing. CENC consulted with PPC Industries to determine the feasibility and emission reduction potential associated with installing DSI-Trona controls. Therefore, DSI-Trona is technically feasible for the CENC facility Boilers 4 and 5.

***SO_2* Emissions Management:** CENC is subjected to variations in as-received coal sulfur content. Figure 3 provided by CENC shows that there are clearly historical (2000 – 2005) short-term peaks in SO_2 emissions that can be attributed to infrequent deliveries of high-sulfur coal. CENC has no capability or additional storage space on site to store coal or to blend with other lower sulfur coals in order to manage SO_2 emissions to lower levels, and has not had a regulatory need to do so. Once delivered, the facility has no choice but to use the coal delivered before a subsequent lower sulfur shipment can be obtained and burned.

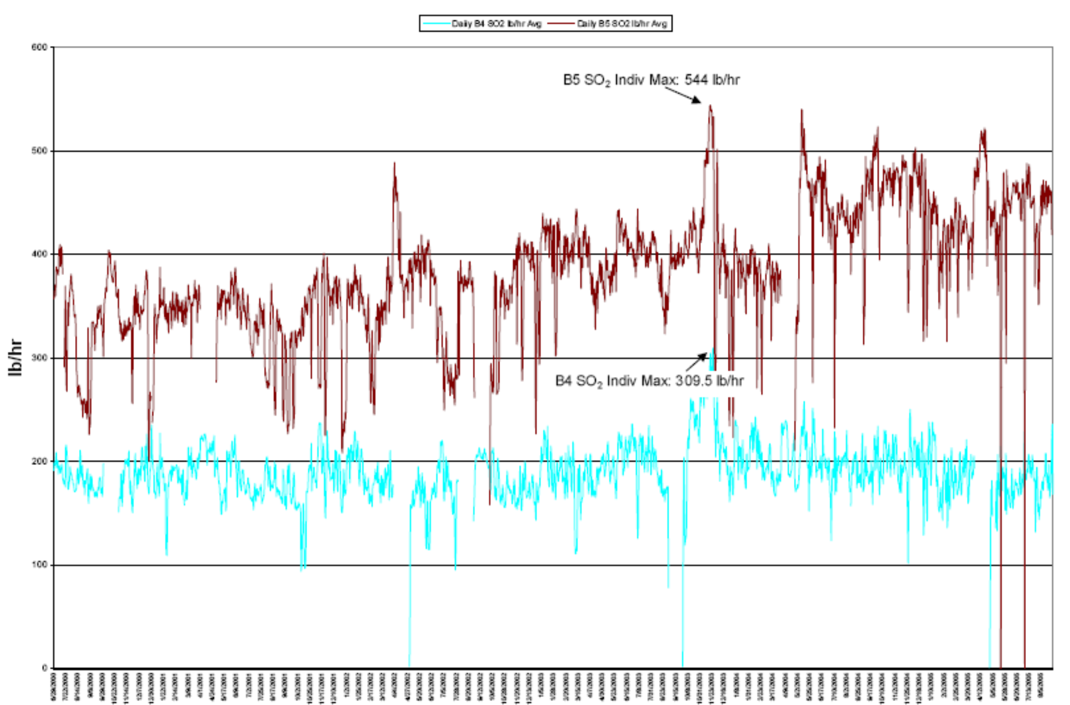

Figure 3: Boilers 4 and 5 SO_2 lb/hour daily average (2000 - 2005)

Using alternative approaches to operations management, CENC proposes a new, enforceable permit limit to reduce peak lb/hr SO_2 emissions. CENC can employ a variety of options to reduce emissions: dispatch natural gas-fired capacity, reduce total system load, and/or reduce coal firing rate to maintain a new peak SO_2 limits. Since these two boilers already have CEMs and stack flow monitors installed, the CEMs could be used to demonstrate continuous compliance. CENC proposes reducing peak levels with limits at 280 lb/hr for Boiler 4 and 500 lb/hour for Boiler 5 on a 24-hour average basis. This option is technically feasible for Boilers 4 and 5.

Emission limit tightening: The Division and CENC conducted technical analyses of sulfur % and heat content in historical coal supplies to determine whether the current SO_2 emission limit could be more stringent based on actual emissions (2006 – 2008) from the units. This option is technically feasible for Boilers 4 and 5.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CENC provided the Division annual average control estimates. In the Division's experience, 30-day SO_2 rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 5% for CENC Boilers 4 and 5 to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by CENC as well as other control techniques applied to pulverized coal boilers. A Division review of the EPA's RBLC revealed recent BACT SO_2 determinations range from 0.06 – 0.167 lbs/MMBtu. The Division narrowed down this range depending on the averaging time, permit type, facility size, and fuel type. This narrowed range is 0.095 – 0.161 lbs/MMBtu, with an average of 0.119 lbs/MMBtu rounded to 0.12 lbs/MMBtu. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details. The Division notes that for CENC, any RBLC determinations apply for DSI only, since SO_2 emissions management is unit-specific.

DSI: CENC asserts that the maximum SO_2 removal rate that can be achieved to be 65% SO_2 removal due to the small size of the boilers, and non-ideal gas/solids residence time. The Division adjusted this removal rate to 60%, based on other Colorado submittals[3] and to be conservative since this technology is relatively novel.

SO_2 Emissions Management: Table 5 summarizes current Title V permit limits and projected emission reductions using CENC's proposed limits.

[3] Colorado Springs Utilities, 2010. "RE: Question Regarding the Application of Dry Sorbent Injection to Martin Drake Power Plant Unit 5." Submitted to the Colorado Air Pollution Control Division on May 10, 2010.

Table 5: CENC Boiler 4 and 5 Current vs. Proposed SO_2 Permit Limits and Emissions Reduction

<table>
<tr><th>Unit</th><th>Current Title V SO_2 permit limits</th><th>Actual Emissions (2000 – 2005)</th><th>Actual Emissions (2006 – 2008)</th><th>CENC proposed SO_2 limits</th></tr>
<tr><td rowspan="3">Boiler 4</td><td>1892.0 tons/year (approx. 432 lb/hour)</td><td rowspan="3">911.8 tons/year (approx. 208 lb/hour)</td><td rowspan="3">780.6 tons/year (approx. 178 lb/hour)</td><td rowspan="3">280 lb/hour (CEM 24-hr rolling avg.)</td></tr>
<tr><td>Coal – 1.2 lb/MMBtu (CEM 3-hr rolling avg.)</td></tr>
<tr><td>Fuel Oil – 0.8 lb/MMBtu (CEM 3-hr rolling avg.)</td></tr>
<tr><td rowspan="3">Boiler 5</td><td>3,416.0 tons/year (approx. 780 lb/hour)</td><td rowspan="3">1,954.7 tons/year (approx. 446 lb/hour)</td><td rowspan="3">1,406.0 tons/year (approx. 321 lb/hour)</td><td rowspan="3">500 lb/hour (CEM 24-hr rolling avg.)</td></tr>
<tr><td>Coal – 1.2 lb/MMBtu (CEM 3-hr rolling avg.)</td></tr>
<tr><td>Fuel Oil – 0.8 lb/MMBtu (CEM 3-hr rolling avg.)</td></tr>
<tr><td>Combined limit</td><td>4,888.0 tons/year (approx. 1,116 lb/hour) (PM_{10} SIP Agreement)</td><td>2,866.5 tons/year (approx. 655 lb/hour)</td><td></td><td>780 lb/hour (CEM 24-hr rolling avg.)</td></tr>
</table>

*Refer to pages A-31, A-34, and A-35 of CENC BART Submittal (July 31, 2006) for detailed SO_2 emission documentation.

Emission limit tightening: Since emission limit tightening is based on actual data, there will be minimal, if any, reductions from baseline period (2006 – 2008) SO_2 emissions. The Division found that the maximum 30-day rolling emission rate was 0.80 lb/MMBtu for Boiler 4 and 0.9 lb/MMBtu for Boiler 5. However, for these small industrial boilers with very limited coal storage capacity, the Division and CENC agree that reviewing sulfur % and heat content is a better basis for determining an appropriate SO_2 emission limit. CENC submitted supplemental information on October 26 and November 10, 2010 to support this methodology. Refer to Table 6 for more details.

Table 6: Coal Supply Analysis for SO2 Emission Limit

	2006 – 2008
Minimum (Btu/lb)	9.997
Maximum (% Sulfur) (30-day period)	0.52
Theoretical lb/MMBtu	
Boiler 4 Sulfur to SO_2 conversion averages at 99%*	1.03 (rounded to 1.0)
Boiler 5 Sulfur to SO_2 conversion averages at 100%*	1.04 (rounded to 1.0)

*CEMs data vs. theoretical

Based on the boiler sulfur to SO_2 conversions, the appropriate emission limit based on actual fuel supply data for the baseline period is 1.0 lb/MMBtu (30-day rolling average). This option serves as assurance that CENC will be able to both continually comply with an appropriate emission limit while simultaneously eliminating future potential emission increases.

Table 7summarizes each available technology and technical feasibility for SO_2 control.

Table 7: CENC Boilers 4 and 5 SO_2 Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)

Wet FGD	52-98%, median 90%[4]	Y
Dry FGD (SDA)	70-90% (CENC)	Y
DSI (Trona)	~60%	Y
SO_2 Emissions Management	30%	Y
Emission Limit Tightening	Minimal	Y

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

Wet FGD: The significant cost issue associated with securing sufficient water supplies (a costly and scarce resource in the Front Range) to support a wet FGD control system along with the cost of disposing the sludge byproduct at an approved landfill since on-site storage is not an option. There are other costs and environmental impacts that the Division 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. Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Boilers 4 and 5.

DSI: PCC Industries provided the cost to CENC for the basic equipment required for Trona injection. DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system. However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Additional costs for equipment redundancy, modifications to the facility's ash handling system, and increased transformer capacity were estimated by CENC based on the need to maintain continuous compliance with a short-term emission rate (30-day rolling) and past experience with retrofits at other CENC facilities. CENC derived total installed costs from the purchased equipment cost using USEPA factors (EPA's Cost Control Manual). Operating costs were based on estimated Trona requirements of 2.8 lb Trona per lb of SO_2 collected for 65 percent control. The theoretical minimum requirement is 2.4 lb Trona per lb of SO_2 collected. Detailed capital and annual cost data are presented in "CENC APCD Technical Analysis".

The Division compared CENC's costs for DSI to other Colorado facilities similar in size that analyzed DSI, shown inTable 8.

Table 8: DSI Cost Comparisons

Facility & Unit	Size (MW)	Annualized Costs ($/year)	Cost Effectiveness ($/ton)	Ratio ($/kW)
Colorado Energy Nations – Boiler 4	35	$1,766,000	$3,774	$50.46
Colorado Springs Utilities – Drake Unit 5	51	$1,746,172	$2,293	$34.33

[4] U.S. EPA, 2000. "Controlling SO_2 Emissions: A Review of Technologies." Prepared by Ravi K. Srivastava for the U.S. Environmental Protection Agency, Office of Research and Development. Office of Research and Development. Washington, D.C. 20460.

Colorado Energy Nations – Boiler 5	65	$2,094,000	$2,485	$32.22
Colorado Springs Utilities – Drake Unit 6	85	$2,910,287	$1,741	$34.24

The Division considers CENC's DSI costs to be within a reasonable cost range that is comparable to other Colorado facility submittals.[5] CENC Boiler 4 is more expensive compared to other units because of the small size of the boiler and the increased difficulty of the retrofit. Therefore, the Division did not adjust CENC's DSI cost estimates.

SO_2 Emissions Management: CENC notes that the costs for implementing a SO_2 Emission Management Plan are based on essentially zero capital cost with increment variable operating costs based on the replacement of a portion of coal boiler capacity with natural gas as needed to reduce historical 24-hour SO_2 peaks. The emission level projected for this alternative was derived from the analysis of historical emission level variability detailed in Figure 3.

The Division verified CENC's calculated costs for SO_2 Emission Management based on SO_2 hourly CEMs data (06/29/2000 through 01/04/2006), the amount of curtailment that will be required, and average natural gas costs ($10/MMBtu). In reviewing CENC's DSI estimate, the Division found that the ratio of annual costs to the total capital costs for the control technology option projected by CENC to be higher than those projected by other facilities that were amortized over the same 20 year time frame. The annualized costs for DSI are about 35% of the total capital investment. The EPA found that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments[6]. However, CENC is a much smaller facility than the facilities in Arizona, New Mexico, and Oregon, which can significantly increase costs. CENC also clearly followed the Cost Control Manual methodology for estimating operation and maintenance costs. Therefore, the Division did not adjust CENC's cost estimates.

Emission limit tightening: There are no costs associated with this option. This option is considered equivalent to the "baseline" row in the tables below, and is not considered as a separate cost option.

Table 9, Table 10,Table 11, and Table 12 depict controlled SO_2 emissions and control cost comparisons.

Table 9: Boiler 4 Control Resultant SO_2 Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	780	0.64	0.74

[5] ENSR, 2006. BART Analysis for the TriGen Colorado Energy Corporation Facility in Golden, Colorado. Prepared for Trigen. Document No: 10279-017-700.
[6] Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.

SO_2 Emissions Management	0.13	767	0.64	0.74
DSI - Trona	60	312	0.26	0.30

Table 10: Boiler 5 Control Resultant SO_2 Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,406	0.71	0.82
SO_2 Emissions Management	0.06	1,448	0.71	0.82
DSI - Trona	60	562	0.29	0.33

Table 11: Boiler 4 SO_2 Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)*	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
SO_2 Emissions Management	1.0	$44,299	$43,690	$43,089
DSI - Trona	468	$1,766,000	$3,744	-$85

Table 12: Boiler 5 SO_2 Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
SO_2 Emissions Management	0.8	$65,882	$78,095	$92,572
DSI - Trona	844	$2,094,000	$2,482	-$90

Energy and Non-Air Quality Impacts

Traditional Wet FGD: Based upon its experience, and as discussed in detail below, the Division has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including massive water usage. This is a significant issue in Colorado, where water is a costly, precious and scarce resource. In the arid West, securing sufficient water supplies to support a wet FGD control system is a difficult undertaking that precludes other beneficial uses for such water. In Colorado, water law is based upon the doctrine of prior appropriation or "first in time - first in right," and the priority date is established by the date the water was first put to a beneficial use. Thus, depending upon whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the state, particularly in the Front Range, to accommodate the added demands of wet FGD controls. At a minimum, the water demands of wet FGDs will compete for what is already a scarce resource needed for Colorado's domestic, agricultural and industrial demands. Wet scrubbers consume approximately 23% more water than LSD scrubbers, depending on boiler size.[7]

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. On-site storage of wet ash is an increasing regulatory concern, as evidenced by the recent Tennessee Valley Authority spill. In addition, the steam plume resulting from a wet FGD control system in such a confined creek bed will produce a noticeable cloud that will hang over a densely populated area (City of Golden). The Division has received complaints regarding the more visible plumes associated with wet scrubbing; a potential irony in light of the visibility issues at the heart of the BART program. The Division largely focused its BART SO_2 control technology consideration on commercially available once-through dry FGD controls, specifically, "lime spray dryers" (LSD), that have an established record of reliable performance on boilers burning low-sulfur coal. Generally, wet FGD controls can achieve a higher level of SO_2 control on a percent capture basis that exceeds the capabilities of LSDs but, as noted above, there are a number of non-air quality and other environmental impacts including increased water usage, sludge disposal and wet plume issues that often overshadow any incremental improvement in SO_2 emission reductions. Recent PSD applications in Colorado have demonstrated lime spray dryer systems to be BACT.

The Division finds that the non-air quality environmental impacts outweigh the visibility benefits from this technology. Therefore, the State has eliminated this option as BART.

SO_2 Emissions Management: The Division has determined that there are not any negative energy or non-air quality related impacts related to the proposed SO_2 emission management scenario.

DSI: CENC documents additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash.

The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash,[8] which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls.

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[7] 2008. "Revised BART Analysis for Unit 1 & 2 Gerald Gentleman Station Sutherland, Nebraska: Nebraska Public Power District." Prepared by: HDF 701 Xenia Avenue South, Suite 600 Minneapolis, MN 55416 With control technology costs provided by: Sargent & Lundy.

[8] Department of Energy, 2001. LIFAC Sorbent Injection Desulfurization Demonstration Project: A DOE Assessment. U.S. Department of Energy: National Energy Technology Laboratory. P.O. Box 880, 3610 Collins Ferry Road Morgantown, WV 26507-0880. http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/lifac/LIFAC_PPA.pdf

Emission Limit Tightening: There are no known non-air quality or energy impacts associated with emission limit tightening. Thus, this factor does not influence the selection of this option.

Remaining Useful Life

CENC asserts that there are no near-term limitations on the useful of these boilers, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 13 shows the number of days pre- and post-control. Table 14 depicts the visibility results (98^{th} percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[9], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO_2 BART control technology on a given unit, emission rates for the other pollutants and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with NO_x emissions at 0.07 lb/MMBtu (SCR control) and SO_2 emissions (DSI control) at 0.258 lb/MMBtu for Boiler 4 and 0.286 lb/MMBtu for Boiler 5.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 13: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

<table>
<tr><th rowspan="2">SO_2 Control Scenario</th><th rowspan="2">Unit(s)</th><th rowspan="2">SO_2 Emission Rate (lb/MMBtu)</th><th rowspan="2">Class I Area Affected</th><th colspan="2">3-year totals</th><th></th><th colspan="2">3-year totals</th><th></th></tr>
<tr><th>Pre-Control Days >0.5 dv</th><th>Post-Control Days >0.5 dv</th><th>Δdays</th><th>Pre-Control Days >1.0 dv</th><th>Post-Control Days >1.0 dv</th><th>Δdays</th></tr>
<tr><td rowspan="2">Max 24-hr</td><td>4</td><td>0.90</td><td rowspan="2">Rocky Mountain</td><td rowspan="2">33</td><td rowspan="2">---</td><td rowspan="2">---</td><td rowspan="2">10</td><td rowspan="2">---</td><td rowspan="2">---</td></tr>
<tr><td>5</td><td>0.98</td></tr>
</table>

[9] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

DSI	4	0.258	National Park	33	29	4	10	7	3
	5	0.286		33	28	5	10	7	3
Combo	4&5	0.361 0.392		33	3	30	10	0	10

Table 14: Visibility Results – SO_2 Control Options

Scenario	Boiler(s)	SO_2 Emission Rate (lb/MMBtu)	Output (@ 98th Percentile Impact)	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	($/dv)
Max 24-hr	4 5	0.90 0.98	1.07	---	---	---
DSI	4	0.258	0.99	0.08	8%	$21,802,469
	5	0.286	0.94	0.13	12%	$16,752,000
Combo	4 5	0.361 0.392	0.28	0.79	74%	$18,393,225

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that SO_2 BART is the following SO_2 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.

B. Filterable Particulate Matter (PM_{10})

CENC Boilers 4 and 5 are each equipped with fabric filter baghouses to control PM/PM_{10} emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Colorado Operating Permit 96OPJE143 Conditions 3.5 and 4.4 require Boilers 4 and 5 to each meet a PM/PM_{10} emission limit of 0.1 lb/MMBtu. Additionally, Condition 18.1 mandates that each baghouse be equipped with an operating pressure drop measuring device and outlines the Continuous Opacity Monitor requirements.

Table 15 shows the most recent stack test data (August 23, 2007 for Boiler 4 and October 10, 2007 for Boiler 5). It is important to note that the most recent stack test, which at a minimum, occurs every five years in accordance with Colorado Operating Permit 96OPJE143 Condition 18.2, and more frequently depending on the results, demonstrates that these baghouses are meeting >95% control.

Table 15: CENC 2007 Stack Test Results

Pollutant	Boiler 4 (lb/MMBtu)	Boiler 5 (lb/MMBtu)
Filterable PM_{10}	0.013	0.012
PM_{10} Control efficiency	98.4%	98.3%

A Division review of EPA's RBLC revealed recent BACT PM/PM_{10} determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls. The current stack test results above are well below the range of recent BACT determinations. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details regarding BACT determinations.

These boilers are subject to National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, more commonly known as the Boiler MACT, which was proposed on June 4, 2010.[10] As currently proposed, the boilers will be subject to a PM limit of 0.02 lb/MMBtu (monthly average).[11]

Other commercial EGUs must meet a PM limit of 0.03 lb/MMBtu, so the Division evaluated the possibility of tightening the existing PM limit of 0.07 lb/MMBtu on CENC units 4 and 5 based on the idea that there may not be any cost associated with a tighter limit. However, compliance with the PM limit is demonstrated through periodic performance tests, where compliance is unknown until the test results are evaluated. Consequently, a tighter emission limit has the effect of increasing the likelihood of non-compliance without any possibility of remedy until after the test is complete. This dilemma is further complicated by the presumption that any non-compliance is assumed backward in-time until the last performance test indicating compliance. Thus a tighter PM limit has the effect of forcing sources into more frequent performance testing to ensure that any unanticipated non-compliance is of shorter duration and thus less costly for any associated enforcement actions. Consequently, a tighter emission limit does have an associated increase in costs to the source.

Furthermore, the Division conducted sensitivity analysis of the CALPUFF model for several sources that indicated that tightening of PM emissions by 0.07 lb/MMBtu resulted in negligible

[10] EPA, 2009. 40 CFR Part 63 [EPA HQ-OAR-2002-058; FRL-RIN 2060-AG69]. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.
[11] EPA, 2009. 40 CFR Part 63 [EPA HQ-OAR-2002-058; FRL-RIN 2060-AG69]. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Pg. 34 – Table 1 – Existing Coal Stoker.

(less than a tenth to several hundredths of a delta dv) visibility improvement. Since a tighter PM emission limit does increase costs and does not result in any appreciable visibility improvement, the Division concludes a PM emission limitation of 0.07 lb/MMBtu is appropriate level of control that satisfies BART.

The Division has determined that an emission limit of 0.07 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 fabric filter baghouses. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for PM/PM_{10} is not needed for CENC Boilers 4 and 5.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies

CENC identified four NO_x control options:

- Selective catalytic reduction (SCR)
- Selective non-catalytic reduction (SNCR)
- Combustion modifications/low-NO_x burners (LNB)
- Low-NO_x burners + Separated Overfire Air (LNB+SOFA)

The Division also identified and examined the following additional control options for these units:

- Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Fuel Switching – Natural Gas
- Coal reburn +SNCR

Step 2: Eliminate Technically Infeasible Options

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

CENC estimated that the retrofit SCR systems on Boilers 4 and 5 could achieve 0.06 lb/MMBtu. The SCR reaction occurs within the temperature range of 600°F to 750°F where the extremes are highly dependent on the fuel quality. There are three different types of SCR arrangements – high-dust, low-dust, and tail-end. The pre-dominant arrangement applied in the United States has been high-dust. In most circumstances, a high-dust SCR system is the most economical arrangement alternative and would likely be the arrangement for Units 4 and 5 if applicable. For high- and low-dust arrangements, the catalyst, because of its location directly downstream of the boiler and upstream of the air heater, can impact the boiler through its effect on the air heater. The magnitude of this effect is dependent on the power plant configuration, air quality control components, type of fuel, and overall emission control requirements. For retrofit applications, adequate space between the economizer outlet and the air heater inlet to allow boiler outlet and air heater return duct is a prerequisite for the installation of a high-dust system and is the case for the CENC boilers. Therefore, high-dust SCR is a technically feasible alternative for CENC Boilers 4 and 5.

SNCR/SNCR+LNB/SOFA: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for CENC Boilers 4 and 5.

LNB/LNB+SOFA: Low NO_x burners are designed to control fuel and air mixing at each burner in order to create large and more branched flames. Peak flame temperature is thereby reduced, and results in less NO_x formation. The improved flame structure also reduces the amount of oxygen available in the hottest part of the flame thus improving burner efficiency. Combustion, reduction and burnout are achieved in three stages within a conventional low NO_x burner. In the initial stage, combustion occurs in a fuel rich, oxygen deficient zone where the NO_x are formed. A reducing atmosphere follows where hydrocarbons are formed which react with the already formed NO_x. In the third stage internal air staging completes the combustion but may result in additional NO_x formation. This however can be minimized by completing the combustion in an air lean environment. Installing LNB with separated OFA may increase carbon monoxide (CO) emissions. LNB/LNB+SOFA are a technically feasible alternative for CENC Boilers 4 and 5.

Low NO_x burners can be combined with other primary measures such as overfire air (OFA) or for even greater NO_x emission reductions, separated overfire air (SOFA). The SOFA system diverts secondary air from the main windbox and injects it into the furnace above the main firing zone. This staged combustion process is one of the first principles of aggressive NO_x reductions. LNB+SOFA is a technically feasible alternative for CENC Boilers 4 and 5.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[12] and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[13] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for CENC Boilers 4 and 5.

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[12] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[13] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu[14]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CENC provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[15] 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for CENC Boilers 4 and 5 to determine control efficiencies and annual reductions.

LNB/LNB+SOFA: CENC estimated that low-NO_x burners (Alstom's Low NO_x Concentric Firing System (LNCFS) System) are capable of reducing NO_x emissions by approximately 10 – 12%, which results in annual emission rates of 0.45 and 0.30 lb/MMBtu for Boilers 4 and 5, respectively. A similar Colorado facility with installed LNB achieves approximately 0.35 – 0.38 lb/MMBtu and estimates an additional 20% reduction if OFA is installed to achieve 0.28 – 0.30 lb/MMBtu. These same burners with Separated Overfire Air were estimated to reduce NO_x emissions by 19 – 35%, resulting in an annualized estimated 0.32 and 0.28 lb/MMBtu for Boilers 4 and 5 respectively.

EPA's AP-42 emission factor tables estimate low-NO_x burners controlling 35 – 55% and LNB with OFA controlling 40 – 60% of NO_x emissions.[16] A recent AWMA study noted that LNB with close-coupled OFA firing bituminous coal in tangentially fired boilers achieved, on average, 35% NO_x reduction.[17] However, due to the size and configuration (e.g. furnace dimensions) of the CENC boilers, the Division concurs that the estimated control efficiency rates are reasonable.

SNCR/SNCR+LNB/SOFA: CENC noted in the original BART submittal (July 2006) that SNCR achieves 30 – 50% control, which is consistent with EPA's SNCR Air Pollution Control Technology Fact Sheet and the Division's experience. However, when CENC calculated SNCR control efficiency in the November 2009 submittal, it was assumed that LNB+SOFA would be installed beforehand. CENC estimated that SNCR would reduce NO_x emissions 40% with LNB+SOFA installed, for resultant emission rates of 0.19 lb/MMBtu and 0.17 lb/MMBtu for Boilers 4 and 5, respectively. This equates to 62 – 67% reduction depending on the boiler, which

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[14] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf

[15] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

[16] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[17] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

is consistent with EPA's AP-42 emission factor tables (50 – 80%).[18] Therefore, the Division concurs with CENC's control efficiency estimates for LNB+SOFA+SNCR.

The Division conducted a separate analysis regarding stand-alone SNCR installation (without LNB+SOFA installation) for comparison purposes. The Division did not use CENC's original estimate of 40% reduction for SNCR. Instead, the Division estimated control efficiency based on a variety of information, including similar Colorado facility estimates, EPA's SNCR Air Pollution Control Fact Sheet and a recent AWMA study[19] to conservatively approximate that the CENC boilers can achieve 30% control when SNCR is applied.

SCR: CENC, via their vendor, estimates that each boiler will be able to achieve a 0.06 lb/MMBtu emission rate on a 30-day rolling average. CENC estimated control efficiencies on the assumption that LNB+SOFA will already be installed. However, this will not change the overall SCR resultant emission rate.

The Division adjusted this emission rate to be 0.07 lb/MMBtu to be consistent with other Colorado facility submittals and literature review. This adjusted rate equates to 86% control for Boiler 4 and 80% control for Boiler 5. These control efficiencies are consistent with EPA's AP-42 emission factor tables, which estimate SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.[20,21]
Table 16 summarizes each available technology and technical feasibility for NO_x control.

Table 16: CENC Boilers 4 and 5 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO_x Burners (LNB)	35 – 55%	Y
LNB + OFA	40 – 60%	Y
Overfire air (OFA)	10 – 25% (alone)	Y
Selective non-catalytic reduction (SNCR)	~30 - 50%	Y
SNCR+LNB+SOFA	~50 – 80%	Y
Selective catalytic reduction (SCR)	~75 – 90%	Y
ECO®	n/a	N
RRI	n/a	N
Coal reburn +SNCR	n/a	N

Step 4: Evaluate Impacts and Document Results

[18] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[19] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.
[20] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[21] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Cost of Compliance

LNB/LNB+SOFA: CENC contracted Alstom Power to determine total installed costs for low-NO_x burners and separated overfire air. Factors from EPA's Cost Control Manual were used to develop the total annual cost estimate. EPA's regulations recommend using the EPA's Office of Air Quality Planning and Standards' Air Pollution Cost Control Manual (Sixth Edition, January 2002) for estimating costs of compliance. This Manual provides guidance and methodologies for developing accurate and consistent estimates of cost for air pollution control devices. The costs that may be estimated include capital costs, operation and maintenance (O&M) expenses, and other annual costs.

In reviewing CENC's estimates, the Division found that the ratio of annual costs to the total capital costs for LNB/LNB+SOFA projected by CENC to be slightly higher than those projected by other facilities that were amortized over the same 20 year time frame. For example, the annualized costs for LNB for Boilers 4 and 5 are 16.1% and 15.5%, respectively, of the total capital investment. The EPA found that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments[22]. However, the Division and CENC note that the boilers are much smaller than those examined by the EPA. Therefore, the Division concurs with CENC's cost estimates for LNBs. Further, the Division compared recent NESCAUM studies estimating LNB+SOFA for tangentially-fired boilers as between \$420 - \$1,600 per ton NO_x reduced.[23] Both the original and revised CENC cost effectiveness estimates are within the NESCAUM ranges, providing further verification that cost estimates are reasonable. The NESCAUM study did not provide cost estimate ranges for LNB on tangentially-fired boilers.

SNCR/SNCR+LNB+SOFA: The difficulty of SNCR retrofit on smaller boilers significantly increases, with the primary concern being that there is adequate wall space within the boiler for installation of injectors. Movement and/or removal of existing watertubes and asbestos from the boiler housing may be required, as in the case of the CENC boilers.

A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.[24] The CENC-estimated SNCR costs for operating expenses are 81% and 86% for Boiler 4 and Boiler 5, respectively. Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[25]

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[22] Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.
[23] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[24] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.
[25] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

The cost effectiveness for SNCR on Boilers 4 and 5 is about $2,900 and $3,350 per ton, respectively. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[26,27] EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NO_x reduced.[28] Although CENC's estimates are greater than these ranges, the small size of the boilers as well as the difficulty of the retrofit leads the Division to the conclusion that CENC's cost estimates for SNCR are reasonable.

SCR: CENC contracted Lutz, Daily, & Brain (LDB) to develop a capital cost estimate. On both boilers, it was determined that the economizers must be moved because there is very little space between the air heater outlet and the current economizer configuration, adding to the capital cost.

Recent NESCAUM studies estimate SCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.10 – 0.15 lb/MMBtu and emission reductions of 75 – 85% as costing $2,600 - $5,000 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[29,30] CENC's cost estimates are higher than this range, but the small size of the boilers as well as the difficulty of the retrofit leads the Division to the conclusion that CENC's cost estimates for SCR are reasonable.

Table 17, Table 18, Table 19, and Table 20 depict controlled NO_x emissions and control cost comparisons.

Table 17: CENC Boiler 4 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions				
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)	Annual Average (lb/hour)	30-day Rolling Average (lb/hour)
Baseline	---	599	0.50		179	
LNB	10	539	0.45	0.515	161	185
SNCR	30	420	0.35	0.400	125	144
LNB+SOFA	35	390	0.32	0.372	116	134
SNCR+LNB+SOFA	61	231	0.192	0.221	69	79
SCR	86	84	0.070	0.080	25	29

[26] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[27] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.
[28] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
[29] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[30] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

Table 18: CENC Boiler 5 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions				
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)	Annual Average (lb/hour)	30-day Rolling Average (lb/hour)
Baseline	---	691	0.34		165	
LNB	7	643	0.32	0.368	153	176
LNB+SOFA	18.5	563	0.28	0.322	134	155
SNCR	30	484	0.24	0.277	115	133
SNCR+LNB+SOFA	51	337	0.17	0.193	80	93
SCR	79.6	141	0.07	0.081	34	39

Table 19: CENC Boiler 4 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
LNB	59.9	$193,433	$3,227	$54
SNCR	179.8	$694,046	$3,860	$5
LNB+SOFA	209.8	$678,305	$3,234	-$21
SNCR+LNB+SOFA	368.0	$1,372,351	$3,729	$3
SCR	515.4	$4,201,038	$8,150	$30

Table 20: CENC Boiler 5 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
LNB	48.4	$249,858	$5,166	$107
LNB+SOFA	127.3	$815,829	$6,383	$15
SNCR	207.3	$923,996	$4,458	($24)
SNCR+LNB+SOFA	353.7	$1,739,825.3	$4,918	$3
SCR	550.0	$6,469,610	$11,764	$35

Energy and Non-Air Quality Impacts

LNB/LNB+SOFA: Installing LNB with separated OFA may increase unburned carbon in the ash, commonly referred to as loss on ignition (LOI). Otherwise, there are no known non-air quality impacts associated with low-NO_x burners and separated overfire air systems. Energy impacts are not significant. Thus, this factor does not influence the selection of this control.

SNCR/SNCR+LNB+SOFA/SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR reagent injection systems have minimal power requirements.

Post-combustion add-on control technologies such as SNCR do increase power needs, in the case of the CENC boilers, 90 kW per hour, or enough energy to power about 9 homes for a year, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases.

SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer. For CENC Boilers 4 and 5, the estimated pressure drop across the catalyst is 7 to 8 inches water column and the total energy consumption is approximately 1,000 kW per hour, or enough energy to power about 100 homes for a year.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas. CENC has indicated to the Division that they would prefer to use urea instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on a urea reagent versus an ammonia reagent. Refer to "CENC BART Submittals" for more information.

Remaining Useful Life

CENC asserts that there are no near-term limitations on the useful of these boilers, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 21 shows the number of days pre- and post-control. Table 22 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[31], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO_2 BART control technology on a given unit, emission rates for the other pollutants and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with NO_x emissions at 0.07 lb/MMBtu (SCR control) and SO_2 emissions at 0.258 lb/MMBtu for Boiler 4 and 0.286 lb/MMBtu for Boiler 5.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 21: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hr	4	0.67	Rocky Mountain National Park	33	---	---	10	---	---
	5	0.66							
LNB	4	0.45*		n/a					
	5	0.30*		n/a					
SNCR	4	0.35*		n/a					
	5	0.24*		n/a					
LNB+SOFA	4	0.32		33	27	6	10	7	3
NOx Modeled Rate	5	0.28		33	25	8	10	6	4
LNB+SOFA	5	0.24*		n/a					
LNB+SOFA+SNCR	4	0.19		33	27	6	10	7	3
	5	0.17		33	19	14	10	6	4
SCR @ 0.07 lb/MMBtu	4	0.07		33	25	8	10	6	4
SCR @ 0.07 lb/MMBtu	5	0.07		33	19	14	10	6	4

[31] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

Combo	4 5	0.07 0.07		33	3	30	10	0	10

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "CENC BART Modeling Summary" for more details.

Table 22: Visibility Results – NO_x Control Options

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)*	Output (@ 98th Percentile Impact)	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	($/dv)
Max 24-hr	4 5	0.67 0.66	1.07	---	---	---
LNB	4	0.45*	1.02	0.05	5%	$3,868,660
	5	0.30*	0.89	0.17	16%	$1,435,965
SNCR	4	0.35*	0.99	0.07	7%	$9,507,477
	5	0.24*	0.86	0.21	20%	$4,358,471
LNB+SOFA	4	0.32	0.99	0.08	7%	$8,478,816
NOx Modeled Rate	5	0.28	0.88	0.18	17%	n/a
LNB+SOFA	5	0.24*	0.86	0.21	20%	$3,848,252
LNB+SOFA+SNCR	4	0.19	0.96	0.11	10%	$12,475,919
	5	0.17	0.82	0.25	23%	$7,101,328
SCR @ 0.07 lb/MMBtu	4	0.07	0.89	0.18	17%	$23,734,677
SCR @ 0.07 lb/MMBtu	5	0.07	0.75	0.31	29%	$20,669,680
Combo	4 5	0.07 0.07	0.28	0.79	74%	$18,393,225

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "CENC BART Modeling Summary" for more details.

Step 6: Select BART Control

The Division and CENC worked together to determine a "flexible" BART option for Boilers 4 and 5. CENC initially proposed this option in its' prehearing statement on September 15, 2010. This option incorporates both an individual limit (lb/MMBtu) for each boiler or a combined average (lbs/hr) for both boilers for a 30-day rolling average period. CENC submitted supplemental information regarding a "flexible" BART plan on October 19, 2010 to the Division, citing the preamble to the BART regulations to 'consider allowing sources to 'average' emissions across any set of BART-eligible emission units within a fencline, so long as the emission reductions from each pollutant being controlled for BART would be equal to those reductions that would be obtained by simply controlling each of the BART-eligible source." This determination adheres to the language in the BART preamble.

Based upon its consideration of the five factors summarized herein, 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.

Based upon its consideration of the five factors summarized herein, the state has determined that NO_x 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 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 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 in section 6.4.3 of the Regional Haze State Implementation Plan.

- 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 of the Regional Haze State Implementation Plan.

Best Available Retrofit Technology (BART) Analysis of Control Options For Public Service Company – Comanche Station, Units 1 and 2

I. Source Description

Owner/Operator:	Public Service Company
Source Type:	Electric Utility Steam Generating Unit
SCC (EGU):	Unit 1: 10100226 Unit 2: 10100222
Boiler Type:	Three Dry-Bottom Pulverized Coal-Fired Boilers, two tangentially fired (Units 1 and 3) and one wall-fired (Unit 2)

Comanche Station is located at 2005 Lime Road in Pueblo, CO, which is located within Pueblo County. Comanche Station commenced operation in the early 1970s. The facility originally consisted of two coal fired boilers, driving steam turbines used to generate electricity and associated support equipment (cooling and service water towers and coal and ash handling equipment). Unit 1 commenced operation in 1972 and serves a generator rated at 325 MW. Unit 2 commenced operation in 1975 and serves a generator rated at 335 MW. The boilers burn sub-bituminous coal from the Powder River Basin (PRB) as fuel and use natural gas for startup, shutdown and flame stabilization.

In August of 2004, Public Service Company of Colorado (PSCo) proposed to construct and operate a new coal-fired boiler (Unit 3) at Comanche Station. As part of that project, PSCo proposed to install control devices on the existing units. PSCo entered into a Settlement Agreement in December 2004 with various citizen groups and voluntarily agreed to install additional control devices and take emission limitations. In addition to the new unit (Unit 3), additional support equipment was proposed including a cooling tower, coal and ash handling equipment and various support equipment for the control device reagents (e.g., silos for lime, recycle ash and sorbent). Construction permits for the project were issued on July 5, 2005.

Low NO_X burners with over-fire air and a lime spray dryer were installed in November 2008 on Unit 1 and low NO_X burners with over-fire air and a lime spray dryer were installed in November 2007 on Unit 2. Operation of the SO_2 controls did not commence until June 3, 2009 for Unit 1 and January 10, 2009 for Unit 2. Unit 3 commenced operation in January 2010.

Units 1 and 2 are considered BART-eligible because the units were in existence on August 7, 1977 and not in operation prior to August 7, 1962 and are located at a fossil-fuel-fired steam electric plant greater than 250 MMBtu/hr, with the potential to emit of more than 250 tons or more of any visibility impairing air pollutant (NO_X, SO_2, PM_{10}). The results of the initial BART modeling analysis, indicated that the visibility impairment exceeded 0.5 deciviews (98% percentile -

8th high), at federal Class I areas. Therefore, since Units 1and 2 “cause or contribute” to visibility impairment BART applies to these units.

Table 1 below lists the units at Public Service Company Comanche Station that are subject to BART and are addressed in this BART analysis as well as the control efficiency of the controls currently installed on Units 1 and 2 (note SO_2 and NO_X controls were installed within the baseline period).

Table 1: Comanche Units 1 and 2 Technical Information

	Unit 1	Unit 2
Placed in Service	December 1973	November 1975
Boiler Rating, MMBtu/Hr for coal	3,531	3.482
Electrical Power Rating, Gross Megawatts	325	335
Description	Combustion Engineering Tangentially Fired Dry Bottom Boiler. Coal-Fired with Natural Gas Used for Startup, Shutdown and/or Flame Stabilization.	Babcock and Wilcox Wall-Fired Dry Bottom Boiler. Coal-Fired with Natural Gas Used for Startup, Shutdown and/or Flame Stabilization.
Air Pollution Control Equipment	PM/PM_{10} – Baghouse – Installed 1993 NO_X – Low NO_X Burners with Over-Fire Air – Installed November 2008 SO_2 – Lime Spray Dryer – Installed November 2008, fully operational 6/3/09	PM/PM_{10} –Baghouse – Installed 1991 NO_X – Low NO_X Burners with Over-Fire Air - Installed November 2007 SO_2 – Lime Spray Dryer – Installed November 2007, fully operational 1/10/09
Emissions Reduction (%)*	NO_X – 62.7% SO_2 – 76.1% PM – 99.7% PM_{10} – 99.0%	NO_X – 44.1% SO_2 – 81.9% PM – 99.8% PM_{10} – 99.3%

*Emissions Reduction estimated by comparing pre-control 2005 – 2007 CAMD data (2005 – 2006 for NO_x on Unit 2) to controlled 2009 data. For PM/PM_{10}., uncontrolled AP-42 factor were compared to actual average emission factors (2006 – 2008). See “Comanche APCD Technical Analysis” for further details. Not based on actual testing.

PSCo submitted a BART analysis to the Division on August 1, 2006, with revisions to that analysis submitted on August 15, 2006 (editorial corrections), October 19, 2006 and January 8, 2007. At the Division’s request, PSCo submitted additional information dated January 19, February 24, March 1, April 12, April 21, May 25, July 14, and July 22, 2010. These documents are included as “PSCo BART Submittals”.

II. Source Emissions

In PSCO’s August 1, 2006 BART application, baseline emissions were based on calendar year 2004 and 2005 emissions. Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses. Additionally, PSCo, as detailed in Table 1, has installed air pollution controls on both units at Comanche in 2008. Therefore, the Division used years 2009 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database.

Controls were installed on Unit 2 in November 2007 and controls were installed on Unit 1 in November 2008. While the SO_2 controls did not commence full operation until 2009, the NO_X controls did commence operation upon installation. In addition, PSCo has indicated that lime was initially injected into the lime spray dryers in December 2008 for Unit 1 and July 2008 for Unit 2 in order to test the controls. The baseline emissions are summarized in Table 2.

Table 2: PSCo Comanche Units 1 & 2 Baseline Emissions

Pollutant	Unit 1		Unit 2	
	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)
NO_x	1,511	0.124	2,349	0.165
SO_2	1,557	0.128	1,244	0.091
PM_{10}	80	0.007***	40	0.005***

*Using daily CEMs data from 2009 calendar year (CAMD data).
**The Division calculated average emission rate or used the CAMD reported rate (lb/MMBtu) from the 2009 calendar year (CAMD data) based on average daily reported data for each unit for NO_x and SO_2 emissions.
***The PM_{10} emission factor is determined from the most recent Title V permit compliance stack tests (March 2003).

III. Units Evaluated for Control

According to PSCo's August 1, 2006 BART application sub-bituminous coal from the Powder River Basin (PRB), Belle Ayr mine in Wyoming is typically used as fuel. The characteristics of the Belle Ayr PRB coal presented in the August 1, 2006 BART application are presented below in Table 3.

Table 3: Comanche Station Coal Specifications (From August 1, 2006 BART Application)

Coal Mine/Region	PRB – Belle Ayr
Coal Rank Classification	Sub-bituminous
Proximate Analysis	
H_2O (Moisture weight %)	29.9
Ash (weight %)	4.6
Sulfur (weight %)	0.31
Ultimate Analysis	
Nitrogen (weight percent %)	0.68
Other	
Heating Value (HHV Btu/lb)	8,550

Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal as well as the highest ash and sulfur content from the two coals for conservative estimates.

Table 4: Uncontrolled emission factors for Comanche BART-eligible sources[1]

	Pollutant (lb/ton)*			
Emission Unit	NO_x	SO_2	PM (filterable)	PM_{10} (filterable)
Unit 1	8.4	9.5	46.6	10.7
Unit 2	7.4	9.5	46.6	10.7

*SO_2 and PM/PM_{10} factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, averaged from APEN data (2006-2009). Please refer to "Comanche APCD Technical Analysis" for more details.

Emission limitations that apply to these boilers are as follows:

- Colorado Regulation No. 1, III.A.1.c limits particulate matter emissions to 0.1 lb/MMBtu, for each boiler.
- Colorado Regulation No. 1, VI.A.3.a.(ii) limits sulfur dioxide emissions to 1.2 lb/MMBtu, for each boiler.
- 40 CFR, Part 76-Acid Rain Nitrogen Oxides Emission Reduction Program limits NO_X emissions to 0.40 lb/MMBtu and 0.46 lb/MMBtu, both on an annual average basis for Units 1 and 2, respectively.
- 40 CFR Part 60 Subpart D §§ 60.44(a)(3) and 60.45(g)(3), as adopted by reference in Colorado Regulation No. 6, Part A limits NO_X emissions to 0.7 lb/mmBtu, on a 3-hr rolling average. Applies to Unit 2 only.
- Colorado Construction Permits 11PB859, IA, mod 1 (Unit 2) and 04PB1429, IA (Unit 1) both issued July 5, 2005)
    - NO_X emissions shall not exceed 0.20 lb/MMBtu, on a 30-day rolling average, for each unit.
    - SO_2 emissions shall not exceed 0.12 lb/MMBtu, on a 30-day rolling average, for each unit.

  These limits shall be met no later than 180 days after the initial startup of the SO_2 and NO_X control equipment for each unit or by July 1, 2009, whichever is earlier
    - NO_X emissions from both Units 1 and 2 together shall not exceed 0.15 lb/MMBtu, on an annual rolling average basis (rolling on a daily basis)
    - SO_2 emissions from both Units 1 and 2 together shall not exceed 0.10 lb/MMBtu, on an annual rolling average basis (rolling on a daily basis)

  PSCo shall begin calculating compliance with these limits no later than 180 days after initial startup of the SO_2 and NO_X control equipment for the last unit.
    - Filterable PM emissions shall not exceed the following limits: Unit 1: 393 tons/quarter and 1,546 tons/yr and Unit 2: 390 tons/quarter and 1,525 tons/yr.

[1] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

- Filterable PM_{10} emissions shall not exceed the following limits: Unit 1: 363 tons/quarter and 1,423 tons/yr and Unit 2: 357 tons/quarter and 1,403 tons/yr.
- SO_2 emissions from Units 1 and 2 together shall not exceed 939.3 tons/quarter and 3,686 tons/yr.
- NO_X emissions from Units 1 and 2 together shall not exceed 1,564.4 tons/quarter and 6,142 tons/yr.

The above limitations take effect 180 days after initial startup of the last control device for the last unit or upon startup of Unit 3, whichever is earlier. Note that the quarterly limits apply for the first year of operation only.

IV. BART Evaluation of Units 1 and 2

A. Sulfur Dioxide (SO_2)

Step 1: Identify All Available Technologies

Semi-Dry FGD Upgrades – As discussed in EPA's BART Guidelines[2], electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls. The Division interprets this to include fuel switching to natural gas, which would require significant boiler modifications, including removing the semi-dry FGD.

However, based on Appendix Y [70 FR 39171], the following dry scrubber upgrades should be considered for Comanche Units 1 and 2 if technically feasible. These upgrades include:
-Use of performance additives
-Use of more reactive sorbent
-Increase the pulverization level of sorbent
-Engineering redesign of atomizer or slurry injection system

The current Construction Permit limits are depicted in Table 5.

Table 5: Comanche Units 1 & 2 SO_2 Operating Permit Limits

	SO_2 limits (lb/MMBtu)	
	30-day rolling	Annual rolling (combined)
Units 1 & 2	0.12	0.10

As indicated in EPA's BART Guidelines [70 FR 39171], for dry-FGD (i.e., LSDs) the following scrubber upgrades should be considered.

- Use of performance additives

[2] EPA, 2005. Federal Register, 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations: Final Rule. Pgs. 39133.

- Use of more reactive sorbent
- Increase the pulverization level of sorbent
- Engineering redesign of atomizer or slurry injection system

In addition to upgrades to the scrubbers, the Division also asked PSCo to look into the feasibility of achieving a lower 30-day SO_2 emission limitation with the existing controls (i.e., SO_2 emission limit tightening) and/or other potential upgrades, including improved operations and maintenance, use of more reagent, and keeping more spare parts on hand.

Step 2: Eliminate Technically Infeasible Options

At the Division's request, PSCo submitted an SO_2 upgrade analysis to the Division on May 25, 2010 and additional information on July 22, 2010 regarding potential upgrades for the LSDs installed on Comanche Units 1 and 2. The following summarizes PSCo's submittal and the Division's analysis of the information provided.

FGD: Flue gas desulfurization removes SO_2 from flue gases by a variety of methods. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

Dry FGD Upgrades: Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants[3]. SDA systems are typically utilized at units that burn lower-sulfur coal in the western U.S., where water resources are limited. A SDA system must be located before the boiler flue gases enter the baghouse. Each reactor vessel requires a "foot print" area comprising about 2,000 to 4,000 square feet (depending on volume of flue gas treated) along with additional space for support equipment access, slurry preparation, mixing and associated tanks.

As indicated previously, as part of a permitting action to construct and operate a new unit (Unit 3) at Comanche Station, PSCo committed to installing both NO_X and SO_2 controls on Units 1 and 2. Permits were issued on July 5, 2005 for Units 1 and 2 which addressed the controls and the associated emission limitations that these units would be required to meet prior to commencing operation of the proposed new unit. To that end, a lime spray dryer (LSD) was installed on Unit 1 in November 2008 and a LSD was installed on Unit 2 in November 2007. Full operation of the LSDs commenced in June 2009 and January 2009 for Units 1 and 2, respectively. Table 1indicates that the LSDs are achieving

[3] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

emission reductions at approximately 76% for Unit 1 and 82% for Unit 2 in comparison with the permit limits[4] depicted in Table 5. It should be noted that since July 1, 2009, when the SO_2 limits became applicable, Unit 1is achieving emission reductions at about 86.5% and Unit 2 at 85.3%. This system exceeds EPA's presumptive limits stated in 40 CFR Part 51 Appendix Y of 0.15 lb/MMBtu, although the current permit limit is higher than the presumptive limits. Therefore, since Comanche Units 1 and 2 are equipped with existing FGD and are achieving removal efficiencies greater than 50%, the BART analysis need not consider replacement of the SO_2 controls but should consider upgrades to the existing FGD.

-*Use of performance additives:* The supplier (Babcock & Wilcox) of PSCo's Colorado dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, which have been used on dry scrubbers. Chlorides are used to slow the drying time of the fly ash/lime mixture used to capture the gaseous SO_2. The chemistry of the calcium sulfate/sulfite reaction is much more effective when liquid water droplets exist. By slowing the drying time the theory is that the lime sorbent will be more efficient and the lime use could be decreased to obtain the same SO_2 reduction capability of the equipment unless the unit is limited on the total amount of lime slurry injection. There are cases on units that use high sulfur coal (significantly greater than 1.2 lbs/MMBtu) where the total amount of lime slurry injection is limited by the solids content of the slurry. When the total limit injection for a unit is limited, additives may allow some increase in SO_2 removal. However, because the Hayden boilers burn low sulfur western coals, PSCo is not limited on lime slurry injection and the use of performance additives on the scrubbers would not be expected to increase the SO_2 removal. Therefore, this upgrade is not technically feasible. Based on the information provided by PSCo, the Division agrees that the use performance additives are not likely to increase SO_2 removal and therefore warrants no further consideration.

-*Use of more reactive sorbent:* All PSCo dry scrubbers were designed to use a highly reactive lime with 92% calcium oxide content. The scrubbers were also designed to inject fly ash to maximize available surface area and allow efficient lime reagent use. Some dry scrubbers used by other companies were designed to use a lower quality lime, a dry hydrated lime product, or operate on lime without fly ash. On these scrubbers, the option of using a higher quality lime or injecting fly ash possibly could improve 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.

Lime is the reagent of choice in modern spray dryer systems on utility scale units. PSCo is aware of only one exception that was designed to use sodium carbonate to remove SO_2. The Coyote Station, a 420MW unit located near Beulah, North Dakota and operated by Otter Tail Power Company, was placed in service in 1981. The spray dryer was supplied

[4] Colorado Operating Permit Number 96OPROB132 Last Revised 5/14/10. Pgs. 6, 9.

by Rockwell and used rotary atomizers. The unit was designed to obtain 70% SO_2 removal. This unit was reported to have a visible plume at times likely due to the conversion from NO to NO_2 due to the sodium reagent. This unit was converted from sodium carbonate to lime after a number of years in service. PSCo verified with the two major suppliers of utility sized spray dryers, B&W and Alstom, and confirmed that there are no other operating utility spray dryers in the United States. B&W also states that in theory the sodium based reagents are more reactive as they have a slower drying time than lime reagents. However, because of their slower drying time, the spray dryer absorber would need to be larger to ensure the product was dry when leaving the scrubber. Thus, the use of sodium reagent in a unit designed for lime would not allow higher SO2 removal and it may not even be possible to convert to a sodium reagent with the existing equipment.

PSCo is using a highly reactive reagent that maximizes SO_2 removal; there are no known acceptable reagents without side effects that would allow additional SO_2 removal in the dry scrubbing systems present at Comanche Station. The Division agrees with PSCo's assessment and considers that use of a more reactive sorbent does not warrant further consideration.

Increase the pulverization level of sorbent: PSCo indicated that Colorado's dry scrubbers are designed with either horizontal or vertical ball mills to obtain optimum particulate size and reduce lime grit generation. Although PSCo notes that there have been some technical papers presented by pulverizer suppliers, that state vertical ball mills may provide a smaller particulate size and reduce lime use. Their experience has been that there is no SO_2 removal benefit in using vertical ball mills versus horizontal ball mills and there is also no measurable reduction in lime use. PSCo considers that they already uses the best available grinding technologies and that there are no improvements that can be done to further decrease lime particle size to reduce SO_2 emissions. The Division agrees that upgrades to grinding technologies are unlikely to produce additional SO_2 reductions and therefore no further consideration is warranted.

Engineering redesign of atomizer or slurry injection system: The Comanche dry scrubber systems are from B&W and use the same size and general design atomizer, a Model F800. While there are differences in the motor size and exact atomizer wheel construction that relate to the total slurry injection rate, the atomizer design is based on the vendor's experience to maximize both SO_2 removal and lime use efficiency. B&W offers no upgrade in atomizer design to improve SO_2 removal. There are certain third-party suppliers who offer different atomizer nozzle designs that they claim can reduce lime use or provide longer maintenance life. To PSCo's knowledge, no vendors claim an improved SO_2 removal. PSCo has tried some of these different nozzle designs and doesn't believe any of the designs improve the SO_2 removal level, although some have improved wear life and reduced maintenance costs. Given that the LSDs installed on Units 1 and 2 were installed recently, the Division would agree that changes to the design of the atomizers are unlikely to result in a higher SO_2 removal.

Emission limit tightening: In addition to considering upgrades to the existing FGDs on Units 1 and 2, the Division asked PSCo to consider whether tightening of the existing BART 30-day limits was feasible. Comanche Units 1 and 2 are subject to the following SO_2 emission limitations:

Table 6: Comanche Units 1 & 2 SO_2 Emission Limitations

	SO2 Emission Limitations				
	Emission Rate (lb/MMBtu)			Mass Emissions (tons)	
	3-hr rolling	30-day rolling*	365-day rolling	Quarterly	Annual
Unit 1	1.2	0.12	N/A	N/A	N/A
Unit 2	1.2	0.12	N/A	N/A	N/A
Units 1 and 2 Together	N/A	N/A	0.10	939	3.686

*Included as limits in the BART construction permit (07PB0112B) issued September 12, 2008.

In their May 25, 2010 submittal, PSCo addressed the feasibility of tightening their 30-day SO_2 emission limits. In their submittal, PSCo indicated that based on operating experience for Comanche Units 1 and 2, as well as other PSCo units equipped with LSDs, that the primary factor affecting the SO_2 control efficiency for short-term averages are startups, equipment malfunctions and low load operations. In order to begin injecting lime/recycle ash slurry into the scrubber, a minimum inlet scrubber temperature must be achieved so the lime/recycle ash slurry dries when it hits the hot flue gas. When the scrubber inlet temperature is below the minimum level, the lime slurry drops out in the scrubber and forms concrete-like deposits that eventually plug the scrubber vessel. PSCo indicated that this had actually occurred while operating Comanche Unit 2 and Valmont Unit 5 and resulted in extended maintenance outages in order to clean the scrubbers. In addition, during unit start-ups, it can take anywhere from between 12 and 24 hours to get the inlet scrubber temperature up to the level necessary for safe slurry injection. The scrubber can be run at higher levels of SO_2 reduction in order to offset the effects of a startup during a 30-day period, but the more startups that occur during that 30 day permit the more difficult it will become to offset the higher emissions during startup. PSCo also indicated that during low load operations, especially in the winter, the inlet temperature at the baghouse approaches the minimum acceptable level, subsequently lowering the overall SO_2 control efficiency during low load operations. PSCo indicated that due to the increased use of wind resources, the boilers will be required to cycle more frequently to accommodate intermittent wind resources and therefore, the units will run at low loads more frequently and as a result the SO_2 reduction levels will be lower during those times.

The Division reviewed available SO_2 emission data from CAMD for 2009 and for part of 2010 (January – October 2010). As previously indicated although the LSDs were installed in 2007 and 2008, they only recently commenced full operation, Unit 1 in June 2009 and Unit 2 in January 2009. As a result there is limited data available to determine post-control achievable emissions. In addition, if as PSCo indicates, the units are cycled more frequently to accommodate increased wind energy resources, it is not clear how well the data represents future operation. In addition, since the LSDs came on line recently, PSCo has limited operating experience with these units. Although PSCo has other units that are equipped with LSDs and have been operating those units with LSDs for some time (e.g., Valmont Unit 5, Hayden Units 1 and 2), those units are not using PRB coal. Comanche Units 1 and 2 represent the first units in PSCo's system with LSDs that are firing PRB coal as fuel. After startup of the LSDs in 2009 both units have had a number of days indicating zero emissions, presumably due to a unit shutdown. In addition, in many cases, emissions data shows that frequently for one or more days following these events, the daily SO_2 emission rate is well above 0.12 lb/MMBtu. Unit 1 averaged 0.07 lb/MMBtu during this period, with a maximum rate of 0.10 lb/MMBtu in December 2009. Unit 2 has had several months (December 2009, May 2010, October 2010) during the 2009 – 2010 timeframe that either exceed or are within 0.01 lb/MMBtu of the existing 0.12 lb/MMBtu 30-day rolling average limit. A review of annual data showed that in 2009, the SO_2 annual average from both units was approximately 0.11 lb/MMBtu. In 2010 thus far, the annual average is 0.07 lb/MMBtu, but it is important to note that it is apparent from the data on both units historically that lower inlet temperature(s) to the scrubber(s) in the winter months result in increased SO_2 emissions.

As explained above, the Division projects 30-day rolling SO_2 emission rates to be approximately 5% higher than annual average emission rates. The uncertainty of evaluating a "maximum" emission rate warrants a similar 5% buffer or greater to be applied in this case, especially due to the facts stated above, including uncertainty regarding load operations, cold-weather operating, start-up, and cycling for renewable energy. Therefore, the Division concurs that tighter 30-day rolling average and annual average SO_2 emission limit is not feasible at this time for either unit.

Additional equipment and maintenance: As discussed in the emission limit tightening section, PSCo reviewed actual operating experience on Comanche along with possible changes to the systems necessary to achieve lower emission rates on a 30-day average basis. The primary factors that affect SO_2 control efficiency for short-term averages are start-ups, equipment malfunctions, and low load operation. In order to begin injecting lime/recycle ash slurry into the scrubber, a minimum inlet scrubber temperature must be achieved so the lime/recycle ash slurry dries when it hits the hot flue gas. When the scrubber inlet temperature is below this minimum level, the lime slurry drops out in the scrubber and forms concrete-like deposits that eventually plug the scrubber vessel. This situation actually occurred while operating PSCo's Comanche Unit 2 and Valmont Unit 5 scrubbers and resulted in extended maintenance outages to clean the scrubbers. During unit start-ups, it can take anywhere from 12-24 hours to get the inlet scrubber temperatures up to the level necessary for safe lime slurry injection.

During these start-up periods, SO_2 emissions rates are at uncontrolled levels based on the sulfur content in the coal. Typically, if the unit only starts once during a 30-day period, operators can over-control SO_2 by running the scrubber below the 30-day average emission rate to "make-up" for higher emission rates during start-up. If the unit has more than one start-up in a 30-day period, which certainly happens with older units, it becomes nearly impossible to scrub hard enough to achieve the 30-day rolling emission rate limits. The same situation occurs under low load operation, especially during winter months. Inlet temperature to the baghouse due to air heater in-leakage can approach minimum acceptable levels, thus lowering overall SO_2 control efficiency during low load operation. PSCo coal-fired units will be required to cycle (under 60% load) more in the future to accommodate the intermittent nature of ever increasing wind generation on the electric grid and thus requiring the boilers to operate more frequently at low loads.

PSCo sent confirmation to the Division on July 22, 2010 that an extra 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. The Division concurs with this assessment. Therefore, since it is not technically feasible to install an extra scrubber module, additional spare atomizer parts and increased operating and maintenance will not result in decreased SO_2 emissions. The Division concludes that this option is not technically feasible for Comanche Units 1 and 2.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

PSCo indicated and the Division concurred that upgrades to the LSDs installed on Comanche Units 1 and 2 were unlikely to result in increased SO_2 reductions and therefore, would not be considered further. Therefore, there are no remaining technologies for which to conduct a control effectiveness evaluation.

Step 4: Evaluate Impacts and Document Results

PSCo indicated and the Division concurred that upgrades to the LSDs installed on Comanche Units 1 and 2 were unlikely to result in increased SO_2 reductions and therefore, would not be considered further. Therefore, there are no remaining technologies for which to conduct an evaluation of the cost, energy and non-air environmental impacts, and remaining useful life.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various potential emission rates. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 6 shows the number of days pre- and post-control. Table 7 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[5], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO_2 BART control technology on a given unit, emission rates for the other pollutants (NO_x and PM/PM_{10}) and other BART-eligible units are held constant at pre-

[5] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed Units 1 and 2 with NO_x emissions at 0.07 lb/MMBtu and SO_2 emissions at 0.12 lb/MMBtu.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together.

Table 6: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO2 Control Scenario	Unit(s)	SO2 Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hour	1 2	0.75 0.74	Great Sand Dunes National Park	60	---	---	27	---	---
Dry FGD	1	0.12		60	49	11	27	21	6
	2			60	50	10	27	21	6
Dry FGD	1	0.10		60	48	12	27	21	6
	2			60	49	11	27	21	6
Dry FGD	1	0.08*		n/a					
	2			n/a					
Dry FGD	1	0.07		60	48	12	27	20	7
	2			60	48	12	27	21	6
Combo	1 2	0.12		60	4	56	27	1	26

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Comanche BART Modeling Summary" for more details.

Table 7: Visibility Results – SO_2 Emission Rates

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Output (@ 98th Percentile Impact)*	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum
			(dv)	(Δ dv)	(%)
Max 24-hour	1 2	0.75 0.74	2.05	---	---
Dry FGD	1	0.12	1.71	0.35	17%
	2		1.72	0.33	16%
Dry FGD	1	0.10	1.69	0.36	17%
	2		1.71	0.35	17%
Dry FGD	1	0.08*	1.68	0.37	18%

	2		1.69	0.36	18%
Dry FGD	1	0.07	1.67	0.38	18%
	2		1.69	0.37	18%
Combo	1 2	0.12	0.36	1.69	82%

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Comanche BART Modeling Summary" for more details.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that SO_2 BART is the following existing SO_2 emission rates:

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 SO_2 limit of 0.12 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology.

B. Filterable Particulate Matter (PM_{10})

Comanche Units 1 and 2 are each equipped with fabric filter baghouses to control PM/PM_{10} emissions. In a baghouse, the particle laden flue gas passes through a series of fabric bags. The bags accumulate a filter cake that removes the particles from the flue gas, and the cleaned flue gas passes out of the fabric filter. The filter cake increases both the filtration efficiency of the cloth and its resistance to gas flow. The bags are periodically cleaned when too much filter cake builds up and increases the pressure drop across the fabric filter. A baghouse is considered the best particulate matter control device particularly for boilers burning low sulfur western coals.

As indicated previously in Table 1, estimated control efficiencies for the baghouse are over 99% for both PM PM_{10}. These control efficiencies are based on the allowable post-control emissions rate of 0.1 lb/MMBtu for PM and 0.092 lb/MMBtu for PM_{10} (assumes PM_{10} = 92% of PM). Actual performance test data shown in Table 8 indicates that PM emissions from Comanche Units 1 and 2 are well below the allowable levels. The results of performance tests conducted in 2003 indicate the following emission rates:

Table 8: Comanche Units 1 and 2 Stack Test Results (2003)

Pollutant	Unit 1 (lb/MMBtu)	Unit 2 (lb/MMBtu)
Filterable PM_{10}*	0.003	0.003
PM_{10} Control efficiency	99.6%	99.6%

*PM_{10} = 0.92 x PM

The BART construction permit (07PB0112B) issued on September 12, 2008 for Comanche Units 1 and 2 set a PM emission limitation of 0.03 lb/MMBtu, which is more stringent than the limit of 0.1 lb/MMBtu that currently applies to these units. Although test results indicate that emissions below the 0.03 lb/MMBtu BART limit are certainly achievable, the 2003 performance test is just one 3-hour test and does not necessarily represent achievable emission rates over all operating conditions. Therefore, the Division considers that the PM limit set the BART permit is still appropriate. Using the allowable post-control PM BART limit of 0.03 lb/MMBtu BART limit, the control efficiency of the baghouses are indicated in Table 8 above.

A Division review of EPA's RBLC revealed recent BACT PM/PM_{10} determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details.

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. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for PM/PM_{10} is not needed for Comanche Units 1 and 2.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies

In various submittals with respect to installing additional NO_X controls on Comanche Units 1 and 2, PSCo looked at two options:

- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)

As part of this BART evaluation, the Division identified and examined the following additional control options for these units:

- Powerspan Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Rotating Opposed Fired Air (ROFA), ROFA with SNCR
- Low NO_X Burners (LNB) with Separated Overfire Air (SOFA)
- Reburning
- Emission limit tightening

Since low NO_X burners with over-fire air (LNB-OFA) were recently installed on Units 1 and 2 (November 2008 for Unit 1 and November 2007 for Unit 2), the Division considers that further upgrades to the LNB-OFA would provide little in the way of additional reductions and therefore upgrades to the existing LNB-OFA were not considered.

Step 2: Eliminate Technically Infeasible Options

Selective non-catalytic reduction (SNCR): The SNCR process is based on a gas-phase homogeneous reaction, within a specified temperature range, between NO_X in the flue gas and either injected ammonia or urea to produce gaseous nitrogen and water vapor. SNCR systems do not employ a catalyst; the NO_X reduction reactions are driven by the thermal decomposition of ammonia and the subsequent reduction of NO_X. Consequently, the SNCR process operates at higher temperatures than the SCR process. Critical to the successful reduction of NO_X with SNCR is the temperature of the flue gas at the point where the reagent is injected. The necessary temperature range is 1,600 - 2,100°F. SNCR can typically achieve NO_X reductions on the order of 40-70%.

PSCo has indicated that SNCR is feasible for Unit 1. According to their April 6, 2009 submittal, PSCo conducted testing in the fall of 2008 on Unit 2 using a temporary SNCR system. The testing was done following the installation of LNB-OFA to determine if additional reductions could be achieved. Testing was conducted primarily at full load over a seven-day period using a single-level urea based-SNCR system. The SNCR system is sensitive to temperature and average exhaust temperature in the injection area for Unit 2 was nearly 2,200 ºF, which exceeds the optimal temperature for the technology. During the test periods, NO_X reductions were less than 10%, and in some cases during testing, an actual increase in NO_X emissions was seen. Therefore, PSCo considers that SNCR is not feasible on Unit 2 and the Division concurs.

Selective Catalytic Reduction (SCR): SCR systems are the most widely used post-combustion NO_X control technology on pulverized coal-fired boilers. The SCR process is an add-on control which uses a catalyst bed and ammonia injection for removal of NO_X emissions. In the SCR process, ammonia injected into the exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_X decomposition reaction. SCR systems can achieve NO_X reductions in the range of 60 – 90%. SCR is technically feasible for Comanche Units 1 and 2.

Powerspan Electro-Catalytic Oxidation (ECO)®: The Powerspan electrostatic oxidation process (ECO)® is an integrated air pollution control process that achieve reductions in multiple pollutants from coal-fired power plants, included NO_X, SO_2, mercury and fine particulate matter (particulate matter less than 2.5 microns). The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse and consists of an ECO reactor (to oxidize pollutants), absorber vessel (saturates and cools the flue gas, removes SO_2, NO_2 and oxidized mercury) and a wet electrostatic precipitator (removes acid aerosols, air toxics and fine particulate matter). To date the ECO® system has been used on a slipstream (50 MW) from a 156 MW boiler equipped with an electrostatic precipitator and low NO_X burners[6]. While the technology may be considered commercially available, it has only been demonstrated on the portion of the exhaust of a smaller boiler. Therefore, the Division considers that this technology is not feasible.

Rich Reagent Injection (RRI): Rich reagent injection is the process of adding NO_X reducing agents in a staged lower furnace to reduce the formation of NO_X, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_X reductions. The combustion process is then completed with the use of overfire air. RRI is similar to SNCR but the reagent at the lower furnace at significantly higher temperatures (2400 – 3100ºF).[7] The RRI process was originally developed for coal-fired cyclone boilers and the Division is not aware that RRI has been utilized on other types of coal-fired boilers. Therefore, the Division considers that RRI is technically infeasible for Comanche Units 1 and 2.

Rotating Opposed Fire Air (ROFA) and ROFA with SNCR: With ROFA air in injected into the furnace first which breaks up the fireball and creates a swirling air flow to increase combustion. The swirling air results in better mixing of the fuel and air and distributes the temperature more evenly throughout the furnace, which improves combustion and reduces NO_X emissions. Typical NO_X reductions from ROFA alone range from 45 – 60 percent.[8] As indicated in Table 3, the estimated NO_X reductions for Units 1 and 2 with LNB-OFA are over 55% percent. Since ROFA is not expected to provide more NO_X reductions than the current controls on Units 1 and 2, further review of ROFA is not warranted.

That same ROFA system can be used to inject urea or ammonia into the furnace. However, since the NO_X reduction efficiency for the Comanche Unit 1 and 2 LNB-OFA systems are comparable to ROFA, combining ROFA and SNCR is not likely to result in NO_X reductions significantly above the level achieved by the Unit 1 existing LNB-OFA in conjunction with SNCR (note that SNCR is not feasible on Unit 2). Therefore, ROFA-SNCR will not be considered further.

Low NO_X Burners (LNB) with Separated Over Fire Air (SOFA): Over-fire air (OFA) is a combustion control technology where a portion of the total combustion air is diverted from the burners and injected later in the combustion process, typically above the combustion zone. There are specific OFA configurations that are typically associated with tangentially-fired boilers, close-coupled to the burner, separated from the burner and combination. The high end of the NO_X reduction ranges for the various OFA configurations for tangentially fired boilers are lower than the range for LNB-OFA on wall-fired units.[9] Since alternate OFA configurations will not result in significant NO_X reductions beyond LNB-OFA, they will not be considered further.

[6] http://www.powerspan.com/FirstEnergy_ECO.aspx
[7] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php
[8] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html
[9] Srivastava et. al, September 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association, volume 55, pg 1370.

Reburning: In reburning, a portion of the total heat input (up to 25%) is provided by injecting a secondary (reburning) fuel above the main combustion zone. Combustion of the reburning fuel results in hydrocarbon fragments, which react with a portion of incoming NO_X which form nitrogen containing compounds which are ultimately reduced to N_2. The fuel used for reburning need not be the primary fuel. Natural gas has frequently been used as reburning fuel, as there are more issues to consider with coal as the reburn fuel (e.g. particle size). In general reburning can achieve greater than 50% NO_X reduction, but many reburning demonstration projects are no longer operating.[10] Reburning can be used in conjunction with other NO_X control technologies, such as LNB-OFA, SCR and SNCR. Given that the control efficiency with reburning alone is similar to the NO_X reduction efficiency of Comanche Units 1and 2 with LNB-OFA (see Table 4), the Division considers that further evaluation of reburning is not warranted.

Emission limit tightening: The Division conducted technical analyses to determine whether the current NO_x emission limit(s) could be more stringent based on actual emissions after installation of the low NO_x burners with over-fire air (Unit 1 – December 2008 – Oct. 2010 and Unit 2 - December 2007 – October 2010). This option is technically feasible for both units.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

PSCo provided the Division 30-day rolling average control estimates. The Division, from experience and other state BART proposals[11], determined that 30-day NO_x rolling average emission rates are expected to be about 5 -15% higher than the annual average emission rate. To be conservative, the Division projected an annual average emission rate at 15% for Comanche to determine control efficiencies and annual reductions.

The Division considered that two additional NO_X reduction options warranted further consideration. Although some of the identified control technologies were not considered technically infeasible, they offered similar NO_X reduction levels that are already achieved with the LNB-OFA installed on Comanche Units 1 and 2. The two additional NO_X reduction technologies warranting further review are SCR and SNCR (Unit 1 only). \

SNCR: In their April 20, 2010 submittal, PSCo indicated that a NO_X emission rate of 0.10 lb/MMBtu was achievable on Unit 1. The Division calculated the control effectiveness based on the difference between the baseline (2009) and expected emission rate. This calculated control effectiveness for Comanche Unit 1 is 29.5%. This control effectiveness estimate is roughly equivalent to EPA's SNCR Air Pollution Control Technology Fact Sheet between 30 – 50% control efficiency for tangentially fired boilers.

SCR: In their April 20, 2010 submittal, PSCo indicated that a NO_X emission rate of 0.07 lb/MMBtu was achievable on both Units 1 and 2. Again, the Division calculated the control effectiveness based on the difference between the baseline (2009) and expected

[10] Srivastava et. al, pp 1371-1372.
[11] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

emission rate. This calculated control effectiveness for Comanche Unit 1 is 51% and for Comanche Unit 2 is 63%. These control efficiencies are lower than EPA's AP-42 emission factor tables, which estimate SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.[12,13] However, the resultant emission rate of 0.07 lb/MMBtu is consistent with the rates cited in the AWMA study. PSCo and the Division recognize and concur that the lower initial emission rates of 0.124 and 0.165 lb/MMBtu for Units 1 and 2 respectively result in reduced SCR control efficiencies.

Emission limit tightening: Since emission limit tightening is based on actual data, there will be minimal, if any, reductions from current NO_x emissions. The Division found that the maximum 30-day rolling emission rate for Unit 1 from December 2008 – October 2010 was about 0.15 lb/MMBtu and the average 30-day rolling rate was around 0.13 lb/MMBtu. For Unit 2, from December 2007 to October 2010, the maximum 30-day rolling emission rate was about 0.17 lb/MMBtu and the average 30-day rolling rate was around 0.17 lb/MMBtu. As explained above, the Division projects 30-day rolling NO_x emission rates to be approximately 15% higher than annual average emission rates. The uncertainty of evaluating a "maximum" emission rate warrants a similar 15% buffer to be applied in this case, especially due to the facts stated above, including uncertainty regarding load operations, cold-weather operating, start-up, and cycling for renewable energy.

The Division also found that for 2009, the annual average emission rate for both units was approximately 0.15 lb/MMBtu, and a review of January – October 2010 found that annual average emission rate thus far is about 0.16 lb/MMBtu. The existing annual limit of 0.15 lb/MMBtu for both units is an appropriate NO_x emission limit at this time. Therefore, appropriate NO_x emission limits assuming existing low NO_x burner with over-fire air technology for Units 1 and 2 are 0.20 lb/MMBtu on a 30-day rolling average for each unit and 0.15 lb/MMBtu annual average for both units. A re-evaluation of these emission limits will occur for the next regional haze planning period.
Table 9 summarizes each available technology and technical feasibility for NO_x control.

Table 9: Comanche Units 1 and 2 NOx Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
SNCR	20 – 50%	Y
SCR	50 – 90%	Y
Electro-Catalytic Oxidation (ECO)®	n/a	N
Rich Reagent Injection (RRI)	n/a	N
Low NO_x Burners (LNB)	10-30%	Y – installed
LNB + OFA	25-45%	Y – installed

[12] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[13] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Air Staging – overfire air (OFA)	5-40%	Y – installed
Rotating overfire air (ROFA)	45 – 65%	N
Coal reburn+SNCR	n/a	N

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

SNCR and SCR: In their January 19, 2010 submittal, PSCo provided cost information associated with SNCR for Unit 1 and SCR for both Units 1 and 2. PSCo used EPA's Coal Utility Environmental Costs (CUECost) workbook model to estimate capital and ongoing operating and maintenance costs. The costs were then levelized at 2016/2017 dollars based on a 20-yr life to determine annual costs. The levelized costs were reported in 2016/2017 dollars on the assumption that SNCR would be installed by 2015 and SCR would be installed by 2016, with an additional year to optimize operation of the new control equipment. PSCo submitted the inputs and outputs from CUECost to the Division in a March 1, 2010 e-mail to the Division. The levelized cost methodology and results were provided in Xcel internal memos dated February, 24, 2010 (submitted to the Division via e-mail on March 1, 2010) and April 16, 2010 (submitted via e-mail to the Division on April 21, 2010). According to PSCo's April 20, 2010 submittal, the cost per ton for SNCR for Unit 1 was estimated to be $ 4,342/ton and the cost per ton for SCR was estimated to be $15,173/ton for Unit 1 and $9,558/ton for Unit 2.

Although the Division does not dispute the levelized annual costs for SNCR and SCR, the baseline emission rates used to determine the cost per ton for the incremental reduction are not appropriate. For Unit 1, PSCo presumed baseline emission rates of 0.12 lb/MMBtu for SNCR and 0.13 lb/MMBtu for SCR and for Unit 2 PSCo presumed a baseline emission rate of 0.18 lb/MMBtu. The Division has set a baseline period of 2009. The baseline emission rates are shown in Table 1.

SNCR: A typical breakdown of annualized costs for SNCR on industrial boilerswill be 15 – 25% for capital recovery and 65 – 85% for operating expenses.[14] The PSCo-estimated SNCR costs for operating expenses is about 69% for Comanche Unit 1. Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[15]

[14] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.
[15] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

The Division-calculated cost effectiveness for SNCR on Unit 1 is $3,644 per ton. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers (similar to Unit 1) achieving NO_x emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[16,17] It should be noted that PSCo is estimating resultant emission rates much lower than 0.30 lb/MMBtu for this boiler. EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NO_x reduced.[18] PSCo's estimates are above this range. However, the Division concludes that PSCo's cost estimates for SNCR are reasonable due to the low input NO_x emission rate and degree of retrofit difficulty.

SCR: Recent NESCAUM studies estimate SCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.10 – 0.15 lb/MMBtu and emission reductions of 75 – 85% as costing $2,600 - $5,000 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[19,20] In reviewing PSCo's estimates, the Division found that the ratio of annual costs to the total costs for LNBs, which at 15.3% is just slightly higher than an EPA assessment that concluded that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments.[21] PSCo's cost estimates are above the NESCAUM study ranges due to the lower control efficiencies explained earlier. The Division concludes that PSCo's cost estimates for SCR are reasonable due to low emission reductions and retrofit difficulties.

Table 10, Table 11, Table 12, and Table 13 depict controlled NO_x emissions and control cost comparisons. Refer to "Comanche APCD Technical Analysis" for more details.

Table 10: Comanche Unit 1 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,511	0.124	

[16] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[17] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.
[18] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
[19] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[20] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.
[21] Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.

SNCR*	29.5	1,065	0.087	0.100
SCR**	51	740	0.061	0.070

*Determined based on difference between baseline (2009) and PSCo's expected emission rates
**The Division calculated SCR reductions using a consistent baseline whereas PSCo uses an adjusted baseline depending on the control technology which results in different control costs.

Table 11: Comanche Unit 2 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	2,349	0.165	
SCR**	63	869	0.061	0.070

**The Division calculated SCR reductions using a consistent baseline whereas PSCo uses an adjusted baseline depending on the control technology which results in different control costs.

Table 12: Comanche Unit 1 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
SNCR	445.6	$1,624,100	$3,644	---
SCR	770.4	$12,265,014	$15,920	$32,762

Table 13: Comanche Unit 2NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
SCR	1,480	$14,650,885	$9,900	---

Energy and Non-Air Quality Impacts

SNCR and SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR reagent injection systems have minimal power requirements.

Post-combustion add-on control technologies like SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. 100 – 300 kW is enough energy to power about 10 homes for a year. These energy requirements are minimal and were confirmed by PSCo in the January 19, 2010 submittal.

SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer. PSCo noted that the retrofit installation of an SCR typically requires the installation of new, larger induced draft fans to over-come the additional pressure drop created by the SCR catalyst. In addition, although PSCo acknowledged that the energy requirements for SCR are more significant than SNCR they did not quantify these impacts since the increase in house power usage are included in the ongoing operating costs for each technology in the CUECost model.

Installing SNCR or SCR increases levels of ammonia, and may create a ‘blue plume’, if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas.

PSCo did identify the change in operating mode for the coal fired boilers as more wind energy is brought onto the PSCo system as a non-air quality impact that would affect any NO_X control technology. PSCo noted that typically coal-fired boilers are operated as base-loaded units and as such they typically run at full load 24-hours a day, with only minor load reductions at night when demand is lower or during off-peak periods in the spring and fall. However, with more wind resources replacing other conventional power sources, the load may be dropped further since demand for power is less. Therefore, the load on coal-fired units may be further reduced, particularly during peak wind generating periods. PSCo considers that operating these units at lower loads may affect the NO_X control technologies and result in lower NO_X reductions than those that would be seen at high loads.

Emission Limit Tightening: There are no known non-air quality or energy impacts associated with emission limit tightening. Thus, this factor does not influence the selection of this option.

Remaining Useful Life

In their January 19, 2010 submittal PSCo indicated that the remaining useful life of Comanche Units 1 and 2 are each in excess of 20 years, which is the maximum amortization period allowed in the BART analysis. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 14 shows the number of days pre- and post-control. Table 15 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[22], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a NO_x BART control technology on a given unit, emission rates for the other pollutants (SO_2 and PM/PM_{10}) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed Units 1 and 2 with NO_x emissions at 0.07 lb/MMBtu and SO_2 emissions at 0.12 lb/MMBtu.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 14: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hour	1 2	0.40 0.53	Great Sand Dunes National	60	---	---	27	---	---
NOx @	1	0.20		60	57	3	27	24	3

[22] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

0.20 lb/MMBtu			Park						
NOx @ 0.20 lb/MMBtu	2	0.20		60	51	9	27	21	6
SNCR @ 0.10 lb/MMBtu	1	0.10		60	51	9	27	22	5
SNCR not feasible	2	n/a		60	n/a	n/a	27	n/a	n/a
SCR @ 0.07 lb/MMBtu	1	0.07		60	51	9	27	21	6
SCR @ 0.07 lb/MMBtu	2	0.07		60	47	13	27	18	9
Combo	1 2	0.07		60	4	56	27	1	26

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Comanche BART Modeling Summary" for more details.

Table 15: Visibility Results – NO_x Control Options

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)*	Output (@ 98th Percentile Impact)	98th Percentile Impact Improvement	98th Percentile Impact Improvement from new LNB (2009)	98th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(Δ dv)	(%)	($/dv)
Max 24-hour	1 2	0.40 0.53	2.05	---	---	---	---
New LNB (2009)	1	0.20	1.90	0.16	n/a	8%	n/a
	2	0.20	1.75	0.31	n/a	15%	n/a
SNCR	1	0.10	1.79	0.26	0.11	13%	$6,175,284
SNCR not feasible	2	n/a					
SCR	1	0.07	1.76	0.30	0.14	14%	$41,576,317
	2	0.07	1.58	0.47	0.17	23%	$31,172,095
Combo	1 2	0.07	0.36	1.69	n/a	82%	n/a

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Comanche BART Modeling Summary" for more details.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein , the state has determined that NO_x BART is following existing NO_x 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 NO_x burners. Although the other alternatives achieve better emissions reductions, the added expense of achieving lower limits through different controls were determined based on the high cost/effectiveness ratios to not be reasonable coupled with the low visibility improvement (under 0.2 delta deciview) afforded.

Best Available Retrofit Technology (BART) Analysis of Control Options For Tri-State Generation & Transmission Association, Inc. – Craig Station Units 1 & 2

I. Source Description

Owner/Operator: Tri-State Generation & Transmission Association, Inc.
Source Type: Electric Utility Steam Generating Unit
SCC (EGU): 10100222
Boiler Type: Dry-Bottom Pulverized Coal-Fired Boilers, two opposed-wall-fired (Units 1 and 2)

The Tri-State Generation & Transmission Association, Inc. (Tri-State) Craig Station is located in Moffat County approximately 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.

Units 1 & 2: Construction of Units 1 and 2 began in 1974; Unit 1 began operation in 1980 and Unit 2 began operation in 1979. These units are equipped with fabric filter (baghouse) systems for controlling particulate matter (PM) emissions, and wet limestone Fuel Gas Desulfurization (FGD) systems for the control of sulfur dioxide (SO_2) emissions. The boilers are equipped with ultra-low nitrogen oxide (NO_x) dual register burners with overfired air for minimization of NO_x emissions. The FGD and ultra low NO_x burner systems were required to be installed and fully operational by December 31, 2004 as a result of a consent decree with the Sierra Club (signed January 10, 2001).

Unit 3: Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. This unit is equipped with a baghouse system for controlling PM emissions, a dry lime system for control of SO_2 and low-NO_x burners with overfired air.

All three units can use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. All three units are subject to the requirements of Title IV, the Acid Rain Program, and were approved for Early Election for NO_x limits, effective January 1, 1997. Associated activities include two cooling towers, coal handling systems, ash handling systems, limestone handling system, and the staging/landfilling area. Unit 3 is not subject to BART.

Table 1 lists the units at Tri-State Craig Station that the Division examined for control to meet BART-eligible requirements. Controlled and uncontrolled emission factors and CAMD data were used to evaluate the control effectiveness of the current emission controls.

Table 1: Craig Boilers Technical Information

	Unit 1	Unit 2
Placed in Service	1980	1979
Gross Boiler Rating, MMBtu/Hr for coal	4,417	4,417
Electrical Power Rating, Net Megawatts	428	428
Description	Babcock & Wilcox Pulverized Coal Opposed-Wall Dry Bottom, firing coal with natural gas, propane or No. 2 fuel oil used for startup, shutdown and/or flame stabilization.	Babcock & Wilcox Pulverized Coal Opposed-Wall Dry Bottom, firing coal with natural gas, propane or No. 2 fuel oil used for startup, shutdown and/or flame stabilization.
Air Pollution Control Equipment	PM/PM_{10} – Pulse Jet Fabric Filter Baghouse NO_x – Ultra-low NO_x Burners with Over-Fire Air SO_2 – Wet Limestone FGD All updated control equipment commenced full operations in 2004.	PM/PM_{10} – Pulse Jet Fabric Filter Baghouse NO_x – Ultra-low NO_x Burners with Over-Fire Air SO_2 – Wet Limestone FGD All updated control equipment commenced full operations in 2004.
Emissions Reduction (%)*	NO_x – 23.8% /53.9% SO_2 – 77.6%/93.8% PM – 99.6% PM_{10} – 99.4%	NO_x – 29.5%/54.7% SO_2 – 79.5%/93.8% PM – 99.9% PM_{10} – 99.5%

*Emissions Reduction estimated by comparing pre-control 2001 – 2002 CAMD data to controlled 2006 – 2008 data. The first NO_x number compares the additional reduction achieved by the ultra-low NO_x burners vs. the original low-NO_x burners and the second NO_x number compares uncontrolled AP-42 factor to actual average emission factor (2006 – 2008). For PM/PM_{10}., uncontrolled AP-42 factor were compared to actual average emission factors (2006 – 2008). See “Craig APCD Technical Analysis” for further details. Not based on actual testing.

Only 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 in existence 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, July 30, 2010, November 23, 2010, and December 8, 2010. The submittals are included as “Tri-State BART Submittals”.

II. Source Emissions

Tri-State estimated that a realistic depiction of anticipated annual emissions for Units 1 and 2, or “Baseline” Emissions”, to be conservative, was the average of two previous (2004, 2005) of emissions data in the July 31, 2006 analysis. Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses.

Therefore, the Division used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database. These emissions are summarized in Table 2.

Table 2: Tri-State Craig Units 1 and 2 Baseline Emissions

Pollutant	Unit 1		Unit 2	
	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)
NO_x	5,190	0.278	5,372	0.271
SO_2	970	0.052	982	0.050
PM_{10}	80	0.006***	40	0.005***

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).
**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for NO_x and SO_2 emissions.
***The PM_{10} emission factor is determined from the most recent Title V permit compliance stack tests (January 2004).

III. Units Evaluated for Control

Tri-State notes that the Craig boilers burn Colorado coal that primarily comes from the Trapper mine, supplemented by ColoWyo coal, which are both high-ranking sub-bituminous coal. Limited amounts of coal from the Twentymile mine, ranked as bituminous, are also burned. All of these mines are located in northwestern Colorado. . Future nearby coal supplies could come from sources such as Trapper, ColoWyo, or Twentymile. Accordingly, the trend of future coal supplies is such that in the context of NO_x-forming characteristics, Craig 1&2 will continue to burn "bituminous-like" coal, plus, it is likely that additional quantities of bituminous coals will be burned at Craig 1&2 in the future. Similar to PSCo, Tri-State notes that these coals are ranked as sub-bituminous, but are closer in characteristics to bituminous coal in many of the parameters influencing NO_x formation. The specifications for these coals are listed below in Table 3. Note that with the exception of moisture content, the coal characteristics are reasonably close for the two coals.

Table 3: Craig Station Coal Specifications (2008)

Coal Mine/Region	ColoWyo	Trapper	Twentymile
Coal Rank Classification	Sub-bituminous, Class A	Sub-bituminous, Class A	Bituminous
H_2O (Moisture %)	17.42	16.7	9.62
Ash (%)	5.71	6.5	11.93
Sulfur (%)	0.37	0.44	0.52
Nitrogen (%)	1.35	~1.5	1.57
Heating Value (HHV Btu/lb)	10,392	9,800	11,084

Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal as well as the highest ash and sulfur content from the two coals for conservative estimates.

Table 4: Uncontrolled emission factors for Craig BART-eligible sources[1]

	Pollutant (lb/ton)*			
Emission Unit	NO_x	SO_2	PM (filterable)	PM_{10} (filterable)
Unit 1	12	16.9	73.9	17.0
Unit 2	12	16.1	71.1	16.4

*SO_2 and PM/PM_{10} factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, averaged from APEN data (2006 – 2008). Please refer to "Craig APCD Technical Analysis" for more details.

IV. BART Evaluation of Units 1 and 2

A. Sulfur Dioxide (SO_2)

Step 1: Identify All Available Technologies

Wet FGD Upgrades – As discussed in EPA's BART Guidelines[2], electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls. The Division interprets this to include fuel switching to natural gas, which would require significant boiler modifications, including removing the wet FGD.

However, based on Appendix Y [70 FR 39171], the following dry scrubber upgrades should be considered for Craig Units 1 and 2 if technically feasible. These upgrades include:
-Elimination of bypass reheat
-Installation of liquid distribution rings
-Installation of perforated trays
-Use of organic acid additives
-Improve or upgrade scrubber auxiliary equipment
-Redesign spray header or nozzle configuration

The current Operating Permit limits are depicted in Table 5.

Table 5: Craig Units 1 & 2 SO_2 Operating Permit Limits

	SO_2 limits (lb/MMBtu)			Reduction (%) Required
	3-hr rolling	30-day rolling	90-day rolling	90-day rolling
Units 1 & 2	1.2	0.160	0.130	90

The current Operating Permit also requires that 100% of the flue gas in the FGD be treated (Conditions 1.3.3 and 2.3.3) and that the Craig Unit 1 and 2 FGDs be designed to meet at least a 97.3% removal rate (Conditions 1.3.4 and 2.3.4).

[1] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[2] EPA, 2005. Federal Register, 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations: Final Rule. Pgs. 39133.

Step 2: Eliminate Technically Infeasible Options

FGD: Flue gas desulfurization removes SO_2 from flue gases by a variety of methods. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

Wet FGD: Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar “foot print” area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney. Colorado Ute Electric Association, which owned Craig before Tri-State, installed wet limestone FGD systems, on Craig Units 1 and 2 when the units began operations in 1980 and 1979, respectively. Tri-State upgraded these FGD systems in the 2003 – 2004 timeframe. This system exceeds EPA’s presumptive limits stated in 40 CFR Part 51 Appendix Y of 0.15 lb/MMBtu.

At the Division’s request, Tri-State submitted a SO_2 upgrade analysis to the Division on June 4, 2010 regarding potential upgrades for the wet FGD systems at Craig Station Units 1 and 2.

Tri-State examined potential upgrades to the Craig wet FGD systems, with the following results:

-*Elimination of bypass reheat*: The FGD system bypass was redesigned to eliminate bypass of the FGD system except for boiler safety situations. After the Yampa Environmental Project (YEP) Upgrades (2003 – 2004), 100 percent of the flue gas now passes through the scrubber with no reheat and no bypassing.

-*Installation of liquid distribution rings:* Liquid distribution rings were not installed during the YEP; however, Tri-State determined that installation of perforated trays, described below, accomplished the same objective.

-*Installation of perforated trays:* Upgrades during the YEP included installation of a perforated plate tray in each scrubber module. The trays improve the absorption of SO_2 by increasing the contact between the flue gas and the limestone slurry. The trays also function like Slurry Distribution Rings by redirecting slurry from running down the absorber wall back to the flue gas flow stream.

-*Use of organic acid additives:* Organic acid additives such as Dibasic Acid (DBA) can be used to improve SO_2 removal efficiency by increasing scrubbing liquor alkalinity. This option was considered for Craig Units 1 and 2 during YEP; however, it was not selected for the following reasons:

1. 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:* YEP 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 YEP. The modified slurry spray distribution system improved slurry spray characteristics and was designed to minimize pluggage in the piping.

Therefore, Tri-State and the Division concur that there are not any technically feasible upgrade options for Craig Station Units 1 and 2. However, the Division has evaluated the option of tightening the SO_2 emission limit for Craig Units 1 and 2.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The control effectiveness of tightening the 30-day rolling emission limits on Craig Units 1 and 2 have been evaluated by the Division. The Division analyzed the baseline period (2006 – 2008) to determine the maximum and average 30-day rolling emission rates, shown in Table 6, to determine potential control effectiveness, if any. This information allows the Division to set a more relevant emission limit for Craig Units 1 and 2 using representative actual emissions.

Table 6: Craig Units 1 & 2 30-day rolling emission rates (baseline 2006 - 2008)

Unit	Maximum 30-day rolling emission rate (lb/MMBtu)	Average 30-day rolling emission rate (lb/MMBtu)
Craig Unit 1	0.081	0.052
Craig Unit 2	0.093	0.079

Step 4: Evaluate Impacts and Document Results

Since there are not any remaining control technologies available for Craig Station Units 1 and 2, there are not any impacts to evaluate or results to document.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with emission limit tightening. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 7 shows the number of days pre- and post-control. Table 8 depicts the visibility results (98th percentile impact and improvements). Cost effectiveness in \$/deciview was not determined since there will minimal, if any, costs associated with emission limit tightening.

Per the April 2010 modeling protocol[3], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO_2 BART control technology on a given unit, emission rates for the other pollutants (NO_x and PM/PM_{10}) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with NO_x emissions at 0.07 lb/MMBtu (SCR control) and SO_2 emissions at 0.10 lb/MMBtu (wet FGD).

[3] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 7: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hour	1	0.166	Mt. Zirkel Wilderness	207	---	---	123	---	---
	2	0.161							
Wet FGD	1	0.150		207	206	1	123	123	0
	2	0.150		207	207	0	123	123	0
Wet FGD	1	0.120		207	204	3	123	123	0
	2	0.120		207	204	3	123	123	0
Wet FGD	1	0.110*		n/a					
	2	0.110*		n/a					
Wet FGD	1	0.100		207	203	4	123	123	0
	2	0.100		207	203	4	123	123	0
Wet FGD	1	0.070		207	202	5	123	122	1
	2	0.070		207	203	4	123	122	1
Combo	1	0.100		207	57	150	123	12	111
	2	0.100							

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Craig BART Modeling Summary" for more details.

Table 8: Visibility Results – SO_2 Control Options

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Output (@ 98th Percentile Impact)*	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum
			(dv)	(Δ dv)	(%)
Max 24-hour	1	0.166	3.73	---	---
	2	0.161			
Wet FGD	1	0.150	3.72	0.01	0%
	2	0.150	3.72	0.01	0%
Wet FGD	1	0.120	3.70	0.02	1%
	2	0.120	3.71	0.02	1%
Wet FGD	1	0.110*	3.70	0.03	1%
	2	0.110*	3.70	0.03	1%
Wet FGD	1	0.100	3.69	0.03	1%
	2	0.100	3.70	0.03	1%
Wet FGD	1	0.070	3.68	0.05	1%
	2	0.070	3.68	0.05	1%
Combo	1	0.070	1.17	2.56	69%
	2	0.070			

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Craig BART Modeling Summary" for more details.

Step 6: Select BART Control

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 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. The tighter emission limits are achievable without additional capital investment. An SO_2 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.

B. Filterable Particulate Matter (PM_{10})

Craig Units 1 and 2 are each equipped with pulse jet fabric filter (PJFF) baghouses to control PM/PM_{10} emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Table 9 shows the most recent stack test data (2004). Real-time data demonstrates that these baghouses are meeting >95% control. The Title V permit limit is 0.03 lb/MMBtu (Condition 1.1.3). The most recent stack test data is used to determine compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

Table 9: Craig Units 1 and 2 Stack Test Results (2004)

Pollutant	Unit 1 (lb/MMBtu)	Unit 2 (lb/MMBtu)
Filterable PM_{10}	0.006	0.005
PM_{10} Control efficiency	99.23%	99.35%

A Division review of EPA's RBLC revealed recent BACT PM/PM_{10} determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations. Both boilers must meet the PM emission standard of 0.03 lb/MMBtu in accordance with the Long-Term Strategy Review and Revision of Colorado's SIP for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements (4/19/01), as approved by EPA at 66 FR 35374 (07/05/01).

The Division has determined that the existing Unit 1 and 2 pulse jet fabric filter baghouses and the 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}.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies
Tri-State identified five options for NO_x control:
New/modified Low NO_x Burners (LNBs) with Overfired Air (OFA) system (next generation)
Advanced OFA system or Rotating overfired Air (ROFA)
Neural network system combustion controls
Selective Non-Catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)

The Division also identified and examined the following additional control options for these units:

Electro-Catalytic Oxidation (ECO)®
Rich Reagent Injection (RRI)
Coal reburn +SNCR

Craig Units 1 and 2 currently have ultra-low NO_x burners with over-fire air (ULNBs+OFA) installed (2004) for NO_x control purposes.

Step 2: Eliminate Technically Infeasible Options

LNBs with OFA Upgrades: Tri-State contracted with ACT to modify the existing Craig 1&2 burners and upgrade the OFA system. ACT determined that burners and OFA system could be upgraded. However, ACT has not modified ultra low-NO_x Babcock & Wilcox 4Z burners such as those in use at Craig Units 1 and 2. In addition ACT stated that a complete plant inspection, data review, baseline testing, and computational fluid dynamics (CFD) modeling would be required for them to guarantee performance predictions. An amended proposal was submitted by ACT upon receipt of updated coal analyses that more closely represent the quality of coal being burned at Craig 1&2. In their amended proposal, ACT again reiterated that "to give a guaranteed NO_x reduction, a lot more information is required." LNBs modifications with OFA upgrades appear to be technically feasible for Craig Units 1 and 2.

Advanced OFA system – rotating overfired air system (ROFA): ROFA® injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA® differs from OFA in that ROFA® utilizes a booster fan to increase the velocity of air to promote mixing and to increase the retention time in the furnace. To date, ROFA® has only been installed as a retrofit technology on units firing eastern bituminous coals.

Tri-State contacted Motobec, the manufacturer of ROFA® technology, to determine if ROFA is feasible for Craig Units 1 and 2. Mobotec could not give Tri-State a definitive guarantee for reductions due to the variability in the quality of coals.

Based on data published by the manufacturer, ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load[4]. While ROFA is considered superior to OFA/SOFA alone, ROFA alone is not superior to LNB+OFA and is not expected to increase emissions reductions for Craig Units 1 and 2. The Division asserts that ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for these units, ROFA® technology is not considered further in this analysis.

Neural network system combustion controls: Tri-State received a neural network proposal from NeuCo in April 2006. The proposal offers to enhance the existing Craig 1&2 control system by providing combustion optimization technology. For a given set of objectives, a neural network directs the unit's distributive control system (DCS) or other control systems to optimize the boiler performance.

Based on review of the Craig 1&2 current operations, NeuCo stated that Craig 1&2 appear to be good candidates for the optimization system. Key aspects to neural network success are the training support provided by the supplier, as well as achieving buy-in from plant operators. Tri-State states that it is important to note that the condition of the unit(s) and the manner in which the unit(s) is operated prior to the installation of the combustion optimization system also play an important role in determining potential NO_x reductions. Neural network system combustion controls appear to be technically feasible for Craig Units 1 and 2.

[4] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. This 20-40% range includes units operating with LNB/combustion modifications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for Craig Units 1 and 2. Tri-State conducted a site-specific SNCR study in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

While a lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for Craig, two retrofit SCR systems, the 0.07 lb/MMBtu controlled NO_x value is more expected, although Tri-State asserts that the units cannot achieve below 0.08 lb/MMBtu. See "Tri-State BART Submittals" for more details. The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. SCR is a technically feasible alternative for Craig Units 1 and 2.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[5] and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfired air. Rich reagent injection was developed for cyclone boilers[6] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 1 and 2.

[5] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[6] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php

LNB/SOFA/LNB+SOFA: Craig Units 1 and 2 are already equipped with ultra-low NO_x burners with over-fire air (ULNB+OFA) as part of a consent decree. Requirements for these control systems were adopted into revisions to Colorado's Visibility SIP, specified in a document entitled "Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements," dated April 19, 2001. Table 1 illustrates that these systems achieve 39.7% and 41.1% NO_x reductions (based on actual emissions) on Units 1 and 2, respectively.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu[7]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Tri-State provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[8] 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Craig Units 1 and 2 to determine control efficiencies and annual reductions.

LNBs with OFA Upgrades: Tri-State noted in the original BART submittal (July 31, 2006) that ACT proposed that a modified LNB with upgraded OFA system could achieve 10 – 15% NO_x reduction above current levels. Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. These control refinements consist mostly of more precise control of fuel and air for combustion. This study conducted by Black & Veatch (B&V) notes that these refinements could achieve approximately 0- 2 % control. B&V explains that the reduction in control efficiency is due to the difference between "design criteria" versus permit limit. The Division notes that the Craig units already have ultra-low NO_x burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinements from December 8, 2010.

Neural network system combustion controls: Tri-State noted in the original BART submittal (July 31, 2006) that NeuCo provided a neural network proposal projecting that an optimization system could achieve 5 – 15% NO_x reductions. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. This study, conducted by Black & Veatch (B&V), notes that the NN equipment will be minimal, consisting of a few computer servers that will interface with existing systems in the same location(s). NN system combustion controls could achieve approximately 0 – 5% control.

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[7] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf

[8] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

B&V explains that the reduction in control efficiency is due to the difference between "design criteria" versus permit limit. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study control efficiency for NN system controls submitted on December 8, 2010.

SNCR: Tri-State stated in the May 14, 2010 submittal that based on the boiler configuration, Tri-State could expect a continuous NO_x reduction performance with SNCR technology in the range of 10 – 15%. This is based on Tri-State's extensive research into the application of SNCR technology at Craig Station. The vast majority of the research was focused on system performance and impacts on plant performance. Tri-State staff conducted a visit to First Energy's Eastlake and W.H. Sammis power plants in Ohio; this visit was specifically design to evaluate boiler designs due to the similarity in boiler/burner configurations similar to the Craig Station boilers. These estimates are lower than EPA's SNCR Air Pollution Control Technology Fact Sheet, which estimates SNCR between 30 – 50% control. Other Colorado facilities estimated SNCR as achieving between 17 – 40% NO_x control. Tri-State conducted a site-specific SNCR study in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010. The results of this study varied significantly depending on what coal type was utilized and were applicable for Craig Unit 1. Control effectiveness has been historically noted to be lower for wall fired boilers similar to the Craig boilers; therefore the Divisions considers approximately 15% to be a reasonable control effectiveness for SNCR.

SCR: Tri-State stated in the May 14, 2010 submittal the expected emission rates for Craig Units 1 and 2 when applying SCR are 0.08 lb/MMBtu. Tri-State did not specify if this estimate was a 30-day rolling averages, although, as stated in the December 31, 2009 submittal, the baselines are averages of 30-day averages. The Division notes that several other Colorado facilities have noted SCR expectations of 0.070 lb/MMBtu[9]or even lower. Additionally, a recent AWMA study found similar-sized EGUs achieve NO_x reduction efficiencies greater than 85% with emission rates between 0.04 and 0.07 lb/MMBtu (during the ozone season).[10] EPA's AP-42 emission factor tables estimate SCR as achieving 75 – 85% NO_x emission reductions. However, an appropriate margin of error must be applied when evaluating SCR. The design goal emission rate may be lower than the permitted limit to ensure that unnecessary non-compliance periods do not become an issue. Table 10 depicts a comparison of SCR control efficiencies. The Division adjusted Tri-State's estimate to 0.07 lb/MMBtu based on the reasoning above.

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[9] Public Service Company of Colorado (April 20, 2010), Colorado Energy Nations Company (November 12, 2009), Colorado Springs Utilities (February 20, 2009), and Platte River Power Authority (January 22, 2009) all note that their individual EGUs can achieve 0.070 lb/MMBtu or even lower on a 30-day rolling average basis.
[10] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Table 10: SCR Control Efficiency Comparison

Unit	Baseline (lb/MMBtu)	Control Efficiency (%)		Resultant Emissions (lb/MMBtu)	
		Tri-State Estimate	Division Estimate	Tri-State Estimate (annual average)	Division Estimate (annual average)
Craig Unit 1	0.278	71.4	74.9	0.080	0.070
Craig Unit 2	0.271	70.5	74.0	0.080	0.070

Table 11 summarizes each available technology and technical feasibility for NO_x control.

Table 11: Craig Units 1 and 2 NOx Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO_x Burners/Ultra-low NO_x burners (LNB/ULNB)	10-30%	Y – installed
LNB + OFA	25-45%	Y – installed
Air Staging – overfired air (OFA)	5-40%	Y – installed
Ultra-Low NO_x Burner (ULNB) Upgrade/Refinements	0 – 2% (Tri-State)	Y
Neural network system	0 – 5% (Tri-State)	Y
SNCR	~15%	Y
Rotating overfired air (ROFA)	45 – 65%	N
SCR	75 – 90%	Y
Electro-Catalytic Oxidation (ECO)®	n/a	N
Rich Reagent Injection (RRI)	n/a	N
Coal reburn+SNCR	n/a	N

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

Low NO_x burner upgrades: Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. Through a literature review, the Division could not find any examples or support for upgrades on ultra-low NO_x burners with overfired air. Ultra-low NO_x burners are fairly new within the industry, so additional upgrades have not yet been researched. The first commercial application for these burners was documented in May 2000.[11] Tri-State estimates that the initial cost of combustion control refinement at about $2,200,000 with an annualized 20-year cost of $122,000. The Division notes that the Craig units already have ultra-low NO_x burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinement cost estimates from December 8, 2010.

[11] Bryk and Kleisley, 2000. "First Commercial Application of DRB-4Z™ Ultra-Low NOx Coal-Fired Burner." Presented to POWER-GEN International 2000. November 14-16, 2000. Orlando, Florida.

Neural network system: Tri-State did not provide a quantitative evaluation of the application of a neural network system to the Division. There are three other facilities in Colorado alone using neural network systems from the same provider that Tri-State contacted.[12] It is unknown why Tri-State will provide further analysis of this system. Costs for these systems are very specific to individual units, so the Division cannot estimate costs for this option. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. Tri-State estimates that the initial cost of neural network systems (per unit) at about $800,000 with an annualized 20-year cost of $280,000. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study cost estimates for NN system controls submitted on December 8, 2010.

SNCR: A typical breakdown of annualized costs for SNCR on industrial boilers will be 15 – 25% for capital recovery and 65 – 85% for operating expenses.[13] The Tri-State-estimated SNCR costs for operating expenses are 67% for Craig Units 1 and 2 (individually). Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[14]

The cost effectiveness for SNCR on Units 1 and 2 (at 15% control efficiency) is approximately $4,877 and $4,712 per ton, respectively. Recent NESCAUM studies estimate SNCR retrofits on wall fired boilers (similar to Units 1 and 2) achieving 0.50 – 0.65 lb/MMBtu and emission reductions of 30 – 50% as costing $590 - $1,100 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[15,16] It should be noted that Tri-State is estimating resultant emission rates lower than 0.30 lb/MMBtu for both boilers, therefore costs will be higher. EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NO_x reduced.[17] On a linear scale, based on the NESCAUM estimates and assuming an achieved rate of 0.23 lb/MMBtu, the costs should be approximately $2,500 per ton. Tri-State and the Division's revised estimates are above this range; the Division has inquired about the reagent and auxiliary power costs, but has not received feedback from Tri-State. The costs for these two items are higher than other Colorado facility estimates.

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[12] NeuCo White Papers and Case Studies. http://www.neuco.net/library/case-studies/default.cfm and Platte River Power Authority January 22, 2009 submittal: "Rawhide Unit 101 NOx Emission Control Cost and Technical Feasibility Information."

[13] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.

[14] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

[15] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[16] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[17] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

Additionally, similar Colorado facility cost estimates fall within the EPA SNCR Fact Sheet range. The Division accepts Tri-State's capital and operation/maintenance costs for this analysis.

SCR: Recent NESCAUM studies estimate SCR retrofits on wall fired boilers achieving NO_x emission rates of 0.15 – 0.25 lb/MMBtu and emission reductions of 75 – 85% as costing $1,700 - $3,200 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[18,19] [20,21] It should be noted that Tri-State is estimating resultant emission rates lower than 0.15 lb/MMBtu for both boilers, therefore costs will be higher. Tri-State's estimates are above this range; on a linear scale (achieving 0.07 lb/MMBtu); the costs should be approximately $7,000 per ton. The Division's revised cost estimates are close to this estimate; therefore, the Division concludes that these cost estimates are reasonable.

Table 12, Table 13, Table 14, and Table 15 depict controlled NO_x emissions and control cost comparisons.

Table 12: Craig Unit 1 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	5,190	0.278	
Combustion control refinements	2	5,087	0.273	0.31
Neural network system	5	4,931	0.264	0.30
SNCR	15	4,412	0.236	0.27
SCR	78.0	1,142	0.061	0.070

[18] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[19] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[20] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[21] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

Table 13: Craig Unit 2 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	5,372	0.271	
Combustion control refinements	2	5,264	0.265	0.31
Neural network system	5		0.257	0.30
SNCR	15	4,566	0.230	0.27
SCR	74	1,397	0.070	0.081

Table 14: Craig Unit 1 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Combustion control refinements	104	$122,000	$1,175	$1,175
Neural network system	260	$280,000	$1,079	$1,015
SNCR	779	$3,797,000	$4,877	$6,776
SCR	4,048	$25,036,709	$6,184	$6,394

Table 15: Craig Unit 2 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Combustion control refinements	107	$122,000	$1,136	$1,136
Neural network system	269	$280,000	$1,043	$980
SNCR	806	$3,797,000	$4,712	$4,712
SCR	3,975	$25,036,709	$6,298	$6,702

Energy and Non-Air Quality Impacts

LNB Upgrades/Neural network system(s): There are no known non-air quality impacts associated with upgrades on low-NO_x burner systems or neural network systems. Energy impacts are not significant. Thus, this factor does not influence the selection of this control.

SNCR/ SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas.

Post-combustion add-on control technologies such as SNCR do increase power needs to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. In particular, SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas.

Remaining Useful Life

Tri-State asserts that there are no near-term limitations on the useful of these boilers, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 16 shows the number of days pre- and post-control. Table 17 depicts the visibility results (98^{th} percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[22], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO_2 BART control technology on a given unit, emission rates for the other pollutants and other BART-eligible units are held constant at pre-control levels.

[22] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with NO_x emissions at 0.07 lb/MMBtu (SCR control) and SO_2 emissions at 0.10 lb/MMBtu (wet FGD control).

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 16: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hour	1 2	0.352 0.345	Mt. Zirkel Wilderness	207	---	---	123	---	---
SNCR	1	0.236		207	192	15	123	123	0
	2	0.230		207	194	13	123	123	0
SCR	1	0.07		207	165	42	123	123	0
	2	0.07		207	166	41	123	123	0
Combo	1 2	0.07 0.07		207	57	150	123	12	111

Table 17: Visibility Results – NO_x Control Options

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Output (@ 98th Percentile Impact)	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	($/dv)
Max 24-hour	1 2	0.352 0.345	3.73	---	---	---
SNCR	1	0.236	3.42	0.31	8%	$12,327,922
	2	0.230	3.42	0.31	8%	$12,327,922
SCR	1	0.07	2.72	1.01	27%	$24,887,384
	2	0.08	2.79	0.94	25%	$26,691,207
Combo	1 2	0.07 0.07	1.17	2.56	69%	$19,537,034

Step 6: Select BART Control

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 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, the state has determined that NOx BART is the following NOx emission rates:

Craig Unit 1: 0.070 lb/MMBtu (30-day rolling average)
Craig Unit 2: 0.080 lb/MMBtu (30-day rolling average)

The 0.08 lb/MMbtu limit for Unit 2 was based upon evidence before the AQCC in 2010, and took into consideration both cost and feasibility. Significant progress towards installation of SCR at Unit 2 has been made, and the vendor has guaranteed performance at the 0.08 lb/MMBtu 30-day rolling average NOx limit. Both vendor performance and equipment performance can improve over time, and the Division has determined, and Tri-State has agreed, that they can achieve a 0.07 lb/MMBtu NOx limit at Unit 1. For SCR at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls above the guidance criteria presented in Chapter 6 of the Regional Haze State Implementation Plan. The criteria in Chapter 6 guide the state's general approach to these policy considerations, but are not binding. Therefore, the state deviates from the guidance criteria in this case due to the notable visibility improvements, the reasonable dollars per ton control costs, and the support of Tri-State for installation of SCR at Units 1 and 2.

- Unit 1: $6,184 per ton NOx removed; 1.01 deciview of improvement
- Unit 2: $6,298 per ton NOx removed; 0.94 deciview of improvement

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. Once EPA approves this revision to the Regional Haze SIP, Tri-State will be required to meet the 0.07 lb/MMBtu NOx emission limit by August 31, 2021. Once the revised emission limit is approved, Tri-State will begin the design and development of bid documents, engage in a process to review bids and select a contractor for the multi-year construction project. Based on Tri-State's experience at Unit 2 (where construction and installation of SCR is already underway), and taking into consideration such factors as the weather in Craig, Colorado, the coordination necessary between the various owners of Unit 1, electric utilities and regional entities responsible for the bulk electric system, and compliance deadlines for other similar types of facilities in Colorado, Arizona and Wyoming, the Division has determined that the compliance deadline of August 31, 2021 is as expeditiously as practicable as SCR can be installed at Unit 1. This BART determination is the result of an agreement between Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state to resolve an appeal of EPA's decision to approve Colorado's Regional Plan.

This BART determination is consistent with the information provided by the FLMs and is supported by the associated visibility improvement information as well as the SCR cost information provided in the SIP materials and otherwise reflected in the 2014 hearing record.

In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a BART reassessment for Craig Unit 1. This reassessment evaluates the additional scenarios:

Scenario 1 (Close by December 31, 2025): Table 18 below assumes an amortization period of four years and four months of operation from the projected compliance date to the date of retirement (December 31, 2025) and that control technology could be installed by August 31, 2021, consistent with the 2014 BART determination In Table 19 below, an assumed amortization period of eight years of operation[23] is used since a projected compliance date could occur earlier depending on the alternative selected. Both of these assumed amortization periods change the remaining useful life for the alternatives as Craig Unit 1 will no longer remain in service for the 20-year amortization period used in the 2014 BART determination, depending on the alternative selected[24]. Both of these reduced timeframes change the cost effectiveness for the alternatives as follows:

Table 18: Craig Unit 1 NOx Cost Comparisons (4 years, 4 months of operation)

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$6,172,522	$7,928
SCR	4,048	$64,106,699	$15,835

Table 19: Craig Unit 1 NOx Cost Comparisons (8 years of operation)

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$4,755,842	$6,109
SCR	4,048	$41,476,535	$10,245

Based on this assessment, both SNCR and SCR are not cost effective when the remaining useful life is shortened, and when considering the remaining BART factors as discussed in Appendix C. For Craig Unit 1, a NOx emission limit of 0.07 lb/MMBtu (2014 BART determination) is BART under a 20 or 30 year remaining useful life; or
Scenario 2: A cease coal burning date of August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu applies after August 31,

[23] Operation period begins calendar year 2018 (December 31, 2017).
[24] EPA finalized revisions of the Air Pollution Cost Control Manual (Chapters 1 and 2) in May 2016; these revisions change the amortization period for SCR from 20 years to 30 years. The amortization period for SNCR remains 20 years.

2021. This scenario (without the inclusions below) is equivalent to the 2014 BART determination.

Both of these scenarios include a 30-day rolling average NOx emission limit of 0.28 lb/MMBtu that will commence on January 1, 2017 (first compliance date January 31, 2017) and be effective until closing or conversion to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1.

The scenario options under this BART reassessment are the result of an agreement. This reassessment relies on the 2014 BART determination for Craig Unit 1 and supplements that determination to reflect the terms of the agreement. This agreement achieves greater air quality benefits than the 2011 Regional Haze SIP. Both of these scenarios achieve greater NOx reductions and other environmental co-benefits compared to the 2014 BART determination.

Consistent with the agreement, Craig Unit 1 will either close on or before December 31, 2025 ***or*** cease burning coal by August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu will apply after August 31, 2021. Effective January 1, 2017 (first compliance date January 31, 2017), Craig Unit 1 will be subject to a NOx emission limit of 0.28 lb/MMBtu 30-day rolling average until closure or conversion to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective on December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1.

Best Available Retrofit Technology (BART) Analysis of Control Options
For
Colorado Springs Utilities – Drake Plant

I. Source Description

Owner/Operator: Colorado Springs Utilities
Source Type: Electric Utility Steam Generating Unit
SCC (EGU): 10100202
Boiler Type: Three Pulverized Coal, Dry-Bottom, Front-Fired, firing coal and natural gas (Units 5, 6, and 7)

The facility is located at 700 South Conejos Street in Colorado Springs. This facility consists of three (3) steam driven turbine/generator units (Units 5, 6, and 7) and the associated equipment needed for generating electricity. These units fire coal as the primary fuel and use natural gas for backup and startup. The facility also includes the various processes necessary to handle the coal and ash. The coal and flyash handling systems are provided with baghouses for air pollution emission control of PM and PM_{10} at appropriate point sources. In addition, the coal is treated with chemical additives to reduce fugitive emissions. Table 1 depicts technical information for each boiler at the Drake Plant.

Table 1: Drake Boilers Technical Information

	Unit 5	Unit 6	Unit 7
Placed in Service	October 28, 1962	July 27, 1968	June 14,1974
Boiler Rating, MMBtu/Hr for coal	548	861	1,336
Electrical Power Rating, Gross Megawatts	51	85	142
Description	Riley Pulverized Coal Front Fired Dry Bottom, firing natural gas and coal. 548 MMBtu/Hr w/ coal, 514 MMBtu/Hr w/ NG.	Babcock and Wilcox Pulverized Coal Front Fired Dry Bottom, firing natural gas and coal. 861 MMBtu/Hr w/ coal 850 MMBtu/Hr w/ NG.	Babcock and Wilcox Pulverized Coal Front Fired Dry Bottom, firing natural gas and coal. 1336 MMBtu/Hr w/Coal, 1310 MMBtu/Hr w/ NG.
Air Pollution Control Equipment	Reverse-Air Fabric Filter Baghouse- installed in May 1998	Reverse-Air Fabric Filter Baghouse – installed in September 1978	Reverse-Air Fabric Filter Baghouse– installed in November 1993
Inherent Special Features	Low NO_x burners – placed in service in May 1998	Low NO_x burners – placed in service in March 1998	Low NO_x burners – placed in service in October 1999
Monitoring Equipment	COM CEMs for SO_2 , NOx,	COM CEMs for SO_2 , NOx,	COM CEMs for SO_2 , NOx,

	CO_2, and stack gas flow rate	CO_2, and stack gas flow rate	CO_2, and stack gas flow rate
Emissions Reduction (%)*	NO_x – 54.7% SO_2 – None PM – 99.7% PM_{10} – 98.6%	NO_x – 52.8% SO_2 – None PM – 99.6% PM_{10} – 98.2%	NO_x – 57.7% SO_2 – None PM – 99.8% PM_{10} – 99.1%

*Emissions Reduction estimated by comparing uncontrolled AP-42 factor to actual average emission factor for PM/PM_{10}. For NO_x estimates, CAMD data was used to calculate reduction. See "Drake APCD Technical Analysis" for further details. Not based on actual testing.

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 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 "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. These documents are all provided as "CSU Drake BART Submittals".

Regulations that apply to these boilers are as follows:

- State Regulation No. 1, III.A.1.c limits particulate matter emissions to 0.1 lb/MMBtu.
- State Regulation No. 1, VI.A.3.a.(ii) limits sulfur dioxide emissions to 1.2 lb/MMBtu.
- 40 CFR, Part 76-Acid Rain Nitrogen Oxides Emission Reduction Program limits NO_X emissions to 0.46 lb/MMBtu of heat input on an annual average basis.
- No other annual emission limitations or State Regulations since units are Grandfathered[1].

II. Emissions for Units 5, 6, & 7

CSU estimated that a realistic depiction of anticipated annual emissions for Boilers 5, 6, and 7, or "Baseline Emissions", to be conservative, was the average of two previous years (2004, 2005) of emissions data in the August 1, 2006 analysis. Several years have

[1] Colorado Department of Public Health and Environment Air Quality Control Commission Regulation Number 3 Stationary Source Permitting and Air Pollutant Emission Notice Requirements 5 CCR 1001-5 Part G.IV states: "A source existing before the adoption of the first Colorado Air Quality Control Act and the date of its implementing regulations of February 1, 1972, is not required to obtain a permit. This revision is intended to clarify the date prior to which existing sources are considered "grandfathered" and exempt from permit requirements."

passed since the original BART submittal, in which the Division has updated modeling and technical analyses. Therefore, the Division used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database as applicable. These emissions are summarized in Table 2.

Table 2: CSU Boilers 5, 6 and 7 Baseline Emissions

Pollutant	Boiler 5		Boiler 6		Boiler 7	
	Annual Emissions* (tpy)	Annual Emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Annual Emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Annual Emissions** (lb/MMBtu)
NO_x	768	0.38	1,413	0.42	2,081	0.39
SO_2	1,269	0.63	2,785	0.82	4,429	0.83
PM_{10}	27	0.01***	58	0.02***	55	0.01***

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).
**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for NO_x and SO_2 emissions.
***The PM_{10} emission rate is determined from the Title V permit compliance stack test. These values are as follows: Drake #5 – 0.0132 lb/MMBtu; Drake #6 – 0.0186 lb/MMBtu; Drake #7 – 0.0111 lb/MMBtu.

III. Units Evaluated for Control

As documented by CSU, these boilers fire a variety of coal types, including coal from the southern Powder River Basin (PRB, located in Wyoming), ColoWyo coal (from northwestern Colorado), 20-Mile Foidel Creek coal (northwestern Colorado), and West Elk coal (western Colorado). The specifications for these coals are listed below in Table 3 (averaged from 2006 – 2008). Table 4 lists the 2006 – 2008 averaged APEN-reported coal characteristics for each boiler. Table 4 is not based on percent of various coals fired, but instead based on the Division's Air Pollutant Emission Notice (APEN) database. Sources submit annual emissions data using APENs. Due to equipment limitations, these boilers cannot achieve full load on PRB-sourced coal and instead fire a blend of the above listed coals. The ratio of PRB was discussed in the initial BART analysis submitted by CSU in an effort to demonstrate that firing sub-bituminous coal may have a minimal effect (if any) on a boiler's NOx emissions. In fact the data suggested at that time that 100% sub-bituminous coal had no effect on NOx emissions for some of the boilers. CSU notes that this effect may be boiler specific. The difference in sulfur content and resultant SO_2 emissions was not discussed in the initial BART analysis. Colorado's BART guidance (Regulation No. 3, Part F, Section IV.B.1.f) states that sources may include an evaluation of representative characteristics of coals from sources they reasonably expect to use, so that these characteristics may be considered in a particular BART limit.

Table 3: Drake Plant Coal Specifications (2004 – 2005)

Coal Mine/Region	Southern PRB	Colowyo	20-Mile Foidel Creek	West Elk
Coal Rank Classification	Sub-bituminous	Sub-bituminous, Class A	Bituminous	Bituminous

As Received Analysis				
H_2O (Moisture %)	27.11	17.42	9.62	7.55
Ash (%)	4.64	5.71	11.93	8.71
Sulfur (%)	0.21	0.37	0.52	0.45
Nitrogen (%)	0.69	1.35	1.57	1.30
Heating Value (HHV Btu/lb)	8,805	10,392	11,084	12,266

Table 4: Coal Specifications (2006 – 2008 Averaged APEN data)

	Specifications		
Emission Unit	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
Boiler #5	9,798	0.36	8.14
Boiler #6	10,749	0.47	10.38
Boiler #7	11,117	0.50	11.14

Table 1 lists the units at Colorado Springs Utilities Drake Plant that the Division examined for control to meet BART-eligible requirements. Controlled and uncontrolled emission factors and CAMD data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 5. The factors are based on firing bituminous coal for conservative estimates.

Table 5: Uncontrolled emission factors for CSU Drake BART-eligible sources[2]

	Pollutant (lb/ton)*			
Emission Unit	NO_x	SO_2	PM (filterable)	PM_{10} (filterable)
Boiler #5	22	13.6	81.5	18.7
Boiler #6	22	18.0	103.8	23.9
Boiler #7	22	18.8	111.4	25.6

*SO_2 and PM/PM_{10} factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, determined from Table 4.

A. Sulfur Dioxide (SO_2)

Step 1: Identify All Available Technologies

CSU identified one control option for Units 6 and 7:
Semi-dry flue gas desulfurization (dry FGD) aka lime spray drying (LSD/SDA)
CSU identified two control options for Unit 5:
Semi-dry flue gas desulfurization (dry FGD) aka lime spray drying (LSD/SDA)
Dry sorbent injection – Trona (DSI)

The Division also identified and examined additional control options for these units:
Lime/limestone-based wet FGD – all units
Emission limit tightening – Unit 5 (no control)

Step 2: Eliminate Technically Infeasible Options

[2] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

FGD: Flue gas desulfurization removes SO_2 from flue gases by a variety of methods. Wet scrubbing uses a slurry of alkaline sorbent, either limestone or lime, to scrub the gases. The most common dry FGD system is a lime spray dry absorber that uses slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that results in acidic precipitation in the duct which results in corrosion issues.

Wet FGD: Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar "foot print" area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney.

Dry FGD: Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants[3]. SDA systems are typically utilized at smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. Additionally, Controlling SO_2 Emissions: A Review of Technologies[4] evaluates various SO_2 control technologies and shows that for low-sulfur coal applications, LSDs can meet comparable emission rates to wet systems.

A SDA system must be located before the boiler flue gases enter the baghouse. Each reactor vessel requires a "foot print" area comprising about 2,000 to 4,000 square feet (depending on volume of flue gas treated) along with additional space for support equipment access, slurry preparation, mixing and associated tanks. The plant is bounded to the north by West Cimarron Street, to the west by federal Interstate Highway 25 and Fountain Creek, to the east by Conejos Street, and the south by Fountain Creek (as the Interstate and the Creek curve to the southeast). Train tracks (the Drake rail spur) also bound the facility to the north, south, and west. Along the east side of the plan (immediately east of Conejos Street) is the main railroad line. Figure 1 illustrates these boundaries. Figure 2, depicting a detailed view of the boilers, respective baghouses, and available spaces for FGD systems, indicates that available physical space is severely constrained at the Drake Plant, due to locations as well as pollution control retrofits for particulate matter. As figure 2 indicates, the square footage available to accommodate a FGD for Unit 5 is 3,025 ft^2 and Units 6 & 7 is 8,346 ft^2 (or about 4,000 ft^2 per unit). The entire site is very congested, with limited access and limited room for major retrofits of new capital equipment. Demolition and site reconfiguration would be required for FGD systems on these units and has been included in the cost analysis provided by Drake. CSU determined that it is technically feasible to install a dry FGD on Unit 5, Unit 6 and Unit 7.

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[3] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

[4] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

Figure 1: Drake Plant Physical Boundaries

Figure 2: Drake Plant Detailed View

The Division conducted site visits and determined:

- Unit 5
    - CSU determined dry FGD controls are technically feasible although available physical space was severely constrained and some demolition and site reconfiguration would be required; the Division conducted a site visit and determined that dry FGD controls were not appropriate considering the space constraints, shown in Figure 1 and Figure 2. Therefore control effectiveness and impacts for dry FGD are not evaluated in this analysis.
    - Traditional wet FGD controls are possible considering that there is adequate space near the baghouse to allow for the installation of controls, but is being eliminated based on other considerations within the five factors (i.e. energy and non-air quality impacts). Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Unit 5.
- Units 6 and 7
    - Dry FGD controls are technically feasible for Units 6 and 7.
    - Traditional wet FGD controls are possible considering that there is adequate space near the baghouse to allow for the installation of controls, but is being eliminated based on other considerations within the five factors (i.e. energy and non-air quality impacts). Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Units 6 and 7.

It is worth noting that CSU-Drake is currently testing a new, innovative non-traditional wet scrubber control system that appears to be as effective, if not more effective, at controlling SO_2 emissions with much less pressure drop (less parasitic load from increased fan demands) and requires a much smaller operational foot print area in comparison to traditional wet scrubbing.. The pilot-scale wet scrubber control system, called the NeuStream-S FGD process, is presently being tested on a 20 MW flue gas stream. CSU anticipates scaling the non-traditional wet scrubber control to full scale pending successful outcome of the current testing. This new wet scrubber technology uses a unique contacting vessel that makes it different from traditional wet scrubbers. It affords a higher liquid to gas contact ratio and so uses much less water / has lower pressure drop. It also uses a dual alkali system that is somewhat unique when compared to most traditional wet scrubbers. In comparison to traditional wet and LSD scrubbers, this new technology will have smaller water and energy requirements. There are several non-air quality aspects of the NeuStream-S process that compare favorably to traditional scrubbers, described in Step 4. Regarding the applicability of the NeuStream process to Drake Unit 5, the Division notes that this technology is not commercially available at this time. CSU has not determined if this technology is feasible for this smaller unit. However, the Division will re-assess this technology in the next Regional Haze planning period.

Although the technology being tested by CSU does not technically meet the definition of "available" as set forth in the BART rules, the Division is willing to allow CSU the opportunity to prove the technology and if successful, the opportunity to install the NeuStream-S FGD scrubber. This process will be required to meet the emission limits established for the LSD technology established in this BART determination. Regardless of the technology utilized, Drake has to meet the LSD-based BART limits within 5 years of EPA approval of the BART

SIP. CSU will test the NeuStream system until December 2011, and at that time, determine the control technology that will be used to comply with the specified SO_2 BART limits for Units 6 and 7.

DSI: Dry sorbent injection involves the injection of typically a sodium based reagent, either the mineral trona (sodium sesquicarbonate) or refined sodium bicarbonate, into the flue gas. The injected reagent reacts with the SO_2 present in the flue gas to create sodium sulfate, which is then collected in the particulate control device as in the case of the Drake boilers. CSU asserts that the flue gas temperatures present downstream of the Unit 5 airheater are in the appropriate range to allow for DSI application. A very important factor in DSI application is the ability for the boiler's particulate control device to accommodate the added particulate loading of the DSI reagent in addition to the flyash loading. CSU's preliminary review indicates that even with the added loading of DSI reagent, the Drake baghouses would be operating within the design specification for particulate loading. The flue gas is not cooled nor saturated with water, so reheating of desulfurized flue gas is not required. No gas-sorbent contacting vessel is required to be installed. DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system. However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Lime, soda ash, and Trona (sodium sesquicarbonate) are possible. Lime is the least reactive reagent resulting in low efficiencies even at high injection rates. Trona is a very reactive reagent that can be used to achieve a range of efficiencies depending on the amount of sorbent injected, and would likely be the chosen reagent.

One major challenge of DSI systems is the possibility of converting the NO_x present in the flue gas from NO which is colorless to NO_2 which has a reddish-brown color. This conversion of NO to NO_2 can create a brown plume from the stack which could create opacity compliance issues. Due to variability of boiler configurations, coal composition, NO_x to SO_2 ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum SO_2 removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CSU estimated the maximum SO_2 removal rate that can be achieved while minimizing the creation of the brown plume condition to be 60% SO_2 removal. In practical application, a higher SO_2 removal rate may be possible, while it is also possible that a lower SO_2 removal rate may be necessary to limit the brown plume formation. This determination would require actual SO_2 removal real-time testing.   Therefore, DSI is technically feasible for Drake Plant Unit 5. The Division assumes that this same technology is also then technically feasible for Unit 6 and Unit 7.

Emission limit tightening (unit 5 only): The Division conducted technical analyses to determine whether the current SO_2 emission limit could be more stringent based on actual emissions (2006 – 2008) from the units. This option is technically feasible for all units. However, the Division only examined this option for Unit 5 since when this option was examined; preliminary SO_2 determinations had already been established for all units. Unit 5 was the only unit where the emission limit could potentially be achieved with the assumption of no control.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CSU provided the Division annual average control estimates. In the Division's experience, 30-day SO_2 rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 5% for Units 5, 6, and 7 to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by CSU as well as other control techniques applied to pulverized coal boilers. A Division review of the EPA's RBLC revealed recent BACT SO_2 determinations range from 0.06 – 0.167 lbs/MMBtu. The Division narrowed down this range depending on the averaging time, permit type, facility size, and fuel type. This narrowed range is 0.095 – 0.161 lbs/MMBtu, with an average of 0.119 lbs/MMBtu rounded to 0.12 lbs/MMBtu. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details.

Dry FGD (LSD): Controlling SO_2 Emissions: A Review of Technologies[5] indicates that the median control efficiency for dry FGD processes, such as LSD, is 90%. Typically dry FGD technology is applied to units that fire coal with a sulfur content below 1.0% to 1.5%. However, when concentrations of pollutants are low, as is the case with low-sulfur western coal, the achievable control efficiency will drop. Due to the very low sulfur content of the coal burned at the Drake Power Plant, typically <0.5% as detailed in Table 3, a 90% removal rate is at the upper end of what may reasonably be expected in practice. Additionally, achievement of a 90% removal rate on a long-term basis would require levels of equipment redundancy that may not be feasible to locate at a congested site such as the Drake Power Plant.
DSI: Based on literature review, CSU estimated the maximum SO_2 removal rate that can be achieved to be 60% SO_2 removal. The Division concurs that this control efficiency is reasonable for retrofit on these units.

Emission limit tightening: Since emission limit tightening is based on actual data, there will be minimal, if any, reductions from baseline period (2006 – 2008) SO_2 emissions. The Division found that the maximum 30-day rolling emission rate for Unit 5 was 0.83 lb/MMBtu. As explained above, the Division projects 30-day rolling SO_2 emission rates to be approximately 5% higher than annual average emission rates. The uncertainty of evaluating a "maximum" emission rate warrants a similar 5% buffer to be applied in this case, especially due to the fact that the Drake facility has limited coal storage capacity and blends four different types of coals. Therefore, an appropriate SO_2 emission limit assuming no control technology for Unit 5 is 0.9 lb/MMBtu on a 30-day rolling average.

Table 6 summarizes each available technology and technical feasibility for SO_2 control.

[5] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

Table 6: Drake Units 5, 6, and 7 SO_2 Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Wet FGD	95%	Y
Dry FGD (LSD)	81 – 90%	N – Unit 5 Y – Units 6 & 7
DSI	60% (CSU)	Y

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

Wet FGD: The significant cost issue associated with securing sufficient water supplies (a costly and scarce resource in the Front Range) to support a wet FGD control system along with the cost of disposing the sludge byproduct at an approved landfill since on-site storage is not an option. There are other costs and environmental impacts that the Division also considers undesirable with respect to wet scrubbers.

LSD/DSI: CSU submitted cost estimates for LSD systems on Units 5, 6 and 7 in the original BART submittal on August 1, 2006 and updated refined cost estimates on March 29, 2007. CSU provided cost estimates for the DSI system evaluated on Unit 5 on May 10, 2010.

The application of LSD or DSI would remove nearly all of the halogens in the flue gas, thus improving the acid gas removal of the baghouse. However, it is anticipated that LSD or DSI would also lower the inherent mercury removal in the baghouses. Recent mercury tests at the Drake Plant have shown that the amount of mercury leaving the stack is approximately 60 – 90% less than what would have been expected based on coal analysis. It is believed that the halogens present in the flue gas are oxidizing the mercury, which is subsequently removed in the baghouse. The application of LSD or DSI would remove the halogens in the flue gas, which may lead to reduced mercury control. Due to this possibility, the provision of adding mercury control via activated carbon injection as part of a LSD or DSI system has been included in the estimated cost of LSD/DSI application.

The Division compared CSU's updated cost information to the study that EPA conducted in developing presumptive BART limits,[6] shown in Table 7.

Table 7: CSU-Drake SO_2 LSD Control Cost Comparison

Unit Capacity (MW)	EPA's Calculated Cost Effectiveness for MW Group ($/ton SO_2 Removed)	CSU Refined Cost Estimate ($/ton SO_2 Removed (Control System))	Cost Differential
Unit 6 –	$2,399	$2,579 - $2,981	+ 8% – 24%

[6] EPA, 2005. Technical Support Document for the Best Available Retrofit Technology (BART) Notice of Final Rulemaking: Setting BART SO_2 Limits for Electric Generating Units: Control Technology and Cost-Effectiveness.

85 MW			
Unit 7 – 142 MW	$1,796	$2,140 - $2,694	+ 19% - 50%

EPA's study was published in 2005 whereas CSU sent the Division updated cost analyses for LSD systems on Units 6 and 7 using various cost updates from the 2006 timeframe. Drake has reflected the costs of retrofitting a facility that is already congested with limited room and access for major retrofits of new capital equipment in the retrofit multiplier that is applied to the cost of new equipment. Therefore, the Division considers CSU's updated cost information for the LSD controls on these units to be reasonable estimations for the cost of control.

The Division considers this cost to be within a reasonable cost range that is comparable to other Colorado facility submittals.[7] Therefore, the Division did not adjust CSU's cost estimates. CSU only submitted DSI cost information for Unit 5. The Division scaled this cost information for Units 6 and 7 in Table 9, Table 10, and Table 11. Please see "Drake APCD Technical Analysis" for more details.

For dry FGD, CSU estimated a removal rate of 83.3% based on a worst-case coal sulfur concentration of 0.9 lb/MMBtu, baseline years 2004 and 2005, and a resulting emission rate at the BART presumptive limits of 0.15 lb/MMBtu. The Division adjusted this removal rate using the baseline SO_2 emissions from Table 2 (lb/MMBtu and tons/year) for each unit and using a realistic removal rate of 76 – 90%that meets or exceeds BART presumptive limits for Units 6 and 7, and exceeds the limits for Unit 5. This range allows the Division to determine the most reasonable BART limit for this control option, if applicable. The Division scaled costs linearly for the LSD systems for higher control efficiencies as applicable. See "Division APCD Technical Analysis" for more details.

Emission limit tightening: There are no costs associated with this option for unit 5. This option is considered equivalent to the "baseline" row in the tables below, and is not considered as a separate cost option.

Table 8 illustrates resultant SO_2 emissions for each technically feasible control option. Table 9, Table 10, and Table 11 show the SO_2 control cost comparisons for each unit based on the detailed cost analyses. The Division used baseline emissions from Table 2. The Division analyzed both annual and 30-day rolling average limits. The Department's experience with power plants suggests that the maximum 30-day rolling average SO_2 emission rate is approximately 5% higher than the annual average emission rate.

[7] ENSR, 2006. BART Analysis for the TriGen Colorado Energy Corporation Facility in Golden, Colorado. Prepared for Trigen. Document No: 10279-017-700.

Table 8: Units 5, 6, and 7 Control Resultant SO_2 Emissions

Alternative	Control Efficiency (%)	Resultant Emissions								
		Unit 5			Unit 6			Unit 7		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day rolling Average (lb/MMBtu)	Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day rolling Average (lb/MMBtu)	Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day rolling Average (lb/MMBtu)
Baseline	---	1,269	0.63		2,785	0.82		4,429	0.83	
DSI	60	508	0.25	0.26	1,114	0.33	0.34	1,771	0.33	0.35
Dry FGD (LSD)	82				501	0.15	0.15	797	0.15	0.16
Dry FGD (LSD)	85				418	0.12	0.13	664	0.12	0.13
Dry FGD (LSD)	90				279	0.08	0.09	433	0.08	0.09

Table 9: Drake Unit 5 SO_2 Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
DSI	762	$1,340,663	$1,760	$1,760

Table 10: Drake Unit 6 SO_2 Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
DSI	1,671	$2,234,438	$1,337	$1,337
Dry FGD (LSD) @ 82% control	2,284	$6,186,854	$2,709	$6,540
Dry FGD (LSD) @ 85% control	2,368	$6,647,835	$2,808	$5,517
Dry FGD (LSD) @ 90% control	2,507	$7,452,788	$2,973	$5,780

Table 11: Drake Unit 7 SO_2 Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
DSI	2,657	$3,732,826	$1,405	$1,405
Dry FGD (LSD) @ 82% control	3,632	$8,216,863	$2,263	$4,602
Dry FGD (LSD) @ 85% control	3,764	$8,829,321	$2,345	$4,610
Dry FGD (LSD) @ 90% control	3,986	$9,898,382	$2,483	$4,828

Energy and Non-Air Quality Impacts

Traditional Wet FGD: Based upon its experience, and as discussed in detail below, the Division has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including massive water usage. This is a significant issue in Colorado, where water is a costly, precious and scarce resource. In the arid West, securing sufficient water supplies to support a wet FGD control system is a difficult undertaking that precludes other beneficial uses for such water. In Colorado, water law is based upon the doctrine of prior appropriation or "first in time - first in right," and the priority date is established by the date the water was first put to a beneficial use. Thus, depending upon whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the state, particularly in the Front Range, to accommodate the added demands of wet FGD controls. At a minimum, the water demands of wet FGDs will compete for what is already a scarce resource needed for Colorado's domestic, agricultural and industrial demands. Wet scrubbers consume approximately 23% more water than LSD scrubbers, depending on boiler size.[8]

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. Potential on-site storage of wet ash is an increasing regulatory concern, as evidenced by the recent Tennessee Valley Authority spill. In addition, the steam plume resulting from a wet FGD control system in such a confined river valley will produce a noticeable cloud that will hang over a densely populated area (City of Colorado Springs). The Division has received complaints regarding the more visible plumes associated with wet scrubbing; a potential irony in light of the visibility issues at the heart of the BART program. The Division largely focused its BART SO_2 control technology consideration on commercially available once-through dry FGD controls, specifically, "lime spray dryers" (LSD), that have an established record of reliable performance on boilers burning low-sulfur coal. Generally, wet FGD controls can achieve a higher level of SO_2 control on a percent capture basis that exceeds the capabilities of LSDs but, as noted above, there are a number of non-air quality and other environmental impacts including increased water usage, sludge disposal and wet plume issues that often overshadow any incremental improvement in SO_2 emission reductions. Recent PSD applications in Colorado have demonstrated lime spray dryer systems to be BACT.

The Division finds that the non-air quality environmental impacts outweigh the visibility benefits from this technology. Therefore, the State has eliminated this option as BART.

Semi-dry FGD (LSD): CSU notes that there are a number of non-air quality environmental impacts with regard to lime spray dryer systems. Application of a dry scrubber will tend to remove halogens from the flue gas (primarily chlorine) that are important to the removal of mercury from the flue gas. Several sources of speciated mercury stack test data, including EPA's own ICR stack test data, show that an unscrubbed plant with a baghouse burning western coal will remove more mercury from the flue gas when compared to a similar plant with a scrubber.

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[8] 2008. "Revised BART Analysis for Unit 1 & 2 Gerald Gentleman Station Sutherland, Nebraska: Nebraska Public Power District." Prepared by: HDF 701 Xenia Avenue South, Suite 600 Minneapolis, MN 55416 With control technology costs provided by: Sargent & Lundy.

There will be a greater volume of material being landfilled. A LSD scrubber consumes a significant amount of water, as detailed in Table 12.

Table 12: LSD Water Requirements

Unit	Water required for LSD (gpm)	Water required for LSD (Mg/year)
6	68	35.7
7	100	53.0

CSU states that the direct energy cost of the LSD systems due to additional auxiliary loads on the plant, as well as increased headloss through the scrubber, is the primary energy impact. These loads reduce the net output of each unit; therefore, both the lost energy production, as well as the reduced capacity, must be replaced. CSU estimates energy costs for replacement capacity and differential cost between existing MW-h of output and a replacement MW-h in **Error! Reference source not found.**. This is the incremental cost of a unit of replacement energy, and does not double count the direct energy cost already included in the operating cost. The reduced unit output will consequently reduce unit efficiency, thereby increasing emissions of CO_2 when measured on a per MW-h basis.

Table 13: LSD Energy Replacement Costs

Unit	Replacement capacity cost ($/kW-yr)	Differential energy cost ($/MW-h)
6/7	44	35

This information, including detailed capital and annual cost data, are provided as “CSU Drake BART Submittals”. CSU originally generated costs using EPRI’s FGD Cost model.[9] This model uses specific unit data to calculate the cost of controlling emissions, and is considered to be accurate within ± 30%. The refined cost estimates from March 2007 were further extrapolated to account for retrofit difficulties, annual inflation, and also hyperinflation of certain construction commodities and energy. The March 2007 submittal also incorporates budgetary quotes from vendors for the major pieces of equipment as well as noting the need for a non-recycling LSD due to the ash removal system’s operation at a very high capacity factor. As depicted in Figure 3, a non-recycling LSD would eliminate slurry solids; instead the FGD solids (removed in the baghouse) are immediately disposed.

[9] EPA’s BART Guidelines recommend that the OAQPS Control Cost Manual be used to develop cost estimates, where possible. Unfortunately, the Control Cost Manual does not contain a section for SO2 removal equipment as of the date of this report. The Fifth edition (EPA 453/B-96-001) of the Control Cost Manual is referenced in the BART guideline; however, the Sixth edition (EPA 452/B-02-001, 7-22-2002) is now available.

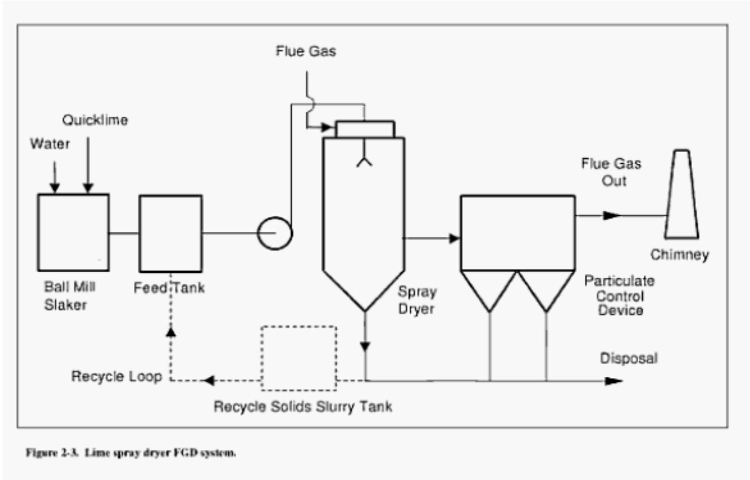

Figure 3: Lime Spray Dryer (LSD) Schematic[10]

Although these non-air quality/energy impacts have been identified, the State has determined that these impacts are not significant or unusual enough to warrant elimination of this control option.

DSI: CSU documents additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Application of DSI would be effective in further enhancing the removal of halogenated acid gases in the baghouse. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash.

The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash at some plants,[11] which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls.

Emission Limit Tightening: There are no known non-air quality or energy impacts associated with emission limit tightening. Thus, this factor does not influence the selection of this option.

[10] EPA, 2000. "Controlling SO_2 Emissions: A Review of Technologies." Prepared by Ravi K. Srivastava for Office of Research and Development, Washington, D.C. 20460. Pg. 12.
[11] Department of Energy, 2001. LIFAC Sorbent Injection Desulfurization Demonstration Project: A DOE Assessment. U.S. Department of Energy: National Energy Technology Laboratory. P.O. Box 880, 3610 Collins Ferry Road Morgantown, WV 26507-0880.
http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/lifac/LIFAC_PPA.pdf

Remaining Useful Life
CSU asserts that the remaining useful life of Drake Units 5, 6, and 7 are each in excess of 20 years, which is the maximum amortization period allowed in the BART analysis. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results
CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 14 shows the number of days pre- and post-control. Table 15 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[12], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO_2 BART control technology on a given unit, emission rates for the other pollutants (NO_x and PM/PM_{10}) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed all units with NO_x emissions at 0.07 lb/MMBtu and SO_2 emissions at 0.12 lb/MMBtu for Units 6 and 7 and at 0.32 lb/MMBtu for Unit 5. The Division modeled Drake Unit 5 for 0.12 lb/MMBtu as a theoretical examination of the potential impacts of lower emission limits on that unit.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 14: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO_2 BART Control Limit	Unit(s)	SO2 Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hr SO_2 rates	5	0.943	Rocky Mountain National Park	34	---	---	17	---	---
	6	0.997							
	7	0.994							
DSI	5	0.251		34	32	2	17	14	3

[12] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

	6	0.328		34	32	2	17	14	3
	7	0.333		34	31	3	17	13	4
dry FGD (LSD)	5	0.120		n/a					
	6	0.120		34	31	3	17	14	3
	7	0.120		34	28	6	17	12	5
dry FGD (LSD)	6	0.100		34	31	3	17	14	3
	7	0.100		34	28	6	17	12	5
dry FGD (LSD)	6	0.070		34	31	3	17	14	3
	7	0.070		34	28	6	17	12	5
Combo	5	0.321							
	6	0.120		34	1	33	17	0	17
	7	0.120							

Table 15: Visibility Results – SO_2 Control Options

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)	Output (@ 98th Percentile Impact)	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	($/dv)
Max 24-hr SO_2 rates	5	0.943				
	6	0.997	1.84	---	---	---
	7	0.994				
DSI	5	0.251	1.72	0.12	6%	$14,673,714
	6	0.328	1.65	0.18	10%	$15,903,206
	7	0.333	1.55	0.29	16%	$16,765,140
dry FGD (LSD)	5	0.120	n/a			
	6	0.120	1.59	0.24	13%	$27,470,391
	7	0.120	1.45	0.39	21%	$22,697,484
dry FGD (LSD)	6	0.100	1.59	0.25	14%	n/a
	7	0.100	1.44	0.40	22%	n/a
dry FGD (LSD)	6	0.070	1.58	0.26	14%	$28,999,176
	7	0.070	1.42	0.41	22%	$23,967,026
Combo	5	0.321				
	6	0.120	0.25	1.59	86%	n/a
	7	0.120				

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that SO_2 BART for Unit 5 is the following SO_2 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.

Based upon its consideration of the five factors summarized herein, the state has determined that SO_2 BART for Unit 6 and Unit 7 is the following SO_2 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 (LSDs). 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).

The emission rates for Units 6 and 7 provide 85% SO_2 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 SO_2 removed; 0.24 deciview of improvement
- Unit 7: $2,345 per ton SO_2 removed; 0.39 deciview of improvement

B. Filterable Particulate Matter (PM_{10})

Drake Units 5, 6, and 7 are each equipped with reverse-air fabric filter baghouses to control PM/PM_{10} emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Colorado Operating Permit 95OPEP107 Condition 2.4.2 requires Units 5, 6, and 7 to conduct performance testing for PM_{10} annually. While the emission in Condition 2.4 is set at 0.1 lb/MMBtu, the annual performance test must be used as an emission factor in determining emissions.

Table 16 shows the most recent stack test data (June 14, 2006). It is important to note that the most recent stack test, which at a minimum, occurs every five years, and more frequently depending on the results, demonstrates that these baghouses are meeting >95% control.

Table 16: Drake 2006 Stack Test Results

Pollutant	Unit 5 (lb/MMBtu)	Unit 6 (lb/MMBtu)	Unit 7 (lb/MMBtu)
Filterable PM_{10}	0.0132	0.0186	0.0111

PM_{10} Control efficiency	98.6%	98.3%	99.0%

A Division review of EPA's RBLC revealed recent BACT PM/PM_{10} determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The current stack test results above are well below the range of recent BACT determinations. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details.

The State determines that the existing regulatory emissions limit of 0.03 lb/MMBtu (PM/PM_{10}) for the three units represents the most stringent control options. 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. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for PM/PM_{10} is not needed for Drake Units 5, 6, and 7.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies

CSU identified four NO_x control options:

- Overfire air (OFA)
- Ultra-low NO_x burners (ULNBs)
- Selective Catalytic Reduction (SCR)
- Ultra-low NO_x burners and SCR (ULNBs + SCR)

The Division also identified and examined the following additional control options for these units:

- Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Selective Non-Catalytic Reduction (SNCR)
- Ultra-low NO_x burners and Over-fire air (ULNB+OFA)
- Coal reburn +SNCR

Rotating overfire air (ROFA) was not considered in this analysis because ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load[13]. While ROFA is considered superior to SOFA alone, ROFA alone is not superior to LNB+OFA and cannot achieve the predicted 70% or greater NO_x reduction for Units 5, 6, and 7. Since ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for this unit, ROFA® technology is not considered further in this analysis.

Step 2: Eliminate Technically Infeasible Options

[13] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html

OFA: Air staging or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Staging the air in the burner (internal air staging) is generally one of the design features of low NO_x burners, such as those already present on Units 5, 6, and 7. Furnace overfire air (OFA) technology requires the introduction of combustion air to be separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of N_2 rather than NO_x. Primary air (70-90%) is mixed with the fuel producing a relatively low temperature; oxygen deficient, fuel-rich zone and therefore moderate amounts of fuel NO_x are formed[14]. The secondary (10-30%) of the combustion air is injected above the combustion zone through a special wind-box with air introducing ports and/or nozzles, mounted above the burners. Combustion is completed at this increased flame volume. Hence, the relatively low-temperature secondary-stage limits the production of thermal NO_x. The location of the injection ports and mixing of overfire air are critical to maintain efficient combustion. Retrofitting overfire air on an existing boiler involves waterwall tube modifications to create the ports for the secondary air nozzles and the addition of ducts, dampers and the wind-box. OFA is a technically feasible option for Units 5, 6, and 7.

ULNBs: Each unit has low NO_x burners installed, shown in Table 1 . These LNBs can be replaced with ULNBs. Burner designs have improved in recent years to improve flame stability and combustion control schemes for increased NO_x emission reductions with these ultra-low NO_x burners. ULNBs are a technically feasible option for Units 5, 6, and 7.

ULNB+OFA: Since ULNB and OFA are each technically feasible options and would be installed separately for Units 5, 6, and 7, it stands to reason that ULNB+OFA is technically feasible option for Units 5, 6, and 7.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

While lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for CSU, a retrofit SCR, the 0.07 lb/MMBtu controlled NO_x value is more expected. The SCR reaction occurs within the temperature range of 600°F to 750°F where the extremes are highly dependent on the fuel quality. There are three different types of SCR arrangements – high-dust, low-dust, and tail-end. The pre-dominant arrangement applied in the United States has been high-dust. In most circumstances, a high-dust SCR system is the most economical arrangement alternative and would likely be the arrangement for Unit 5, 6, and 7 if applicable. For high- and low-dust arrangements, the catalyst, because of its location directly downstream of the boiler and upstream of the air heater, can impact the boiler through its effect on the air heater. The magnitude of this effect is dependent on the power plant configuration, air

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[14] IEA Clean Coal Centre: Clean Coal Technologies – Air Stating for NO_x control (overfire air and two-stage combustion), 2010. http://www.iea-coal.org/site/ieacoal_old/clean-coal-technologies-pages/air-staging-for-nox-control-overfire-air-ofa-or-two-stage-combustion?

quality control components, type of fuel, and overall emission control requirements. For retrofit applications, adequate space between the economizer outlet and the air heater inlet to allow boiler outlet and air heater return duct is a prerequisite for the installation of a high-dust system and is the case at the Drake Plant. Therefore, high-dust SCR is a technically feasible alternative for Drake Units 5, 6, and 7.

ULNBs/SCR layered: A layered approach of installing ULNBs pre-combustion and SCR post-combustion is technically feasible for Drake Units 5, 6, and 7. This scenario considers that less NO_x would enter the SCR system and reduce aqueous ammonia storage, handling, and injection. CSU considered this scenario to determine if this option would be more economically and technically feasible for the three boilers at the Drake Plant.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[15] and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[16] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 5, 6, and 7.

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost.

It should be noted that selective non-catalytic reduction (SNCR) was not considered in CSU's BART analysis because CSU asserts that SNCR achieves full-load NO_x removal in the same range as ULNB at a higher levelized cost (\$/ton NO_x removed), and therefore should be ruled out due to a "least-cost envelope" analysis as detailed in the BART rule. The higher cost is primarily due to much higher operating costs, with most of the operating costs being for the reagent. Additionally, the chemical reaction required for SNCR to work is temperature sensitive. The CSU Drake boilers often operate below full load, when the temperature is no longer conducive to optimal NO_x removal, resulting in NO_x removal declines. The weighted average NO_x removal over an annual load range can be less than ULNB depending on the portion of time the units operate at partial load. Therefore, SNCR was eliminated from consideration by CSU because of higher costs and efficiency losses at partial loads. However, the Division considers SNCR a

[15] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[16] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php

technically feasible alternative for Drake Units 5, 6, and 7. Similar Colorado facilities evaluated SNCR as an option and it is recognized nationally as a NO_x control option for EGUs, so the Division included SNCR in the full four-factor analysis.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu[17]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CSU provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[18] 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Drake Units 5, 6, and 7 to determine control efficiencies and annual reductions.

OFA: CSU estimated that overfire air, in conjunction with the existing low-NO_x burners, is capable of reducing NO_x emissions approximately an additional 20% from existing conditions in the original BART submittal (August 1, 2006). EPA's AP-42 emission factor tables estimate low-NO_x burners controlling 35 – 55% and LNB with OFA controlling 40 – 60% of NO_x emissions.[19] The low NO_x burners currently achieve about 50 – 56% control. However, in a more recent AWMA study, it is noted that OFA achieves an additional 10 – 25% control with the installed low NO_x burners.[20] Therefore, the Division concurs with CSU's additional 20% NO_x control estimate.

ULNBs: CSU asserts that additional NO_x reductions of 20 – 30% are possible with implementation of some or all of the modifications that will be needed to retrofit ULNBs at the Drake boilers. These additional NO_x reductions could be achieved while meeting acceptable CO levels. The ULNBs are estimated to control approximately 75% of uncontrolled NO_x emissions, which is consistent with a U.S. Department of Energy Study which estimated NO_x emissions reductions between 75 – 85%.[21] Therefore, the Division concurs with CSU NO_x reduction estimat3es for ULNBs.

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[17] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf

[18] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

[19] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[20] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

[21] U.S. Department of Energy, 2004. Office of Fossil Energy, National Energy Technology Laboratory. http://www.netl.doe.gov/publications/factsheets/project/Proj294.pdf

ULNB+OFA: The Division used information from CSU regarding ULNBs and OFA control efficiencies as described above. CSU noted in the February 2009 submittal that ULNB are assumed to achieve 20% efficiency *assuming* OFA is already installed (at 0.35 lb/MMBtu for each unit). The Division is employing a different baseline that CSU originally utilized (e.g. NOx emissions prior to consideration of OFA). The Division requested additional information from CSU to verify that the 20% ULNB assumption is still valid for all units. CSU noted that Units 6 and 7 will likely be able to achieve the 20% reduction (using the Division's higher NOx emission baseline). However, Unit 5 has an older technology coal mill and other technical issues and would not be able to achieve 20% reduction. Unit 5 has an older mill (ball-type pulverizers vs. the hammermills present at Units 6 and 7), which limits the level of coal fineness. In addition, Unit 5 is a smaller boiler than the other units. In light of these specific technical feasibility issues, the Division used 10% additional reduction efficiency for ULNBs for Unit 5. Therefore, the overall control efficiencies for ULNB+OFA in combination for the three units are 28% for Unit 5 and 36% for Units 6 and 7 respectively.

SNCR: Other Colorado facilities have noted a variety of control ranges for SNCR. The Division used a variety of information, including similar Colorado facility estimates, EPA's SNCR Air Pollution Control Fact Sheet and a recent AWMA study[22] to conservatively approximate that the Drake boilers can achieve 30% control when SNCR is applied.

*SCR:*CSU approximates that SCR can achieve an approximate 80% NO_x reduction using 2004 – 2005 baseline emissions (or 0.07 lb/MMBtu), determined by URS WD using a survey of a large collection of photographs, and experience in developing retrofit factors for many types of units and configurations at numerous facilities. The Division adjusted the control efficiency percent reduction to reflect the 2006 – 2008 baseline emissions, but kept the resultant 0.07 lb/MMBtu constant. This control efficiency is consistent with EPA's AP-42 emission factor discussion, which estimates SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.[23,24]

ULNBs/SCR layered approach: CSU evaluated a layered approach of installing ULNBs upstream of the combustion process to reduce NO_x entering the boiler and thus reducing subsequent SCR reduction requirements. This approach will achieve the same NO_x emission reductions as SCR alone and is deemed to be appropriate by the Division.

Table 17 summarizes each available technology and technical feasibility for NO_x control.

Table 17: Drake Units 5, 6, and 7 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO_x Burners (LNB)	50 -56%	Y – installed

[22] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.
[23] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[24] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

LNB + OFA	60 – 81%	Y (LNBs are installed on each unit)
Overfire air (OFA)	10 – 25% (alone)	Y
Ultra-low NO_x burners (ULNBs)	26 – 32%	Y
ULNB+OFA	28 – 36%	Y
Selective non-catalytic reduction (SNCR)	~ 30%	Y
Selective catalytic reduction (SCR)	75 – 90%	Y
ULNB/SCR layered approach	75 – 90%	Y
ECO®	n/a	N
RRI	n/a	N
Coal reburn +SNCR	n/a	N

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

OFA: Washington Group International Inc. estimated the cost of overfire air during the course of a pollution control study for the Drake boilers in 2004. The cost estimates were generated using EPRI's IECCOst model. This model uses specific unit data to calculate the cost of controlling emissions and is typically considered to be accurate within ±30%. Overfire air will not require large pieces of new equipment, but instead the costs consist primarily of labor and materials related to modifying the boiler waterwall tubes to allow for new air injection ports and the necessary ductwork, dampers, and instrumentation and control to supply the air from the existing secondary air duct. In a technical support document issued by the Northeast States for Coordinated Air Use Management (NESCAUM) entitled "NO_x Controls for Existing Utility Boilers,"[25] OFA alone ranges from \$410 - \$1,100 per ton NO_x reduced annually for units estimating 15 – 30% NO_x control, which is within the range of Drake's estimated OFA NO_x reductions (20%). The estimates in Table 18, Table 20, and Table 22 are within this range. Therefore, the Division concurs with the OFA cost estimates.

ULNBs: CSU's cost estimate includes the burners, oil or gas lighter systems and controls at burner front, automatic air register adjustment and control drives, flame scanners and controls, all wind box controls including control drawings, all control and burner logic drawings. The estimates do not include burner wind box extensions or stove pipe, ducts installed on top of existing wind boxes, furnace water wall openings, structural steel support for ULNBs beyond supplemental support steel, cost for engineering, supply and construction of wind box extensions, physical modeling, math modeling, or wind box baffling, pulverizer upgrades, burner piping or classifiers for improved coal fineness and required size distribution. CSU notes that some or all of the items must be determined by boiler modeling and pulverizer testing. If all of these are needed, the capital costs could increase by 40 – 70% compared to the base scope listed in Table 19, Table 21, and Table 23. The Division considers CSU's estimated costs more than

[25] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

reasonable, with ULNBs under $1,000/ton which is comparable or lower than LNB costs presented in recent NESCAUM papers.[26, 27]

ULNB+OFA: The Division based cost estimates for this control option assuming that OFA and ULNBs will be installed separately; therefore, the cost for this layering option is a summation of individual annualized costs for OFA and ULNBs for each unit. The Division checked this assumption with CSU on November 8, 2010.

SNCR: The difficulty of SNCR retrofit on smaller boilers significantly increases, with the primary concern being that there is adequate wall space within the boiler for installation of injectors. Movement and/or removal of existing watertubes and asbestos from the boiler housing may be required, as in the case of the Drake boilers.

A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.[28] A similar Colorado facility estimated operating expenses at approximately 81 – 86%.[29] Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[30]

The Division used information from a similar facility submittal to determine approximate SNCR costs for the Drake boilers since CSU did not have SNCR information.[31] The Division consulted with CSU on this decision to ensure that these boilers are roughly equivalent to the Drake boilers in scope and retrofit difficulty.

The resultant cost effectiveness for SNCR on Units 5, 6, and 7 ranges from $2,700 to $4,400 per ton. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[32,33]

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[26] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114. www.nescaum.org/documents/**nox**-2000.pdf

[27] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[28] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.

[29] CENC, 2009. "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado." Prepared by AECOM.

[30] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

[31] CENC, 2009. "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado." Prepared by AECOM.

[32] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[33] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NO_x reduced.[34] Although the resulting cost estimates for the Drake boilers are greater than these ranges, the small size of the boilers as well as the difficulty of the retrofit leads the Division to the conclusion that the estimated cost estimates for SNCR are reasonable.

SCR: CSU estimated the cost for the SCR system(s) using the IECCOST program. This estimate includes the cost of a new ID booster fan, since CSU/URS noted that the current ID fan does not have sufficient capacity to accommodate the additional pressure drop of the SCR retrofit. Recent NESCAUM studies estimate SCR retrofits achieving NO_x emission rates of 0.05 – 0.15 lb/MMBtu and emission reductions of 65 – 85% as costing $2,600 - $7,400 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[35,36] The SCR system estimates for the CSU Drake boilers range from approximately $5,000 - $7,100, which is within the NESCAUM estimates. The Division concurs that CSU cost estimates for SCR controls are reasonable.

ULNBs/SCR layered approach: CSU chose to examine the ULNB/SCR layered approach because the cost of the SCR would be reduced somewhat in this scenario. The reduced costs would be noted in the reactor housing, amount of catalyst required, and the aqueous ammonia storage, handling, and injection. Therefore, this option was examined to determine the significance of the potential cost differential. The Division concurs that this is an appropriate option and may possibly reduce costs.

Table 18, Table 20, and Table 22 illustrate resultant NO_x emissions for each technically feasible control option. Table 19, Table 21, and Table 23 show the NO_x control costs for each unit based on detailed cost analyses. The Division estimated resultant NO_x using annual average reductions for tons of NO_x reduced per year, as noted in Table 2. The Division's experience with power plants suggest that the maximum 30-day rolling average NO_x emission rate is 5-15% higher than the annual average emission rate.

Table 18: Drake Unit 5 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	768	0.38	
Overfire air (OFA)	20	615	0.30	0.35
Ultra-low NOx burners (ULNBs)	26	569	0.28	0.32
ULNBs+OFA	28	553	0.27	0.31
Selective Non-Catalytic Reduction (SNCR)	30	538	0.26	0.30

[34] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
[35] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[36] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

ULNBs/SCR layered approach	81.5	142	0.070	0.080
Selective Catalytic Reduction (SCR)	81.5	142	0.070	0.080

Table 19: Drake Unit 5 NO_x Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Overfire air (OFA)	154	$141,844	$923	$923
Ultra-low NOx burners (ULNBs)	200	$147,000	$736	$112
ULNBs+OFA	215.2	$288,844	$1,342	$9,230
Selective Non-Catalytic Reduction (SNCR)	231	$1,011,324	$4,387	$47,011
ULNB/SCR layered approach	626	$4,467,000	$7,133	$8,732
Selective Catalytic Reduction (SCR)	626	$4,580,349	$7,314	---

Table 20: Drake Unit 6 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,413	0.42	
Overfire air (OFA)	20	1,130	0.33	0.38
Selective Non-Catalytic Reduction (SNCR)	30	989	0.29	0.33
Ultra-low NOx burners (ULNBs)	32	961	0.28	0.32
ULNBs+OFA	36	904	0.27	0.31
ULNBs/SCR layered approach	83.2	237	0.070	0.080
Selective Catalytic Reduction (SCR)	83.2	237	0.070	0.080

Table 21: Drake Unit 6 NO_x Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Overfire air (OFA)	283	$104,951	$371	$371
Selective Non-Catalytic Reduction (SNCR)	424	$1,208,302	$2,851	$7,810
Ultra-low NOx burners (ULNBs)	452	$232,800	$515	($34,525)
ULNBs+OFA	509	$337,751	$664	$1,857

ULNBs/SCR layered approach	1,175	$6,182,800	$5,260	$8,226
Selective Catalytic Reduction (SCR)	1,175	$6,340,797	$5,395	---

Table 22: Drake Unit 7 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	2,081	0.39	
Overfire air (OFA)	20	1,665	0.31	0.36
Ultra-low NOx burners (ULNBs)	28	1,498	0.28	0.33
Selective Non-Catalytic Reduction (SNCR)	30	1,457	0.28	0.32
ULNBs+OFA	36	1,332	0.25	0.29
ULNBs/SCR layered approach	80.1	372	0.070	0.080
Selective Catalytic Reduction (SCR)	80.1	372	0.070	0.081

Table 23: Drake Unit 7 NO_x Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Overfire air (OFA)	416	$75,217	$181	$181
Ultra-low NOx burners (ULNBs)	583	$386,000	$662	$1,867
Selective Non-Catalytic Reduction (SNCR)	624	$2,018,575	$3,233	$39,226
ULNBs+OFA	749	$461,217	$616	($12,473)
ULNBs/SCR layered approach	1,708	$8,196,000	$4,797	$5,698
Selective Catalytic Reduction (SCR)	1,708	$8,510,067	$4,981	---

Energy and Non-Air Quality Impacts

OFA: Overfire air does not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

ULNBs: The additional energy required to further pulverize coal is relatively small and is accounted for in CSU's February 2009 submittal. Therefore, ULNBs do not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

SNCR /SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR reagent injection systems have minimal power requirements.

Post-combustion add-on control technologies like SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. 100 – 300 kW is less than 1.0% of the power generated by the Drake Unit 7 boiler annually, or enough energy to power about 10 homes for a year. These energy requirements are minimal.

SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer. For example, CSU estimates that on Drake 7, the power consumption for a SCR system will be over 700 kW. These energy requirements are moderate (0.5% of Drake 7's gross output).

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas. CSU has indicated to the Division that they would prefer to use aqueous ammonia instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on an aqueous ammonia reagent versus an ammonia reagent.

Remaining Useful Life

CSU asserts that the remaining useful life of Drake Units 5, 6, and 7 are each in excess of 20 years, which is the maximum amortization period allowed in the BART analysis. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 24 shows the number of days pre- and post-control. Table 25 depicts the visibility results (98^{th} percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[37], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a NO_x BART control technology on a given unit, emission rates for the other pollutants (SO_2 and PM/PM_{10}) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed all units with NO_x emissions at 0.07 lb/MMBtu and SO_2 emissions at 0.12 lb/MMBtu for Units 6 and 7 and at 0.32 lb/MMBtu for Unit 5.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 24: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hour NOx rates	5	0.619	Rocky Mountain National Park		---	---	17	---	---
	6	0.827		34					
	7	0.710							
NOx Control Scenario	5	0.390		34	34	0	17	15	2
	6	0.390		34	31	3	17	14	3
	7	0.390		34	31	3	17	14	3
OFA	5	0.300*		n/a					
	6	0.330*		n/a					
	7	0.310*		n/a					
ULNBs	5	0.280*		n/a					
	6	0.282*		n/a					
	7	0.283*		n/a					
ULNBs+OFA	5	0.272*		n/a					
	6	0.266*		n/a					

[37] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

	7	0.251*		n/a					
SNCR	5	0.265*		n/a					
	6	0.291*		n/a					
	7	0.275*		n/a					
NOx Control Scenario	5	0.234		34	34	0	17	14	3
	6	0.234		34	31	3	17	14	3
	7	0.234		34	28	6	17	14	3
SCR	5	0.070		34	32	2	17	14	3
	6	0.070		34	27	7	17	14	3
	7	0.070		34	26	8	17	13	4
Combo	5	0.070		34	1	33	17	0	17
	6	0.070							
	7	0.070							

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "CSU Drake BART Modeling Summary" for more details.

Table 25: Visibility Results – NO_x Control Options

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)*	Output (@ 98th Percentile Impact)	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	($/dv)
Max 24-hour NOx rates	5	0.619	1.84	---	---	---
	6	0.827				
	7	0.710				
NOx Control Scenario	5	0.390	1.79	0.05	3%	n/a
	6	0.390	1.68	0.16	9%	n/a
	7	0.390	1.66	0.18	10%	n/a
OFA	5	0.300*	1.76	0.08	4%	$1,970,053
	6	0.330*	1.66	0.18	10%	$583,061
	7	0.310*	1.61	0.22	12%	$335,791
ULNB	5	0.280*	1.76	0.08	4%	$1,934,212
	6	0.282*	1.64	0.197	11%	$1,181,727
	7	0.283*	1.60	0.24	13%	$1,615,062
SNCR	5	0.265*	1.76	0.08	4%	$12,641,549
	6	0.291*	1.64	0.19	11%	$6,228,362
	7	0.275*	1.59	0.24	13%	$8,272,850
ULNBs+OFA	5	0.272*	1.76	0.08	4%	$3,703,128
	6	0.266*	1.63	0.20	11%	$1,663,798

	7	0.251*	1.58	0.26	14%	$1,794,618
NOx Control Scenario	5	0.234	1.75	0.24	5%	n/a
	6	0.234	1.62	0.24	12%	n/a
	7	0.234	1.57	0.24	15%	n/a
SCR	5	0.070	1.71	0.12	7%	$36,024,194
	6	0.070	1.56	0.27	15%	$22,647,619
	7	0.070	1.47	0.37	20%	$22,091,644
Combo	5	0.070	0.25	1.59	86%	n/a
	6	0.070				
	7	0.070				

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "CSU Drake BART Modeling Summary" for more details.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that NO_x BART for Units 5, 6, and 7 is the following NO_x emission rates:

Drake Units 5 and 6: 0.31 lb/MMBtu (30-day rolling hour average)
Drake Unit 7: 0.29 lb/MMBtu (30-day rolling hour 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 does not meet the criteria guidance described in Chapter 6.4.3 of the Regional Haze SIP (*e.g.* less than 0.50 Δdv)

Best Available Retrofit Technology (BART) Analysis of Control Options For Public Service Company – Hayden Station

I. Source Description

Owner/Operator:	Public Service Company
Source Type:	Electric Utility Steam Generating Unit
SCC (EGU):	Unit 1: 10100222 Unit 2: 10100226
Boiler Type:	Pulverized Coal, Dry-Bottom, Front-Fired, firing coal (Unit 1 a) Pulverized Coal, Dry Bottom, Tangentially-Fired, firing coal (unit 2)

The facility is located four miles east of Hayden, Colorado at 13125 U.S. Highway 40 in Routt County. This facility consists of two (2) steam driven turbine/generator units (Units 1 and 2) and the associated equipment needed for generating electricity. The Unit 1 ignitors utilize either natural gas or No. 2 fuel oil and the Unit 2 ignitors utilize No. 2 fuel oil for startup, shutdown and/or flame stabilization. In addition to the coal fired boilers, other significant sources of emissions at this facility include fugitive emissions from coal handling, ash handling and disposal and vehicle traffic on paved and unpaved roads. Point source emissions of particulate matter include coal crushing and conveying, an ash storage silo, two (2) ash recycle silos (recycle ash used with lime in the spray dryer), two (2) lime storage silos, two (2) ball mill slakers (prepares lime slurry for spray dryer) and two (2) recycle mixers (prepares recycle as slurry for spray dryer). Additional emission units at this facility include two (2) cooling towers. Only Units 1 and 2 are BART-eligible. Table 1 below lists the units at Public Service Company Hayden Station that the Division examined for control to meet BART-eligible requirements. Controlled and uncontrolled emission factors and CAMD data were used to evaluate the control effectiveness of the current emission controls.

Table 1: Hayden Boilers Technical Information

	Unit 1	Unit 2
Placed in Service	July 1965	1976
Boiler Rating, MMBtu/Hr for coal	1,963	2,712
Electrical Power Rating, Gross Megawatts	190	275
Description	Riley-Stoker Pulverized Coal Front Fired Dry Bottom, firing coal with natural gas and No. 2 fuel oil used for startup, shutdown and/or flame stabilization.	Combustion Engineering Pulverized Coal Tangentially Fired Dry Bottom, firing coal with No. 2 fuel oil used for startup, shutdown, and/or flame stabilization.
Air Pollution Control Equipment	PM/PM_{10} - Reverse-Air Fabric Filter Baghouse NO_x – Low NO_x Burners with Over-Fire Air SO_2 – Lime Spray Dryer	PM/PM_{10} – Reverse-Air Fabric Filter Baghouse NO_x – Low NO_x Burners with Over-Fire Air SO_2 – Lime Spray Dryer

	All equipment commenced operation in December 1998	All equipment commenced operation in October – December 1999
Emissions Reduction (%)*	NO_x – 54.1% SO_2 – 82.0% PM – 99.7% PM_{10} – 98.8%	NO_x – 33.3% SO_2 – 79.6% PM – 99.7% PM_{10} – 98.9%

*Emissions Reduction estimated by comparing uncontrolled AP-42 factor to actual average emission factor for PM/PM_{10}. For NO_x and SO_2 estimates, CAMD data was used to calculate reductions. See "Hayden APCD Technical Analysis" for further details. Not based on actual testing.

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 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 Division requests, PSCo submitted additional information on May 25 and July 14, 2010. The submittals are included as "PSCo BART Submittals".

II. Emissions for Units 1 & 2

PSCo estimated that a realistic depiction of anticipated annual emissions for Units 1 and 2, or "Baseline Emissions", to be conservative, was the average of two previous years (2004, 2005) of emissions data in the September 14, 2006 analysis. Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses. Therefore, the Division used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database. These emissions are summarized in Table 2.

Table 2: PSCo Hayden Units 1 & 2 Emissions

Pollutant	Unit 1		Unit 2	
	Annual Emissions* (tpy)	Annual emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Annual emissions** (lb/MMBtu)
NO_x	3,750	0.415	3,743	0.320
SO_2	1,172	0.131	1,469	0.127
PM_{10}	88.0	0.006***	109.3	0.004***

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).
**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for NO_x and SO_2 emissions.
***The PM_{10} emission rate is determined from the latest Title V permit compliance stack test (June 2009). These values are as follows: Hayden Unit 1: 0.006 lb/MMBtu Hayden Unit 2: 0.004 lb/MMBtu

III. Units Evaluated for Control

PSCo notes that the Hayden boilers burn Colorado coal that primarily comes from two different mines in northwestern Colorado, the Twenty Mile Mine and the ColoWyo Mine. Coal characteristics are very similar from both of these mines. However, the ColoWyo coal is ranked as sub-bituminous while the Twenty Mile coal is ranked as bituminous (ASTM Method 388). However, PSCo performed an analysis using the Electric Power Research Institute ("EPRI") NOx/LOI Predictor software program (Version 2.1) to demonstrate that the more appropriate rating for ColoWyo coal is bituminous. The specifications for these coals are listed below in Table 3. Note that with the exception of moisture content, the coal characteristics are reasonably close for the two coals.

Table 3: Hayden Station Coal Specifications (2004 – 2005)

Coal Mine/Region	Colowyo	Twentymile
Coal Rank Classification	Sub-bituminous, Class A	Bituminous
As Received Analysis		
H_2O (Moisture %)	16.8	9.8
Ash (%)	5.82	9.5
Sulfur (%)	0.36	0.49
Nitrogen (%)	1.33	1.65
Heating Value (HHV Btu/lb)	10,450	11,350
EPRI Model NO_x Prediction (lb/MMBtu)	0.46	0.39

Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal as well as the highest ash and sulfur content from the two coals for conservative estimates.

Table 4: Uncontrolled emission factors for PSCo Hayden BART-eligible sources[1]

	Pollutant (lb/ton)*			
Emission Unit	NO_x	SO_2	PM (filterable)	PM_{10} (filterable)
Hayden Unit 1	22**	18.6	95	21.9
Hayden Unit 2	15**	18.6	95	21.9

*SO_2 and PM/PM_{10} factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, determined from Table 3.
**Assumed no low-NO_x burners.

IV. BART Evaluation of Units 1 and 2

A. Sulfur Dioxide (SO_2)

Step 1: Identify All Available Technologies

Semi-Dry FGD Upgrades – As discussed in EPA's BART Guidelines[2], electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not

[1] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[2] EPA, 2005. Federal Register, 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations: Final Rule. Pgs. 39133.

required to remove these controls and replace them with new controls. The Division interprets this to include fuel switching to natural gas, which would require significant boiler modifications, including removing the semi-dry FGD.

However, based on Appendix Y [70 FR 39171], the following dry scrubber upgrades should be considered for Hayden Units 1 and 2 if technically feasible. These upgrades include:
-Use of performance additives
-Use of more reactive sorbent
-Increase the pulverization level of sorbent
-Engineering redesign of atomizer or slurry injection system
-Additional equipment and maintenance: In the May 25, 2010 response to the Division, PSCo noted that Hayden Units 1 and 2 could potentially achieve a new reduced 30-day average emission rate limit of 0.13 lbs/MMBtu by conducting changes to the dry scrubber systems, so this option will be evaluated as part of possible semi-dry FGD upgrades.

The current Operating Permit limits are depicted in Table 5.

Table 5: Hayden Units 1 & 2 SO_2 Operating Permit Limits

	SO_2 limits (lb/MMBtu)			Reduction (%) Required 30-day rolling
	3-hr rolling	30-day rolling	90-day rolling	
Units 1 & 2	1.2	0.160	0.130	82 (rounded)

Step 2: Eliminate Technically Infeasible Options

At the Division's request, PSCo submitted an SO_2 upgrade analysis to the Division on May 25, 2010 regarding potential upgrades for the LSDs installed on Hayden Units 1 and 2. The following summarizes PSCo's submittal and the Division's analysis of the information provided.

FGD: Flue gas desulfurization removes SO_2 from flue gases by a variety of methods. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

Dry FGD Upgrades: Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants[3]. SDA systems are typically utilized at units that burn lower-sulfur coal in the western U.S., where water resources are limited. A SDA system must be located before the boiler flue gases enter the baghouse. Each reactor vessel requires a "foot print" area comprising about 2,000 to 4,000 square feet (depending on volume of flue gas treated) along with additional space for support equipment access, slurry preparation, mixing and associated tanks.

[3] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

PSCo installed lime spray dryers (LSDs) in connection with baghouses on Hayden Units 1 and 2 1998 and 1999, respectively. PSCo notes that both of these dryers currently achieve greater than 80% removal, with actual annual averages of 0.13 lbs SO_2/MMBtu (each unit) in comparison with the permit limits[4] depicted in Table 5. This system exceeds EPA's presumptive limits stated in 40 CFR Part 51 Appendix Y of 0.15 lb/MMBtu, although the current permit limit is higher than the presumptive limits.

At the Division's request, PSCo submitted a SO_2 upgrade analysis to the Division on May 25, 2010 regarding potential upgrades for the lime spray dryer systems at Hayden Station. Hayden's Babcock and Wilcox (B&W) lime spray dryers that use a single atomizer per scrubber module design that sprays a mixture of lime and recycled ash into the flue gas. This atomized mist then dries, reacts with SO_2 in the flue gas and is collected in the baghouse.

PSCo examined potential upgrades to the Hayden dry scrubbers, with the following results:

-*Use of performance additives:* The supplier (Babcock & Wilcox) of PSCo's Colorado dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, which have been used on dry scrubbers. Chlorides are used to slow the drying time of the fly ash/lime mixture used to capture the gaseous SO_2. The chemistry of the calcium sulfate/sulfite reaction is much more effective when liquid water droplets exist. By slowing the drying time the theory is that the lime sorbent will be more efficient and the lime use could be decreased to obtain the same SO_2 reduction capability of the equipment unless the unit is limited on the total amount of lime slurry injection. There are cases on units that use high sulfur coal (significantly greater than 1.2 lbs/MMBtu) where the total amount of lime slurry injection is limited by the solids content of the slurry. When the total limit injection for a unit is limited, additives may allow some increase in SO_2 removal. However, because the Hayden boilers burn low sulfur western coals, PSCo is not limited on lime slurry injection and the use of performance additives on the scrubbers would not be expected to increase the SO_2 removal. Based on the information provided by PSCo, the Division agrees that the use performance additives are not likely to increase SO_2 removal and therefore warrants no further consideration.

-*Use of more reactive sorbent:* All PSCo dry scrubbers were designed to use a highly reactive lime with 92% calcium oxide content. The scrubbers were also designed to inject fly ash to maximize available surface area and allow efficient lime reagent use. Some dry scrubbers used by other companies were designed to use a lower quality lime, a dry hydrated lime product, or operate on lime without fly ash. On these scrubbers, the option of using a higher quality lime or injecting fly ash possibly could improve 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.

[4] Colorado Operating Permit Number 96OPROB132 Last Revised 5/14/10. Pgs. 6, 9.

Lime is the reagent of choice in modern spray dryer systems on utility scale units. PSCo is aware of only one exception that was designed to use sodium carbonate to remove SO_2. The Coyote Station, a 420MW unit located near Beulah, North Dakota and operated by Otter Tail Power Company, was placed in service in 1981. The spray dryer was supplied by Rockwell and used rotary atomizers. The unit was designed to obtain 70% SO_2 removal. This unit was reported to have a visible plume at times likely due to the conversion from NO to NO_2 due to the sodium reagent. This unit was converted from sodium carbonate to lime after a number of years in service. PSCo verified with the two major suppliers of utility sized spray dryers, B&W and Alstom, and confirmed that there are no other operating utility spray dryers in the United States. B&W also states that in theory the sodium based reagents are more reactive as they have a slower drying time than lime reagents. However, because of their slower drying time, the spray dryer absorber would need to be larger to ensure the product was dry when leaving the scrubber. Thus, the use of sodium reagent in a unit designed for lime would not allow higher SO_2 removal and it may not even be possible to convert to a sodium reagent with the existing equipment.

PSCo is using a highly reactive reagent that maximizes SO_2 removal; there are no known acceptable reagents without side effects that would allow additional SO_2 removal in the dry scrubbing systems present at Hayden Station. The Division agrees with PSCo's assessment and considers that use of a more reactive sorbent does not warrant further consideration.

-*Increase the pulverization level of sorbent:* The Hayden dry scrubbers are designed with either horizontal or vertical ball mills to obtain optimum particulate size and reduce lime grit generation. There have been some technical papers presented by pulverizer suppliers, that state vertical ball mills may provide a smaller particulate size and reduce lime use. PSCO's experience is that there is no SO_2 removal benefit in using vertical ball mills versus horizontal ball mills and there is also no measurable reduction in lime use. Since PSCo already uses the best available grinding technologies, the Division would agree that changes to the design of the atomizers are unlikely to result in a higher SO_2 removal.

-*Engineering redesign of atomizer or slurry injection system:* The Hayden dry scrubber systems are from B&W and use the same size and general design atomizer, a Model F800. While there are differences in the motor size and exact atomizer wheel construction that relate to the total slurry injection rate, the atomizer design is based on the vendor's experience to maximize both SO_2 removal and lime use efficiency. B&W offers no upgrade in atomizer design to improve SO_2 removal. There are certain third-party suppliers who offer different atomizer nozzle designs that they claim can reduce lime use or provide longer maintenance life. To PSCo's knowledge, no vendors claim an improved SO_2 removal. PSCo has tried some of these different nozzle designs and doesn't believe any of the designs improve the SO_2 removal level, although some have improved wear life and reduced maintenance costs.

However, PSCo provided to the Division upon additional request (July 14, 2010) additional information stating that an additional scrubber module (i.e. atomizer) would be required for each unit as well as additional spare parts and maintenance personnel in order to meet a lower emission limit. Therefore, this option is technically feasible.

-*Additional equipment and maintenance*: PSCo reviewed actual operating experience on Hayden along with possible changes to the systems necessary to achieve lower emission rates on a 30-day average basis. The primary factors that affect SO_2 control efficiency for short-term averages are start-ups, equipment malfunctions, and low load operation. In order to begin injecting lime/recycle ash slurry into the scrubber, a minimum inlet scrubber temperature must be achieved so the lime/recycle ash slurry dries when it hits the hot flue gas. When the scrubber inlet temperature is below this minimum level, the lime slurry drops out in the scrubber and forms concrete-like deposits that eventually plug the scrubber vessel. This situation actually occurred while operating PSCo's Comanche Unit 2 and Valmont Unit 5 scrubbers and resulted in extended maintenance outages to clean the scrubbers. During unit start-ups, it can take anywhere from 12-24 hours to get the inlet scrubber temperatures up to the level necessary for safe lime slurry injection.

During these start-up periods, SO_2 emissions rates are at uncontrolled levels based on the sulfur content in the coal. Typically, if the unit only starts once during a 30-day period, operators can over-control SO_2 by running the scrubber below the 30-day average emission rate to "make-up" for higher emission rates during start-up. If the unit has more than one start-up in a 30-day period, which certainly happens with older units, it becomes nearly impossible to scrub hard enough to achieve the 30-day rolling emission rate limits. The same situation occurs under low load operation, especially during winter months. Inlet temperature to the baghouse due to air heater in-leakage can approach minimum acceptable levels, thus lowering overall SO_2 control efficiency during low load operation. PSCo coal-fired units will be required to cycle (under 60% load) more in the future to accommodate the intermittent nature of ever increasing wind generation on the electric grid and thus requiring the boilers to operate more frequently at low loads.

Based on a review of actual operating data and the factors noted above that affect short-term average SO_2 emission rates, PSCo believes Hayden Units 1 and 2 can achieve a lower 30-day average emission rate limit of 0.13 lbs/MMBtu as BART. This is currently the 90-day average emission limit for these units. In order to meet this lower limit on a 30-day average basis, the plant needs to purchase additional spare atomizer parts and increase annual operating and maintenance due to increased labor and reagent requirements.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

PSCo provided the Division 30-day rolling average control estimates. In the Division's experience, 30-day SO_2 rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected an annual average emission rate at 5% for Hayden to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by PSCo as well as other control techniques applied to pulverized coal boilers. A Division review of the EPA's RBLC revealed recent BACT SO_2 determinations range from 0.06 – 0.167 lbs/MMBtu. The Division narrowed down this range depending on the averaging time, permit type, facility size, and fuel type. This narrowed range is 0.095 – 0.161 lbs/MMBtu, with an average of 0.119 lbs/MMBtu rounded to 0.12 lbs/MMBtu. While determinations made by other states do not dictate the emissions rate choice made by the

Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details.

Engineering redesign of atomizer or slurry injection system: At the Division's request, PSCo sent cost information regarding the requirements for an additional scrubber module on July 14, 2010 in order to meet a SO_2 30-day rolling emission limit of 0.08 lb/MMBtu, or 90% control efficiency (pre-control). This upgrade/redesign will result in control efficiencies of 41.7% and 40.1% beyond the current reductions shown in Table 1 on Units 1 and 2, respectively. Using this information, the Division calculated the resultant control effectiveness using the baseline and annual emissions for each unit. See "Hayden APCD Technical Analysis" for more information.

Dry FGD Upgrade – Additional equipment and maintenance: To evaluate the control effectiveness of tightening the 30-day rolling emission limits on Hayden Units 1 and 2, the Division used the annual baseline emissions, the average annual operating hours (2006 – 2008), and the daily heat input (MMBtu/day) to determine the emission rates at 0.13 lb/MMBtu and calculated the resultant control effectiveness and annual emissions for each unit.

Table 6 summarizes each available technology and technical feasibility for SO_2 control.

Table 6: Hayden Units 1 and 2 SO_2 Technology Options and Technical Feasibility

Technology		Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Dry FGD Upgrades			
	Use of performance additives	n/a	N
	Use of more reactive sorbent	n/a	N
	Increase pulverization level of sorbent	n/a	N
	Engineering redesign of atomizer or slurry injection system	~40 – 42%	Y
	Additional equipment and maintenance	~3 - 5%	Y

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

Engineering redesign of atomizer or slurry injection system: The Division calculated cost estimates for an additional scrubber module – based on total capital and operating and maintenance costs provided in PSCo's July 14, 2010 letter. PSCo stated that Hayden Station will need for an additional module on each unit as well as estimated spare parts and additional maintenance personnel (i.e. O&M costs). PSCo estimated capital costs for Unit 1 at $37,000,000 and Unit 2 at $43,000,000 and operating & maintenance costs at $650,000 and $750,000 for Units 1 and 2, respectively. These costs are determined based on meeting a more stringent 30-day rolling limit of 0.08 lb/MMBtu for each unit.

Dry FGD Upgrade – Additional equipment and maintenance: The Division calculated cost estimates for dry FGD upgrade – additional equipment and maintenance – based on total capital and operating and maintenance costs provided in PSCO's May 25, 2010 letter. PSCo stated that Hayden Station will need spare atomizer parts at a cost of $330,000 along with increased annual operating and maintenance costs of $220,000 per year for reagent and labor to meet the more stringent 30-day rolling SO_2 emission limit of 0.13 lbs/MMBtu. This cost analysis was conducted to demonstrate the impact of meeting the more stringent limit only. Table 7, Table 8, Table 9, and Table 10 show the SO_2 control cost per unit.

Table 7: Hayden Unit 1 Control Resultant SO_2 Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,172	0.131	
Dry FGD Upgrade – Additional Equipment and Maintenance	5.2%	1,111	0.124	0.130
Additional Scrubber Module	41.7%	684	0.076	0.080

Table 8: Hayden Unit 2 Control Resultant SO_2 Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,469	0.127	
Dry FGD Upgrade – Additional Equipment and Maintenance	2.7%	1,430	0.124	0.130
Additional Scrubber Module	40.1%	880	0.076	0.080

Table 9: Hayden Unit 1 SO_2 Cost Effectiveness

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Dry FGD Upgrade – Additional Equipment and Maintenance	61	$141,150	$2,317	$2,317
Additional Scrubber Module	488	$4,142,538	$8,490	$9,370

Table 10: Hayden Unit 2 SO_2 Cost Effectiveness

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Dry FGD Upgrade – Additional Equipment and Maintenance	39	$141,150	$3,626	$3,626
Additional Scrubber Module	589	$4,808,896	$8,164	$8,485

Energy and Non-Air Quality Impacts

There are no energy and non-air quality impacts related to tightening the emission limit for SO_2 beyond the acquisition of additional reagent. Thus, this factor does not influence the selection of controls.

Remaining Useful Life

PSCo asserts that the remaining useful life of Hayden Units 1 and 2 are each in excess of 20 year, which is the maximum amortization period allowed in the BART analysis. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 11 shows the number of days pre- and post-control. Table 12 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[5], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO_2 BART control technology on a given unit, emission rates for the other pollutants (NO_x and PM/PM_{10}) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed Units 1 and 2 with NO_x emissions at 0.07 lb/MMBtu and SO_2 emissions at 0.12 lb/MMBtu.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together.

[5] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 11: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals Pre-Control Days >0.5 dv	3-year totals Post-Control Days >0.5 dv	Δ days	3-year totals Pre-Control Days >1.0 dv	3-year totals Post-Control Days >1.0 dv	Δdays
Max 24-hr SO_2 rates	1	0.339	Rocky Mountain National Park	236	---	---	155	---	---
	2	0.402							
Dry FGD Upgrade	1	0.160*		n/a					
	2	0.160*		n/a					
Dry FGD Upgrade	1	0.130		236	228	8	155	147	8
	2	0.130		236	224	12	155	143	12
Additional Scrubber Module	1	0.100		236	228	8	155	146	9
	2	0.100		236	223	13	155	143	12
Additional Scrubber Module	1	0.070		236	228	8	155	146	9
	2	0.070		236	223	13	155	142	13
Combo	1	0.070		236	57	179	155	6	149
	2	0.070							

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Hayden BART Modeling Summary" for more details.

Table 12: Visibility Results – SO_2 Control Options

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Output (@ 98th Percentile Impact)	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	($/dv)
Max 24-hr SO_2 rates	1	0.339	3.627	---	---	---
	2	0.402				
Dry FGD Upgrade	1	0.160*	3.540	0.09	2%	n/a
	2	0.160*	3.445	0.18	5%	n/a
Dry FGD Upgrade	1	0.130	3.525	0.10	3%	$1,383,820
	2	0.130	3.422	0.21	6%	$688,535
Additional Scrubber Module	1	0.100	3.505	0.12	3%	$33,955,232
	2	0.100	3.395	0.23	6%	$20,727,999
Additional Scrubber Module	1	0.070	3.485	0.14	4%	n/a
	2	0.070	3.367	0.26	7%	n/a

Combo	1 2	0.120 0.120	0.91	2.72	75%	n/a

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Hayden BART Modeling Summary" for more details.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that SO_2 BART the following SO_2 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 (LSDs). 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 SO_2 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.

B. Filterable Particulate Matter (PM_{10})

Hayden Units 1 and 2 are each equipped with reverse-air fabric filter baghouses to control PM/PM_{10} emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Table 13 shows the most recent stack test data (2009). Real-time data demonstrates that these baghouses are meeting >99% control. The Title V permit limit is 0.03 lb/MMBtu. The most recent stack test data is used to determine compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

Table 13: Hayden Units 1 and 2 Stack Test Results (2009)

Pollutant	Unit 1 (lb/MMBtu)	Unit 2 (lb/MMBtu)
Filterable PM_{10}	0.006	0.004
PM_{10} Control efficiency	99.85%	99.91%

A Division review of EPA's RBLC revealed recent BACT PM/PM_{10} determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. While determinations made by other states do not dictate the emissions rate choice made by the

Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to “Division RBLC Analysis” for more details.

Both boilers must meet the PM emission standard of 0.03 lb/MMBtu in accordance with the Long-Term Strategy Review and Revision of Colorado’s SIP for Class I Visibility Protection Part I: Hayden Station Requirements (8/15/96), as approved by EPA at 62 FR 2305 (1/16/97), Section VI.C.V.8.c.ii(2).

The state has determined that the 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 control technology and 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. Thus, as described in EPA’s BART Guidelines, a full five-factor analysis for PM/PM_{10} is not needed for Hayden Units 1 and 2.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies
PSCo identified three options for NO_x control:
Low NO_x burners (next generation)
Selective Non-Catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)

The Division also identified and examined the following additional control options for these units:
Electro-Catalytic Oxidation (ECO)®
Rich Reagent Injection (RRI)
Rotating overfire Air (ROFA)
Separated overfire Air (SOFA)
Low NO_x Burners (LNB)
LNB + SOFA
Coal reburn +SNCR

Step 2: Eliminate Technically Infeasible Options
Low NO_x burners (PSCo – LNB): PSCo evaluated low NO_x burner upgrades for Hayden Units 1 and 2, completing studies in July 2006. Units 1 and 2 currently have first-generation low NO_x burners and over-fire air systems. The combustion modifications include upgrades to these existing low NO_x burners rather than complete burner replacements. In addition, changes to the over-fire air systems were also needed to achieve further NO_x reductions on these units. LNB upgrades are technically feasible for Hayden Units 1 and 2.

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for Hayden Units 1 and 2.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

While a lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for Hayden, two retrofit SCR systems, the 0.07 lb/MMBtu controlled NO_x value is more expected. The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. There are three different types of SCR arrangements – high-dust, low-dust, and tail-end. The pre-dominant arrangement applied in the United States has been high-dust. In most circumstances, a high-dust SCR system is the most economical arrangement alternative. PSCo economically evaluated a high-dust SCR arrangement. SCR is a technically feasible alternative for Hayden Units 1 and 2.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[6] and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[7] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 1 and 2.

LNB/ROFA®/SOFA/LNB+SOFA: Hayden Units 1 and 2 are already equipped with low NO_x burners with over-fire air (LNB+OFA)as part of a consent decree entered by the District Court on August 19,1996, Civil Action 93-B-1749 and adopted into revisions to Colorado's Visibility SIP, specified in a document entitled "Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part I: Hayden Station Requirements," dated August 15, 1996. Table 1 illustrates that these systems achieve 49.5% and 43.3% NO_x reductions (based on actual emissions) on Units 1 and 2, respectively.

ROFA® injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA® differs from OFA in that ROFA® utilizes a booster fan to

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[6] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[7] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php

increase the velocity of air to promote mixing and to increase the retention time in the furnace. To date, ROFA® has only been installed as a retrofit technology on units firing eastern bituminous coals.

Based on data published by the manufacturer, ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load[8]. While ROFA is considered superior to SOFA alone, ROFA alone is not superior to LNB+SOFA and is not expected to increase emissions reductions for Hayden Units 1 and 2. Since ROFA® technology would not be expected to provide better emissions performance than the LNB+SOFA baseline for these units, ROFA® technology is not considered further in this analysis.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu[9]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

PSCo provided the Division 30-day rolling average control estimates. The Division, from experience and other state BART proposals[10], determined that 30-day NO_x rolling average emission rates are expected to be about 5 -15% higher than the annual average emission rate. The Division projected an annual average emission rate at 15% for Hayden to determine control efficiencies and annual reductions.

Low NO_x burners (PSCo – LNB): PSCo stated in their April 20, 2010 submittal that Hayden Units 1 and 2 can meet a 30-day rolling limit of 0.30 lb/MMBtu and 0.24 lb/MMBtu respectively with upgraded low NO_x burner systems. The baselines from Table 2 show that Hayden Unit 1 baseline NO_x emissions are 0.415 lb/MMBtu and Unit 2 baseline NO_x is 0.320 lb/MMBtu. Therefore, the control effectiveness for upgraded low NO_x systems for Unit 1 is 37.1% and Unit 2 is 34.8%. As shown in Table 1, the current low-NO_x burners with overfire air systems achieve 54.1% and 31.3% control respectively. These upgrade control estimates are greater than EPA's AP-42 emission factor table, which estimate LNB with OFA as achieving 40 – 60% reduction.[11] In a recent AWMA study, wall-fired boilers burning sub-bituminous coal fitted with LNB+OFA system achieved NO_x reductions from 40 – 80.9% (similar to Hayden Unit 1). Tangential-fired boilers achieved NO_x reductions ranging from 11.3 – 74.4%.[12] With such wide control

[8] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html
[9] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf
[10] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.
[11] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[12] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

efficiency ranges, the Division concludes that the 88.9% and 66.1% (pre-control) reductions estimated by PSCo are reasonable.

SNCR: PSCo stated in their April 20, 2010 submittal that Hayden Units 1 and 2 can meet a 30-day rolling limit of 0.30 lb/MMBtu and 0.21 lb/MMBtu respectively by installing SNCR on each boiler. Therefore, the control effectiveness for SNCR on Unit 1 is 37.1% and Unit 2 is 43.0%. These control effectiveness estimate is consistent with EPA's SNCR Air Pollution Control Technology Fact Sheet between 30 – 50% control efficiency for tangentially fired boilers. Control effectiveness has been historically noted to be lower for wall fired boilers similar to Unit 1. Therefore, the Division concludes that the reductions estimated by PSCo are reasonable.

SCR: PSCo stated in their April 20, 2010 submittal that Hayden Units 1 and 2 can meet a 30-day rolling limit of 0.08 lb/MMBtu and 0.07 lb/MMBtu respectively by installing SCR on each boiler. Therefore, the control effectiveness for SCR on Unit 1 is 83.2% and Unit 2 is 81.0%. These control efficiencies are consistent with EPA's AP-42 emission factor tables, which estimate SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.[13,14]

Table 14 summarizes each available technology and technical feasibility for NO_x control.

Table 14: Hayden Units 1 and 2 NOx Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO_x Burner (LNB) Upgrade	~35 - 37%	Y
SNCR	20 – 50%	Y
SCR	75 – 90%	Y
Electro-Catalytic Oxidation (ECO)®	n/a	N
Rich Reagent Injection (RRI)	n/a	N
Low NO_x Burners (LNB)	10-30%	Y – installed
LNB + OFA	25-45%	Y – installed
Air Staging – overfire air (OFA)	5-40%	Y – installed
Rotating overfire air (ROFA)	45 – 65%	N
Coal reburn+SNCR	n/a	N

[13] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[14] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

Low NO_x burners (PSCo – LNB)/SNCR/SCR: PSCo completed engineering studies in July 2006 to evaluate the cost of combustion controls on Hayden Units 1 and 2. These cost estimates, in 2006 dollars, were based on vendor data and not on actual bids with performance guarantees. PSCo used the Coal Utility Environmental Cost Workbook (CUECost) to develop cost estimates for capital and annual costs ,an EPA-approved methodology to estimate rough order-of-magnitude (ROM) cost estimates for air pollution control systems installed on coal-fired power plants (± 30%).[15] PSCo provided CUECost input files at the Division's request on April 20, 2010. PSCo used this program for LNB, SNCR, and SCR system estimates. The Division concurs that CUECost is an appropriate methodology for determining cost effectiveness regarding these control technologies.

LNB: In reviewing PSCo's estimates, the Division found that the ratio of annual costs to the total costs for LNBs, which at 11.7% is consistent with an EPA assessment that concluded that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments. [16] Therefore, the Division concludes that PSCo's estimates for LNBs are reasonable.

SNCR: A typical breakdown of annualized costs for SNCR on industrial boilers will be 15 – 25% for capital recovery and 65 – 85% for operating expenses.[17] The PSCo-estimated SNCR costs for operating expenses are 74% and 77% for Hayden Units 1 and 2 respectively. Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[18]

The cost effectiveness for SNCR on Units 1 and 2 is about $1,000 and $1,200 per ton, respectively. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers (similar to Unit 2) achieving NO_x emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of NO_x reduced,

[15] 2009, Yelverton, William H. "Coal Utility Environmental Cost (CUECost) Workbook Development Documentation Version 5.0. Prepared by: ARCADIS, 4915 Prospectus Drive, Suite F, Durham, NC 27713. Prepared for: U.S. Environmental Protection Agency, Office of Research and Development, Air Pollution Prevention and Control Division, Research Triangle Park, NC 27711.
[16] Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.
[17] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.
[18] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

depending on initial capital costs and capacity factor.[19,20] This same study estimate SNCR retrofits on wall fired boilers (similar to Unit 1) achieving 0.50 – 0.65 lb/MMBtu and emission reductions of 30 – 50% as costing $590 - $1,100 per ton of NO_x reduced, depending on initial capital costs and capacity factor. It should be noted that PSCo is estimating resultant emission rates lower than 0.30 lb/MMBtu for both boilers. EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NO_x reduced.[21] PSCo's estimates are within this range. Therefore, the Division concludes that PSCo's cost estimates for SNCR are reasonable.

SCR: Recent NESCAUM studies estimate SCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.10 – 0.15 lb/MMBtu and emission reductions of 75 – 85% as costing $2,600 - $5,000 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[22,23] In reviewing PSCo's estimates, the Division found that the ratio of annual costs to the total costs for LNBs, which at 17% is higher than an EPA assessment that concluded that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments.[24] However, PSCo's cost estimates are within the NESCAUM study ranges, so the Division concludes that PSCo's cost estimates for SCR are reasonable.

Table 15, Table 16, Table 17, and Table 18 depict controlled NO_x emissions and control cost comparisons.

Table 15: Hayden Unit 1 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	3,750	0.415	
LNB*	37.1	2,359	0.261	0.300
SNCR*	37.1	2,359	0.261	0.300
SCR**	83.2	630	0.070	0.080

*Determined based on difference between baseline (2006 – 2008) and PSCo's expected emission rates

[19] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[20] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.
[21] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
[22] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[23] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.
[24] Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.

**The Division calculated SCR reductions using a consistent baseline whereas PSCo uses an adjusted baseline depending on the control technology which results in different control costs.

Table 16: Hayden Unit 2 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	3,743	0.320	
LNB*	34.8	2,441	0.209	0.240
SNCR*	43.0	2,134	0.183	0.210
SCR**	81.0	711	0.061	0.070

*Determined based on difference between baseline (2006 – 2008) and PSCo's expected emission rates
**The Division calculated SCR reductions using a consistent baseline whereas PSCo uses an adjusted baseline depending on the control technology which results in different control costs.

Table 17: Hayden Unit 1 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
LNB	1,391	$572,010	$411	$411
SNCR	1,391	$1,353,500	$973	---
SCR	3,120	$10,560,612	$3,385	$5,326

Table 18: Hayden Unit 2NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
LNB	1,303	$992,729	$762	$762
SNCR	1,610	$1,893,258	$1,176	$2,934
SCR	3,032	$12,321,491	$4,064	$7,331

Energy and Non-Air Quality Impacts

LNB: There are no known non-air quality impacts associated with upgrades on low-NO_x burner systems. Energy impacts are not significant. Thus, this factor does not influence the selection of this control.

SNCR/ SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR reagent injection systems have minimal power requirements.

Post-combustion add-on control technologies such as SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. 100 – 300 kW is less enough energy to power about 10 homes for a year. These energy requirements are minimal.

SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer. These energy requirements are moderate.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas.

Remaining Useful Life

PSCo asserts that there are no near-term limitations on the useful of these boilers, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 19 shows the number of days pre- and post-control. Table 20 depicts the visibility results (98^{th} percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[25], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a NO_x BART control technology on a given unit, emission rates for the other pollutants (SO_2 and PM/PM_{10}) and other BART-eligible units are held constant at pre-control levels. For BART

[25] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed Units 1 and 2 with NO_x emissions at 0.07 lb/MMBtu and SO_2 emissions at 0.12 lb/MMBtu.

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 19: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals Pre-Control Days >0.5 dv	3-year totals Post-Control Days >0.5 dv	Δdays	3-year totals Pre-Control Days >1.0 dv	3-year totals Post-Control Days >1.0 dv	Δdays
Max 24-hr NOx rates	1	0.610	Mt. Zirkel Wilderness Area	236	---	---	155	---	---
	2	0.367							
NOx Scenario	1	0.390		236	227	9	155	131	24
	2	0.280		236	230	6	155	144	11
NOx Scenario	1	0.300		236	218	18	155	125	30
	2	0.210		236	226	10	155	137	18
LNB	1	0.261*		n/a					
	2	0.209*		n/a					
SNCR	1	0.261*		n/a					
	2	0.183*		n/a					
SCR	1	0.070		236	188	48	155	91	64
	2	0.070		236	213	23	155	116	39
Combo	1	0.070		236	57	179	155	6	149
	2	0.070							

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Hayden BART Modeling Summary" for more details.

Table 20: Visibility Results – NO_x Control Options

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)*	Proposed Limit (@ 98th Percentile Impact) (deciviews)	98th Percentile Impact Improvement (deciviews)	98th Percentile Improvement from Maximum (%)	Cost Effectiveness ($/deciview)
Max 24-hr	1	0.610	3.63	---	---	---

NOx rates	2	0.367				
NOx Scenario	1	0.390	3.13	0.50	14%	n/a
	2	0.280	3.42	0.20	6%	n/a
NOx Scenario	1	0.300	3.02	0.60	17%	n/a
	2	0.210	3.23	0.40	11%	n/a
LNB	1	0.261*	2.94	0.69	19%	$832,621
	2	0.209*	3.23	0.40	11%	$2,500,576
SNCR	1	0.261*	2.94	0.69	19%	$1,970,161
	2	0.183*	3.15	0.48	13%	$3,969,094
SCR	1	0.070	2.51	1.12	31%	$9,462,914
	2	0.070	2.77	0.85	24%	$14,427,975
Combo	1	0.070	0.91	2.72	75%	n/a
	2	0.070				

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Hayden BART Modeling Summary" for more details.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that NO_x BART is the following NO_x 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 in Chapter 6 of the Regional Haze State Implementation Plan:

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

The dollars per ton control costs, coupled with notable visibility improvements leads the state to this determination. The NO_x 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.

APPENDIX D

Regional Haze State Implementation Plan

Technical Support for the Reasonable Progress Determinations

Reasonable Progress (RP) Four-Factor Analysis of Control Options
For
Colorado Energy Nations, Golden, Colorado

I. Source Description

Owner/Operator: Colorado Energy Nations (CENC) (formerly Trigen Colorado Energy Corporation)
Source Type: Steam Generating Unit
Boiler Type(s): Boiler 1 – Natural Gas Front-Fired (SCC: 10200601 for natural gas)
Boiler 2 – Natural Gas Front-Fired (SCC: 10200601 for natural gas)
Boiler 3 – Pulverized Coal Spreader Stoker (SCC: 10200224)
Boiler 4 – Pulverized Coal Dry-Bottom Tangentially-Fired (SCC: 10200222 for coal)
Boiler 5 – Pulverized Coal Dry-Bottom Tangentially-Fired (SCC: 10200222 for coal)

The CENC facility is located in Jefferson County on 10th Street in the town of Golden, Colorado. Figure 1 below provides an aerial perspective of the CENC site. The two large buildings are separated by Clear Creek and US Highway 58 borders the northern side of the CENC site.

Figure 1: CENC facility Aerial Perspective

The CENC facility consists of five (5) boilers and the associated equipment for coal and ash handling. The boilers provide steam for one (1) 20 MW generator, two (2) 10 MW generators, and for industrial use. The boilers are rated at 228 MMBtu/hr (Boilers 1 and 2), 225 MMBtu/hr (Boiler 3), 360 MMBtu/hr (Boiler 4) and 650 MMBtu/hr (Boiler 5). Boilers 1 and 2 normally operate in hot standby mode or when one of the coal boilers (Boilers 3, 4, or 5) is down. Boilers 3, 4, and 5 are controlled for PM/PM_{10} by separate fabric filter baghouses, which were installed at the time of construction for each boiler. The boilers were installed as follows:

- Boiler 1 – 1962
- Boiler 2 – 1962
- Boiler 3 – 1962 – updated to coal in 1981
- Boiler 4 – 1974 – last modification in 1975
- Boiler 5 – 1979 – reached full capacity in 1980

No coal processing is performed on-site. The coal is received ready for feed to the boilers. Boilers 4 and 5 are equipped with pulverizers that process the coal directly into the fire zone. The ash and flyash from the boilers may be sold or transported off-site for disposal. Therefore, all fugitive dust sources at the facility are related to coal conveying or ash handling. There is also one Detroit Diesel engine (<100 HP) at the facility for maintenance of equipment and/or backup operation of air compressors that was installed prior to 1970. This engine is tested weekly. The Coors Brewery currently contracts for the purchase of the total electricity and steam output.

For this analysis, the Division also relied on the existing Title V permit, historical information regarding the CENC facility, and information about similar facilities to determine RP for NO_x, SO_2, and PM_{10}. EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must considered in making BART and RP determinations are largely the same. 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 commenced operation in the 15-year period prior to August 7, 1977. Therefore, these two boilers have been evaluated for BART, which the Division has determined meets the requirements of RP at this time.

The Division has elected to set a *de minimis* threshold for actual baseline emissions for evaluating reasonable progress units at each facility equal to the federal Prevention of Significant Deterioration levels. The Division defines "unit" as an Air Pollutant Emission Notice (APEN) subject source, or a stationary source, defined as "any building, structure, facility, equipment, or installation, or any combination thereof belonging to the same industrial grouping that emit or may emit any air pollutant subject to regulation under the Federal Act that is located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control[1] ."

These levels are as follows:

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

Boiler 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. CENC submitted a "Reasonable Progress Control Evaluation" on May 7, 2010 as well as additional relevant information on February 8, 2010. Table 1 depicts technical information for Boiler 3 at the CENC facility.

Table 1: CENC Boiler 3 RP-eligible Emission Controls and Reduction (%)

	Unit B003
Placed in Service	1962; updated to coal in 1981
Boiler Rating, MMBtu/Hr for coal	225
Electrical Power Rating, Gross Megawatts	24
Description	Combustion Engineering Model CE-VU40 225 MMBtu/hr (coal), traveling grate stoker, firing only coal for primary fuel and fuel oil/coal for a cold start
Air Pollution Control Equipment	Carter Day fabric filter baghouse with 4 compartments
Emissions Reduction (%)	NO_x – None SO_2 – None PM/PM_{10} – 93+%

II. Source Emissions

CENC estimated that a realistic depiction of annual emissions for Boiler 3, or "Baseline Emissions" was the years 2006 – 2008. CENC determined that the maximum year within this scope was 2006, since it had the highest capacity factor and heat input.

Table 2 summarizes the NO_x, SO_2, and PM actual emissions averaged over the 2006 – 2008 timeframe for the facility. Table 3 summarizes each unit at the facility and applicable NO_x, SO_2, and PM_{10} actual emissions averaged over the 2006 – 2008 timeframe with data from Colorado's Air Pollutant Emission Notices

[1] Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

submitted by the facility and as applicable, EPA's CAMD Database (Boilers 4 and 5).

Table 2: Summary of 2006 - 2008 Averaged Emissions – CENC Facility

NO_x (tons/year)	SO_2 (tons/year)	PM_{10} (tons/year)
1,512	2,433	38

Table 3: Summary of 2006 - 2008 Averaged Emissions by Unit - CENC Facility

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
Boiler #1 (288 MMBtu/hour – natural gas fired)	*SO_2 (tons)*	*0.1*	*0.1*	*0.1*	*0.1*
	SO_2 (lb/ MMBtu)	*0.00*	*0.00*	*0.00*	*0.00*
	NO_x (tons)	*30.8*	*23.9*	*30.3*	*28.3*
	NO_x (lb/ MMBtu)	*0.02*	*0.02*	*0.02*	*0.02*
	PM_{10} (tons)	*0.8*	*0.7*	*0.8*	*0.7*
	PM_{10} (lb/ MMBtu)	*0.00*	*0.00*	*0.00*	*0.00*
Boiler # 2 (288 MMBtu/hour – natural gas fired)	*SO_2 (tons)*	*0.1*	*0.0*	*0.1*	*0.1*
	SO_2 (lb/ MMBtu)	*0.00*	*0.00*	*0.00*	*0.00*
	NO_x (tons)	*32.4*	*10.4*	*27.6*	*23.5*
	NO_x (lb/ MMBtu)	*0.03*	*0.01*	*0.02*	*0.02*
	PM_{10} (tons)	*0.9*	*0.3*	*0.7*	*0.6*
	PM_{10} (lb/ MMBtu)	*0.00*	*0.00*	*0.00*	*0.00*
Boiler #3 (225 MMBtu/hour – coal fired)	SO_2 (tons)	264	205	267	245
	SO_2 (lb/ MMBtu)	0.27	0.21	0.27	0.25
	NO_x (tons)	185	150	170	168
	NO_x (lb/ MMBtu)	0.19	0.15	0.17	0.17
	PM_{10} (tons)	2.3	1.9	2.1	2.1
	PM_{10} (lb/ MMBtu)	0.00	0.00	0.00	0.00
Boiler #4 – (360 MMBtu/hour – coal fired)	SO_2 (tons)	764	815	763	781
	SO_2 (lb/ MMBtu)	0.48	0.52	0.48	0.49
	NO_x (tons)	637	589	575	600
	NO_x (lb/ MMBtu)	0.40	0.37	0.37	0.38
	PM_{10} (tons)	10.9	10.0	10.4	10.4
	PM_{10} (lb/ MMBtu)	0.01	0.01	0.01	0.01
Boiler #5 – (650 MMBtu/hour – coal fired)	SO_2 (tons)	1,598	1,333	1,289	1,407
	SO_2 (lb/ MMBtu)	0.56	0.47	0.45	0.49
	NO_x (tons)	900	614	559	691
	NO_x (lb/ MMBtu)	0.32	0.22	0.20	0.25
	PM_{10} (tons)	21	17	16	18
	PM_{10} (lb/ MMBtu)	0.01	0.01	0.01	0.01
P005 – Coal Unloading and Conveying	*PM_{10} (tons)*	*0.03*	*0.03*	*0.03*	*0.03*
P007 – Boiler #5 Silos – coal conveyor to Unit 5 silos	*PM_{10} (tons)*	*0.00*	*0.00*	*0.00*	*0.00*
P008 – Ash Handling – 11, 12, 13 – general ash silo	*PM_{10} (tons)*	*5.57*	*5.57*	*5.38*	*5.51*
P009 – Boiler #3 Silos – coal conveyor to Unit 5 silos	*PM_{10} (tons)*	*0.00*	*0.00*	*0.00*	*0.00*
P010 – Ash Handling – Boiler #4 & #5 fly ash	*PM_{10} (tons)*	*0.02*	*0.02*	*0.02*	*0.02*

collection					
P011 – Ash Handling – Fly ash silo loadout	*PM_{10} (tons)*	*0.00*	*0.00*	*0.00*	*0.00*
P012 – Ash Handling – Fly ash silo bin vent	*PM_{10} (tons)*	*0.00*	*0.00*	*0.00*	*0.00*
P013 – Diesel Air Compressors – GM diesel engine for backup operation of air compressor	*SO_2 (tons)*	*0.00*	*0.00*	*0.00*	*0.00*
	NO_x (tons)	*0.00*	*0.00*	*0.00*	*0.00*
	PM_{10} (tons)	*0.00*	*0.00*	*0.00*	*0.00*

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average. 30-day rolling averages are estimated to be 5-15% higher than the annual average emission rate (i.e. the 30-day NO_x rolling average is likely about 0.44 lbs/MMBtu for Boiler 4 and 0.29 lbs/MMBtu for Boiler 5).

Units *italicized* in Table 3 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress.

Boiler 3 currently has grandfathered status for State construction permits. This boiler is included in the current Title V permit, but does not currently have fuel usage or emission limitations for NO_x, PM, or SO_2. This boiler is subject to opacity requirements under Colorado Regulation No. 1, Section II.A.1 and a sulfur dioxide limit of 1.8 lbs/MMBtu when burning coal. Boiler 3 has a PM emission rate limit of 0.122 lbs/MMBtu and is controlled with a baghouse that was installed in the early 1980s. In addition to not utilizing a CEMS, a sophisticated automatic Data Acquisition System for control parameters, such as fuel usage, is not installed. The actual NOx emissions is based on AP-42 factors applicable to the coal type (bituminous, sub-bituminous, etc.) and coal usage based on rail car / truck unloading records. This AP-42 factor has a B-rating and may be subject to change in the future. Unit 3 is a base-loaded boiler. It's load range varies from the low end (plant reliability—ready to respond in the event of a malfunction in Unit 4 or Unit 5), medium loads (increased customer steam loads) to high loads (i.e., during Unit 4 or Unit 5 overhauls). The load range varies within the month, and has patterns throughout the year. Therefore, the Division believes that a baseline period of 2000 – 2008 is warranted for CENC Boiler 3 due to the factors listed above. The baseline emissions for Boiler 3 are further detailed in Table 4

Table 4: CENC Unit 3 Detailed Baseline Emissions

Pollutant	Unit 3 (2000 – 2008)	
	Annual Emissions* (tpy)	Annual Emissions** (lb/MMBtu)
NO_x	205	0.21
SO_2	257	0.26
PM_{10}	2	0.037***

*Using most recent three calendar years (Division APEN data).
**The Division calculated annual average rate (lb/MMBtu) from the most recent three calendar years, the maximum heat input and annual operating hours.
***The PM_{10} emission rate is determined from the last Title V permit compliance stack test (August 24, 2007).

III. Units Evaluated for Control

As documented by CENC, this boiler fires low sulfur, high heating value bituminous coal from western Colorado. The specifications for the coal are listed in Table 5.

Table 5: Coal Specifications (2006 – 2008 Averaged APEN data)

	Specifications		
Emission Unit	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
B003	12,541	0.42	8.38

Table 1 lists the units at Colorado Energy Nations Golden Facility that the Division examined for control to meet reasonable progress requirements. Controlled and uncontrolled emission factors and APEN data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 6.

Table 6: Uncontrolled emission factors for CENC Boilers

Emission Unit	Pollutant	Fuel
		Coal (bituminous) (lb/ton)
Boiler 3[2]	NO_x	11
	SO_2	38 x %S = 16.0*
	PM/PM_{10}	PM – 66 PM_{10} – 13.2

*%S = % of sulfur present in coal supply. For example, 38 x 0.42 = 16.0
**%A = % of ash present in coal supply. For example, 10 x 8.39 = 83.9

It is worth noting that although Boiler 3 was on-line the majority of the time, it ran at reduced capacity due to production requirements, demonstrated in Table 7.

Table 7: Boiler 3 Baseline Capacity Factor

Heat Input (HI) (MMBtu/year)		
Potential HI	1,971,000	B3 % Potential-HI
2006	874,569	44.37%
2007	711,157	36.08%
2008	805,320	40.86%
Average	797,015	40.44%

IV. Reasonable Progress Evaluation of Boiler 3

a. Sulfur Dioxide

Step 1: Identify All Available Technologies

CENC identified five SO_2 control options:

Flue gas desulfurization (FGD):

Lime or limestone-based (wet FGD)

[2] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf

Lime spray dry absorber (SDA or dry FGD)
Dry sorbent injection – Trona (DSI)
Fuel switching – different coal type
Fuel switching – natural gas

Step 2: Eliminate Technically Infeasible Options
FGD: Flue gas desulfurization removes SO_2 from flue gases by a variety of methods. Wet scrubbing uses a slurry of alkaline sorbent, either limestone or lime, to scrub the gases. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

Wet FGD: Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar "foot print" area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney.

Dry FGD: Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants[3]. SDA systems are typically utilized at smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. Additionally, Controlling SO_2 Emissions: A Review of Technologies[4] evaluates various SO_2 control technologies and shows that for low-sulfur coal applications, LSDs can meet comparable emission rates to wet systems.

A SDA system must be located before the boiler flue gases enter the baghouse. Each reactor vessel requires a "foot print" area comprising about 2,000 to 4,000 square feet (depending on volume of flue gas treated) along with additional space for support equipment access, slurry preparation, mixing and associated tanks.

The plant is bounded to the north by US Highway 58 and Coors Brewery buildings, to the west by 12th street and a small parking, to the east by Coors rail yard lots, and the south by Clear Creek and the Coors Brewery. Train tracks also

[3] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.
[4] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

bound the facility to the north and east. Table 1 illustrates these boundaries. Figure 2, depicting a detailed view of the boilers, respective baghouses, and available spaces for FGD systems, indicates that available physical space is severely constrained at the CENC facility, due to locations as well as pollution control retrofits for particulate matter. The entire site is very congested, with limited access and limited room for major retrofits of new capital equipment. CENC asserts that in order to allow sufficient residence time for evaporation and reaction with SO_2, the design gas residence time in a SDA is approximately 10 seconds. For Boiler 3, a SDA vessel for each boiler, not including other associated equipment, would be approximately 27 feet in diameter by 47 feet high. In addition, in order to provide high reagent utilization, the unreacted lime mixed with ash form the baghouse must be recycled. This would increase solids loading in each baghouse by a factor of 3 and require extra baghouse capacity and a complete reconstruction of the ash handling system. Subsequently, CENC determined that it is not technically feasible to install dry FGD systems on Boiler 3.

In 2007, the Division conducted an on-site visit to determine the technical feasibility of potential SO_2 controls on Units 4 and 5. It can be reasonably assumed that this visit also applies to Unit 3. The Division noted:

- CENC determined dry FGD controls are not technically feasible as discussed above, therefore control effectiveness and impacts are not evaluated in this analysis. After the site visit, the Division concurred with this conclusion.
- Traditional wet FGD controls are possible considering that there is adequate space near the baghouse to allow for the installation of controls, but are eliminated based on other considerations within the five factors (i.e. energy and non-air quality impacts). Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Boiler 3.

Figure 2: Aerial Zoom of CENC Facility

DSI: Dry sorbent injection involves the injection of typically a sodium based reagent, either the mineral trona (sodium sesquicarbonate) or refined sodium bicarbonate, into the flue gas. The injected reagent reacts with the SO_2 present in the flue gas to create sodium sulfate, which is then collected in the particulate control device, in the case of CENC. CENC asserts that the flue gas temperatures present upstream of the boiler airheaters are in the appropriate range to allow for DSI application. A very important factor in DSI application is the ability for the boiler's particulate control device to accommodate the added particulate loading of the DSI reagent in addition to the flyash loading. CENC's preliminary review indicates that even with the added loading of DSI reagent, the CENC baghouses would be operating within the design specification for particulate loading, but the ash collection system(s) would require modifications. The flue gas is not cooled nor saturated with water, so reheating of desulfurized flue gas is not required. No gas-sorbent contacting vessel is required to be installed. DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system. However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Lime, soda ash, and Trona (sodium sesquicarbonate) are possible. Lime is the least reactive reagent resulting in low efficiencies even at high injection rates. Trona is a very reactive reagent that can be used to achieve a range of efficiencies depending on the amount of sorbent injected, and would likely be the chosen reagent.

Due to variability of boiler configurations, coal composition, NO_x to SO_2 ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum SO_2 removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CENC estimated the maximum SO_2 removal rate that can be achieved while minimizing the creation of the brown plume condition to be 65% SO_2 removal. In practical application, a higher SO_2 removal rate may be possible, while it is also possible that a lower SO_2 removal rate may be necessary to limit the brown plume formation. This determination would require actual SO_2 removal real-time testing. CENC consulted with PPC Industries to determine the feasibility and emission reduction potential associated with installing DSI-Trona controls. Therefore, DSI-Trona is technically feasible for the CENC facility Boiler 3.

Fuel Switching – Different Coal Type: CENC asserts that the facility already utilizes low sulfur, high heating value bituminous coal from western Colorado. Typically, the coal contains only about 0.43 percent sulfur with a heating value of 12,100 Btu/lb and potential SO_2 emissions of 0.73 lb/MMBtu. The sulfur content of CENC's Colorado coal rivals the low sulfur properties of Powder River Basin (PRB) coal from Wyoming, and therefore, it represents the lowest sulfur coal available. Any shift from the purchase of local Colorado coal would have an adverse effect on Colorado mining and transportation industries.

Additionally, CENC notes that PRB coal is extremely dusty to handle, being much more friable than the Colorado coal presently used) and it generates dust through weathering much more quickly than bituminous coal. PRB coal also is subject to spontaneous combustion in and around material handling systems and silos. The generation of fugitive dust and periodic spontaneous combustion is a tremendous issue at a site such as a Coors Brewery, which precludes conversion to PRB coal. Therefore, a change in coal supply is not a feasible RP control option.

Fuel Switching – Natural gas: Natural gas offers some operating and maintenance advantages. The use of natural gas would eliminate coal handling and baghouse operating and maintenance labor as well as ash handling and disposal. Natural gas fuel switching is a feasible option for CENC Boiler 3.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CENC provided the Division annual average control estimates. In the Division's experience, 30-day SO_2 rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 5% for CENC Boiler 3 to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by CENC as well as other control techniques applied to pulverized coal boilers.

DSI: CENC asserts that the maximum SO_2 removal rate that can be achieved to be 65% SO_2 removal due to the small size of the boilers, and non-ideal gas/solids residence time. The Division adjusted this removal rate to 60%, based on other Colorado submittals[5] and to be conservative since this technology is relatively novel.

Fuel Switching – Natural Gas: Conversion from coal to natural gas would reduce SO_2 emissions by almost 100% from each unit using EPA's AP-42 emission factors[6] and concurs with CENC's submittal.

Table 8 summarizes each available technology options and technical feasibility for SO_2 control on CENC Boiler 3.

Table 8: CENC Boiler 3 SO2 Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Wet FGD	52-98%, median 90%[7]	Y
Dry FGD	70 – 90% (CENC)	N
DSI (Trona)	≤65% (CENC)	Y
Fuel switching – different coal type	minimal (CENC)	N
Fuel switching – natural gas	99% (EPA AP-42)	Y

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

CENC submitted cost estimates for DSI and natural gas fuel switching for Boiler 3 on May 7, 2010.

Wet FGD: The significant cost issue associated with securing sufficient water supplies (a costly and scarce resource in the Front Range) to support a wet FGD control system along with the cost of disposing the sludge byproduct at an approved landfill since on-site storage is not an option. There are other costs and environmental impacts that the Division 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. Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Boiler 3.

[5] Colorado Springs Utilities, 2010. "RE: Question Regarding the Application of Dry Sorbent Injection to Martin Drake Power Plant Unit 5." Submitted to the Colorado Air Pollution Control Division on May 10, 2010.

[6] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.4, Table 1.4-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[7] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

DSI: PCC Industries provided the cost to CENC for the basic equipment required for Trona injection. . DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system. However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Additional costs for equipment redundancy, modifications to the facility's ash handling system, and increased transformer capacity were estimated by CENC based on the need to maintain continuous compliance with a short-term emission rate (30-day rolling) and past experience with retrofits at other CENC facilities. CENC derived total installed costs from the purchased equipment cost using USEPA factors (EPA's Cost Control Manual). Operating costs were based on estimated Trona requirements of 2.8 lb Trona per lb of SO_2 collected for 65 percent control. The theoretical minimum requirement is 2.4 lb Trona per lb of SO_2 collected. Detailed capital and annual cost data are presented in "CENC RP APCD Technical Analysis".

The Division compared CENC's costs for DSI to other Colorado facilities similar in size that analyzed DSI.

Table 9: DSI Cost Comparisons

Facility & Unit	Size (MW)	Annualized Costs ($/year)	Cost Effectiveness ($/ton)	Ratio ($/kW)
Colorado Energy Nations – Boiler 3	24	$1,340,661	$9,114	$55.86
Colorado Energy Nations – Boiler 4	35	$1,766,000	$3,774	$50.46
Colorado Springs Utilities – Drake Unit 5	51	$1,746,172	$2,293	$34.33
Colorado Energy Nations – Boiler 5	65	$2,094,000	$2,485	$32.22
Colorado Springs Utilities – Drake Unit 6	85	$2,910,287	$1,741	$34.24

The Division considers CENC's DSI costs to be within a reasonable cost range that is comparable to other Colorado facility submittals.[8] CENC Boiler 3 is more expensive compared to other units because of the small size of the boiler and the increased difficulty of the retrofit. Therefore, the Division did not adjust CENC's DSI cost estimates.

Fuel Switching – Natural Gas: The Division used EPA's Cost Control Manual[9] to estimate annual operating costs, of approximately $25,000 per ton of SO_2

[8] ENSR, 2006. BART Analysis for the TriGen Colorado Energy Corporation Facility in Golden, Colorado. Prepared for Trigen. Document No: 10279-017-700.
[9] EPA, 2002. EPA Air Pollution Control Cost Manual, Sixth Edition. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, 27711.

removed annually for Boiler 3 at the CENC facility.[10] However, it should be noted that natural gas prices vary significantly; the Division used 2008 commercial natural gas prices reported by the U.S. Energy Information Administration[11] to determine natural gas costs. Therefore, the Division concurs that the natural gas estimates submitted by CENC on May 7, 2010 to be reasonable.

In the February 8, 2010 submittal, CENC notes that the fuel is the largest steam production cost incurred by CENC, and stresses the variability in natural gas prices. CENC also emphasized the added negative Colorado economic impact in that CENC coal is purchased from Colorado mines, which may be offset by the natural gas purchases also from Colorado-based corporations. The use of natural gas would eliminate pulverizer and baghouse operating and maintenance costs as well as ash handling and disposal costs. Other boiler maintenance costs would be reduced if coal was not burned.

Table 10: CENC Unit 3 Resultant SO2 Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	257	0.260	0.273
DSI - Trona	60	103	0.104	0.109
Fuel Switching - Natural Gas	100	0	0.000	0.000

Table 11: CENC Unit 3 SO2 Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
DSI - Trona	154	$1,340,661	$8,709	$57
Fuel Switching - Natural Gas	257	$1,428,911	$5,569	-$31

Factor 2: Time Necessary for Compliance

In the May 7, 2010 submittal, CENC notes that due to the gross estimate of this evaluation, compliance time must include a more extensive study of the control

[10] Colorado Air Pollution Control Division Technical Analysis – CENC RP APCD Technical Analysis, 2010.

[11] U.S. Energy Information Administration, 2010. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm

options and their technical feasibility. It is anticipated that if controls were required, at least five years after SIP approval would be needed to perform this study, work with the Division regarding the final options, incorporate the decision, and finally initiate and complete the construction process.

Factor 3: Energy and Non-Air Quality Impacts

Traditional Wet FGD: Based upon its experience, and as discussed in detail below, the Division has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including massive water usage. This is a significant issue in Colorado, where water is a costly, precious and scarce resource. In the arid West, securing sufficient water supplies to support a wet FGD control system is a difficult undertaking that precludes other beneficial uses for such water. In Colorado, water law is based upon the doctrine of prior appropriation or "first in time - first in right," and the priority date is established by the date the water was first put to a beneficial use. Thus, depending upon whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the state, particularly in the Front Range, to accommodate the added demands of wet FGD controls. At a minimum, the water demands of wet FGDs will compete for what is already a scarce resource needed for Colorado's domestic, agricultural and industrial demands.

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. On-site storage of wet ash is an increasing regulatory concern, as evidenced by the recent Tennessee Valley Authority spill. In addition, the steam plume resulting from a wet FGD control system in such a confined creek bed will produce a noticeable cloud that will hang over a densely populated area (City of Golden). The Division has received complaints regarding the more visible plumes associated with wet scrubbing; a potential irony in light of the visibility issues at the heart of the Regional Haze program. The Division largely focused its RP SO_2 control technology consideration on commercially available once-through dry FGD controls, specifically, "lime spray dryers" (LSD), that have an established record of reliable performance on boilers burning low-sulfur coal. Generally, wet FGD controls can achieve a higher level of SO_2 control on a percent capture basis that exceeds the capabilities of LSDs but, as noted above, there are a number of non-air quality and other environmental impacts including increased water usage, sludge disposal and wet plume issues that often overshadow any incremental improvement in SO_2 emission reductions. Recent PSD applications in Colorado have demonstrated lime spray dryer systems to be BACT.

The Division finds the negative environmental impacts of a traditional wet FGD control system far outweigh minimal incremental SO_2 emission reduction benefits (tons of SO_2 reduced annually) and visibility improvement (deciview improvement at nearest Class I area) when applied to this small boiler at the CENC facility (Boiler 3).

DSI: CENC documents additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash.

The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash,[12] which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls.

Fuel Switching – Natural Gas: Fuel switching to natural gas does not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

Factor 4: Remaining Useful Life

CENC asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

The Division conducted CALPUFF modeling to determine the projected visibility improvement associated with various control technologies for Boilers 4 and 5 at the CENC facility. The projected visibility improvements attributed to DSI are outlined in Table 12. CALPUFF modeling indicates a 0.08 Δdv for DSI applied to Boiler 4 (360 MMBtu/hr). DSI controls for Boiler 4 would reduce SO_2 emissions by approximately 268 tons per year. DSI controls for Boiler 3 would reduce SO_2 emissions by about 147 tons per year. Fuel switching to natural gas would reduce SO_2 emissions by an estimated 245 tons annually. Consequently, it is reasonable to infer, based on scaling, that either control applied to Boiler 3, a smaller boiler at the same site (225 MMBtu/hr), would yield model results much less than 0.10 Δdv.

[12] Department of Energy, 2001. LIFAC Sorbent Injection Desulfurization Demonstration Project: A DOE Assessment. U.S. Department of Energy: National Energy Technology Laboratory. P.O. Box 880, 3610 Collins Ferry Road Morgantown, WV 26507-0880.
http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/lifac/LIFAC_PPA.pdf

Table 12: CENC Boiler 4 SO_2 Modeling Results

SO_2 Control Method	Emission Reduction (tpy)	CENC - Boiler 4	
		SO_2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	---	0.90	---
DSI - Trona	268	0.26	0.08

Determination
Table 13 illustrates fuel analysis from 2000 – 2010. The Division believes a 20% contingency factor is warranted for CENC Boiler 3 due to the factors listed on page 5. Based on Table 13, the maximum SO2 emissions from the past decade (2000 – 2010) is 0.99 lb/MMBtu. With the uncertainty factor, the Division believes that a 1.2 lb/MMBtu is appropriate for RP.

Table 13: CENC Boiler 3 Coal Supply SO2 Limit Support

	2000-2006	2006-2008	2009-2010
Minimum Btu/lb	11,068	11,221	11,444
Maximum % Sulfur	0.55	0.55	0.57
Theoretical lb/MMBtu…			
Maximum B3 Conversion Sulfur to SO2 (using fuel analysis)	0.99	0.98	0.99

Based upon its consideration of the five factors summarized herein, the state has determined that SO_2 RP is the following SO2 emission rate:

CENC Boiler 3: 1.2 lb/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.

b. Filterable Particulate Matter (PM and PM_{10})
CENC Boiler 3 is equipped with fabric filter baghouses to control PM/PM_{10} emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Colorado Operating Permit 96OPJE143 Condition 2.2 requires Boiler 3 to comply with State Regulation No. 1 where the PM/PM_{10} emission limit is calculated from the equation $PE = 0.5(FI)^{-0.26}$, where PE= Particulate Emissions in lbs/MMBtu and FI = Fuel input in million Btu per hour. Additionally, Condition 18.1 mandates that each baghouse be equipped with an operating pressure drop measuring device and outlines the Continuous Opacity Monitor requirements.

Table 14 shows the most recent stack test data (August 24, 2007). It is important to note that the most recent stack test, which at a minimum, occurs every five years in accordance with Colorado Operating Permit 96OPJE143 Condition 18.2, and more frequently depending on the results, demonstrates that these baghouses are meeting >90% control.

Table 14: CENC 2007 Stack Test Results

Pollutant	Boiler 3 (lb/MMBtu)
Filterable PM_{10}	0.037
PM_{10} Control efficiency	93.0%

A Division review of EPA's RBLC revealed recent BACT PM/PM_{10} determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls. The current stack test results above are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations.

This boiler is subject to National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, more commonly known as the Boiler MACT, which was proposed on June 4, 2010.[13] As currently proposed, the boiler will be subject to a PM limit of 0.02 lb/MMBtu (monthly average).[14]

Other commercial EGUs must meet a PM limit of 0.03 lb/MMBtu, so the Division evaluated the possibility of tightening the existing PM limit of 0.07 lb/MMBtu on CENC units 4 and 5 based on the idea that there may not be any cost associated with a tighter limit. However, compliance with the PM limit is demonstrated through periodic performance tests, where compliance is unknown until the test results are evaluated. Consequently, a tighter emission limit has the effect of increasing the likelihood of non-compliance without any possibility of remedy until after the test is complete. This dilemma is further complicated by the presumption that any non-compliance is assumed backward in-time until the last performance test indicating compliance. Thus a tighter PM limit has the effect of

[13] EPA, 2009. 40 CFR Part 63 [EPA HQ-OAR-2002-058; FRL-RIN 2060-AG69]. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

[14] EPA, 2009. 40 CFR Part 63 [EPA HQ-OAR-2002-058; FRL-RIN 2060-AG69]. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Pg. 34 – Table 1 – Existing Coal Stoker.

forcing sources into more frequent performance testing to ensure that any unanticipated non-compliance is of shorter duration and thus less costly for any associated enforcement actions. Consequently, a tighter emission limit does have an associated increase in costs to the source.

Furthermore, the Division conducted sensitivity analysis of the CALPUFF model for several sources that indicated that tightening of PM emissions by 0.07 lb/MMBtu resulted in negligible (less than a tenth to several hundredths of a delta dv) visibility improvement. Since a tighter PM emission limit does increase costs and does not result in any appreciable visibility improvement, the Division concludes a PM emission limitation of 0.07 lb/MMBtu is appropriate level of control that satisfies BART.

The state has determined that an emissions limits of 0.07 lb/MMBtu (PM/PM10 represents the most stringent control option. The unit is exceeding a PM control efficiency of 90%, and the control technology and emission limit is RP for PM/PM_{10}. The state assumes that the RP emission limit can be achieved through the operation of the existing fabric filter baghouse.

c. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

CENC, using a similar unit's NO_x analysis[15], identified eight potential NO_x control options:

- Flue Gas Recirculation (FGR)
- Low-temperature Oxidation System (LoTOx)
- Selective Non-Catalytic reduction (SNCR)
- Rotating Over-Fire Air w/ Rotamix (ROFA)
- Fuel switching – different fuel type (natural gas)
- Regenerative Selective Catalytic Reduction (RSCR)
- High Temperature Selective Catalytic Reduction (HT SCR)
- Low Temperature Selective Catalytic Reduction (LT SCR)

The Division also identified and examined the following additional control option for this unit:

- Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Coal reburn +SNCR

Step 2: Eliminate Technically Infeasible Options

Flue Gas Recirculation (FGR): FGR technology extracts up to 20 to 30% of the flue gas from downstream of the economizer, air heater, or particulate control equipment, and is mixed into the combustion inlet air duct. The amount of FGR

[15] "Black Hills Clark Station NO_x Reduction Feasibility Study" BH Clark Station Unit 1. Prepared by CH2MHill. December 2009.

that is achievable is determined by a boiler's operating characteristics and the ability to mix with primary air to allow for good fuel bed combustion stability. Flue gas recirculation is considered technically feasible for CENC Boiler 3.

LoTOx System: The LoTox system has the potential of significant NO_x reduction; however, the process requires operation in conjunction with a wet scrubber. CENC does not currently have a wet scrubber in service, has a limited footprint in which to locate a wet scrubber, and the Division has determined that wet scrubbers are not being considered for this facility due to non-air and energy impacts. Therefore, the LoTOx alternative is not considered due to the determination regarding wet scrubbers.

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for CENC Boiler 3.

ROFA: Nalco Mobotec markets ROFA as an improved second generation OFA system. ROFA® injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA® differs from OFA in that ROFA® utilizes a booster fan to increase the velocity of air to promote mixing and to increase the retention time in the furnace. Nalco Mobotec offers the ROFA system as a stand-alone installation, or with the Rotamix feature. Rotamix is Nalco Mobotec's version of SNCR technology, and ammonia is injected into the ROFA airstream. ROFA is considered technically feasible for CENC Boiler 3.

Fuel switching – different fuel type (natural gas): Natural gas reburning technology is a staged fuel approach using an expanded volume of the furnace to control NO_x production, rather than only within the flame envelope, also referred to as Methane de-NO_x. The primary solid fuel combustion delivery and boiler location remains the same, and for the case of CENC Boiler 3 this is currently assumed to occur on the traveling fuel grate. The secondary fuel introduction point is after the primary fuel burn zone, in a fuel-rich reaction zone (the reburn zone). While other fuels may be used in the reburning zone, natural gas is most common and NO_x reductions of 30-70% may be feasible. Higher removals are associated with longer boiler residence times. Therefore, 50% was used for the analysis due to the relatively short boiler at CENC (similar to Black Hills Clark Station Unit 1). Natural gas fuel switching is considered a technically feasible alternative for CENC Boiler 3.

RSCR/HT SCR/LT SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

CENC estimated that a retrofit SCR system on Boiler 3 could achieve 0.024 lb/MMBtu. The SCR reaction occurs within the temperature range of 600°F to 750°F where the extremes are highly dependent on the fuel quality. CENC evaluated three types of SCR for this analysis – regenerative SCR, high-temperature SCR, and low-temperature SCR. These three different options were evaluated because of the potential variable inlet temperature on a spreader stoker boiler such as Unit 3. Regenerative SCR notably may not achieve the same reductions as the other two SCR options, but regardless was evaluated. All three SCR options – RSCR, HTSCR, and LTSCR – are considered technically feasible for CENC Boiler 3.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[16] and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[17] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for CENC Boiler 3.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu[18]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

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[16] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx

[17] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php

[18] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CENC provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[19] 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for CENC Boiler 3 to determine control efficiencies and annual reductions.

Flue Gas Recirculation (FGR): CENC estimated a 20% NO_x reduction. Flue gas recirculation is considered an operational modification, since fuel is rearranged in the main combustion zone. EPA's AP-42 emission factor tables estimate operational modifications to reduce NO_x 10 –20%.[20] It should be noted the baseline NO_x emission rate (0.17 lb/MMBtu) is much lower than other spreader stoker boilers examined in many control case studies.[21] The Division considers this level of control optimistic and concurs with CENC's control efficiency estimates for FGR.

SNCR: CENC noted in the May 6, 2010 submittal that the similar unit was assumed to achieve 40% control for SNCR. However, CENC determined that 30% control was a more realistic estimate. EPA's SNCR Air Pollution Control Technology Fact Sheet states that SNCR achieves 30 – 50% control, which concurs with the Division's experience. The Division determined in CENC's BART analysis that an appropriate NO_x reduction estimate is 30%; therefore, the Division concurs with CENC's control efficiency estimate.

ROFA: A recent AWMA study noted that ROFA achieves from 45 – 60% NO_x reduction depending on temperature and distribution of combustion products. [22] CENC estimated a reduction of 57.1% based on a vendor guarantee for a similar unit. This results in a resultant NO_x emission rate of 0.07 lb/MMBtu. In the Division's experience, this emission rate may not be realistically achievable and will require more study if applicable.

Fuel switching – different fuel type (natural gas): CENC estimates 50% NO_x reduction by converting fuel to natural gas. This is equal to about 0.09 lb/MMBtu, which is consistent with EPA's AP-42 emission factor tables for a

[19] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.
[20] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[21] EPA, Office of Air and Radiation. "Alternative Control Technique Document – NO_x Emissions from Industrial/Commercial/Institutional (ICI) Boilers." Emission Standards Division. http://www.epa.gov/ttncatc1/dir1/icboiler.pdf
[22] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

large wall-fired boiler controlled with flue gas recirculation (0.098 lb/MMBtu).[23] Therefore, the Division concurs with CENC's control efficiency estimate.

RSCR/HT SCR/LT SCR: CENC estimates 74.5% NO_x control for RSCR and 85.7% for HTSCR and LTSCR. These control efficiencies are consistent with EPA's AP-42 emission factor tables, which estimate SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.[24,25] RSCR will not achieve the same control efficiencies as HTSCR and/or LTSCR due to the heat input being required through burner arrangement located between two canisters and can be applied to relatively cold flue gas temperatures seen after particulate control equipment. The Division notes that these control efficiencies, due to the low baseline NO_x emission rate, result in extreme emission rates (0.02 – 0.04 lb/MMBtu) and may not be realistically achievable, but concurs with CENC's current estimate for purposes of this RP evaluation.

Table 15: CENC Boiler 3 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO_x Burners (LNB)	n/a	N – coal stoker boiler
Flue Gas Recirculation (FGR)	~20%	Y
Selective non-catalytic reduction (SNCR)	~30 - 50%	Y
Rotating Overfire Air (ROFA)	45-60%	Y
Fuel switching – natural gas	~50%	Y
Selective catalytic reduction options (RSCR, HTSCR, LTSCR)	~75 – 90%	Y
ECO®	n/a	N
RRI	n/a	N
Coal reburn +SNCR	n/a	N

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

FGR: The costs of flue gas recirculation for stoker boilers are not well documented. This type of modification is considered a pre-combustion boiler modification. This modification should be more cost-effective than other options,

[23] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.4, Table 1.4-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf
[24] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[25] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

considering that either a new FGR fan will have to be installed or that the existing forced draft (FD) fan may be used to inject the flue gas into the combustion air. The Division considers the annualized cost of approximately $280,000 for FGR to be reasonable for this small boiler.

SNCR: The difficulty of SNCR retrofit on smaller boilers significantly increases, with the primary concern being that there is adequate wall space within the boiler for installation of injectors. Movement and/or removal of existing watertubes and asbestos from the boiler housing may be required, as in the case of CENC Boiler 3.

A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.[26] The CENC-estimated SNCR costs for operating expenses is about 77% for Boiler 3. Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[27]

The Division calculates cost effectiveness (using CENC cost estimates) for SNCR on Boiler 3 to be about $10,150 per ton. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[28,29] EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NO_x reduced.[30] CENC's estimates are greater than these ranges due to the small size of the boiler, the difficulty of the retrofit, and the different boiler configuration. There is a lack of information regarding the application of SNCR to spreader stoker boiler. Therefore, the Division concludes that CENC's cost estimates for SNCR are reasonable.

ROFA: The Division notes lack of information regarding ROFA cost estimates, especially applied to spreader stoker boilers. Therefore, the Division notes that CENC's estimated ROFA annualized costs are similar to SNCR, which is a

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[26] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.
[27] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
[28] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[29] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.
[30] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

comparable control technology in terms of achievable reductions and concludes that CENC's cost estimates for ROFA are reasonable.

RSCR/HTSCR/LTSCR: Using CENC estimates, the Division calculates that the three SCR options range from $15,650 - $22,300 per ton. Recent NESCAUM studies estimate SCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.10 – 0.15 lb/MMBtu and emission reductions of 75 – 85% as costing $2,600 - $5,000 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[31,32] CENC's cost estimates are much higher than this range, but the small size of the boiler, the difficulty of the retrofit, and the boiler configuration, the Division concludes that CENC's cost estimates for SCR are reasonable.

Table 16: CENC Boiler 3 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions				
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)	Annual Average (lb/hour)	30-day Rolling Average (lb/hour)
Baseline	---	180	0.25		56	65
Flue Gas Recirculation	20.0	144	0.15	0.17	41	47
SNCR	30.0	144	0.13	0.15	33	38
Fuel Switching - NG	34.8	118	0.12	0.14	29	33
ROFA w/ Rotamix	57.1	77	0.08	0.09	18	20
Regenerative SCR	74.5	46	0.05	0.05	11	12
High Temperature SCR	85.7	26	0.03	0.03	6	7
Low Temperature SCR	85.7	26	0.03	0.03	6	7

[31] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[32] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

Table 17: CENC Boiler 3 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Flue Gas Recirculation	33.7	$278,358	$7,716	$214
SNCR	50.6	$513,197	$9,484	$98
Fuel Switching - NG	58.7	$1,428,911	$22,763	$1,534
ROFA w/ Rotamix	96.3	$978,065	$9,496	-$330
Regenerative SCR	125.6	$1,965,929	$14,629	$164
High Temperature SCR	144.5	$2,772,286	$17,933	$164
Low Temperature SCR	144.5	$3,222,223	$20,844	---

Factor 2: Time Necessary for Compliance

In the May 7, 2010 submittal, CENC notes that due to the gross estimate of this evaluation, compliance time must include a more extensive study of the control options and their technical feasibility. It is anticipated that if controls were required, at least five years after SIP approval would be needed to perform this study, work with the Division regarding the final options, incorporate the decision, and finally initiate and complete the construction process.

Factor 3: Energy and Non-Air Quality Impacts

FGR: Installation of a FGR system is not expected to impact the boiler efficiency or forced draft fan power usage significantly. Thus, this factor does not influence the selection of this control.

Fuel Switching – Natural Gas: Fuel switching to natural gas does not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

ROFA w/ Rotamix: The ROFA system requires installation and operation of the ROFA fans on this boiler, with a 125 hp fans being anticipated based on a similar boiler analysis. The Rota system alone will have a modest increase in power consumption. This system may result in higher levels of carbon in the fly ash due to incomplete combustion. Rotamix may impact any potential salability of fly ash due to ammonia levels. However, the Division is not currently aware of CENC selling fly ash.

SNCR /SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas.

Post-combustion add-on control technologies such as SNCR do increase power needs to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. In particular, SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas. CENC has indicated to the Division that they would prefer to use urea instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on a urea reagent versus an ammonia reagent. Refer to "CENC BART Submittals" for more information.

Factor 4: Remaining Useful Life

CENC asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

The Division conducted CALPUFF modeling to determine the projected visibility improvement associated with various control technologies for Boilers 4 and 5 at the CENC facility. The projected visibility improvements attributed to DSI are outlined in Table 12. CALPUFF modeling indicates a 0.12 Δdv for LNB+SOFA+SNCR applied to Boiler 4 (360 MMBtu/hr). LNB+SOFA+SNCR controls for Boiler 4 would reduce NO_x emissions by approximately 368 tons per year. SCR controls for Boiler 3 would reduce NO_x emissions by about 145 tons per year. Consequently, it is reasonable to infer that either control applied to

Boiler 3, a smaller boiler at the same site (225 MMBtu/hr), would yield model results much less than 0.10 Δdv.

Table 18: CENC Boiler 4 NO_x Modeling Results

NOx Control Method		CENC - Boiler 4	
	Emission Reduction (tpy)	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	---	0.67	
LNB	60	0.45	0.05
SNCR	180	0.35	0.07
LNB + SOFA	210	0.32	0.08
LNB + SOFA + SNCR	368	0.19	0.12

Determination

Based on review of historical actual load characteristics of this boiler, the Division proposes 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 (similar to SO_2) due to the reasons listed on page 5.

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 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 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 State Implementation Plan, and thus not reasonable.

V. Reasonable Progress Evaluation of Boiler 4 and Boiler 5

Boiler 4 and Boiler 5 have been evaluated under Best Available Retrofit Technology (BART) provisions. BART for Boilers 4 and 5 can be found in Chapter 6 of the Regional Haze State Implementation Plan. The Division determines that BART represents the most stringent available NO_x, SO_2, and PM/PM_{10} control technologies and represents reasonable progress. Therefore, a full 4-factor analysis is not needed to evaluate reasonable progress for NO_x, SO_2, or PM/PM_{10} for Boiler 4 and Boiler 5 at the CENC facility.

COMBUSTION TURBINE POINT SOURCE CATEGORY 4-FACTOR ANALYSIS

I. Source Description

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).

Control strategies for this source category are:
NOx – Steam or water injection, advanced dry low NOx combustion system, and selective catalytic reduction (SCR)

Cumulatively, this emissions source category is projected to be a minimal single category of Colorado point sources with a total of 56 turbines. Of this total, turbines located as single sources at Reasonable Progress facilities are 18. Total state-wide NO_x emissions (2007 inventory) are approximately 284,037 tons/year. This source category is about 0.7% of total statewide emissions; therefore, the Division considers this source category to be nominal. Regardless, the Division evaluated all combustion turbines, regardless of fuel type, at Reasonable Progress facilities. The majority of combustion turbines (assumed 17 out of 18 based on inventory limitations) are natural-gas fired.

II. Source Emissions

Pollutant	Total 2006 – 2008 Averaged Annual Emissions (tpy)	Total RP Turbine 2006 – 2008 Averaged Annual Emissions (tpy)	RP Turbine Emissions compared to total state-wide turbine emissions (%)
NO_2	2,003	473	24%

The Division analyzed total state-wide combustion turbine emissions averaged over the 2006 – 2008 Reasonable Progress baseline period. There are 5 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 emit over federal significance levels as depicted below.

For the purposes of evaluating RP, the Division has elected to set *de minimis* thresholds for any emission unit at a subject-to-RP source with actual baseline emissions of NO_x equal to or exceeding the federal Prevention of Significant Deterioration (PSD) significance levels. The Division has established *de minimis* thresholds for SO_2, NO_x and PM_{10} to focus the technical emission control analysis on significant emission sources where potential controls could provide a meaningful improvement in visibility if emission controls are determined to be cost effective.

The *de minimis* levels are applicable to individual emission units at a stationary source. The Division defines “emissions unit” as “any part or activity of a stationary source that emits or has the potential to emit any air pollutant regulated under the state or Federal Acts. This term is not meant to alter or affect the definition of the term “unit” for purposes of Title IV (acid deposition control) of the federal act, or of the term “source” for purposes of the Air Pollutant Emission Notice requirements of Regulation Number 3, Part A, Section II.B.3. [1] .” These *de minimis* levels are as follows:

- 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?**
Valmont – Turbine #6	12.6	0.4	0.1	No
Valmont – Turbine #7	27.4	0.2	2.8	No
Valmont – Turbine #8	1.5	0.0	0.1	No
Arapahoe – Turbine #5	25.5	0.4	5.0	No
Arapahoe – Turbine #6	15.3	0.4	5.0	No
Arapahoe – Turbine	4.1	0.2	3.7	No
Nixon – Turbine #2	0.7	0.0	0.2	No
Nixon – Turbine #3	1.2	0.0	0.3	No
Nixon – Front Range Power	159.6	2.9	4.9	Yes – NOx only

[1] Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

Plant – Turbine #1				
Nixon – Front Range Power Plant – Turbine #2	147.9	2.8	4.9	Yes – NOx only
Rawhide Turbine A	2.5	0.1	0.5	No
Rawhide Turbine B	4.0	0.1	0.8	No
Rawhide Turbine C	2.7	0.1	0.5	No
Rawhide Turbine D	2.9	0.1	0.5	No
Pawnee – Turbine #1	25.4	0.3	3.3	No
Pawnee – Turbine #2	25.0	0.2	2.7	No

Therefore, for the purposes of this RP planning period, the Division will evaluate the Nixon – Front Range Power Plant – Turbines #1 and #2 as they are the two combustion turbines emitting over *de minimis* levels.

III. Control Technology Evaluation

Step 1: Identify All Available Technologies

Four technologies have been identified to lower emissions from combustion turbines:

1. Wet controls using steam or water injection to reduce combustion temperatures for NOx control

2. Dry controls using advanced combustor design to suppress NOx formation and/or promote CO burnout

3. Adding post combustion technology – selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR)

Technology #2: This technology (retrofitting with low-NOx burners) was identified by the EPA and is documented in the AP-42 “Compilation of Air Pollutant Emission Factors.” The following is from the 5th Edition, Volume 1, Chapter 1, Section 3.1.4.1: “Water or steam injection is a technology that has been demonstrated to effectively suppress NOx emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.”

Technology #3: This technology was identified by the EPA and is documented in the AP-42 “Compilation of Air Pollutant Emission Factors.” The following is from the 5th

Edition, Volume 1, Chapter 1, Section 3.1.4.2: "Since thermal NOX is a function of both temperature (exponentially) and time (linearly), the basis of dry controls are to either lower the combustor temperature using lean mixtures of air and/or fuel staging, or decrease the residence time of the combustor. A combination of methods may be used to reduce NOx emissions such as lean combustion and staged combustion (two stage lean/lean combustion or two stage rich/lean combustion).

Lean combustion involves increasing the air-to-fuel ratio of the mixture so that the peak and average temperatures within the combustor will be less than that of the stoichiometric mixture, thus suppressing thermal NOX formation. Introducing excess air not only creates a leaner mixture but it also can reduce residence time at peak temperatures.

Two-stage lean/lean combustors are essentially fuel-staged, premixed combustors in which each stage burns lean. The two-stage lean/lean combustor allows the turbine to operate with an extremely lean mixture while ensuring a stable flame. A small stoichiometric pilot flame ignites the premixed gas and provides flame stability. The NOx emissions associated with the high temperature pilot flame are insignificant. Low NOx emission levels are achieved by this combustor design through cooler flame temperatures associated with lean combustion and avoidance of localized "hot spots" by premixing the fuel and air.

Two stage rich/lean combustors are essentially air-staged, premixed combustors in which the primary zone is operated fuel rich and the secondary zone is operated fuel lean. The rich mixture produces lower temperatures (compared to stoichiometric) and higher concentrations of CO and H2, because of incomplete combustion. The rich mixture also decreases the amount of oxygen available for NOx generation. Before entering the secondary zone, the exhaust of the primary zone is quenched (to extinguish the flame) by large amounts of air and a lean mixture is created. The lean mixture is pre-ignited and the combustion completed in the secondary zone. NOx formation in the second stage are minimized through combustion in a fuel lean, lower temperature environment. Staged combustion is identified through a variety of names, including Dry-Low NOx (DLN), Dry-Low Emissions (DLE), or SoLoNOx."

Technology #4: This technology (adding SNCR or SCR) involves adding control equipment and reagent to treat turbine exhaust.

Step 2: Eliminate Technically Infeasible Options

Technology #1: This technology is technically feasible.

Technology #2: This technology is technically feasible.

Technology #3: This technology is technically feasible and is already installed at the Nixon – Front Range Power Plant combustion turbines.

Technology #4: This technology is technically feasible, although a Division of the EPA's RBLC database revealed SCR is the predominant post-combustion control technology for combustion turbines and did not find any examples of SNCR post-combustion technology applied to combustion turbines.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Technology #1: Since this control technology is specific fuel type usage, control efficiency are not applicable.

Technology #2: EPA's AP-42 factor database cites this technology as achieving control efficiencies of 60% or greater. However, this technology will not be evaluated in this analysis further since the dry low-NOx combustion systems already installed on the turbines at the Front Range Power Plant achieve greater than 85% control, which is greater than the 60% estimate achievable by wet controls.

Technology #3: The Division calculated that the controlled-uncontrolled ratio for advanced dry-low NOx combustions using EPA's AP-42 emission factors is approximately 70% and may be greater in site-specific cases. The combustion turbines at the Nixon – Front Range Power Plant were installed with these systems, and based on 2006 – 2008 CEMs data and AP-42 emission factors, are achieving 89.4% and 90.1% NOx reductions (calculated using the 2006 – 2008 RP baseline period), respectively.

Technology #4: EPA's AP-42 emission factor description indicates that a SCR in good working order can achieve removal efficiencies ranging from 65 – 90 percent from the NOx exhaust stream. AP-42 is silent on control efficiencies regarding SNCR. During a research review, the Division could not find any instances of a commercial-scale SNCR applied at a natural-gas fired combustion turbine. Therefore, SNCR will not be considered further in this analysis.

Step 4: Evaluate Impacts and Document Results

The Division reasons that SCR requires significant capital expenditures and will result in minimal additional NOx reductions, if any. Regardless, the Division analyzed additional achievable NOx reductions if SCR was installed at these two turbines. Applying SCR at 90% to both turbines would result in about 275 additional tons of NOx reduced annually. Using another Colorado SCR analysis from the same utility (Colorado Springs Utilities), the Division estimates that annualized costs for installing SCR to both turbines will be approximately $8 million each, resulting in about $57,000 - $62,000 per ton of NOx reduced annually.

The time necessary for compliance will depend on the type of control implemented. Based on other Colorado facility submittals, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take CSU approximately 3 – 5 years to implement any of the SCR control option. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

There are no energy or non-air quality impacts for fuel usage of pipeline quality natural gas or for advanced dry low-NOx combustion systems. The energy and non-air quality impacts of SCR and 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.

Step 5: Select Reasonable Progress Control

The Division determines that any potential reductions from this source category are minimal, if any. Pipeline quality natural gas is inherently clean for SO_2 and PM10. For NOx, the majority of combustion turbines already apply advanced dry-low NOx combustion systems, especially the larger turbines.

Based on its consideration of the four factors summarized herein, the state has determined that NOx RP for combustion turbines is existing controls and emission limits. Though other controls achieve better emission reductions, the expense of these options coupled with predicted minimal visibility improvement were determined to be excessive.

Reasonable Progress Analysis of Control Options
For
Tri-State Generation & Transmission Association, Inc. – Craig Station Unit 3

I. Source Description

Owner/Operator:	Tri-State Generation & Transmission Association, Inc.
Source Type:	Electric Utility Steam Generating Unit
SCC (EGU):	10100202
Boiler Type:	Three Dry-Bottom Pulverized Coal-Fired Boilers, two opposed-wall-fired (Units 1 and 2) and one front-fired (Unit 3)

The Tri-State Generation & Transmission Association, Inc. (Tri-State) Craig Station is located in Moffat County approximately 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. Unit 3, rated at 4,600 MMBtu/hour (net 408 MW) was placed in service in 1984.

Units 1 & 2: Construction of Units 1 and 2 began in 1974; Unit 1 began operation in 1980 and Unit 2 began operation in 1979. These units are equipped with fabric filter (baghouse) systems for controlling particulate matter (PM) emissions, and wet limestone Fuel Gas Desulfurization (FGD) systems for the control of sulfur dioxide (SO_2) emissions. The boilers are equipped with ultra-low nitrogen oxide (NO_x) dual register burners with overfire air for minimization of NO_x emissions. The FGD and ultra low NO_x burner systems were required to be installed and fully operational by December 31, 2004 as a result of a consent decree with the Sierra Club (signed January 10, 2001).

Unit 3: Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. This unit is equipped with a baghouse system for controlling PM emissions, a dry lime system for control of SO_2 and low-NO_x burners with overfire air.

All three units can use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. All three units are subject to the requirements of Title IV, the Acid Rain Program, and were approved for Early Election for NO_x limits, effective January 1, 1997. Associated activities include two cooling towers, coal handling systems, ash handling systems, limestone handling system, and the staging/landfilling area.

For this analysis, the Division also relied on the existing Construction permit, historical information regarding Craig Station, and information about similar facilities to determine RP for NO_x, SO_2, and PM_{10}. EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must considered in making BART and RP determinations are largely the same. Units 1 and 2 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 commenced operation in the 15-year period prior to August 7, 1977. Therefore, these two boilers have been evaluated for BART, which the Division has determined meets the requirements of RP at this time.

The Division has elected to set a *de minimis* threshold for actual baseline emissions for evaluating reasonable progress units at each facility equal to the federal Prevention of Significant Deterioration levels. The Division defines "unit" as an Air Pollutant Emission Notice (APEN) subject source, or a stationary source, defined as "any building, structure, facility, equipment, or installation, or any combination thereof belonging to the same industrial grouping that emit or may emit any air pollutant subject to regulation under the Federal Act that is located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control[1] ."

These levels are as follows:

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

Boiler 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. **Error! Reference source not found.** depicts technical information for Unit 3 at Craig Station.

Table 1: Craig Unit 3 Technical Information

	Unit 3
Placed in Service	1984
Gross Boiler Rating, MMBtu/Hr for coal	4,600
Electrical Power Rating, Net Megawatts	408
Description	Babcock & Wilcox coal, dry bottom boiler - Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization
Air Pollution Control Equipment	PM/PM_{10} – Pulse Jet Fabric Filter Baghouse (1984 – upgraded between 2007 and 2009) NO_x – Low NO_x Burners with Over-Fire Air (upgraded between 2007 and 2009) SO_2 – Dry Limestone FGD (1984 – upgraded between 2007 and 2009) Existing turbine generator replaced with larger unit completed in May 2009.
Emissions Reduction (%)*	NO_x – 19.0%/38.8%* SO_2 – 80.9%

[1] Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

	PM – 99.8% PM_{10} – 99.6%

*Emissions Reduction estimated by comparing pre-control upgrade 2006-2008 CAMD data to AP-42 emission factor data. The first NO_x number compares the additional reduction achieved by the ultra-low NO_x burners vs. the original low-NO_x burners and the second NO_x number compares uncontrolled AP-42 factor to actual average emission factor (June 2009 – June 2010). For PM/PM_{10}., uncontrolled AP-42 factor were compared to actual average emission factors (2006 – 2008). See "Craig APCD Technical Analysis" for further details. Not based on actual testing.

II. Source Emissions

Table 2 summarizes the NO_x, SO_2, and PM_{10} actual emissions averaged over the 2006 – 2008 baseline timeframe from EPA's CAMD Database for the facility. Table 3 summarizes each unit at the facility and applicable NO_x, SO_2, and PM_{10} actual emissions averaged over the 2006 – 2008 timeframe with data from Colorado's APEN's submitted by the facility and as applicable, EPA's CAMD Database (primarily for the Unit 101 boiler and the turbines).

Table 2. Summary of 2006 - 2008 Averaged Emissions – Craig Station

NO_x (tons/year)	SO_2 (tons/year)	PM_{10} (tons/year)
16,942	3,769	363

Table 3. Summary of 2006 - 2008 Averaged Emissions by Unit – Craig Station

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
Unit 1	SO_2 (tons)	865.1	1053.0	990.5	969.5
	SO_2 (lb/ MMBtu)	0.06	0.06	0.06	0.06
	NO_x (tons)	4665.7	5817.3	5056.9	5180.0
	NO_x (lb/ MMBtu)	0.34	0.32	0.30	0.32
	PM (tons)	92.9	107.3	101.1	100.4
	PM (lb/ MMBtu)	0.007	0.006	0.006	0.006
Unit 2	SO_2 (tons)	999.6	797.1	1149.1	981.9
	SO_2 (lb/ MMBtu)	0.05	0.05	0.06	0.06
	NO_x (tons)	5548.7	4965.7	5566.4	5360.3
	NO_x (lb/ MMBtu)	0.30	0.32	0.30	0.31
	PM (tons)	90.7	81.9	87.5	86.7
	PM (lb/ MMBtu)	0.005	0.005	0.005	0.005
Unit 3	SO_2 (tons)	1721.3	1948.5	1782.6	1817.5
	SO_2 (lb/ MMBtu)	0.10	0.11	0.11	0.10
	NO_x (tons)	6592.1	6670.1	5943.9	6402.0
	NO_x (lb/ MMBtu)	0.38	0.36	0.35	0.37
	PM (tons)	70.4	71.8	67.7	70.0
	PM (lb/ MMBtu)	0.004	0.004	0.004	0.004
Auxiliary Boiler (130 MMBtu/hr) Fuel Oil Boiler	*SO_2 (tons)*	*0*	*0*	*0*	*0*
	SO_2 (lb/ MMBtu)	*0*	*0*	*0*	*0*
	NO_x (tons)	*0*	*0*	*0*	*0*

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
	NO_x (lb/ MMBtu)	*0*	*0*	*0*	*0*
	PM (tons)	*0*	*0*	*0*	*0*
	PM (lb/ MMBtu)	*0*	*0*	*0*	*0*
F101a – Coal Hauling – Units 1 & 2	*PM (tons)*	*8.15*	*8.15*	*11.39*	*9.23*
F101b – Coal Unloading to Grizzly – Units 1 & 2	*PM (tons)*	*0.04*	*0.04*	*0.05*	*0.04*
F101c – Coal Surge Pile	*PM (tons)*	*0.05*	*0.05*	*0.05*	*0.05*
S101d – Primary Coal Crushing – Units 1 & 2	*PM (tons)*	*0.18*	*0.18*	*0.23*	*0.20*
S101e – Secondary Coal Crushing Bldg – Units 1 & 2	*PM (tons)*	*0.46*	*0.46*	*0.56*	*0.49*
S101f – Common Coal Transfer Bldg Belt A	*PM (tons)*	*0.001*	*0.001*	*0.0013*	*0.0011*
S101g – Common Coal Transfer Bldg Belt B	*PM (tons)*	*0.001*	*0.001*	*0.0013*	*0.0011*
S101h – Coal Stackout Building – Units 1 & 2	*PM (tons)*	*0.002*	*0.002*	*0.0025*	*0.0022*
S101i - Coal Stackout – Units 1 & 2	*PM (tons)*	*0.051*	*0.051*	*0.063*	*0.055*
F101 j -Coal Storage Piles – Units 1 & 2	*PM (tons)*	*0.63*	*0.63*	*0.63*	*0.63*
S101k – Coal Reclaim A – Units 1 & 2	*PM (tons)*	*0.0018*	*0.0018*	*0.0019*	*0.0018*
S101l – Coal Reclaim B – Units 1 & 2	*PM (tons)*	*0.0018*	*0.0018*	*0.0019*	*0.0018*
S101m – coal Tripper Deck & Silos – Units 1 & 2	*PM (tons)*	*0.0036*	*0.0036*	*0.0038*	*0.0037*
S101n – Common Coal Drive House	*PM (tons)*	*0.0036*	*0.0036*	*0.0038*	*0.0037*
S203a – Fly Ash Storage Silo A – Units 1 & 2	*PM (tons)*	*0.0047*	*0.0047*	*0.002*	*0.0038*
S203b – Fly Ash Storage Silo B – Units 1 & 2	*PM (tons)*	*0.0047*	*0.0047*	*0.002*	*0.0038*
F203c – Fly Ash Truck Loading – Units 1 & 2	*PM (tons)*	*0.0079*	*0.0079*	*0.0034*	*0.0064*
P204 – Ash Hauling & Storage – Unit 3	PM (tons)	62.2	62.2	62.2	62.2
P201 – Limestone Hauling	PM (tons)	14.7	14.7	17.5	15.6
F102a – Coal Train Unloading – Unit 3	*PM (tons)*	*0.0607*	*0.0607*	*0.0676*	*0.063*
S102b/c – Coal Conveyor Portal Building – Unit 3	*PM (tons)*	*0.003*	*0.003*	*0.0034*	*0.0031*
S102d – Secondary Coal Crushing (2 crushers0 – Unit 3	*PM (tons)*	*0.68*	*0.68*	*0.76*	*0.71*
S102e – Coal Stackout Building – Unit 3	*PM (tons)*	*0.003*	*0.003*	*0.0034*	*0.0031*
F102f – Coal Stackout – Unit 3	*PM (tons)*	*0.076*	*0.076*	*0.085*	*0.078*

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
F102g – Coal Storage Pile – Unit 3	*PM (tons)*	*0.24*	*0.24*	*0.24*	*0.24*
S102h – Coal Reclaim System – Unit 3	*PM (tons)*	*0.003*	*0.003*	*0.0034*	*0.0031*
S102k – Common Coal Transfer Building Extension	*PM (tons)*	*0.003*	*0.003*	*0.0034*	*0.0031*
S102n – Common Coal Drive House	*PM (tons)*	*0.003*	*0.003*	*0.0034*	*0.0031*
S102i – Coal Tripper Deck and Silos – Unit 3	*PM (tons)*	*0.0018*	*0.0018*	*0.0018*	*0.0018*
S102j – Loadout Coal to Railcars – Unit 3	*PM (tons)*	*0*	*0*	*0*	*0*
F205a – Ash Hauling to "Landfill" (Outage Waste to Trapper)	*PM (tons)*	*0.114*	*0.114*	*0.114*	*0.114*
F205b – Ash and Wet Waste Hauling to/from Decant Basin	*PM (tons)*	*0.676*	*0.676*	*0.676*	*0.676*
F205c – Ash Unloading at "Landfill" (Outage Waste) & Ash Unloading at Decant Basin	*PM (tons)*	*0.0024*	*0.0024*	*0.0024*	*0.0024*
F205d – Wet Waste Unloading at Decant Basin	*PM (tons)*	*0*	*0*	*0*	*0*
F202a – Lime Hauling (trucks)	*PM (tons)*	*0*	*0*	*0*	*0*
S202b – Lime Unloading – Unit 3	*PM (tons)*	*0.0011*	*0.0011*	*0.0012*	*0.0011*
S202c – Lime Conveying & Silo – Unit 3	*PM (tons)*	*0.0011*	*0.0011*	*0.0012*	*0.0011*
S202d – Lime Day Bin	*PM (tons)*	*0.0011*	*0.0011*	*0.0012*	*0.0011*
S401/2 – Cooling Towers – Units 1 & 2	*PM (tons)*	*10.3*	*10.3*	*10.3*	*10.3*
Auxiliary Boiler	*PM (tons)*	*0*	*0*	*0*	*0*
S403 - Cooling Tower – Unit 3	*PM (tons)*	*5.8*	*5.2*	*5.2*	*5.4*

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average. 30-day NO_x rolling averages for the boilers are estimated to be 5-15% higher than the annual average emission rate.

Units *italicized* in Table 3 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress.

Tri-State estimated that a realistic depiction of anticipated annual emissions for Unit 3, or "Baseline" Emissions", to be conservative, was the average of 30-day averages from 2009, or 0.33 lb/MMBtu for NO_x. Tri-State noted that this baseline reflects the recent PSD permit limit of 6,752 tons associated with a 2009 turbine upgrade. This baseline reflects the low-NO_x burners and overfire air installed at Craig 3 in 2009. The Division notes that the 2006 – 2008 baseline period used for other RP and BART sources is not reasonable for Craig Unit 3 due to the recent upgrades. The Division also used the recent PSD permit limit of 6,752 tons for NO_x and 2,125 tons for SO_2 to determine a baseline.

The notable difference is that the Division used the average capacity factor (based on heat input) from 2006 – 2008 to determine the baseline emissions, resulting in 0.28 lb/MMBtu for NO_x and 0.09 lb/MMBtu for SO_2. Craig Unit 3 ran at an average of 86.4% capacity (based on heat input) from 2006 – 2008, thus this factor is assumed to be a reasonable baseline for this planning period. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database. These emissions are summarized in Table 4.

Table 4: Tri-State Craig Unit 3 Baseline Emissions

Pollutant	Unit 3	
	Annual Emissions* (tpy)	Average Emissions (lb/MMBtu)
NO_x	5,693	0.283
SO_2	1,792	0.089
PM_{10}	148**	0.007**

*The Division calculated annual (tpy and lb/MMBtu) NO_x and SO_2 emissions using 2006 – 2008 capacity factor and current PSD permit limits.
**The PM_{10} emissions and emissions factor are from August 2009 stack test data; PM_{10} current construction permit annual emission limit is 403 tons/year and 0.012 lb/MMBtu.

III. Units Evaluated for Control

Tri-State notes that the Craig boilers burn Colorado coal that primarily comes from the Trapper mine, supplemented by ColoWyo coal, which are both high-ranking sub-bituminous coal. Limited amounts of coal from the Twentymile mine, ranked as bituminous, are also burned. All of these mines are located in northwestern Colorado. The Trapper contract expires in 2014. Future nearby coal supplies could come from sources such as Trapper, ColoWyo, or Twentymile. Accordingly, the trend of future coal supplies is such that in the context of NO_x-forming characteristics, Craig 3 will continue to burn "bituminous-like" coal, plus, it is likely that additional quantities of bituminous coals will be burned at Craig 3 in the future. Similar to PSCo, Tri-State notes that these coals are ranked as sub-bituminous, but are closer in characteristics to bituminous coal in many of the parameters influencing NO_x formation. The specifications for these coals are listed below in Table 6. Note that with the exception of moisture content, the coal characteristics are reasonably close for the two coals. The actual APEN coal specifications (2006 – 2008) are listed below in Table 5.

Table 5: Coal Specifications (2006 - 2008 Averaged APEN data)

	Specifications		
Emission Unit	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
Craig Unit 3	10,224	0.39	6.47

Table 6: Craig Station Coal Specifications (2008)

Coal Mine/Region	Colowyo	Trapper	Twentymile
Coal Rank Classification	Sub-bituminous, Class A	Sub-bituminous, Class A	Bituminous
H_2O (Moisture %)	17.42	16.7	9.62
Ash (%)	5.71	6.5	11.93
Sulfur (%)	0.37	0.44	0.52
Nitrogen (%)	1.35	~1.5	1.57

Heating Value (HHV Btu/lb)	10,392	9,800	11,084

Uncontrolled emission factors are outlined in Table 7. The factors are based on firing bituminous coal as well as the highest ash and sulfur content from the two coals for conservative estimates.

Table 7: Uncontrolled emission factors for Craig BART-eligible sources[2]

	Pollutant (lb/ton)*			
Emission Unit	NO_x	SO_2	PM (filterable)	PM_{10} (filterable)
Unit 3	12	14.7	64.7	14.9

*SO_2 and PM/PM_{10} factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, averaged from APEN data (2006 – 2008). Please refer to "Craig APCD Technical Analysis" for more details.

IV. Reasonable Progress Evaluation of Unit 3

A. Sulfur Dioxide (SO_2)

Step 1: Identify All Available Technologies

The Division requested that Tri-State evaluate the option below, and received relevant information for this request on June 4, 2010:

Dry FGD upgrades

As discussed in EPA's BART Guidelines[3], electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls. However, upgrades need to be considered for the scrubber if technically feasible. These upgrades include:

- -Use of performance additives
- -Use of more reactive sorbent
- -Increase the pulverization level of sorbent
- -Engineering redesign of atomizer or slurry injection system

The current PSD permit SO_2 limits are depicted in Table 8.

Table 8: Craig Unit 3 SO_2 PSD Permit Limits

	SO_2 limits (lb/MMBtu) Calendar day average	Reduction (%) Required 30-day rolling	Annual Emission Limit (tons/year)
Unit 3	0.20*	80	2,125

*May be exceeded once during any calendar month.

[2] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[3] EPA, 2005. Federal Register, 40 CFR Part 51. Regional haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Pgs. 39133.

Step 2: Eliminate Technically Infeasible Options

Dry Flue Gas Desulfurization (FGD) Upgrades: Dry FGD systems are commonly known as spray dry absorbers (SDA), and currently make up about 12% of FGD systems at U.S. power plants[4]. SDA systems are typically utilized at smaller units that burn lower-sulfur in the western U.S., where water resources are limited. A SDA system captures SO_2 by using slaked lime slurry that is sprayed into the flue gas, subsequently dried by the heat of the flue gas, and then collected in a particulate control device.

Craig Unit 3 was installed in 1984 with a "Spray Dryer Removal System" in connection with the aforementioned baghouse for control of the resultant SDA materials. At the time, the system was a new control technology for SO_2 removal from the gaseous emission stream of a utility boiler. Tri-State has since upgraded this system (between 2007 and 2009) and currently achieves greater than 80% SO_2 removal, with an actual annual average of approximately 0.09 lb/MMBtu. This system exceeds EPA's presumptive limits stated in 40 CFR part 51 Appendix Y of 0.15 lb/MMBtu[5]. Lime spray dryers have been determined to be Best Available Control Technology (BACT) for new Electric Generating Unit (EGU) sources proposed in the West according to EPA's RBLC (RACT/BACT/LAER Clearinghouse) database. The RBLC database lists recent BACT determinations ranging from 0.06 – 0.167 lb/MMBtu, with an average of 0.11 lb/MMBtu on a 30-day rolling average. Refer to "Division RBLC Analysis" for more details regarding recent RBLC BACT determinations. Additionally, an EPA Report regarding the control of SO_2 emissions found that lime spray drying processes have a median design efficiency of 90%[6] .

The BART Guidelines note potential upgrades for dry scrubbing systems[7]. These upgrades include:

- *Use of performance additives*
- *Use of more reactive sorbent*
- *Increase the pulverization level of sorbent*
- *Engineering redesign of atomizer or slurry injection system*

Tri-State examined BART-guideline dry scrubbing potential upgrades, with the following results:

- *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.

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[4] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.
[5] Colorado Operating Permit 96OPLR142 pg. 5 – SO_2 30-day rolling average limit is 0.13 lb/MMBtu.
[6] EPA, 2000. "Controlling SO_2 Emissions: A Review of Technologies." Prepared by Ravi K. Srivastava for Office of Research and Development, Washington, D.C. 20460. Pg. 33.
[7] EPA, 2005. Federal Register, 40 CFR Part 51. Regional haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Pgs. 39171.

-*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 peblle lime and lime fines. Fines are generated at the Craig facility in the pneumatic lime handling system. Therefore, the Division concurs that Tri-State 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, Tri-State and the Division concur that there are not any technically feasible upgrade options for Craig Station Unit 3. However, the Division has evaluated the option of tightening the SO_2 emission limit for Craig Unit 3.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The control effectiveness of tightening the 30-day rolling emission limit on Craig Unit 3 has been evaluated by the Division. The Division analyzed the period after Tri-State upgraded the turbine (post-control: June 2009 – June 2010) against baseline emissions (2006 – 2008) to determine the maximum and average 30-day rolling emission rates, shown in Table 9, to determine potential control effectiveness, if any. Additionally, the Division evaluated the baseline heat input, capacity factor, and hours of operation pre-upgrade (2006 – 2008) and post-upgrade (June 2009 – June 2010) to evaluate whether the data was consistent with baseline information, and whether there was enough information to determine if a tighter emission limit is warranted, in Table 10. This information allows the Division to set a more relevant emission limit for Craig Unit 3 using representative actual emissions.

Table 9: Craig Unit 3 30-day rolling emission rates (baseline 2006 - 2008)

Unit and Timeline	Maximum 30-day rolling emission rate (lb/MMBtu)	Average 30-day rolling emission rate post-control (lb/MMBtu)
Craig Unit 3 – post control (June 2009 – June 2010)	0.1350	0.1081
Craig Unit 3 – pre-control (2006 – 2008)	0.1412	0.1088

Table 10: Craig Unit 3 30-day rolling emission rates (baseline 2006 - 2008)

Unit and Timeline	Capacity Factor (Heat Input %)	Hours of Operation (% of total possible operating hours)
Craig Unit 3 – June – December 2009	98.1%	95.5%
Craig Unit 3 – January – June 2010	89.7%	96.1%
Craig Unit 3 – June 2009 – June 2010 Average	93.9%	95.8%
Craig Unit 3 – pre-control (2006 – 2008)	86.4%	96.3%

The Division notes that there are not significant differences between the maximum or average 30-day rolling emissions before and after the turbine and control upgrades. Similarly, the capacity factor and hours of operation do not change discernibly. Therefore, the Division concludes that post-upgrade operations may be used in determining a tighter SO_2 emission limit in this reasonable progress.

Table 11 summarizes each available technology options and technical feasibility for SO_2 control on Craig Unit 3.

Table 11: Craig Unit 3 SO2 Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Wet FGD	52-98%, median 90%[8]	Y – not evaluated
Dry FGD	70 – 90%	Y - installed
DSI (Trona)	60-65%	Y – not evaluated, will not provide further SO2 control
Fuel switching – different coal type	None	Y – will not provide further SO2 control
Use of performance additives	None	N
Use of more reactive sorbent	None	N
Increase the pulverization level of sorbent	None	N
Engineering redesign of atomizer or slurry injection system	None	N

[8] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance
A more stringent emission limit is not anticipated to result in any increased costs. Thus, this factor does not influence the selection of controls.

Factor 2: Time Necessary for Compliance
A more stringent emission limit is not anticipated to result in any system upgrades or changes and can be implemented as soon as the SIP is approved. Thus, this factor does not influence the selection of controls.

Factor 3: Energy and Non-Air Quality Impacts
There is not any negative energy or non-air quality impacts related to a more stringent emission limit. Thus, this factor does not influence the selection of controls.

Factor 4: Remaining Useful Life
Tri-State asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with emission limit tightening. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 12 shows the number of days pre- and post-control. Table 13 depicts the visibility results (98th percentile impact and improvements). Cost effectiveness in $/deciview was not determined since there will minimal, if any, costs associated with emission limit tightening.

Table 12: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hour SO2 rates	3	0.326	Mt. Zirkel Wilderness	239	---	---	173	---	---
Dry FGD	3	0.150		239	233	6	173	170	3
Dry FGD	3	0.070		239	230	9	173	168	5

Table 13: Visibility Results – SO_2 Control Options

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)	Output (@ 98th Percentile Impact)*	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum
			(dv)	(Δ dv)	(%)
Max 24-hour SO2 rates	3	0.326	5.20	---	---
Dry FGD	3	0.150	4.94	0.26	5%
Dry FGD	3	0.070	4.82	0.38	7%

Step 6: Select RP Control

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.

Based upon its consideration of the five factors summarized herein, the state has determined that SO2 RP is dry FGD controls at the following SO2 emission rates:

Craig Unit 3: 0.15 lb/MMBtu (30-day rolling average)

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.

B. Filterable Particulate Matter (PM_{10})

Craig Unit 3 is equipped with pulse jet fabric filter (PJFF) baghouses to control PM/PM_{10} emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Table 14 shows the most recent stack test data (2009). Real-time data demonstrates that these baghouses are meeting >95% control. The current Colorado construction permit limit is 0.013 lb/MMBtu for filterable PM emissions and 0.012 lb/MMBtu for filterable PM_{10} emissions and also limits total PM and PM_{10} (filterable and condensable) emissions to 0.022 and 0.020 lb/MMBtu respectively (Condition 4). The most recent stack test data is used to determine compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

Table 14: Craig Unit 3 Stack Test Results (August 2009)

Pollutant	Unit 3 (lb/MMBtu)
Total PM	0.013
Filterable PM	0.0091
Condensable PM	0.0035
Total PM_{10}	0.007
Filterable PM_{10}	0.0035
Condensable PM_{10}	0.0035
PM Control efficiency	99.5%
PM_{10} Control efficiency	98.8%

A Division review of EPA's RBLC revealed recent BACT PM/PM_{10} determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations.

The State has determined that the existing Unit 3 fabric filter baghouse and regulatory emissions limit 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 control technology and emission limit is RP for PM/PM_{10}.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies
Tri-State identified five options for NO_x control:
New/modified Low NO_x Burners (LNBs) with Overfire Air (OFA) system (next generation)
Advanced OFA system or Rotating overfire Air (ROFA)
Neural network system combustion controls
Selective Non-Catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)

The Division also identified and examined the following additional control options for these units:
Electro-Catalytic Oxidation (ECO)®
Rich Reagent Injection (RRI)
Coal reburn +SNCR

Step 2: Eliminate Technically Infeasible Options
LNBs with OFA Upgrades: TriState contracted with ACT to modify the existing Craig 3 burners and upgrade the OFA system. ACT determined that burners and OFA system could be upgraded. However, ACT has not modified ultra low-NO_x Babcock & Wilcox 4Z burners such as those in use at Craig Unit 3. In addition ACT stated that a complete plant inspection, data review, baseline testing, and computational fluid dynamics (CFD) modeling would be required for them to guarantee performance predictions. An amended proposal was submitted by ACT

upon receipt of updated coal analyses that more closely represent the quality of coal being burned at Craig 1&2. In their amended proposal, ACT again reiterated that "to give a guaranteed NO_x reduction, a lot more information is required." LNBs modifications with OFA upgrades appear to be technically feasible for Craig Unit 3.

Advanced OFA system – rotating overfire air system (ROFA): ROFA® injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA® differs from OFA in that ROFA® utilizes a booster fan to increase the velocity of air to promote mixing and to increase the retention time in the furnace. To date, ROFA® has only been installed as a retrofit technology on units firing eastern bituminous coals.

TriState contacted Motobec, the manufacturer of ROFA® technology, to determine if ROFA is feasible for Craig Unit 3. Mobotec could not give TriState a definitive guarantee for reductions due to the variability in the quality of coals.

Based on data published by the manufacturer, ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load[9]. While ROFA is considered superior to OFA/SOFA alone, ROFA alone is not superior to LNB+OFA and is not expected to increase emissions reductions for Craig Units 1 and 2. The Division asserts that ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for these units, ROFA® technology is not considered further in this analysis.

Neural network system combustion controls: TriState received a neural network proposal from NeuCo in April 2006. The proposal offers to enhance the existing Craig 3 control system by providing combustion optimization technology. For a given set of objectives, a neural network directs the unit's distributive control system (DCS) or other control systems to optimize the boiler performance.

Based on review of the Craig 3 current operations, NeuCo stated that Craig 1&2 appear to be good candidates for the optimization system. Key aspects to neural network success are the training support provided by the supplier, as well as achieving buy-in from plant operators. TriState states that it is important to note that the condition of the unit(s) and the manner in which the unit(s) is operated prior to the installation of the combustion optimization system also play an important role in determining potential NO_x reductions. Neural network system combustion controls appear to be technically feasible for Craig Unit 3.

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for Craig Unit 3. Tri-State conducted a site-specific SNCR study

[9] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html

in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

While a lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for Craig, a retrofit SCR system, the 0.07 lb/MMBtu controlled NO_x value is more expected, although Tri-State asserts that the unit cannot achieve below 0.08 lb/MMBtu. See "Tri-State BART Submittals" for more details. The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. SCR is a technically feasible alternative for Craig Unit 3.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[10] and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[11] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 1 and 2.

***LNB/SOFA/LNB+SOFA:* Craig Unit 3 is equipped with low-NO_x burners with over-fire air (LNB+OFA) as part of a construction permit modification.**

Table 1 illustrates that this system achieves about 39% NO_x reductions (based on actual emissions) on Unit 3.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu[12]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

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[10] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[11] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php
[12] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Tri-State provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[13] 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Craig Unit 3 to determine control efficiencies and annual reductions.

LNBs with OFA Upgrades: TriState noted in the original BART submittal (July 31, 2006) that ACT proposed that a modified LNB with upgraded OFA system could achieve 10 – 15% NO_x reduction above current levels. Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. These control refinements consist mostly of more precise control of fuel and air for combustion. This study conducted by Black & Veatch (B&V) notes that these refinements could achieve approximately 0- 2 % control. B&V explains that the reduction in control efficiency is due to the difference between "design criteria" versus permit limit. The Division notes that the Craig units already have ultra-low NO_x burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinements from December 8, 2010.

Neural network system combustion controls: TriState noted in the original BART submittal (July 31, 2006) that NeuCo provided a neural network proposal projecting that an optimization system could achieve 5 – 15% NO_x reductions. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. This study, conducted by Black & Veatch (B&V), notes that the NN equipment will be minimal, consisting of a few computer servers that will interface with existing systems in the same location(s). NN system combustion controls could achieve approximately 0 – 5% control. B&V explains that the reduction in control efficiency is due to the difference between "design criteria" versus permit limit. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study control efficiency for NN system controls submitted on December 8, 2010.

SNCR: Tri-State stated in the May 14, 2010 submittal that based on the boiler configuration, Tri-State could expect a continuous NO_x reduction performance with SNCR technology in the range of 10 – 15%. This is based on Tri-State's extensive research into the application of SNCR technology at Craig Station. The vast majority of the research was focused on system performance and impacts on plant performance. Tri-State staff conducted a visit to First Energy's Eastlake and Sammis power plants in Ohio; this visit was specifically design to evaluate boiler designs due to the similarity in boiler/burner configurations similar to the Craig Station boilers. These estimates are lower than EPA's SNCR Air Pollution Control Technology Fact Sheet, which estimates SNCR between 30 – 50% control. Other Colorado facilities estimated SNCR as achieving between 17 – 40% NO_x control. Control effectiveness has been historically noted to be lower for wall fired boilers similar to the Craig boilers; therefore the Divisions considers 15% to be a reasonable control effectiveness for SNCR.

[13] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

SCR: Tri-State stated in the May 14, 2010 submittal the expected emission rate for Craig Unit 3 when applying SCR are 0.08 lb/MMBtu. Tri-State did not specify if this estimate was a 30-day rolling averages, although, as stated in the December 31, 2009 submittal, the baselines are averages of 30-day averages. The Division notes that several other Colorado facilities have noted SCR expectations of 0.070 lb/MMBtu[14]or even lower. Additionally, a recent AWMA study found similar-sized EGUs achieve NO_x reduction efficiencies greater than 85% with emission rates between 0.04 and 0.07 lb/MMBtu (during the ozone season).[15] EPA's AP-42 emission factor tables estimate SCR as achieving 75 – 85% NO_x emission reductions. Table 15 depicts a comparison of SCR control efficiencies. The Division adjusted Tri-State's estimate to 0.07 lb/MMBtu based on the reasoning above.

Table 15: SCR Control Efficiency Comparison

Unit	Baseline (lb/MMBtu)	Control Efficiency (%)		Resultant Emissions (lb/MMBtu)	
		Tri-State Estimate	Division Estimate	Tri-State Estimate (annual average)	Division Estimate (annual average)
Craig Unit 3	0.283	71.8	75.2	0.080	0.070

Table 16 summarizes each available technology and technical feasibility for NO_x control.

Table 16: Craig Unit 3 NOx Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
LNB + OFA	25-45%	Y – installed
Air Staging – overfire air (OFA)	5-40%	Y – installed
Ultra-Low NO_x Burner (ULNB) Upgrade/Refinements	0 – 2% (TriState)	Y
Neural network system	0 – 5% (TriState)	Y
SNCR	10 – 40%	Y
Rotating overfire air (ROFA)	45 – 65%	N
SCR	75 – 90%	Y
Electro-Catalytic Oxidation (ECO)®	n/a	N
Rich Reagent Injection (RRI)	n/a	N
Coal reburn+SNCR	n/a	N

[14] Public Service Company of Colorado (April 20, 2010), Colorado Energy Nations Company (November 12, 2009), Colorado Springs Utilities (February 20, 2009), and Platte River Power Authority (January 22, 2009) all note that their individual EGUs can achieve 0.070 lb/MMBtu or even lower on a 30-day rolling average basis.
[15] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

Low NO_x burner upgrades: Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. Through a literature review, the Division could not find any examples or support for upgrades on ultra-low NO_x burners with overfire air. Ultra-low NO_x burners are fairly new within the industry, so additional upgrades have not yet been researched. The first commercial application for these burners was documented in May 2000.[16] Tri-State estimates that the initial cost of combustion control refinement at about $2,200,000 with an annualized 20-year cost of $122,000. The Division notes that the Craig units already have ultra-low NO_x burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinement cost estimates from December 8, 2010.

Neural network system: TriState did not provide a quantitative evaluation of the application of a neural network system to the Division. There are three other facilities in Colorado alone using neural network systems from the same provider that TriState contacted.[17] It is unknown why TriState will provide further analysis of this system. Costs for these systems are very specific to individual units, so the Division cannot estimate costs for this option. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. Tri-State estimates that the initial cost of neural network systems (per unit) at about $800,000 with an annualized 20-year cost of $280,000. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study cost estimates for NN system controls submitted on December 8, 2010.

SNCR: A typical breakdown of annualized costs for SNCR on industrial boilers will be 15 – 25% for capital recovery and 65 – 85% for operating expenses.[18] The Tri-State-estimated SNCR costs for operating expenses are 70% for Craig Unit 3. Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[19]

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[16] Bryk and Kleisley, 2000. "First Commercial Application of DRB-4Z™ Ultra-Low NOx Coal-Fired Burner." Presented to POWER-GEN International 2000. November 14-16, 2000. Orlando, Florida.
[17] NeuCo White Papers and Case Studies. http://www.neuco.net/library/case-studies/default.cfm and Platte River Power Authority January 22, 2009 submittal: "Rawhide Unit 101 NOx Emission Control Cost and Technical Feasibility Information."
[18] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.
[19] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

The cost effectiveness for SNCR on Unit 3 (at 15% control efficiency) is approximately $4,887 per ton. Recent NESCAUM studies estimate SNCR retrofits on wall fired boilers (comparable to Unit 3) achieving 0.50 – 0.65 lb/MMBtu and emission reductions of 30 – 50% as costing $590 - $1,100 per ton of NO_x reduced, depending on initial capital costs and capacity factor. [20,21] It should be noted that Tri-State is estimating resultant emission rates lower than 0.30 lb/MMBtu for both boilers, therefore costs will be higher. EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NO_x reduced.[22] On a linear scale, based on the NESCAUM estimates and assuming an achieved rate of 0.23 lb/MMBtu, the costs should be approximately $2,500 per ton. Tri-State and the Division's revised estimates are above this range; the Division inquired about the reagent and auxiliary power costs; Tri-State responded on July 30, 2010 adjusted the auxiliary power and lost generation costs for all of the Craig Units for both SNCR and SCR. Tri-State also provided further information regarding the cost of potential reagent options. The costs for these two items remain higher than other Colorado facility estimates; however, Tri-State has provided adequate information detailing the reasoning for power and reagent costs. The Division and Tri-State still do not completely concur on other cost items, including an annual 3% escalation rate for capital material, capital labor, capital indirect, and operation and maintenance. Additionally, similar Colorado facility cost estimates fall within the EPA SNCR Fact Sheet range. The Division will use Tri-State's capital and operation/maintenance costs for this analysis in the absence of additional information at this time.

SCR: Recent NESCAUM studies estimate SCR retrofits on wall fired boilers achieving NO_x emission rates of 0.15 – 0.25 lb/MMBtu and emission reductions of 75 – 85% as costing $1,700 - $3,200 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[23,24 25,26] It should be noted that Tri-State is estimating resultant emission rates lower than 0.15 lb/MMBtu for both boilers, therefore costs will be higher. Tri-State's estimates are above this range; on a linear scale (achieving 0.07 lb/MMBtu); the costs should be approximately $7,000 per ton. The Division's revised cost estimates are close to this estimate; therefore, the Division concludes that these cost estimates are reasonable.

Table 17 and Table 18 depict controlled NO_x emissions and control cost comparisons.

[20] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[21] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[22] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

[23] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[24] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[25] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[26] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

Table 17: Craig Unit 3 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	5,693	0.283	
Combustion control refinements	2	5,579	0.277	0.32
Neural network system	5	5,408	0.268	0.31
SNCR	15	4,839	0.240	0.28
SCR	75	1,412	0.070	0.08

Table 18: Craig Unit 3 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Combustion control refinements	114	$122,000	$1,071	$1,071
Neural network system	285	$280,000	$984	$925
SNCR	854	$4,173,000	$4,887	$4,887
SCR	4,281	$29,762,387	$6,952	$7,466

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take Tri-State approximately 3 - 5 years to implement any of the above control options. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: Energy and Non-Air Quality Impacts

LNB Upgrades/Neural network system(s): There are no known non-air quality impacts associated with upgrades on low-NO_x burner systems or neural network systems. Energy impacts are not significant. Thus, this factor does not influence the selection of this control.

SNCR/ SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas.

Post-combustion add-on control technologies such as SNCR do increase power needs to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. In particular, SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas.

Factor 4: Remaining Useful Life

Tri-State asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 19 shows the number of days pre- and post-control. Table 20 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

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.

Table 19: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hour 2nd	3	0.365	Mt. Zirkel Wilderness	239	---	---	173	---	---

half 2009 NOx rate									
2009 New LNBs	3	0.283		239	234	5	173	170	3
SNCR	3	0.240		239	233	6	173	166	7
SCR	3	0.070		239	224	15	173	149	24

Table 20: Visibility Results – NO_x Control Options

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Output (@ 98th Percentile Impact)	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum
			(dv)	(Δ dv)	(%)
Max 24-hour 2nd half 2009 NOx rate	3	0.365	5.20	---	---
2009 New LNBs	3	0.283	4.99	0.21	4%
SNCR	3	0.240	4.88	0.32	6%
SCR	3	0.070	4.41	0.79	15%

Step 6: Select RP Control

Based upon its consideration of the five factors summarized herein, the state has determined that NOx RP for Craig Unit 3 is SNCR control at the following NOx emission rates:
Craig Unit 3: 0.28 lb/MMBtu (30-day rolling average)

For SNCR 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. 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. 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 of the Regional Haze State Implementation Plan.

V. Reasonable Progress Evaluation of Ash Hauling & Storage (P204) and Limestone Hauling (P201)

Both of these fugitive dust sources are permitted within Colorado Operating Permit 96OPMF155.

Ash hauling (P204) is controlled with two methods to minimize fugitive emissions:

- Ash deposited in trucks for transport to disposal areas shall be sufficiently moist (Condition 8.2).
- The scrubber sludge/ash haul road servings Units 1, 2, and 3 shall be treated with magnesium chloride or equivalent as a dust suppressant. The magnesium chloride shall be applied according to manufacturer's specifications. The frequency of application shall be according to manufacturer's recommendations (Condition 8.3).

Limestone hauling (P201) activities are controlled several ways to minimize fugitive emissions:

- Opacity limitations of 20% except under certain operational conditions (U.S. EPA Reference Method 9) (Conditions 6.2, 11.2, and 11.3)
- Unloading facilities are vented to a baghouse (Condition 6.3)
- All process equipment shall be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their in the pollution control system (Condition 6.4)

These existing controls and corresponding emission limits in Section II, Conditions 6 and 8 of Operating Permit 96OPMF155 represent the most stringent level of control available for these fugitive dust sources.

Therefore, the Division proposes that RP for these sources is no additional control and the current emission limit for the above units is RP.

VI. Reasonable Progress Evaluation of Units 1 & 2

Units 1 and 2 have been evaluated under Best Available Retrofit Technology (BART) provisions. BART for Units 1 and 2 can be found in Chapter 6 of the Regional Haze State Implementation Plan. The Division determines that BART represents the most stringent available NO_x, SO_2, and PM/PM_{10} control technologies and represents reasonable progress. Therefore, a full 4-factor analysis is not needed to evaluate reasonable progress for NO_x, SO_2, or PM/PM_{10} for Units 1 and 2 at Craig Station.

HEATER-TREATER SOURCE CATEGORY

NOx Emission 4-Factor Analysis for Reasonable Progress (RP)

I. Source Description

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 the gas plant. Generally, the contaminants include liquid hydrocarbons and water. The composition of the liquid hydrocarbons (oil and condensate) can vary by gas field but the majority of gas wells in Colorado are located in the Denver-Julesburg (DJ) Basin which produces a condensate liquid.

The heater-treater is a combination of a heater, free-water knockout, and oil/condensate and gas separator. 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. Since chokes in the wellhead restrict the flow of the oil and gas from the well, temperatures may drop due to the pressure changes of the choke. This may cause the water or hydrates to freeze and plug the well, thereby slowing or stopping the condensate and gas production. Two diagrams at the end of this document show examples of heater-treaters.

Information regarding heater-treater emissions and control strategies is scarce. The paucity of information is likely due to the very low emissions associated with each heater-treater that very often falls below regulatory thresholds. However, the multitude of gas wells in Colorado (~26,000 by 2018) result in cumulative heater-treater NOx emissions that are projected to be the largest single area source category in Colorado by 2018.

II. Heater-Treater Source Category Emissions - Statewide

Pollutant	Heater-Treater Emissions (tpy)	2018 Annual Emissions (tpy)
CO	0.18[1]	4,809
NO_2	0.88[1]	22,901
PM_{10}	negligible [2]	negligible
SO_2	Negligible[3]	negligible

Notes:

1. Source: "Final Report – Oil and Gas Emission Inventories for the Western States", by ENVIRON International Corporation for Western Governors' Association, December 27, 2005
2. Source: AP-42, 5th Edition, Volume 1, Chapter 1, Section 1.4.3
3. Source: "A Comprehensive Oil and Gas Emissions Inventory for the Denver-Julesburg Basin in Colorado," by ENVIRON International Corporation, May 2008

III. Control Technology Evaluation

Step 1: Identify All Available Technologies

Five technologies have been identified to lower NOx emissions from heater-treaters:

Technology #1 - Lowering the heater-treater temperature

Technology #2 - Installing insulation on the separator

Technology #3 - Retrofitting with low-NOx burners

Technology #4 - Adding post combustion technology – selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR)

Technology #5 - Using central gathering facilities

Technology #1: This technology (lowering the heater-treater temperature) was identified by EPA Natural GasSTAR in PRO Fact Sheet No. 906. The fact sheet was written with reduction of methane in mind, although this technology would also reduce combustion emissions because it would reduce fuel use. The following is from the fact sheet: "…heater-treater temperatures at remote sites may be higher than necessary, resulting in increased methane emissions. Commonly, the reason for this is that operators need to reduce the chance of having a high water content in the produced oil and manpower limitations do not allow for constant monitoring at remote sites. Field personnel, consequently, are inclined to operate the equipment at levels that cause the least problems, but also result in higher than necessary emissions."

Technology #2: This technology (installing insulation on the separator) was identified by the Four Corners Air Quality Task Force in 2007. This technology would reduce combustion emissions because it would reduce fuel use.

Technology #3: This technology (retrofitting with low-NOx burners) was identified by the EPA and is documented in the AP-42 "Compilation of Air Pollutant Emission Factors." The following is from the 5th Edition, Volume 1, Chapter 1, Section 1.4.4: "Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NO_x formation."

Technology #4: This technology (adding NSCR or SCR) involves adding post-combustion control equipment to treat engine exhaust.

Technology #5: This technology (central gathering facilities) is being used by some companies, including in the Piceance Basin and in the Jonah/Pinedale region of Wyoming. Other terms include central collection facilities, liquid gathering systems, or 3-phase gathering systems. In some cases, produced natural gas is separated into two or three phases (gas and liquids [produced water and condensate] or gas, produced water, and condensate) at the wellhead and those liquid streams are sent to central gathering facilities. In other cases, including a facility in the Piceance Basin, produced gas (including the liquids) is sent directly to the central gathering facilities. In those cases, emissions from heater-treaters would be reduced because fewer heater-treater devices would be required.

Step 2: Eliminate Technically Infeasible Options

Technology #1: This technology is technically feasible.

Technology #2: This technology is technically feasible.

Technology #3: The Four Corners Air Quality Task Force considered low NOx burners as a mitigation option for the Four Corners area and had the following finding: "Application not appropriate for the San Juan Basin, because most burners commonly used in the Four Corners Area are smaller than the technology is capable of providing emission reduction." It appears likely that this technology would also be technically infeasible for the Denver-Julesburg (DJ) Basin considering that low-NO_x burners are not commercially available for very small combustion sources such as heater-treaters.

Technology #4: A heater-treater is a combustion device that is similar to internal combustion engines where the application of NSCR and SCR on engines smaller than 100 hp is not practical or technically feasible. Moreover, the cost per unit of power is higher, and there are uncertainties as to whether the proper exhaust temperature for optimum performance can be reliably maintained. Consequently, NSCR and SCR may not be commercially available for many small engines. (source: Four Corners Air Quality Task Force document available at www.nmenv.state.nm.us/aqb/4C/Docs/ArgonneRICEmat.DOC). Similarly, for small fuel burning equipment, such as heater-treaters, the availability of post combustion controls is anticipated to be unavailable and therefore technically infeasible.

Technology #5: This technology is technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Technology #1: The EPA Natural GasSTAR in PRO Fact Sheet No. 906 regarding lowering heater-treater temperatures was written from the methane reduction perspective. Emission reductions for NO2 and CO were not provided.

Technology #2: The Four Corners Air Quality Task Force did not provide the control effectiveness of installing insulation and additional information on the effectiveness of such control appears to be unavailable.

Technology #5: Removing individual heater-treaters and replacing them with a central gathering facility would eliminate emissions from the heater-treaters. The central gathering facility would be a new source of emissions; however, overall emissions will be reduced. Not only would combustion emissions from the multiple heater-treaters be eliminated, VOC emissions from condensate tanks (which would also be removed from wellheads if this technology was implemented) would be eliminated. If a vapor recovery unit (VRU) were used at the central gathering facility, VOCs could be compressed back into the gas stream.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Technology #1 - Lowering the heater-treater temperature: Although the EPA Natural GasSTAR fact sheet was written with methane reductions in mind, the costs of implementing the control technology also applies to combustion emission reductions. Capital costs range from $1,000 to $10,000. Annual operating and maintenance costs are $100 to $1000. The payback, through incremental labor and fuel gas savings, is less than one year.

Technology #2 - Installing insulation on the separator: Installing insulation on heater-treaters will reduce fuel usage and is economically feasible where there is a payback that meets an operators respective investment targets (e.g., ROI or NPV). For older units where the remaining life of the equipment is limited, the economics may not justify the application of insulation.

Technology #5 – Centralized gas well gathering facilities to reducing the number of Heater-Treaters: The cost of removing a group of heater-treaters and replacing them with a central gathering facility will vary due to many parameters, including topography, composition of the produced natural gas, number of heater-treaters being removed, and mineral rights. Topography may cause difficulties in dealing with large slugs of liquids; frequent pigging may be required to move liquids to the central gathering facility. It would be more cost efficient to implement this technology on a new field, rather than retrofitting an existing field that already has infrastructure based on wellhead separation. Typically when a well is drilled there are multiple ownerships in the well due to land and mineral rights. This requires that volumes be allocated back to each specific well for proper royalty treatment. To track this requires equipment at each well, which increases capital and operating costs and reduces the savings from eliminating equipment at each wellhead. This allocation issue goes away when a company owns all associated mineral and land rights. Cost savings include recovery of product that was previously lost to the atmosphere, reduced truck traffic to wellheads, and reduction of condensate and water tanks.

Factor 2: Time Necessary for Compliance

Technology #1 - Lowering the heater-treater temperature: Additional time for achieving compliance with this technology is not anticipated.

Technology #2 - Installing insulation on the separator: Additional time for achieving compliance with this technology is not anticipated.

Technology #5 – Centralized gas well gathering facilities to reduce the number of Heater-Treaters: The additional time necessary to comply with centralizing gas well gathering would be very site specific and would likely vary depending on gas well density and topographical barriers.

Factor 3: Energy Impacts and Non Air-Quality Environmental Impacts

Technology #1 - Lowering the heater-treater temperature: Lowering the heater-treater temperature will reduce fuel use. There are not any non air-quality impacts.

Technology #2 - Installing insulation on the separator: Installing insulation on heater-treaters will reduce fuel use. There are not any non air-quality impacts.

Technology #5 – Centralized gas well gathering facilities to reduce the number of Heater-Treaters: It is more energy efficient to operate a central gathering facility rather than multiple individual heater-treaters. There are not any non air-quality impacts.

Factor 4: Remaining Useful Life

Technology #1 - Lowering the heater-treater temperature: Heater-treaters typically have a service life of approximately 30 to 40 years. (source: manufacturer, ProSept Technologies) This control technology would not affect the service life.

Technology #2 - Installing insulation on the separator: Heater-treaters typically have a service life of approximately 30 to 40 years. (source: manufacturer, ProSept Technologies) This control technology would not affect the service life.

Technology #5 – Centralized gas well gathering facilities to reduce the number of Heater-Treaters: Heater-treaters typically have a service life of approximately 30 to 40 years. (source: manufacturer, ProSept Technologies) If heater-treaters were removed and replaced with a central gathering facility, the heater-treaters would not be used for their entire service.

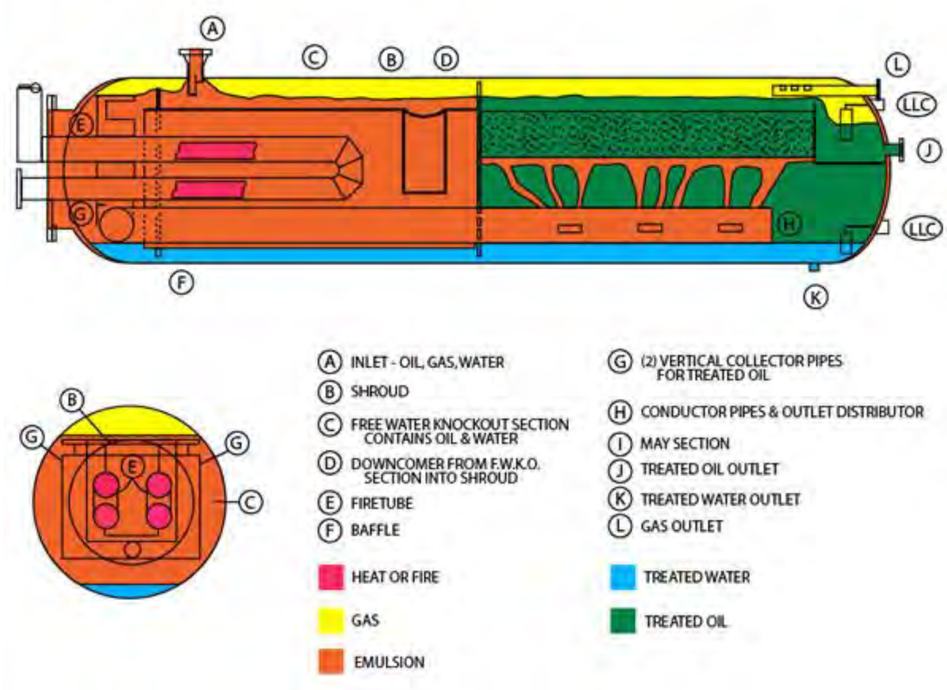
Step 5: Select Reasonable Progress Control

Currently, heater treaters are not regulated (issued permits) by the Division as they fall under an exemption for fuel burning equipment that uses gaseous fuel and has a design rate of less than or equal to 5 million BTUs/hour (AQCC Regulation 3, Part A, II.D.1.k). Generally, reports from source operators (provided to the Division on emission inventory reporting forms) indicate that a typical heater-treater design rate is about half of the exemption threshold.

Due to the lack of sufficient data, the Division is not able to make a control technology determination for heater-treaters in this planning period. The Division intends to reassess this category in the next planning period.

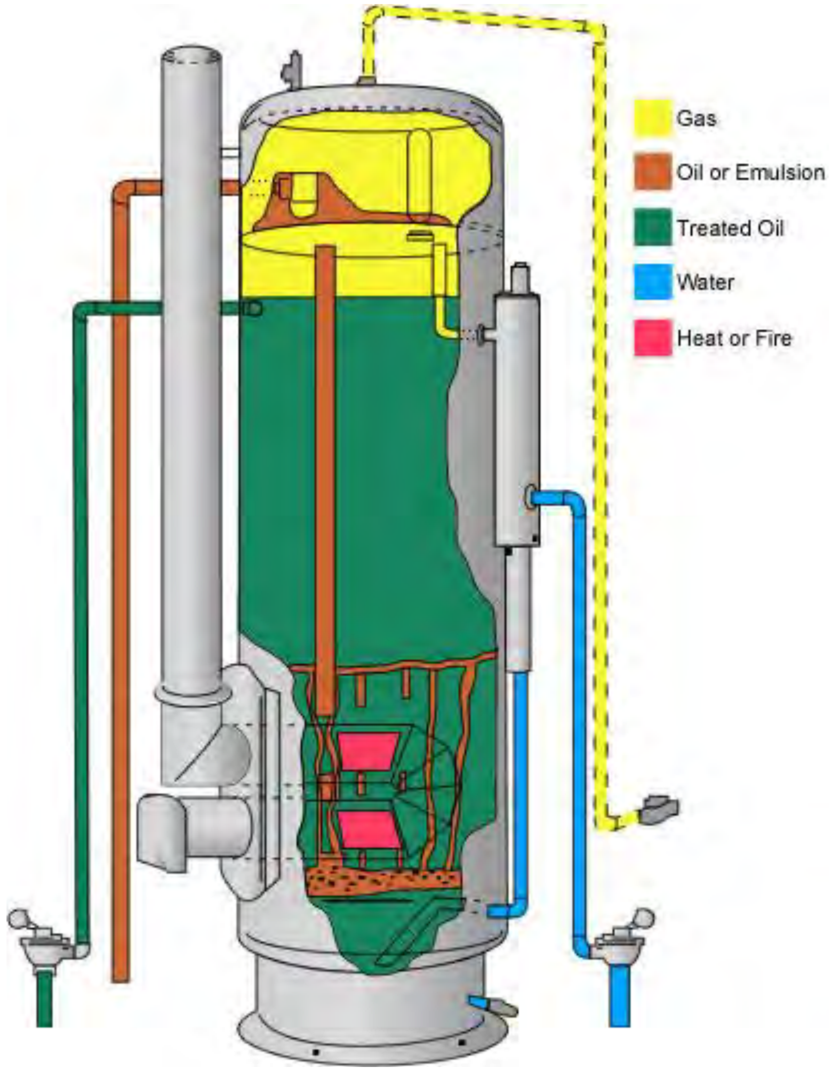
The below diagrams provide basic information on the typical heater-treater designs.

Diagram 1: Horizontal Heater-Treater



This diagram was provided by KW International. Further explanation about heater-treaters is available at http://www.kwintl.com/oil-treating.html.

Diagram 2: Vertical Heater-Treater



This diagram was provided by KW International. Further explanation about heater-treaters is available at http://www.kwintl.com/oil-treating.html.

Reasonable Progress (RP) Four-Factor Analysis of Control Options
For
Holcim Portland Plant, Florence, Colorado

I. Source Description

Owner/Operator: Holcim (US) Inc.
Source Type: Portland Cement Manufacturing (dry process)
SCC (Cement Plant): 30500623
Kiln Type: Preheater/Precalciner Kiln

The Holcim Portland plant is located in Fremont County on Highway 120 near the town of Florence, Colorado, 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. Figure 1 below provides an aerial perspective of the Portland Plant site.

Figure 1: Holcim Portland Plant Aerial Perspective

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 NOx, SO2, and PM/PM10 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 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/PM10, by the inherent recycling and scrubbing of exhaust gases in the cement manufacturing process and by a tail-pipe wet lime scrubber for SO2, by burning alternative fuels (i.e., tire-derived fuel [TDF]) and using a Low-NOX precalciner, indirect firing, Low-NOX burners, staged combustion and a Linkman Expert Control System for NOX, and by the use of good combustion practices for both NOX and SO2.

For this analysis, the Division also relied on the existing construction permit, historical information regarding the Holcim facility, and information about similar facilities to determine RP for NOx, SO2, and PM10. EPA‟s BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must considered in making BART and RP determinations are largely the same.

The Division has elected to set a de minimis threshold for actual baseline emissions for evaluating reasonable progress units at each facility equal to the federal Prevention of Significant Deterioration (PSD) levels. The Division defines "unit" as an Air Pollutant Emission Notice (APEN) subject source, or a stationary source, defined as "any building, structure, facility, equipment, or installation, or any combination thereof belonging to the same industrial grouping that emit or may emit any air pollutant subject to regulation under the Federal Act that is located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control1." These levels are as follows:

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

In addition to the kiln system/main stack emissions, there are two other process points whose PM/PM10 emissions exceed the 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 for the Portland Plant, though it did submit limited information on the feasibility of post-combustion NOX 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. The previous September 14, 2010 version of this document has been revised to reflect this additional information.

II. Source Emissions

Table 1 summarizes the NOX, SO2 and PM10 actual emissions for the period of 2007-2009. Table 2 summarizes each unit at the facility and applicable NOx, SO2 and PM10 actual emissions.

Table 1 – Summary of Plant-Wide Emissions

Year	Pollutant (1, 2)		
	PM10 (tpy)	NOx (tpy)	SO2 (tpy)
2007	262.05	2,447.30	189.80
2008	268.98	2,294.60	306.66
2009	183.26	1,251.66	297.14

Notes:
(1) Emission data from CDPHE – PTS data base.
(2) Annual emissions are less than permitted emissions due in part to economic conditions resulting in less than full production.

[1] Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

Table 2 – Summary of Emissions by Unit Process

AIRS ID	Process	Pollutant	Emissions(2,3) (tons per year)			
			2007 (1)	2008	2009	Average
101A	Top soil removed Topsoil hauled Wind erosion	PM10 (fug)	----	1.14	0.57	0.855
101B	Explosives	PM10 (fug) NOx SO2	----	0.29 7.47 0.88	0.20 4.99 0.59	0.245 6.23 0.735
101C	Overburden removed/hauled	PM10 (fug)	----	14.43	11.41	12.92
101D	Raw material removed/hauled	PM10 (fug)	----	25.91	16.68	21.295
101E	CKD disposed/hauled	PM10 (fug)	----	0.40	0.60	0.50
101F	Disturbed Area	PM10 (fug)	----	83.61	83.61	83.61
101G	Mined land Reclamation	PM10 (fug)	----	0	0	0
102A	Unload Crusher #1	PM10 (fug)	----	0.01	0	0.005
102B	Unload Crusher #2	PM10 (fug)	----	0.01	0.01	0.01
102C	Crusher #1	PM10	----	0.03	0.02	0.025
102D	Transfer to secondary crusher	PM10	----	0.01	0	0.005
102E	Secondary crusher	PM10	----	0.02	0.01	0.015
102F	Crusher #2	PM10	----	0.64	0.41	0.535
102G	Transfer to storage silo	PM10	----	0.06	0.03	0.045
102H	Transfer to blending hall	PM10	----	0.19	0.13	0.16
102J	Transfer outside materials	PM10	----	0	0	0
102K	Pre-Blend Hall activities	PM10	----	0.18	0.11	0.145
102L	Transfer from Bins	PM10	----	0.15	0.10	0.125
103A	Coal unloaded	PM10 (fug)	----	0.98	0.68	0.83
103B	Coal Stockpile/Coal stored	PM10 (fug)	----	0.18	0.12	0.15
103C	Coal Handled	PM10	----	0.10	0.07	0.085
103D	Coal screened/. Crushed	PM10	----	0.09	0.06	0.075

AIRS ID	Process	Pollutant	Emissions(2,3) (tons per year)			
			2007 (1)	2008	2009	Average
103E	Coal Transferred	PM10	----	0.01	0.01	0.01
104	Unloading additives	PM10 (fug)	----	0.05	0.04	0.045
105	Coal transferred	PM10	----	0.01	0.01	0.01
106	Raw material Blend	PM10	----	0.15	0.10	0.125
107	Coal Mill	PM10	----	5.16	1.52	3.34
108	Raw Material Milled	PM10	----	4.28	2.76	3.52
109	Raw Meal Elevated	PM10	----	2.68	1.73	2.205
110	Raw Meal Handled	PM10	----	1.07	0.69	0.83
111	Kiln Operations	PM10 NOx SO2	68.17 2,439.7 188.9	47.23 2,287.04 305.76	13.9 1,246.55 296.55	43.1 1,931.1 263.7
112	Cement clinker cooler	PM10	----	21.52	6.34	13.93
113	Cement clinker stored	PM10	----	0.05	0.03	0.04
114	Cement clinker handled	PM10	----	0.06	0.04	0.05
115	Total cement produced	PM10	59.62	52.12	37.61	32.38
116	Cement handled	PM10	----	1.78	1.29	1.485
117	Cement bagged	PM10	----	0.	0	0
118	Cement bulk loadout	PM10	----	2.04	1.32	1.68
119	Cement product hauled	PM10 (fug)	----	1.00	0.64	0.82
135	Clinker import	PM10	----	0	0	0
138	Tire shredder	PM10 (fug)	----	0.29	0.08	0.185
139	Clinker reclaim	PM10	----	0.26	0.08	0.17
142	Tire debeader	PM10 NOx SO2	----	0.01 0.09 0.	0 0.02 0	0.005 0.055 0
144	Tire shredder	PM10 (fug)	----	0.82	0.23	0.523
145	Clinker export	PM10 (fug)	----	----	0.02	0.02

Notes:

1) A different reporting format was used in 2007.
2) Production has been limited in recent years due to economic factors. The plant is permitted to produce up to 1,873,898 tons of clinker per year. Production in 2008 = 1,332,888 tons and in 2009 = 914,193 tons. Emissions would be higher if the plant were operating at its permitted production level.
3) For some emission points, permit limits have been decreased over the last several years so that current permit limits are now lower than historical actual emissions.

Because clinker production in 2009 was significantly lower than in previous recent years, due in large part to challenging economic conditions, the state instead included 2004 and 2005 in the baseline calculation to represent a more realistic depiction of anticipated annual production and emissions for the plant. Table 3 presents emissions and production data for the 2004, 2005, 2006, 2007 and 2008 baseline years:

Table 3 – Kiln System Production and Emissions (2004 through 2008)

Year	Actual Emissions/Production					Projected Annual Emissions at Full Production of 1,873,898 tpy clinker	
	NO_x (tons)	SO_2 (tons)	Clinker (tons)	NO_x (lbs/ton)	SO_2 (lbs/ton)	NO_x (tons)	SO_2 (tons)
2004	2,741.3	780.6	1,641,423	3.34	0.95	3,129.6	891.2
2005	2,572.3	371.5	1,642,740	3.13	0.45	2,934.3	423.8
2006	3,098.0	366.4	1,686,451	3.67	0.43	3,442.3	407.1
2007	2,439.7	188.9	1,361,523	3.58	0.28	3,357.8	260.0
2008	2,287.0	305.8	1,332,888	3.43	0.46	3,215.3	429.9
Avg	2,627.7	402.6	1,533,005	3.43	0.51	3,215.8	482.4
Max	3,098.0	780.6	1,686,451	3.67	0.95	3,442.3	891.2

III. Units Evaluated for Control

As discussed above, the only emission points whose current permitted level of emissions exceed the *de minimis* thresholds are the kiln system, quarry and finish mill. These emission points will be evaluated as a part of this reasonable progress analysis. The other emission points at the Portland Plant will not be considered further.

IV. Reasonable Progress Evaluation of the Kiln System

A. Sulfur Dioxide (SO_2)

Step 1: Identify All Available Technologies

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. The wet lime scrubbing process involves passing the flue gas from the kiln system through a sprayed aqueous calcium-based suspension that is contained within the scrubbing device. In the wet lime scrubber, the SO_2 reacts with the scrubbing reagent to form $CaSO_4$ that is collected and retained as aqueous sludge. The sludge is then dewatered and disposed.

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.

Step 2: Eliminate Technically Infeasible Options

The currently installed combination of good combustion practices, the inherent scrubbing nature of the cement manufacturing process, and the wet lime scrubber represent the highest level of control for Portland cement kilns. This set of controls is operating and is technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The currently installed and operating controls are the only controls being considered and are assumed to be cost-effective.

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

The currently installed and operating controls are assumed to be cost-effective.

Factor 2: Time Necessary for Compliance

The controls are already installed and operating.

Factor 3: Energy and Non-Air Quality Impacts

Because there are no changes to the existing controls for SO2, there are no associated energy and non-air quality impacts for this determination.

Factor 4: Remaining Useful Life

There are no remaining useful life issues for the source, as the state has presumed that the source and controls will remain in service for a 20-year amortization period.

Factor 5 (optional): Evaluate Visibility Results

CALPUFF modeling was conducted by the Division as a part of the development of the September 14, 2010 version of this document for the kiln system using a SO2 emission rate of 99.17 pounds per hour (lbs/hour), a NOx emission rate of 837.96 lbs/hour, and a PM10 emission rate of 19.83 lbs/hour. The modeling indicated a 98th percentile visibility impact of 0.435 delta deciview (Δdv) at Great Sand Dunes National Park. Because the baseline emission rates and proposed RP emission rates have been revised, this specific impact value is no longer directly associated with the emission rates discussed in this section. However, in any event, because no additional controls are proposed for SO2 emissions, there is no visibility improvement associated with SO2 emissions.

Determination

While the state has determined that the existing controls represent the top-level control technology, 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 SO2. 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 SO2 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 SO2 value of 0.77 pound per 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.

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 SO2 emission limit of 1.30 pounds per ton of clinker on a 30-day rolling average basis and a long-term annual emission limit of 721.4 tons of SO2 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.

Summary of SO_2 RP Determination for Kiln System

1.30 pounds of SO_2 per ton of clinker (30-day rolling average)

721.4 tons of SO2 per year (12-month rolling total)

B. Filterable Particulate Matter (PM and PM_{10})

Step 1: Identify All Available Technologies

The state has determined that the existing baghouses installed on the kiln system represent the most stringent control option. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter.

Holcim has reported 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.

Step 2: Eliminate Technically Infeasible Options

The currently installed baghouses represent the highest level of control for Portland cement kilns. This set of controls is operating and is technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The currently installed and operating controls are the only controls being considered and are assumed to be cost-effective.

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

The currently installed and operating controls are assumed to be cost-effective.

Factor 2: Time Necessary for Compliance

The controls are already installed and operating.

Factor 3: Energy and Non-Air Quality Impacts

Because there are no changes to the existing controls for PM/PM10, there are no associated energy and non-air quality impacts for this determination.

Factor 4: Remaining Useful Life

There are no remaining useful life issues for the source, as the state has presumed that the source and controls will remain in service for a 20-year amortization period.

Factor 5 (optional): Evaluate Visibility Results

As described above, CALPUFF modeling was conducted by the Division as a part of the development of the September 14, 2010 version of this document for the kiln system using a SO2 emission rate of 99.17 lbs/hour, a NOx emission rate of 837.96 pounds per hour (lbs/hour), and a PM10 emission rate of 19.83 lbs/hour. The modeling indicates a 98th percentile visibility impact of 0.435 delta deciview (Δdv) at Great Sand Dunes National Park.

As a part of our September 14, 2010 analysis, the state modeled possible visibility improvements associated with two emission rates – an 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 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.

Determination

While the state has determined that the existing controls represent the top-level control technology, 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.

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.

Summary of PM/PM10 RP Determination for Kiln System

246.3 tons of PM10 per year (12-month rolling total)

C. Nitrogen Oxides (NOx)

Step 1: Identify All Available Technologies

There are a number of technologies available to reduce NOX emissions from the Portland Plant kiln system below the current baseline emissions level (the current configuration already includes indirect firing, low-NOX burners, staged combustion, a low-NOX 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 NOX emissions from Portland cement kilns. Additional discussion on SNCR is provided below:

For SNCR, within the relatively narrow temperature window of 1600 to 2000°F, ammonia (NH3) reacts with NOx without the need for a catalyst to form water and molecular nitrogen in accordance with the following simplified reactions:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Above this temperature range, the NH3 is oxidized to NOx, thereby increasing NOx emissions. Below this temperature range, the reaction rate is too slow for completion and unreacted NH3 may be emitted from the pyroprocess. This temperature window generally is available at some location within rotary kiln systems. The NH3 could be delivered to the kiln system through the use of anhydrous NH3, or an aqueous solution of NH3 (ammonium hydroxide) or urea [(NH2)2CO]. A concern about application of SNCR technology is the breakthrough of unreacted NH3 as "ammonia slip" and its subsequent reaction in the atmosphere with SO2, sulfur trioxide (SO3), hydrogen chloride (HCl) and/or chlorine (Cl2) to form a detached plume of PM10–PM2.5.

As part of this analysis, the state also considered the use selective catalytic reduction (SCR) as a NOX control technology. The state has determined that SCR is not commercially available for the cement kiln system at the Holcim Portland Plant. 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 "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 the Holcim Portland Plant for purposes of this RP analysis. Additional information regarding SCR, as developed by the state as part of its BART analysis for the CEMEX Lyons plant is provided below:

SCR refers to the reduction of NOx in the presence of ammonia to water and elemental nitrogen in the presence of a catalyst. The term "selective" refers to the unique ability of ammonia to react selectively with NOx. The EPA released a NOx control technology update for new cement kilns entitled "Alternative Control Techniques Document Update – NOx Emissions from New Cement Kilns," EPA-453/R-07-006, November 2007 that discusses SCR control for cement kilns. The following discussion is excerpted from the EPA report:

SCR is the process of adding ammonia or urea in the presence of a catalyst to selectively reduce NO_x emissions from exhaust gases. The SCR process has been used extensively on gas turbines, internal combustion (IC) engines, and fossil fuel-fired utility boilers. In the SCR system, anhydrous ammonia, usually diluted with air or steam or aqueous ammonia solution, is injected through a catalyst bed to reduce NO_x emissions. A number of catalyst materials have been used, such as titanium dioxide, vanadium pentoxide, and zeolite-based materials. The catalyst is typically supported on ceramic materials (e.g., alumina in a honeycomb monolith *form) and promotes the NO_x reduction reactions by providing a site for these reactions to occur. The catalyst is not consumed in the process, but allows the reactions to occur at a lower temperature. The optimum temperature for the catalyst reactions depends on the specific catalyst used. Several different catalysts are available for use at different exhaust gas temperatures. Base metal catalysts are useful between 450 °F and 800 °F (232 °C and 427 °C). For high temperature operations (675 °F [357 °C] to over 1100 °F [593 °C]), zeolite catalysts containing precious metals such as platinum and palladium are useful. The two principal reactions in the SCR process at cement plants using SCR are the following:*

$$4\ NH_3 + 4\ NO + O_2 \rightarrow 4\ N2 + 6\ H_2O$$

and

$$4\ NH_3 + 2\ NO_2 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

The first equation is the predominant reaction because 90-95% of NO_x in flue gas is NO. It is important to note that the desired chemical reactions are identical with SNCR and SCR. The only difference is that a catalyst is present with SCR, which allows the reactions to occur at a lower temperature. In an SCR system, ammonia is typically injected to produce a NH_3: NO_x molar ratio of 1.05–1.1:1 to achieve a NO_x conversion of 80–90% with an ammonia slip of about 10 ppm of unreacted ammonia in gases leaving the reactor. The NO_x removal efficiency depends on the flue gas temperature, the molar ratio of ammonia to NO_x, and the flue gas residence time in the catalyst bed. All these factors must be considered in designing the desired NO_x reduction, the appropriate reagent ratios, the catalyst bed volume, and the operating conditions. As with SNCR, the appropriate temperature window must be maintained to assure that ammonia slip does not result in a visible plume. SCR can be installed at a cement kiln at two possible locations:

After the PM control device – a "low-dust" system
After the last cyclone without ducting – a "high-dust" system.

The advantages of a "low-dust" system are longer catalyst life and lower danger of blockage. The disadvantage is the additional energy costs required to heat the cooled exhaust to achieve proper reaction temperatures in the catalyst. On a worldwide basis, three cement kilns have used SCR: Solnhofen Zementwerkes in Germany and Cementeria di Monselice and Italcementi Sarche di Calavino in Italy. The SCR system was operated at the Solnhofen plant from 2001 to January 2006, at which time the plant began using SNCR to compare the operational costs of the two systems to evaluate which technology is better and more economical. Both Solnhofen and Cementeria di Monselice have preheater kilns. The Italcementi plant operates a small Polysius Lepol technology kiln, which is a traveling grate preheater kiln. Both plants use a 25% aqueous ammonia solution, have 6 catalyst layers but only use 3 layers. Both plants have similar designs and facilities that are similar in size and raw materials. At Solnhofen, 200 mg/m^3 (~ 0.8 lb/t) of NO_x is typically achieved from an inlet of 1,050 mg/Nm^3 (4.2 lb/t) or 80% control. Also, ammonia slip was less than 1 mg/m^3. Greater than 80% control is frequently achieved. At the end of 2003, the catalyst had logged 20,000–25,000 hours with no discernable problems. The catalyst was guaranteed for 16,000 hrs, with an expected catalyst life of 3–4 yrs.

The SCR system at Cementeria di Monselice in Bergamo, Italy began operation in June 2006. Catalyst activity remains high after 3,500 hours of operation. Following startup in June 2006, continuous testing was conducted for six weeks.

The design of a SCR system is expected to be site specific. According to Schreiber[2], the technology transfer of SCR systems from the power plant industry to the Portland cement industry requires substantial research and pilot testing before the technology could be considered commercially available. Figure 2, from Granger[3] shows the performance of a typical catalyst under different conditions of temperature and gas composition. The highest NOx reduction efficiencies for this particular catalyst (vanadium pentoxide with titanium dioxide substrate) were achieved at a temperature range of 350^{o}C to 450^{o}C. At a particular temperature, as denoted by the sweeping arcs, small incremental increases in ammonia result in an increase in the NOx reduction until the optimal rate is achieved beyond which a rapid increase in ammonia slip results. This also provides evidence of the narrow temperature window for effective SCR performance.

Figure 2: Catalyst Performance for NOx Control and Ammonia slip at Various Temperatures

272 *Past and Present in DeNO$_x$ Catalysis*

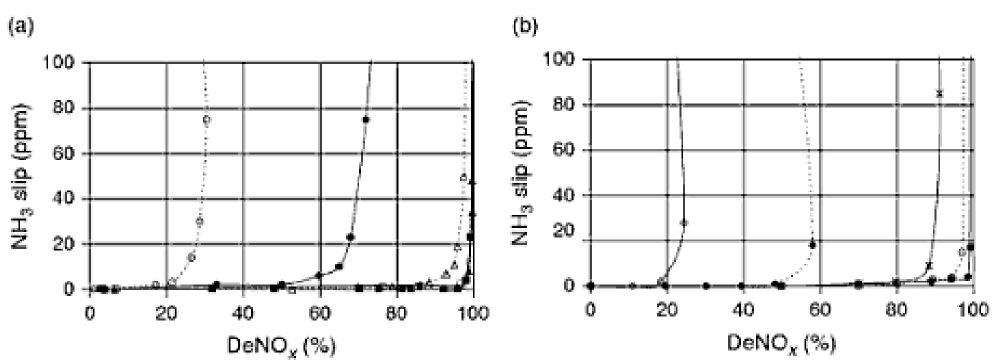


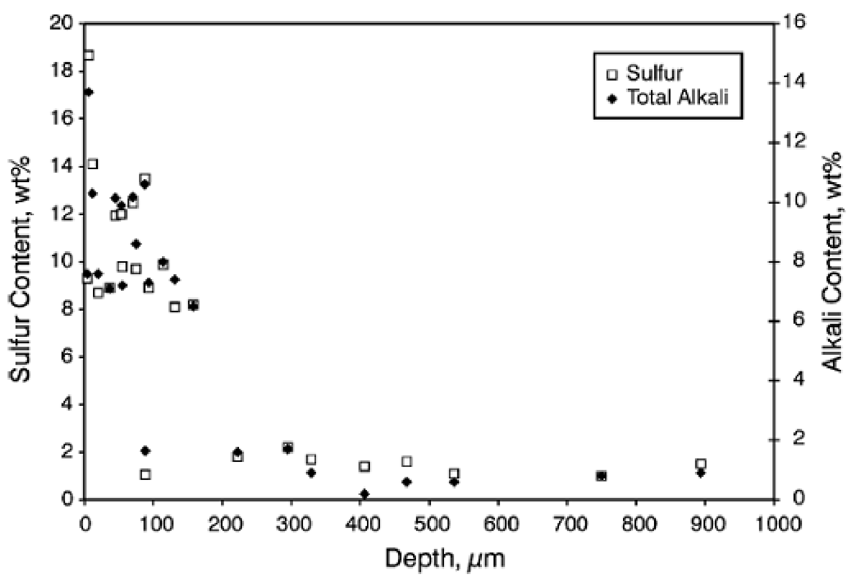
Figure 9.9. Performance of a coated V_2O_5/WO_3-TiO_2 SCR catalyst developed in our laboratory (Table 9.1) with (a) pure NO and with (b) $NO:NO_2 = 1:1$. (◇) 120°C, (◆) 150°C, (*) 180°C, (○) 200°C, (•) 250°C, (▲) 300°C, (Δ) 350°C, (□) 400°C, and (■) 450°C. Cell density: ≈400 cpsi. $V_{cat} = 7.5\ cm^3$. Model gas investigation with 10% O_2, 5% H_2O, 1000 ppm NO or 500 ppm NO + 500 ppm NO_2, 0–1500 ppm NH_3, and balance N_2 in a laboratory test unit [13]. High Resolution FTIR gas analysis [13]. GHSV = 52 000 h^{-1}.

Additionally, multiple challenges exist to achieve SCR effectiveness: selection of catalyst type, positioning of the catalyst, management of catalyst life, catalyst poisoning and ammonia slip. A good catalyst must ensure high activity and selectivity for NOx reduction and low activity in the oxidation of SO2 to SO4. Because of the high selectivity, the catalyst will have a specific temperature window at which the NOx reduction is optimal (Granger 2007).

[2] See Schreiber, R, *et al* "Evaluation of Suitability of Selective Catalytic Reduction and Selective Non-Catalytic Reduction for use in Portland Cement Industry", (2006)
[3] See Granger, P. Elsevier, "Past and Present in DeNOx Catalysis: From Molecular Modeling to Chemical Engineering", (2007)

There is limited information regarding the geometry and optimal positioning of the catalyst to allow for effective NOx reduction and low pressure loss. Further, engineering analysis on overall efficiency during the catalyst life-cycle would be required to ascertain effectiveness. According to Benson[4], alkali and alkaline-earth rich oxides (sodium, magnesium, calcium and potassium) have strong influence on catalyst deactivation (*See also* Nicosia *et al.,* 2008, and Strege *et al.,* 2008). Figure 3 shows evidence of catalyst poisoning by both sulfur and alkalies[5]. The contaminants occupy active sites that otherwise would be available for ammonia storage thus reducing the reactivity and selectivity of the catalyst resulting in lower NOx control effectiveness. Also, particulates from the calcining process would likely combine with available ammonia to form a sticky dust that may adhere to the active sites on the catalyst thereby further reducing the effectiveness of the NOx reduction. Particulate scouring of the catalyst surface has been identified as another mechanism that reduces the effectiveness of the catalyst.

Figure 3: Sulfur and Alkali Penetration into the pores of the catalyst



Total alkali (Na + K) and sulfur content with depth beneath catalyst surface.

Figure 3 indicates that sulfur and alkali compounds penetrate into the catalyst surface resulting in a reduction in the number of active sites thereby reducing the activity and selectivity toward NOx reduction (see Strege *et al.*, 2008).

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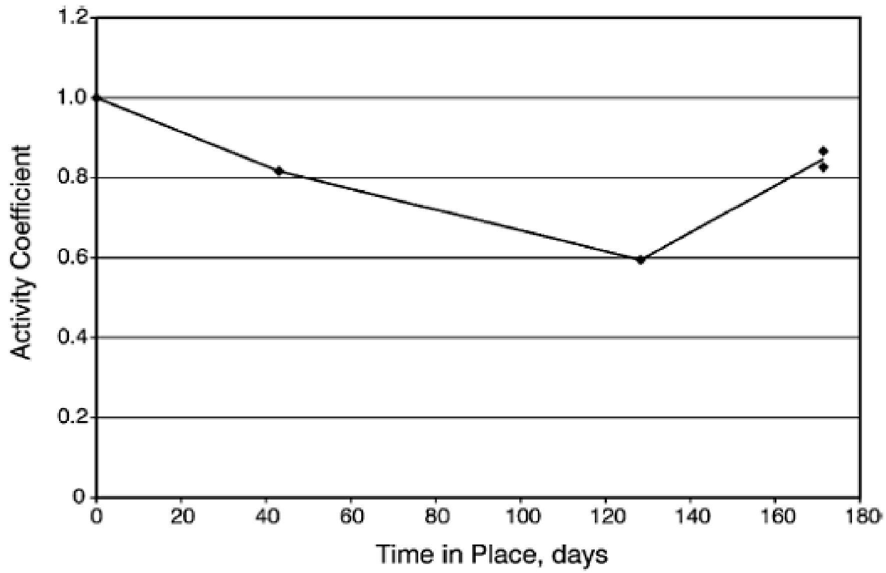
[4] See Benson, S. *et al.* "SCR catalyst performance in flue gases derived from subbituminous and lignite coals, Fuel Processing Technology, Vol. 86" (2005)
[5] See Strege, J. et al., "SCR deactivation in a full-scale cofired utility boiler, Fuel 87" (2008)

Figure 4: Bench Scale Test Results of Catalyst Deactivation over a Period of Time

J.R. Strege et al. / Fuel



Bench-scale test results of catalyst deactivation with time.

Figure 4 provides evidence of catalyst deactivation. If the catalyst life is assumed to end when activity coefficient is around 0.6, then the catalyst life is about 130 days or 3,100 hours, which is much lower than the ~23,000 hour catalyst life cited in the report on the Solnhofen Zementwerkes in Germany.

Ammonia slip is also an issue of concern as it readily reacts to form secondary particulates. A catalyst must combine high NOx conversions to elemental nitrogen and water along with low ammonia slip. In principle, the catalyst has acidic surfaces that retain unreacted ammonia; the storage capacity of these acidic sites depends on temperature. According to Barbaro[6], a good flow distribution is needed to ensure minimal ammonia slip. The potential for ammonia slip to create visibility impairment that is readily transported into nearby Great Sand Dunes National Park exists.

The state finds that a limited use - trial basis application of an SCR control technology on three kilns in Europe does not constitute "available" control technology for purposes of Reasonable Progress at the Holcim Portland Plant. The Division notes that very specific temperature and dust content parameters must be achieved prior to the catalyst reactor elements to preclude plugging issues. As mentioned in the EPA report, *"The advantages to the low dust configuration are longer catalyst life and lower danger of blockage. The disadvantage is the additional energy costs required to heat the cooled exhaust to achieve proper reaction temperatures in the catalyst*." Cement kilns are inherently very dusty environments; consequently for many cement kilns, the catalyst reactor must be installed after the baghouse.

[6] See Barbaro, P.; Bianxhini, C. Wiley-VCH, Catalysis for Sustainable Energy Production (2009)

The Division believes that commercial demonstration of SCR controls on a cement plant in the United States is necessary for a control technology to be "available" for purposes of retrofitting such control technology on the Portland Plant. Reasonable Progress should not be a forum to test new experimental controls to see if they work, particularly when ideal design parameters are constrained in retrofit situations. Therefore, given this fact and the difficulty that Holcim has had in obtaining viable vendor quotations for an SCR system, the Division has eliminated SCR as an available control technology for the Holcim Portland Plant for purposes of Reasonable Progress.

Step 2: Eliminate Technically Infeasible Options

As described above, water injection and SNCR were determined to be technically feasible and appropriate for reducing NO_X emissions from Portland cement kilns.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The design of the Holcim Portland Plant does allow for the effective use of SNCR, which requires ammonia-containing 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. Holcim has indicated to the state that SNCR is technically and economically feasible for the Portland Plant.

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. 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 NO_X per ton of clinker by adjusting upward the short-term baseline emission rate of 4.47 pounds of NO_X 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 NO_X limit.

Because SNCR is technically and economically feasible, the state did not further consider water injection because the levels of control associated with this option are 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[1]
SNCR	45%[2]	2.73	2,086.8

[1] Defaulted to the permit limit since the calculated baseline was higher.

[2] This is calculated based on the 50% SNCR removal efficiency and 10% bypass

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

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 4th quarter of 2006. Holcim estimated that NOX 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. Considering the concern with the ammonia slip, an overall SNCR removal efficiency of 45% was used in this analysis. This estimate was based on an installation cost of $400,000 to $600,000 and an annual cost of $2,520,000. In February 2010, Holcim also provided a general direct capital investment cost estimate of $700,000 to $1,400,000 (excluding the capability for winter operations). 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	Annualized Cost	Cost Effectiveness	Incremental Cost Effectiveness
	(tons/yr)	($/yr)	($/ton)	($/ton)
Baseline NOx Emissions	-			
SNCR (45% control)	1,098.9	$2,520,000[1]	$2,293	-

[1] 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.

Factor 2: Time Necessary for Compliance

It is anticipated that within five years or less after SIP approval, all the work necessary to study, design, construct and begin operating the SNCR system would be complete.

Factor 3: Energy and Non-Air Quality Impacts

SNCR systems do increase power needs to operate injection equipment, drive the pumps and fans necessary to supply reagents, and overcome additional pressure drops caused by the control equipment. Installing SNCR also increases levels of ammonia emissions, and can create a „blue plume‟ if ammonia rates are not adequately controlled. Other environmental factors include the storage and transportation of the selected ammonia-based reagent. For SNCR systems, these types of energy and non-air quality impacts, while necessary to address, are not generally considered significant and do not adversely affect the selection of this technology.

Factor 4: Remaining Useful Life

The state is not aware of any near-term limitations on the useful life of the cement kiln system, so it can be assumed that it will remain in service for a 20-year amortization period. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

As described above, CALPUFF modeling was conducted by the Division as a part of the development of the September 14, 2010 version of this document for the kiln system using a SO_2 emission rate of 99.17 lbs/hour, a NOx 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 98th percentile visibility impact of 0.435 delta deciview (Δdv) at Great Sand Dunes National Park.

As a part of their late October 2010 submittals, Holcim provided modeling data for their proposed NOx RP limitations. The following table lists the projected visibility improvements for these NOx 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) (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 45% overall NOx control efficiency Limits of **2.73 lb/ton** (30-day rolling average) and **2,086.8 tons per year** (based on modeled emission rates of 750 lb/hr NOx, 586 lb/hr SO_2, 86.4 lb/hr PM_{10})	0.526	0.288

Determination

For the kiln system, the state has determined that SNCR is the best NOx control system available with NOx 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 NOx reduction from the kiln system (1,098.9 tpy) and contributes to significant visibility improvement.

Summary of NOx RP Determination for Kiln System

2.73 pounds of NOx per ton of clinker (30-day rolling average)

2,086.8 tons of NOx per year (12-month rolling total)

V. Reasonable Progress Evaluation of the Quarry and Finish Mill

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 PM10 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.

Particulate Matter RP Determination for Quarry

The state has determined that the existing fugitive dust control plan and associated control measures which include: watering and the use of chemical stabilizers, compaction and re-vegetation of stockpiles, vehicle speed limitations, reclamation and sequential extraction of materials, paving, graveling and cleaning of haul roads, sequential blasting, wet drilling, and the suspension of activities during high wind events represent the most stringent control option for these types of emission sources. The existing fugitive dust control plan and the 47.9 tpy fugitive PM10 emission limit (12-month rolling total) for the quarry represent RP for PM10.

Summary of PM/PM10 RP Determination for Quarry

47.9 tons of fugitive PM10 per year (12-month rolling total)

Particulate Matter RP Determination for Finish Mill

The state has determined that the existing fabric filter baghouses and the existing emissions limits of 34.3 tpy of PM10 (12-month rolling total) for the finish mill represent the most stringent control option. Holcim has reported nominal control efficiency for the finish mill baghouses of 99.5%. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits represent RP for PM10 for the finish mill. In addition to the ton per year emission limit associated with this RP determination, the finish mill will also be subject to the recent changes to the PC MACT standard, which contains a visible emission limitation for finish mills.

Summary of PM/PM10 RP Determination for Finish Mill

34.3 tons of PM10 per year (12-month rolling total)

Reasonable Progress (RP) Four-Factor Analysis of Control Options
For
Colorado Springs Utilities – Ray D. Nixon Power Plant

I. Source Description

Owner/Operator:	Colorado Springs Utilities
Source Types:	Electric Utility Steam Generating Unit
SCC (EGU):	10100222
Boiler Type:	Pulverized Coal, Dry-Bottom, Front-Fired, firing coal and natural gas

The Nixon facility is located at 14020 Ray Nixon Road in Fountain, Colorado. This facility consists of one (1) steam driven turbine/generator unit, auxiliary boiler, the associated equipment needed for generating electricity, and two natural gas fired simple cycle combustion turbines driving electricity generators. The boiler fires low sulfur western coal as the primary fuel and can currently use No. 2 distillate oil or natural gas for an ignition fuel. The ignition fuels are used for startup of the boiler, flame stabilization, and the coal pulverizer startup. The facility also includes the various processes necessary to handle the coal, flyash and bottom ash. The coal and flyash handling systems are provided with baghouses for air pollution emission control at appropriate point sources.

For this analysis, the Division also relied on the existing Title V permit, historical information regarding the Nixon power plant, and information about similar facilities to determine RP for NO_x, SO_2, and PM_{10}. EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must considered in making BART and RP determinations are largely the same.

The Division has elected to set a *de minimis* threshold for actual baseline emissions for evaluating reasonable progress units at each facility equal to the federal Prevention of Significant Deterioration levels. The Division defines "unit" as an Air Pollutant Emission Notice (APEN) subject source, or a stationary source, defined as "any building, structure, facility, equipment, or installation, or any combination thereof belonging to the same industrial grouping that emit or may emit any air pollutant subject to regulation under the Federal Act that is located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control[1]."

These levels are as follows:

- NO_x – 40 tons per year

[1] Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

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

Nixon Power Plant is considered a single source with six (6) other facilities, depicted in Table 1.

Table 1: Facilities Co-Located or Considered to be a Single Source with Nixon Power Plant

Emission Sources	Colorado Construction/Operating Permit #	Permit Holder
Coal Screen	98PO149	Western Resources
2 Anaerobic Digestors, 4 Biogas Boilers and 2 Flares	96OPEP152	CSU – Clear Spring Ranch Solids & Handling
2 Natural Gas Turbines	99EP0851	Front Range Power Company, LLC
1 Coal-fired Boiler, 2 Natural Gas Turbines, Cooling Tower, Ash Handling, Coal Handling, Auxiliary Boiler	95OPEP106	CSU – Nixon Power Plant
Wastewater Treatment and 3 Internal Combustion Engines	95EP1097	CSU – Las Vegas Street Municipal Treatment Plant
Custom Anaerobic Wastewater Treatment System	03EP0158	CSU – Northern Water Reclamation Facility

The two natural-gas fired combustion turbines at Front Range Power Plant (FRPP) are above the Prevention of Significant Deterioration significance level for NO_x. The other single source facilities emit NO_x, SO_2, and/or PM_{10} below the Prevention of Significant Deterioration significance levels.

The Front Range Power Plant (FRPP) is located at 6615 Generation Drive, Fountain, Colorado. The facility produces electrical power using two natural gas combustion turbines, with two Heat Recovery Steam Generators (HRSG), and duct burners. These two combustion turbines are evaluated within the source category “Combustion Turbines” in Section 8.2.3 of the Regional Haze SIP.

Nixon Unit 1 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. CSU provided 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 February 21, March 21, May 10, and June 2, 2010. Table 2 depicts technical information for Nixon Unit 1.

Table 2: Nixon/FRPP RP-eligible Emission Controls and Reduction (%)

	Nixon Unit 1
Placed in Service	April 1980
Boiler Rating, MMBtu/Hr for coal	2,049
Electrical Power Rating, Gross Megawatts	227
Description	Babcock and Wilcox Pulverized Coal Front Fired Dry Bottom, firing coal. The coal burner ignitors fire No. 2 fuel or spec oil & NG
Air Pollution Control Equipment	Western Precipitation Thermoflex Fabric Filter (baghouse)
Special Features	Low NOx burners placed in service in 1989
Emissions Reduction (%)	NO_x – 37% SO_2 – None PM/PM_{10} – 99.9/99.7%

Regulations that apply to the boiler are as follows:
For Nixon Unit 1:

- NSPS Subpart D regulates particulate matter emissions to 0.1 lb/MMBtu.
- NSPS Subpart D regulates NO_X emissions to 0.7 lb/MMBtu.
- The Title V Operating Permit limits annual NO_X emissions to 2853.3 tons per year.
- 40 CFR, Part 76-Acid Rain Nitrogen Oxides Emission Reduction Program regulates NO_X emissions to 0.50 lb/MMBtu of heat input on an annual average basis.
- NSPS Subpart D regulates SO_2 emissions to 1.2 lb/MMBtu.

II. Source Emissions

Table 3 summarizes each unit at the facility and applicable NO_x, SO_2, and PM actual emissions averaged over the 2006 – 2008 timeframe with data from EPA's CAMD database, Colorado's Air Pollutant Emission Notices submitted by the facility, and Colorado inspection reports as applicable. Table 4 summarizes the NO_x, SO_2, and PM actual emissions averaged over the 2006 – 2008 timeframe (baseline) for each RP-eligible unit.

Table 3. Summary of 2006 - 2008 Averaged Emissions by Unit - Nixon Facility

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
Boiler #1	SO_2 (tons)	3877.6	4043.1	4442.3	4121.0
	SO_2 (lb/MMBtu)	0.46	0.52	0.53	0.50
	NO_x (tons)	2390.1	2137.0	2542.9	2356.7
	NO_x (lb/MMBtu)	0.26	0.26	0.26	0.26

	PM_{10} (tons)	89.24	82.29	88.78	86.8
	PM_{10} (lb/MMBtu)	0.011	0.011	0.011	0.011
Auxiliary Boiler	*SO_2 (tons)*	*0*	*0*	*0*	*0.0*
	SO_2 (lb/MMBtu)	*0.00*	*0.00*	*0.00*	*0.00*
	NO_x (tons)	*0.02*	*0.02*	*0.05*	*0.0*
	NO_x (lb/MMBtu)	*1.50*	*1.50*	*1.52*	*1.51*
	PM_{10} (tons)	*0*	*0*	*0*	*0.0*
	PM_{10} (lb/MMBtu)	*0.000*	*0.000*	*0.000*	*0.000*
Nixon Combustion Turbine 1	*SO_2 (tons)*	*0.01*	*0.01*	*0.01*	*0.0*
	SO_2 (lb/MMBtu)	*0.00*	*0.00*	*0.00*	*0.00*
	NO_x (tons)	*0.81*	*0.61*	*0.76*	*0.7*
	NO_x (lb/MMBtu)	*0.04*	*0.04*	*0.04*	*0.04*
	PM_{10} (tons)	*0.23*	*0.19*	*0.25*	*0.2*
	PM_{10} (lb/MMBtu)	*0.011*	*0.012*	*0.012*	*0.012*
Nixon Combustion Turbine 2	*SO_2 (tons)*	*0.01*	*0.02*	*0.01*	*0.0*
	SO_2 (lb/MMBtu)	*0.00*	*0.00*	*0.00*	*0.00*
	NO_x (tons)	*0.97*	*1.67*	*0.85*	*1.2*
	NO_x (lb/MMBtu)	*0.04*	*0.05*	*0.05*	*0.05*
	PM_{10} (tons)	*0.27*	*0.36*	*0.23*	*0.3*
	PM_{10} (lb/MMBtu)	*0.012*	*0.012*	*0.014*	*0.012*
Coal Reclaim Conveyor (003)	PM_{10} (tons)	25.97	25.97	21.85	24.60
Ash Handling/Disposal (006)	*PM_{10} (tons)*	*1.41*	*1.41*	*1.41*	*1.41*
Coal Handling (008)	PM_{10} (tons)	23.2	23.2	1.47	15.96
Ash Haul Roads & Disposal (009)	*PM_{10} (tons)*	*1.85*	*1.85*	*1.87*	*1.86*
Unit #1 Cooling Tower	*PM_{10} (tons)*	*0.8*	*0.8*	*0.75*	*0.78*
Four Digester Gas Boilers	*SO_2 (tons)*	*10.15*	*9.03*	*9.03*	*9.40*
	NO_x (tons)	*4.95*	*3.84*	*3.84*	*4.21*
	PM_{10} (tons)	*0.50*	*0.35*	*0.35*	*0.40*
2 Digester Gas Flares	*SO_2 (tons)*	*11.0*	*11.19*	*11.19*	*11.13*
	NO_x (tons)	*2.61*	*2.65*	*2.65*	*2.64*
	PM_{10} (tons)	*0.54*	*0.40*	*0.40*	*0.45*
Sludge Injection & Unpaved Roads	*PM_{10} (tons)*	*8.90*	*8.90*	*8.90*	*8.90*

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average. 30-day rolling averages are estimated to be 5-15% higher than the annual average emission rate (i.e. the 30-day NO_x rolling average is likely about 0.58 lbs/MMBtu for Boiler 1).

Units *italicized* in Table 2 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress.

Table 4. Nixon Unit 1 Baseline Emissions

Pollutant	Nixon Unit 1	
	Annual Emissions* (tpy)	Annual Emissions** (lb/MMBtu)
NO_x	2,357	0.258
SO_2	4,121	0.453
PM_{10}	87	0.002***

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).

**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for NO_x and SO_2 emissions and for PM_{10} emissions for the turbines.
***The PM_{10} emission rate is determined from the Title V permit compliance stack test. These values are as follows: Nixon Unit 1 – 0.0021 lb/MMBtu (4/15/2008)

III. Units Evaluated for Control

As documented by CSU, Nixon Unit 1 fires low sulfur, high heating value Power River Basin sub-bituminous coal. The specifications for the coal are listed below in Table 5.

Table 5: Coal Specifications (2006 - 2007 Averaged APEN data)

	Specifications		
Emission Unit	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
Nixon Unit 1	8,752	0.22	4.99

Table 1 lists the units at Nixon that the Division examined for control to meet reasonable progress requirements. Controlled and uncontrolled emission factors and APEN data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 6.

Table 6: Uncontrolled emission factors for Nixon Unit 1

Emission Unit	Pollutant	Fuel
		Coal (sub-bituminous) (lb/ton)
Nixon Unit 1[2]	NO_x	7.2
	SO_2	35 x %S = 7.7*
	PM/PM_{10}	PM – 49.90** PM_{10} – 11.48

*%S = % of sulfur present in coal supply. For example, 35 x 0.22 = 7.7
**%A = % of ash present in coal supply. For example, 10 x 4.99 = 49.90

IV. Reasonable Progress Evaluation of Nixon Unit 1

a. Sulfur Dioxide

Step 1: Identify All Available Technologies

CSU identified one SO_2 control option:
Flue gas desulfurization (FGD):
Lime spray dry absorber (SDA or dry FGD)

The Division identified two additional SO_2 control options:
Flue gas desulfurization (FGD):
- Lime or limestone-based (wet FGD)
- Dry sorbent injection – Trona (DSI)

[2] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

Step 2: Eliminate Technically Infeasible Options

FGD: Flue gas desulfurization removes SO_2 from flue gases by a variety of methods. Wet scrubbing uses a slurry of alkaline sorbent, either limestone or lime, to scrub the gases. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

Wet FGD: Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar “foot print” area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney.

Dry FGD: Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants[3]. SDA systems are typically utilized at smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. Additionally, Controlling SO_2 Emissions: A Review of Technologies[4] evaluates various SO_2 control technologies and shows that for low-sulfur coal applications, LSDs can meet comparable emission rates to wet systems.

CSU’s 2009 submittal states that a dry FGD (SDA) system is technically feasible. The Division concurs with this conclusion.

The Division notes that traditional wet FGD controls are possible at Nixon Unit 1 considering that there is adequate space near the baghouse to allow for the installation of controls, but are eliminated based on other considerations within the five factors (i.e. energy and non-air quality impacts). Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls at Nixon Unit 1.

It is worth noting that CSU is currently testing a new, innovative non-traditional wet scrubber control system at another facility that appears to be as effective, if not more effective, at controlling SO_2 emissions with much less pressure drop (less parasitic load from increased fan demands) and requires a much smaller operational foot print area in comparison to traditional wet scrubbing.. The pilot-scale wet scrubber control system,

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[3] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

[4] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

called the NeuStream-S FGD process, is presently being tested on a 20 MW flue gas stream. CSU anticipates scaling the non-traditional wet scrubber control to full scale pending successful outcome of the current testing. This new wet scrubber technology uses a unique contacting vessel that makes it different from traditional wet scrubbers. It affords a higher liquid to gas contact ratio and so uses much less water / has lower pressure drop. It also uses a dual alkali system that is somewhat unique when compared to most traditional wet scrubbers. In comparison to traditional wet and LSD scrubbers, this new technology will have smaller water and energy requirements. There are several non-air quality aspects of the NeuStream-S process that compare favorably to traditional scrubbers, described in Step 4.

Although the technology being tested by CSU does not technically meet the definition of "available" as set forth in the BART (Regional Haze) rules, the Division is willing to allow CSU the opportunity to prove the technology and if successful, the opportunity to install the NeuStream-S FGD scrubber at Nixon Unit 1 if desired and applicable. This process will be required to meet the emission limits established for the LSD technology established in this RP determination. Regardless of the technology utilized, Nixon has to meet the LSD-based RP limits within 5 years of EPA approval of the Regional Haze SIP. CSU will test the NeuStream system at this facility until December 2011, and at that time, determine the control technology that will be used to comply with the specified SO_2 RP limit for Nixon Unit 1.

DSI: Dry sorbent injection involves the injection of typically a sodium based reagent, either the mineral trona (sodium sesquicarbonate) or refined sodium bicarbonate, into the flue gas. The injected reagent reacts with the SO_2 present in the flue gas to create sodium sulfate, which is then collected in the particulate control device as in the case of the Drake boilers. CSU asserts that the flue gas temperatures present downstream of the airheater are in the appropriate range to allow for DSI application. A very important factor in DSI application is the ability for the boiler's particulate control device to accommodate the added particulate loading of the DSI reagent in addition to the flyash loading. CSU's preliminary review indicates that even with the added loading of DSI reagent, the Drake baghouses would be operating within the design specification for particulate loading. The flue gas is not cooled nor saturated with water, so reheating of desulfurized flue gas is not required. No gas-sorbent contacting vessel is required to be installed. DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system. However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Lime, soda ash, and Trona (sodium sesquicarbonate) are possible. Lime is the least reactive reagent resulting in low efficiencies even at high injection rates. Trona is a very reactive reagent that can be used to achieve a range of efficiencies depending on the amount of sorbent injected, and would likely be the chosen reagent.

One major challenge of DSI systems is the possibility of converting the NO_x present in the flue gas from NO which is colorless to NO_2 which has a reddish-brown color. This conversion of NO to NO_2 can create a brown plume from the stack which could create opacity compliance issues. Due to variability of boiler configurations, coal composition, NO_x to SO_2 ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum SO_2 removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CSU estimated the maximum SO_2 removal rate that can be achieved while minimizing the creation of the brown plume condition to be 60% SO_2 removal at another facility. In practical application, a higher SO_2 removal rate may be possible, while it is also possible that a lower SO_2 removal rate may be necessary to limit the brown plume formation. This determination would require actual SO_2 removal real-time testing. Therefore, since CSU notes that DSI is technically feasible for a similar facility, the Division assumes this same technology is also then technically feasible for Nixon Unit 1.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CSU provided the Division annual average control estimates. In the Division's experience, 30-day SO_2 rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 5% for Unit 1 to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by CSU as well as other control techniques applied to pulverized coal boilers. A Division review of the EPA's RBLC revealed recent BACT SO_2 determinations range from 0.06 – 0.167 lbs/MMBtu. The Division narrowed down this range depending on the averaging time, permit type, facility size, and fuel type. This narrowed range is 0.095 – 0.161 lbs/MMBtu, with an average of 0.119 lbs/MMBtu rounded to 0.12 lbs/MMBtu. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details.

Dry FGD (LSD): Controlling SO_2 Emissions: A Review of Technologies[5] indicates that the median control efficiency for dry FGD processes, such as LSD, is 90%. Typically dry FGD technology is applied to units that fire coal with a sulfur content below 1.0% to 1.5%. However, when concentrations of pollutants are low, as is the case with low-sulfur western coal, the achievable control efficiency will drop. Due to the very low sulfur content of the coal burned at the Nixon Power Plant, typically <0.5% as detailed in Table 5, a 90% removal rate is at the upper end of what may reasonably be expected in practice. Therefore, dry FGD is evaluated at two control efficiencies level – 78% (0.010 lb/MMBtu annual average) and 82.3% (0.08 lb/MMBtu annual average) for comparison purposes.

DSI: Based on literature review, CSU estimated the maximum SO_2 removal rate that can be achieved to be 60% SO_2 removal. The Division concurs that this control efficiency is reasonable for retrofit on these units.

[5] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

Table 7 summarizes each available technology and technical feasibility for SO_2 control.

Table 7: Nixon Unit 1 SO_2 Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Wet FGD	95%	Y
Dry FGD (LSD)	75 – 85%	Y
DSI	60% (CSU)	Y

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

Wet FGD: The significant cost issue associated with securing sufficient water supplies (a costly and scarce resource in the Front Range) to support a wet FGD control system along with the cost of disposing the sludge byproduct at an approved landfill since on-site storage is not an option. There are other costs and environmental impacts that the Division also considers undesirable with respect to wet scrubbers.

LSD/DSI: CSU submitted cost estimates for a LSD system on Unit 1 on February 20, 2009. CSU provided cost estimates for the DSI system evaluated on another similar Colorado unit (CSU Drake Unit 5) on May 10, 2010.

CSU states that the direct energy cost of the LSD systems due to additional auxiliary loads on the plant, as well as increased headloss through the scrubber, is the primary energy impact. These loads reduce the net output of each unit; therefore, both the lost energy production, as well as the reduced capacity, must be replaced. CSU estimates energy costs for replacement capacity and differential cost between existing MW-h of output and a replacement MW-h in Table 8. This is the incremental cost of a unit of replacement energy, and does not double count the direct energy cost already included in the operating cost. The reduced unit output will consequently reduce unit efficiency, thereby increasing emissions of CO_2 when measured on a per MW-h basis. These estimates are for another facility, Drake Units 6 and 7, but are assumed to be directly applicable to Nixon Unit 1 as well.

Table 8: LSD Energy Replacement Costs

Unit	Replacement capacity cost ($/kW-yr)	Differential energy cost ($/MW-h)
Drake 6/7	44	35

This information, including detailed capital and annual cost data, are provided as "CSU Drake BART Submittals" and "CSU Nixon RP Submittals". CSU originally generated costs using EPRI's FGD Cost model for Drake.[6] This model uses specific unit data to

[6] EPA's BART Guidelines recommend that the OAQPS Control Cost Manual be used to develop cost estimates, where possible. Unfortunately, the Control Cost Manual does not contain a section for SO2 removal equipment as of

calculate the cost of controlling emissions, and is considered to be accurate within ± 30%. When preparing cost estimates for Nixon, cost estimates were developed using the IECCOST program.

The application of LSD or DSI would remove nearly all of the halogens in the flue gas, thus improving the acid gas removal of the baghouse. However, it is anticipated that LSD or DSI would also lower the inherent mercury removal in the baghouses. Recent mercury tests at the Drake Plant have shown that the amount of mercury leaving the stack is approximately 60 – 90% less than what would have been expected based on coal analysis. It is believed that the halogens present in the flue gas are oxidizing the mercury, which is subsequently removed in the baghouse. The application of LSD or DSI would remove the halogens in the flue gas, which may lead to reduced mercury control. Due to this possibility, the provision of adding mercury control via activated carbon injection as part of a LSD or DSI system has been included in the estimated cost of LSD/DSI application.

The Division compared CSU's updated cost information to the study that EPA conducted in developing presumptive BART limits,[7] shown in Table 9.

Table 9: CSU-Drake SO_2 LSD Control Cost Comparison

Unit Capacity (MW)	EPA's Calculated Cost Effectiveness for MW Group ($/ton SO_2 Removed)	CSU Refined Cost Estimate ($/ton SO_2 Removed (Control System))	Cost Differential
Drake Unit 6 – 85 MW	$2,399	$2,579 - $2,981	+ 8% – 24%
Drake Unit 7 – 142 MW	$1,796	$2,140 - $2,694	+ 19% - 50%
Nixon Unit 1 – 225 MW	$1,282	$3,744 - $3,950	+ 192% - 208%

EPA's study was published in 2005 whereas CSU sent the Division updated cost analyses for LSD systems on Unit 1 using various cost updates from the 2008 timeframe. Nixon has reflected the costs of retrofitting a facility that is moderately congested with limited room and access for major retrofits of new capital equipment in the retrofit multiplier that is applied to the cost of new equipment. The Division does not necessarily concur with these estimates, but will accept them for purposes of this RP analysis.

CSU only submitted DSI cost information for another facility, Drake Unit 5. The Division scaled this cost information for Units 1 in Table 10. Please see "Drake APCD Technical Analysis" and "Nixon APCD Technical Analysis" for more details.

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the date of this report. The Fifth edition (EPA 453/B-96-001) of the Control Cost Manual is referenced in the BART guideline; however, the Sixth edition (EPA 452/B-02-001, 7-22-2002) is now available.

[7] EPA, 2005. Technical Support Document for the Best Available Retrofit Technology (BART) Notice of Final Rulemaking: Setting BART SO_2 Limits for Electric Generating Units: Control Technology and Cost-Effectiveness.

For dry FGD, CSU estimated a removal rate of 80% based on 2008 average data and a resulting emission rate at the BART presumptive limits of 0.10 lb/MMBtu. The Division adjusted this removal rate using the baseline SO_2 emissions from Table 4 (lb/MMBtu and tons/year) for each unit and using a realistic removal rate of 78 - 82%that meets the BART presumptive limit for Nixon Unit 1. This range allows the Division to determine the most reasonable RP limit for this control option, if applicable. The Division scaled costs linearly for the LSD systems for higher control efficiencies as applicable. See "Nixon APCD Technical Analysis" for more details.

Table 10 illustrates resultant SO_2 emissions for each technically feasible control option. Table 11 shows the SO_2 control cost comparisons for each unit based on the detailed cost analyses. The Division used baseline emissions from Table 4. The Division analyzed both annual and 30-day rolling average limits. The Department's experience with power plants suggests that the maximum 30-day rolling average SO_2 emission rate is approximately 5% higher than the annual average emission rate.

Table 10: Nixon Unit 1 Control Resultant SO_2 Emissions

Alternative	**Control Efficiency (%)**	**Resultant Emissions**		
		Unit 1		
		(tons/year)	**Annual Average (lb/MMBtu)**	**30-day Rolling Average (lb/MMBtu)**
Baseline	---	4,121	0.453	
DSI	60	1,649	0.181	0.190
Dry FGD (LSD) @ 78% control	78	907	0.100	0.105
Dry FGD (LSD) @ 82.3% control	82.3	729	0.080	0.084

Table 11: Nixon Unit 1 SO_2 Cost Comparison

Alternative	**Emissions Reduction (tpy)**	**Annualized Cost ($)**	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
Baseline	0	$0	$0	---
DSI	2,473	$4,938,692	$1,997	$1,997
Dry FGD (LSD) @ 78% control	3,215	$12,036,604	$3,744	$9,568
Dry FGD (LSD) @ 82.3% control	3,392	$13,399,590	$3,950	$7,691

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals[8], the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take CSU approximately 3 – 5 years to implement any of the above control options. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: Energy and Non-Air Quality Impacts

Traditional Wet FGD: Based upon its experience, and as discussed in detail below, the Division has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including massive water usage. This is a significant issue in Colorado, where water is a costly, precious and scarce resource. In the arid West, securing sufficient water supplies to support a wet FGD control system is a difficult undertaking that precludes other beneficial uses for such water. In Colorado, water law is based upon the doctrine of prior appropriation or "first in time - first in right," and the priority date is established by the date the water was first put to a beneficial use. Thus, depending upon whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the state, particularly in the Front Range, to accommodate the added demands of wet FGD controls. At a minimum, the water demands of wet FGDs will compete for what is already a scarce resource needed for Colorado's domestic, agricultural and industrial demands.

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. Potential on-site storage of wet ash is an increasing regulatory concern, as evidenced by the recent Tennessee Valley Authority spill. In addition, the steam plume resulting from a wet FGD control system in such a confined river valley will produce a noticeable cloud that will hang over a densely populated area (City of Colorado Springs). The Division has received complaints regarding the more visible plumes associated with wet scrubbing; a potential irony in light of the visibility issues at the heart of the Regional Haze program. The Division largely focused its RP SO_2 control technology consideration on commercially available once-through dry FGD controls, specifically, "lime spray dryers" (LSD), that have an established record of reliable performance on boilers burning low-sulfur coal. Generally, wet FGD controls can achieve a higher level of SO_2 control on a percent capture basis that exceeds the capabilities of LSDs but, as noted above, there are a number of non-air quality and other environmental impacts including increased water usage, sludge disposal and wet plume issues that often overshadow any incremental improvement in SO_2 emission reductions. Recent PSD applications in Colorado have demonstrated lime spray dryer systems to be BACT.

The Division finds the negative environmental impacts of a traditional wet FGD control system far outweigh minimal incremental SO_2 emission reduction benefits (tons of SO_2 reduced annually) and visibility improvement (deciview improvement at nearest Class I

[8] Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. "Black Hills Clark Station NOx Reduction Feasibility Study." Pgs. 3-13 and 3-14.

area) when compared to LSD or the pilot NeuStream-S FGD scrubber when applied to the Nixon Unit 1 boiler.

Semi-dry FGD (LSD): CSU notes that there are a number of non-air quality environmental impacts with regard to lime spray dryer systems. Application of a dry scrubber will tend to remove halogens from the flue gas (primarily chlorine) that are important to the removal of mercury from the flue gas. Several sources of speciated mercury stack test data, including EPA's own ICR stack test data, show that an unscrubbed plant with a baghouse burning western coal will remove more mercury from the flue gas when compared to a similar plant with a scrubber. There will be a greater volume of material being landfilled. A LSD scrubber consumes a tremendous amount of water, as detailed in Table 12. Wet scrubbers consume approximately 23% more water than LSD scrubbers, depending on boiler size.[9]

Table 12: LSD Water Requirements

Unit	Water required for LSD (gpm)	Water required for LSD (Mg/year)
Drake 6	68	35.7
Drake 7	100	53.0
Nixon 1 (scaled)	~160	~84.0

Although these non-air quality/energy impacts have been identified, the State has determined that these impacts are not significant or unusual enough to warrant elimination of this control option.

DSI: CSU documents additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Application of DSI would be effective in further enhancing the removal of halogenated acid gases in the baghouse. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash.

The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash at some plants,[10] which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality

[9] 2008. "Revised BART Analysis for Unit 1 & 2 Gerald Gentleman Station Sutherland, Nebraska: Nebraska Public Power District." Prepared by: HDF 701 Xenia Avenue South, Suite 600 Minneapolis, MN 55416 With control technology costs provided by: Sargent & Lundy.

[10] Department of Energy, 2001. LIFAC Sorbent Injection Desulfurization Demonstration Project: A DOE Assessment. U.S. Department of Energy: National Energy Technology Laboratory. P.O. Box 880, 3610 Collins Ferry Road Morgantown, WV 26507-0880.
http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/lifac/LIFAC_PPA.pdf

related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls.

Factor 4: Remaining Useful Life

CSU asserts that the remaining useful life of Nixon Unit 1 in excess of 20 years, which is the maximum amortization period allowed in the RP analysis. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 13 shows the number of days pre- and post-control. Table 14 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

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.

Table 13: Visibility Results - Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO2 Control Scenario	Unit(s)	Class I Area Affected	3-year totals			3-year totals		
			Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hr SO_2 rates	1	RMNP	17	---	---	6	---	---
DSI @ 0.18 lb/MMBtu	1		17	6	11	6	1	5
LSD @ 0.10 lb/MMBtu	1		17	6	11	6	1	5
LSD @ 0.08 lb/MMBtu	1		17	6	11	6	1	5

Table 14: Visibility Results – SO2 Control Scenarios

SO2 Control Scenario	Unit(s)	Output (@ 98th Percentile Impact)*	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum	Cost Effectiveness
		(deciviews)	(deciviews)	(%)	($/deciview)
Max 24-hr SO_2 rates	1	0.914			---
DSI @ 0.18 lb/MMBtu	1	0.48	0.44	48%	$11,249,869

LSD @ 0.10 lb/MMBtu	1	0.46*	0.46	50%	$26,454,076
LSD @ 0.070 lb/MMBtu	1	0.42	0.50	55%	$28,307,522

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “Nixon Modeling Summary” for more details.

Determination

Based upon its consideration of the five factors summarized herein, the state has determined that SO2 RP 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.

b. Filterable Particulate Matter (PM) & Particulate Matter (PM_{10})

Nixon Unit 1 is equipped with a reverse-air fabric filter baghouse to control PM/PM_{10} emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Colorado Operating Permit 95OPEP106 Condition 1.5.5 requires Unit 1 to conduct performance testing for PM_{10} annually. While the emission limit in Condition 1.5.1 is set at 0.1 lb/MMBtu, the annual performance test must be used as an emission factor in determining emissions.

Table 15 shows the most recent stack test data (April 14, 2008). It is important to note that the most recent stack test, which at a minimum, occurs every five years, and more frequently depending on the results, demonstrates that these baghouses are meeting >95% control.

Table 15: Nixon Unit 1 2008 Stack Test Results

Pollutant	Unit 1 (lb/MMBtu)
Filterable PM_{10}	0.0021
PM_{10} Control efficiency	99.5%

A Division review of EPA's RBLC revealed recent BACT PM/PM_{10} determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The current stack test results above are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations.

The state determines that the existing Unit 1 regulatory emissions limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent control options. The unit is exceeding a PM control efficiency of 95%, and the control technology and emission limits are RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse. Thus, as described in EPA's BART Guidelines, a full four-factor analysis for PM/PM_{10} is not needed for Nixon Unit 1.

c. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

CSU identified four NO_x control options:

- Overfire air (OFA)
- Ultra-low NO_x burners (ULNBs)
- Selective Catalytic Reduction (SCR)
- Ultra-low NO_x burners and SCR (ULNBs + SCR)

The Division also identified and examined the following additional control options for these units:

- Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Ultra-low NO_x burners and Over-fire air (ULNBs+OFA)
- Selective Non-Catalytic Reduction (SNCR)
- Coal reburn +SNCR

Rotating overfire air (ROFA) was not considered in this analysis because ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load[11]. While ROFA is considered superior to SOFA alone, ROFA alone is not superior to LNB+OFA and cannot achieve the predicted 70% or greater NO_x reduction for Unit 1. Since ROFA® technology would not be expected to

[11] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html

provide better emissions performance than the LNB+OFA baseline for this unit, ROFA® technology is not considered further in this analysis.

Step 2: Eliminate Technically Infeasible Options

OFA: Air staging or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Staging the air in the burner (internal air staging) is generally one of the design features of low NO_x burners, such as those already present on Unit 1. Furnace overfire air (OFA) technology requires the introduction of combustion air to be separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of N_2 rather than NO_x. Primary air (70-90%) is mixed with the fuel producing a relatively low temperature; oxygen deficient, fuel-rich zone and therefore moderate amounts of fuel NO_x are formed[12]. The secondary (10-30%) of the combustion air is injected above the combustion zone through a special wind-box with air introducing ports and/or nozzles, mounted above the burners. Combustion is completed at this increased flame volume. Hence, the relatively low-temperature secondary-stage limits the production of thermal NO_x. The location of the injection ports and mixing of overfire air are critical to maintain efficient combustion. Retrofitting overfire air on an existing boiler involves waterwall tube modifications to create the ports for the secondary air nozzles and the addition of ducts, dampers and the wind-box. OFA is a technically feasible option for Unit 1.

ULNBs: Unit 1 has low NO_x burners installed, shown in Table 2. These LNBs can be replaced with ULNBs. Burner designs have improved in recent years to improve flame stability and combustion control schemes for increased NO_x emission reductions with these ultra-low NO_x burners. ULNBs are a technically feasible option for Unit 1.

ULNBs+OFA: Since ULNBs and OFA are each technically feasible options and would be installed separately for Unit 1, it stands to reason that ULNBs+OFA is a technically feasible options for Unit 1.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

[12] IEA Clean Coal Centre: Clean Coal Technologies – Air Stating for NO_x control (overfire air and two-stage combustion), 2010. http://www.iea-coal.org/site/ieacoal_old/clean-coal-technologies-pages/air-staging-for-nox-control-overfire-air-ofa-or-two-stage-combustion?

While lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for CSU Nixon, a retrofit SCR, the 0.07 lb/MMBtu controlled NO_x value is more expected. The SCR reaction occurs within the temperature range of 600°F to 750°F where the extremes are highly dependent on the fuel quality. There are three different types of SCR arrangements – high-dust, low-dust, and tail-end. The pre-dominant arrangement applied in the United States has been high-dust. In most circumstances, a high-dust SCR system is the most economical arrangement alternative and would likely be the arrangement for Unit 1 if applicable. For high- and low-dust arrangements, the catalyst, because of its location directly downstream of the boiler and upstream of the air heater, can impact the boiler through its effect on the air heater. The magnitude of this effect is dependent on the power plant configuration, air quality control components, type of fuel, and overall emission control requirements. For retrofit applications, adequate space between the economizer outlet and the air heater inlet to allow boiler outlet and air heater return duct is a prerequisite for the installation of a high-dust system and is the case at the Drake Plant. Therefore, high-dust SCR is a technically feasible alternative for Nixon Unit 1.

ULNBs/SCR layered: A layered approach of installing ULNBs pre-combustion and SCR post-combustion is technically feasible for Nixon Unit 1.This scenario considers that less NO_x would enter the SCR system and reduce aqueous ammonia storage, handling, and injection. CSU considered this scenario to determine if this option would be more economically and technically feasible for Nixon Unit 1.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[13] and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[14] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Nixon Unit 1.

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have

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[13] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[14] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php

a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost.

It should be noted that selective non-catalytic reduction (SNCR) was not considered in CSU's RP analysis because CSU asserts that SNCR achieves full-load NO_x removal in the same range as ULNB at a higher levelized cost ($/ton NO_x removed), and therefore should be ruled out due to a "least-cost envelope" analysis as detailed in the BART rule, and therefore should be ruled out for RP as well. The higher cost is primarily due to much higher operating costs, with most of the operating costs being for the reagent. Additionally, the chemical reaction required for SNCR to work is temperature sensitive. The CSU Drake boilers often operate below full load, when the temperature is no longer conducive to optimal NO_x removal, resulting in NO_x removal declines. The weighted average NO_x removal over an annual load range can be less than ULNB depending on the portion of time the units operate at partial load. Therefore, SNCR was eliminated from consideration by CSU because of higher costs and efficiency losses at partial loads. However, the Division considers SNCR a technically feasible alternative for Nixon Unit 1. Similar Colorado facilities evaluated SNCR as an option and it is recognized nationally as a NO_x control option for EGUs, so the Division included SNCR in the full four-factor analysis.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu[15]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CSU provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[16] 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Nixon Unit 1 to determine control efficiencies and annual reductions.

OFA: CSU estimated that overfire air, in conjunction with the existing low-NO_x burners, is capable of reducing NO_x emissions approximately an additional 25% from existing conditions in the original BART submittal (August 1, 2006). EPA's AP-42 emission factor tables estimate low-NO_x burners controlling 35 – 55% and LNB with

[15] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf

[16] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

OFA controlling 40 – 60% of NO_x emissions.[17] The low NO_x burners currently achieve about 10% control. However, in a more recent AWMA study, it is noted that OFA achieves an additional 10 – 25% control with the installed low NO_x burners.[18] Therefore, the Division concurs with CSU's additional 25% NO_x control estimate.

ULNBs: CSU asserts that additional NO_x reductions of 20% are possible with implementation of some or all of the modifications that will be needed to retrofit ULNBs at Nixon Unit 1. These additional NO_x reductions could be achieved while meeting acceptable CO levels. The ULNBs are estimated to control approximately 75% of uncontrolled NO_x emissions, which is consistent with a U.S. Department of Energy Study which estimated NO_x emissions reductions between 75 – 85%.[19] Therefore, the Division concurs with CSU NO_x reduction estimates for ULNBs.

ULNBs+OFA: The Division used information from CSU regarding ULNBs and OFA control efficiencies as described above. ULNBs alone can achieve 20% control; OFA alone can achieve 25% control. When determining the appropriate control efficiency regarding the combination of ULNBs and OFA, the most important consideration to note is that Nixon burns only Power River Basin (PRB) coal which is low in nitrogen content initially, so the margin to reduce NO_x is lower than other facilities (i.e. Drake). The Division and CSU concur that a realistic control efficiency assumption is 30% for Nixon Unit 1.

SNCR: Other Colorado facilities have noted a variety of control ranges for SNCR. The Division used a variety of information, including a similar Colorado facility estimates, EPA's SNCR Air Pollution Control Fact Sheet and a recent AWMA study[20] to conservatively approximate that Nixon Unit 1 can achieve 30% control when SNCR is applied.

*SCR:*CSU approximates that SCR can achieve an approximate 80% NO_x reduction using 2008 baseline emissions (or 0.05 lb/MMBtu), determined by URS WD using a survey of a large collection of photographs, and experience in developing retrofit factors for many types of units and configurations at numerous facilities. The Division adjusted the control efficiency percent reduction to reflect the 2006 – 2008 baseline emissions and adjusted the resultant SCR percent removal to 73% (or 0.07 lb/MMBtu), which the Division considers more realistic and consistent with other Colorado facility submittals. This control efficiency is slightly lower than EPA's AP-42 emission factor discussion, which estimates SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80

[17] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[18] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.
[19] U.S. Department of Energy, 2004. Office of Fossil Energy, National Energy Technology Laboratory. http://www.netl.doe.gov/publications/factsheets/project/Proj294.pdf
[20] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

– 90% reduction.[21,22] However, in the Division's experience a emission limit of no lower than 0.07 lb/MMBtu is realistically achievable for a retrofit SCR.

ULNBs/SCR layered approach: CSU evaluated a layered approach of installing ULNBs upstream of the combustion process to reduce NO_x entering the boiler and thus reducing subsequent SCR reduction requirements. This approach will achieve the same NO_x emission reductions as SCR alone and is deemed to be appropriate by the Division.

Table 16 summarizes each available technology and technical feasibility for NO_x control.

Table 16: Nixon Unit 1 7 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO_x Burners (LNB)	~10%	Y – installed
LNB + OFA	60 – 81%	Y (partially installed)
Overfire air (OFA)	10 – 25% (alone)	Y
Ultra-low NO_x burners (ULNBs)	20%	Y
ULNBs+OFA	30%	Y
Selective non-catalytic reduction (SNCR)	20 – 40%	Y
Selective catalytic reduction (SCR)	70 – 90%	Y
ULNB/SCR layered approach	70 – 90%	Y
ECO®	n/a	N
RRI	n/a	N
Coal reburn +SNCR	n/a	N

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

OFA: Washington Group International Inc. estimated the cost of overfire air during the course of a pollution control study for the Drake and Nixon boilers in 2004. The cost estimates were generated using EPRI's IECCOst model. This model uses specific unit data to calculate the cost of controlling emissions and is typically considered to be accurate within ±30%. Overfire air will not require large pieces of new equipment, but instead the costs consist primarily of labor and materials related to modifying the boiler waterwall tubes to allow for new air injection ports and the necessary ductwork, dampers, and instrumentation and control to supply the air from the existing secondary air duct. In a technical support document issued by the Northeast States for Coordinated Air Use Management (NESCAUM) entitled "NO_x

[21] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[22] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Controls for Existing Utility Boilers,"[23] OFA alone ranges from $410 - $1,100 per ton NO_x reduced annually for units estimating 15 – 30% NO_x control, which is within the range of Nixon's estimated OFA NO_x reductions (25%). The estimates in Table 17 and Table 18 are within this range. Therefore, the Division concurs with the OFA cost estimates.

ULNBs: CSU's cost estimate includes the burners, oil or gas lighter systems and controls at burner front, automatic air register adjustment and control drives, flame scanners and controls, all wind box controls including control drawings, all control and burner logic drawings. The estimates do not include burner wind box extensions or stove pipe, ducts installed on top of existing wind boxes, furnace water wall openings, structural steel support for ULNBs beyond supplemental support steel, cost for engineering, supply and construction of wind box extensions, physical modeling, math modeling, or wind box baffling, pulverizer upgrades, burner piping or classifiers for improved coal fineness and required size distribution. CSU notes that some or all of the items must be determined by boiler modeling and pulverizer testing. If all of these are needed, the capital costs could increase by 40 – 70% compared to the base scope listed in Table 18. The Division considers CSU's estimated costs more than reasonable, with ULNBs at about $1,200/ton which is comparable or lower than LNB costs presented in recent NESCAUM papers.[24, 25]

ULNB+OFA: The Division based cost estimates for this control option assuming that OFA and ULNBs will be installed separately; therefore, the cost for this layering option is a summation of individual annualized costs for OFA and ULNBs for each unit. The Division checked this assumption with CSU on November 8, 2010.

SNCR: A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.[26] A similar Colorado facility estimated operating expenses at approximately 81 – 86%.[27] Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[28]

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[23] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[24] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114. www.nescaum.org/documents/**nox**-2000.pdf

[25] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[26] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.

[27] CENC, 2009. "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado." Prepared by AECOM.

[28] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

The Division used information from a similar facility submittal to determine approximate SNCR costs scaled for the Nixon boiler since CSU did not have SNCR information.[29] The Division consulted with CSU on this decision to ensure that these boilers are roughly equivalent to the Nixon boiler in scope and retrofit difficulty.

The resultant cost effectiveness for SNCR on Units 1 is approximately $4,500 per ton. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[30,31] EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NO_x reduced.[32] Although the resulting cost estimates for the Nixon boiler greater than these ranges, the smaller size of the boiler as well as the difficulty of the retrofit leads the Division to the conclusion that the estimated cost estimates for SNCR are reasonable.

SCR: CSU estimated the cost for the SCR system(s) using the IECCOST program. This estimate includes the cost of a new ID booster fan, since CSU/URS noted that the current ID fan does not have sufficient capacity to accommodate the additional pressure drop of the SCR retrofit. Recent NESCAUM studies estimate SCR retrofits achieving NO_x emission rates of 0.05 – 0.15 lb/MMBtu and emission reductions of 65 – 85% as costing $2,600 - $7,400 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[33,34] The SCR system estimates for the CSU Nixon boiler is approximately $6,400, which is within the NESCAUM estimates. The Division concurs that CSU cost estimates for SCR controls are reasonable.

ULNBs/SCR layered approach: CSU chose to examine the ULNB/SCR layered approach because the cost of the SCR would be reduced somewhat in this scenario. The reduced costs would be noted in the reactor housing, amount of catalyst required, and the aqueous ammonia storage, handling, and injection. Therefore, this option was examined to determine the significance of the potential cost differential. The Division concurs that this is an appropriate option and may possibly reduce costs.

Table 17 illustrates resultant NO_x emissions for each technically feasible control option. Table 18 shows the NO_x control costs for each unit based on detailed cost analyses. The Division estimated resultant NO_x using annual average reductions for

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[29] CENC, 2009. "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado." Prepared by AECOM.
[30] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[31] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.
[32] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
[33] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[34] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

tons of NO_x reduced per year. The Division's experience with power plants suggest that the maximum 30-day rolling average NO_x emission rate is 5-15% higher than the annual average emission rate.

Table 17: Unit 1 Control Resultant NOx Emissions

Alternative	Control Efficiency (%)	Resultant Emissions Unit 1		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day rolling (lb/MMBtu)
Baseline	---	2,357	0.258	
Ultra-low NOx burners (ULNBs)	20	1,885	0.206	0.24
Overfire air (OFA)	25	1,768	0.194	0.22
ULNBs+OFA	30	1,650	0.181	0.21
Selective Non-Catalytic Reduction (SNCR)	30	1,650	0.181	0.21
ULNB+SCR	73	636	0.070	0.080
Selective Catalytic Reduction (SCR)	73	636	0.070	0.080

Table 18: Unit 1 NOx Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Ultra-low NOx burners (ULNBs)	471	$567,000	$1,203	$1,203
Overfire air (OFA)	589	$403,000	$684	($1,392)
ULNBs+OFA	707	$907,000	$1,372	$4,812
Selective Non-Catalytic Reduction (SNCR)	707	$3,226,877	$4,564	---
ULNB+SCR	1,720.4	$11,007,000	$6,398	$7,677
Selective Catalytic Reduction (SCR)	1,720	$11,010,000	$6,400	---

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals[35], the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and

[35] Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. "Black Hills Clark Station NOx Reduction Feasibility Study." Pgs. 3-13 and 3-14.

shutdown, after SIP approval, it would take CSU be approximately 2-3 years for SNCR and 3-4 years for SCR. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: Energy and Non-Air Quality Impacts

OFA: Overfire air does not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

ULNBs: The additional energy required to further pulverize coal is relatively small and is accounted for in CSU's February 2009 submittal. Therefore, ULNBs do not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

SNCR /SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR reagent injection systems have minimal power requirements.

Post-combustion add-on control technologies like SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. 100 – 300 kW is less than 1.0% of the power generated by the Drake Unit 7 boiler annually, or enough energy to power about 10 homes for a year. These energy requirements are minimal.

SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas. CSU has indicated to the Division that they would prefer to use aqueous ammonia instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on a aqueous ammonia reagent versus an ammonia reagent.

Factor 4: Remaining Useful Life

CSU asserts that the remaining useful life of Nixon 1 is in excess of 20 years, which is the maximum amortization period allowed in the RP analysis. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 19 shows the number of days pre- and post-control. Table 20depicts the visibility results (98^{th} percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

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.

Table 19: Visibility Results - Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Unit(s)	Class I Area Affected	3-year totals			3-year totals		
			Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hour NOx rates	1	RMNP	17	---	---	6	---	---
ULNBs @ 0.21 lb/MMBtu	1		17	15	2	6	4	2
OFA @ 0.19 lb/MMBtu	1		17	15	2	6	4	2
ULNBs+OFA @ 0.18 lb/MMBtu	1		17	15	2	6	4	2
SNCR @ 0.18 lb/MMBtu	1		17	15	2	6	4	2
SCR @ 0.07 lb/MMBtu	1		17	12	5	6	3	3

Table 20: Visibility Results - NOx Control Scenarios

NOx Control Scenario	Unit(s)	Output (@ 98^{th} Percentile Impact)*	98^{th} Percentile Impact Improvement	98^{th} Percentile Improvement from Maximum	Cost Effectiveness
		(deciviews)	(deciviews)	(%)	($/deciview)
Max 24-hour NOx rates	1	0.91	---	---	---
ULNBs @ 0.21 lb/MMBtu	1	0.77	0.15	16%	$3,831,081
OFA @ 0.19 lb/MMBtu	1	0.76*	0.15	17%	$2,616,883

ULNBs+OFA @ 0.18 lb/MMBtu	1	0.75*	0.16	18%	$6,024,845
SNCR @ 0.18 lb/MMBtu	1	0.75*	0.16	18%	$20,042,714
SCR @ 0.07 lb/MMBtu	1	0.68	0.24	26%	$46,639,831

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Nixon Modeling Summary" for more details.

Determination

Based upon its consideration of the five factors summarized herein, the state has determined that NOx RP for Nixon Unit 1 the following NOx emission rate:

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 ultra-low NOx burners with over-fire air 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.

V. RP Evaluation for Fugitive Dust Sources: Coal Reclaim Conveyor (003) and Coal Handling (008)

Both of these fugitive dust sources are permitted within Colorado Operating Permit 95OPEP106.

Coal handling is comprised of five (6) parts – reclaim tunnel bagfilter vent, coal crusher building bagfilter vent, coal gallery bagfilter vents, and coal train off-loading-conveying-stockpiling. It should be noted that while these two sources are reported individually in Colorado's emission inventory, in the Operating Permit, these sources are combined together since coal handling is treated as one point. Colorado Regulation No.1.II.A.1 limits opacity from these sources to 20%. This source is also subject to NSPS Subpart Y, New Source Performance Standards for Coal Preparation Plants. Additionally, the following measures to control fugitive dust via a fugitive particulate emissions control plan (Condition 3.4):

- A wet dust suppression system shall be used for railroad car unloading.
- Above ground conveyors to and from the transfer building must be covered.
- Loadout to storage must by telescoping chute.
- Emissions from coal storage piles shall be effectively controlled by application of chemical binders and by watering, if need be.

These existing controls and corresponding emission limits in Section II, Condition 3 of Operating Permit 95OPEP106 represent the most stringent level of control available for these fugitive dust sources.

Therefore, the Division proposes that RP for these sources is no additional control and the current emission limit for the above units is RP.

Reasonable Progress (RP) Four-Factor Analysis of Control Options For Tri-State Generation & Transmission Association, Inc. – Nucla Station

I. Source Description

Owner/Operator:	Tri-State Generation & Transmission Association, Inc.
Source Type:	Electric Utility Steam Generating Unit
SCC (EGU):	10100218
Boiler Type:	Atmospheric Circulating Fluidized Bed

The Tri-State Generation Transmission & Association, Inc. (Tri-State) Nucla Station is located in Montrose County approximately 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. The boiler is equipped with a fabric filter (baghouse) system for controlling particulate matter (PM) emissions, and limestone injection into the fluidized bed for the removal of sulfur dioxide (SO_2). The boiler is designed for the reduction of NO_x formation and a small Selective Non-Catalytic Reduction (SNCR) system using anhydrous ammonia injection is used for NO_x trim to ensure compliance with annual NO_x limits. Additionally, the facility includes a number of fugitive dust sources.

For this analysis, the Division also relied on the existing Title V permit, historical information regarding the Nucla facility, and information about similar facilities to determine RP for PM and SO_2. EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must be considered in making BART and RP determinations are largely the same.

The Division has elected to set a *de minimis* threshold for actual baseline emissions for evaluating reasonable progress units at each facility equal to the federal Prevention of Significant Deterioration levels. The Division defines "unit" as an Air Pollutant Emission Notice (APEN) subject source, or a stationary source, defined as "any building, structure, facility, equipment, or installation, or any combination thereof belonging to the same industrial grouping that emit or may emit any air pollutant subject to regulation under the Federal Act that is located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control[1]."

[1] Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

These *de minimis* levels are as follows:

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

The Nucla facility originally consisted of three coal fired stoker boilers that were shut down and replaced with an atmospheric circulating fluidized bed (CFB) boiler (Unit #4). Unit #4 was placed in service in June, 1987. CFBs without post-combustion controls are able to achieve emission rates of NO_x and SO_2 that are lower than Pulverized Coal (PC) fired boilers due to the nature of their design (lower combustion temperatures result in less NO_x formation, while intimate mixing of a sorbent within the fluidized bed results in enhanced SO_2 removal). SO_2 emissions from CFBs without post-combustion controls are typically lower than similarly sized PC-fired boilers equipped with Flue Gas Desulfurization (FGD) systems.[2] The original construction of Unit #4 included four baghouses for the control of PM_{10} emissions, limestone injection to the combustion chamber for SO_2 removal, and inherent minimization of NO_x emissions due to boiler design.

In 2006, Tri-State permitted and installed a small-scale SNCR system that injects anhydrous ammonia to provide additional NO_x reduction. Tri-State does not operate the SNCR system frequently; it is used on occasions when NO_x emissions approach 0.4 lb/MMBtu (operation above this level at high unit capacity factors results in levels that approach the annual NO_x limit of 1,987.9 tons per year on a 12-month rolling basis). The system was designed with a 2,000 gallon tank and a flow rate during operation of around 10 gallons per hour.[3]

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, and July 30, 2010. Table 1 depicts technical information for Unit 4 at Nucla Station.

Table 1: Nucla Unit 4 Technical Information

	Unit 4
Placed in Service	1987
Gross Boiler Rating, MMBtu/Hr for coal	1,112
Electrical Power Rating, Net Megawatts	110
Description	Pyropower Circulating Fluidized Bed, Coal Fired Boiler

[2] Babcock & Wilcox Company, 2000. "Why Build a Circulating Fluidized Bed Boiler to Generate Steam and Electric Power" Presented to POWER-GEN Asia 2000. Page 2.
[3] Tri-State, May 14, 2010. "RE: Response to the Division's January 25, 2010 Letter Regarding NO_x Emissions Control Costs." Page 6.

Air Pollution Control Equipment	PM/PM_{10} –Fabric Filter Baghouses (1987) NO_x – Voluntary SNCR (2006) SO_2 – Limestone Injection (1987)
Emissions Reduction (%)	NOx – NA[4] SO_2 – 77.4% PM/PM_{10} – 98% - 99.9+%[5]

II. Source Emissions

Table 2 summarizes the NO_x and SO_2 actual emissions averaged over the 2006 – 2008 timeframe from EPA's CAMD Database for the facility. Table 3 summarizes each unit at the facility and applicable NO_x, SO_2, and PM_{10} actual emissions averaged over the 2006 – 2008 timeframe with data from Colorado's Air Pollutant Emission Notices (APENs) submitted by the facility (based on amount and heat content and amount of coal combusted, also as reported on the APENs).

Table 2. Summary of 2006 - 2008 Averaged Emissions – Tri-State Nucla Station

NO_x (tons/year)	SO_2 (tons/year)	PM_{10} (tons/year)
1,760	1,335	40

Table 3. Summary of 2006 - 2008 Averaged Emissions by Unit – Tri-State Nucla Station

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
Unit 4 Boiler	SO_2 (tons)	1509.4	1230.4	1265.7	1335.2
	SO_2 (lb/MMBtu)	0.34	0.30	0.30	0.31
	NO_x (tons)	1716.0	1598.0	1711.4	1675.1
	NO_x (lb/MMBtu)	0.39	0.38	0.40	0.39
	PM_{10} (tons)	41.6	39.4	40.24	40.4
	PM_{10} (lb/ MMBtu)	0.009	0.009	0.009	0.009
Coal Handling & Processing	*PM_{10} (tons)*	*2.09*	*2.15*	*2.15*	*2.13*
Ash Handling & Processing	*PM_{10} (tons)*	*8.91*	*10.62*	*10.62*	*10.05*
P401 Cooling Tower	PM_{10} (tons)	37.5	23.7	0.34	20.5
P402 Cooling Tower	*PM_{10} (tons)*	*9.8*	*9.8*	*9.8*	*9.8*
Limestone Preparation	*PM_{10} (tons)*	*1.29*	*1.29*	*1.29*	*1.29*

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average.

Units *italicized* in Table 3 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress.

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[4] NO_x emission reductions from the existing SNCR system have not been characterized because the system is operated only infrequently – total reported emissions are therefore assumed to be uncontrolled.

[5] The low range is calculated assuming uncontrolled emissions based on AP-42 factors. The high range is stated in the U.S. Department of Energy: Project Fact Sheet – Nucla CFB Demonstration Project. http://www.netl.doe.gov/technologies/coalpower/cctc/cctdp/project_briefs/nucla/documents/nucla.pdf. Page 5.

Note also that Tri-State installed improved drift eliminators on the P401 Cooling Tower in 2007. The Operating Permit[6] for the facility includes a limit of 0.55 tons PM_{10} per year effective beginning October 1, 2007 (actual emissions for 2008 were reported to be 0.34 tons per year); therefore this unit will also not be considered further in this analysis.

The Title V permit includes the following limits for the Unit 4 Boiler:

- NO_x: 0.50 lbs/MMBtu on a rolling 30-day average (PSD limit), 0.5 lb/MMBtu on a rolling 30-day average (NSPS Subpart Da) and 1987.9 tons per year on a rolling 12-month total
- SO_2: 1.2 lb/MMBtu on a rolling 30-day average (NSPS Subpart Da), 1.2 lb/MMBtu on a 3-hr average (Colorado Regulation No. 1), 0.4 lb/MMBtu on a 30-day average (Colorado Regulation No. 6) and 1598.9 tons per year on a rolling 12-month total; 70% reduction at less than 0.6 lb/MMBtu (30-day rolling average)
- PM_{10}: 131 tons per year on a rolling 12-month total
- PM: 0.03 lb/MMBtu (PSD limit), 0.03 lb/MMBtu (NSPS Subpart Da) 0.1 lb/MMBtu (Colorado Regulation No. 1) and 135.9 tons per year on a rolling 12-month total

III. Units Evaluated for Control

The Nucla boiler burns Colorado bituminous coal. Nucla Station is a mine-mouth facility; therefore the Division assumes that this facility burns New Horizon Coal, since that facility is the closest coal mine identifiable in Division records. The actual APEN coal specifications (2006 – 2008) are listed below in Table 4. Uncontrolled emission factors are outlined in Table 5.

Table 4: Coal Specifications (2006 - 2008 Averaged APEN data)

	Specifications		
Emission Unit	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
Nucla Unit 4	10,545	0.83	19.95

Table 5: Uncontrolled emission factors for Nucla RP-eligible sources[7]

	Pollutant			
Emission Unit	NO_x	SO_2	PM (filterable)	PM_{10} (filterable)
Unit 4 (lb/ton)	5.0	25.8	17.0	12.4
Unit 4 (lb/MMBtu)	0.24	1.22	0.81	0.59

[6] Colorado Air Pollution Control Division, September 25, 2007. Colorado Operating Permit 96OPMO168: Nucla Station. Section II: Condition 8.2, Page 38.

[7] PM and PM_{10} emission factors are from AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf (for spreader stokers with multiple cyclones and reinjection). Uncontrolled SO_2 emission factors are based on the AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1 emission factor for underfeed stoker boilers (Table 1.1-3). Uncontrolled NO_x emission factors are based on actual emissions from 2006 – 2008.

IV. Reasonable Progress Evaluation of Unit 4

a. Sulfur Dioxide

Step 1: Identify All Available Technologies

The Division identified all of the available CFB control technologies listed below.

Fuel Switching – Natural Gas or Alternate Coal Source
Fuel Washing
Limestone Injection Process Upgrades
Post-Combustion Controls: Dry Scrubbing (Spray Dry Absorber, Circulating Dry Scrubber, Hydrated Ash Reinjection and Dry Sorbent Injection)
Post-Combustion Controls: Wet Scrubbing

As discussed in EPA's BART Guidelines[8], electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls. However, upgrades need to be considered for the existing limestone injection process if technically feasible.

The current PSD permit SO_2 limits are depicted in Table 6.

Table 6: Nucla Unit 4 SO_2 PSD Permit Limits

	SO_2 limits (lb/MMBtu)			Rolling 12-month Emission Limit (tons/year)
	3-hour avg. (Colo. Reg. No. 1)	Rolling 30-day avg. (NSPS Subpart Da)	30-day avg. (Colo. Reg. No. 6)	
Unit 4	1.2	1.2	0.4	1,599

Step 2: Eliminate Technically Infeasible Options

Fuel Switching – Natural Gas or Alternative Coal Sources: CFB boilers are designed to create a circulating bed of solid fuels; the nature and locations of the solids and air injection points as well as the combustion zone itself are inherently different from traditional PC and natural gas-fired boilers. The recent conversion from a natural gas-fired boiler to a CFB-boiler at the Lamar Light and Power facility in Lamar, Colorado required the construction of an entirely new and separate unit. Therefore, the Division determines that the conversion to natural gas is technically infeasible for Nucla's CFB boiler.

Nucla Unit #4 is currently burning coal from the New Horizon Mine located five miles south of the plant, with an average sulfur content of 0.83%. The facility is located approximately 4.5 miles southeast of Nucla, Colorado and does not have rail service. There are no other coal mines located 100 miles of the facility. Because the current coal source is already lower than 1% sulfur and no other sources within a reasonable distance of the facility have been identified, fuel switching to other coal types will not be considered further in this analysis.

[8] EPA, 2005. Federal Register, 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Pgs 39133.

Fuel Washing: Fuel washing has been used historically to reduce the sulfur content of some high sulfur coals prior to combustion. There are no identified fuel-washing processes for low sulfur coal.

Existing Process Upgrades and Post-Combustion Controls: In the absence of any specific feasibility or cost information related to SO_2 controls for the Nucla Station, the Division relied on control evaluations performed for other CFB boilers, with a focus on CFB boilers in the western part of the country. Coal supplies for CFB boilers in the eastern part of the country are significantly different from western coals in terms of sulfur and heat content; therefore the Division believes that the specifics of control devices for eastern CFB boilers may not be wholly applicable to Nucla Unit 4. The majority of recent BACT determinations identify limestone injection, with or without additional post-combustion controls as the chosen SO_2 control device. Refer to "Division RBLC Analysis" for more details. The Division reviewed two of the most recent BACT analysis reports in detail: the lignite-fired Spiritwood Station in North Dakota[9] and the waste coal-fired Bonanza Station in Utah[10]. The Spiritwood Station was intended to fire beneficiated lignite but is designed with the capability for firing dried lignite and subbituminous coal as well, and the BACT analysis specifically identified the findings to be applicable to subbituminous coal. The estimated control efficiencies and costs from these reports were used as a basis to evaluate potential SO_2 emission control options at Nucla.

Limestone Injection Process Upgrades: The average reduction in SO_2 emissions due to limestone injection into the CFB boiler for the baseline period is estimated to be 77.4% as shown in Table 1, above. The unit participated in a U.S. Department of Energy Clean Coal Technology Demonstration Program (CCTDP) from 1988 – 1991 in order to examine the energy and environmental impacts from the unit, which was the first utility-scale atmospheric CFB boiler at the time. The project demonstrated a 70% SO_2 removal rate at a calcium to sulfur ratio (Ca/S) of 1.5 and a 95% removal rate at a calcium to sulfur ratio of 4.0[11]. The demonstration project tested a range of western bituminous coals, including Salt Creek (0.5% sulfur), Peabody (0.7% sulfur) and Dorchester (1.5% Sulfur), with the Salt Creek coal serving as the baseline coal (used in 62 of the 72 tests). Limestone injection process upgrades are feasible for Nucla Unit 4.

Post-Combustion Controls – Dry Scrubbing: Additional treatment of the boiler exhaust gases can potentially be accomplished with several dry scrubbing techniques.

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[9] Barr, July 2007. "Application for a Permit to Construct a Combined Heat and Power (CHP) Plant." Prepared for Great River Energy – Spiritwood Station, Spiritwood, ND.

[10] EPA, August 30, 2007. "Deseret Power Electric Cooperative, Bonanza Power Plant, Waste Coal Fired Unit: Prevention of Significant Deterioration Permit to Construct – Final Statement of Basis for Permit No. PSD-00-0002.01.00. "

[11] U.S. Department of Energy: Project Fact Sheet – Nucla CFB Demonstration Project. http://www.netl.doe.gov/technologies/coalpower/cctc/cctdp/project_briefs/nucla/documents/nucla.pdf

Spray Dryer Absorption (SDA) is the most commonly used follow-on controls for CFB boilers with limestone injection. SDAs currently make up about 12% of Flue Gas Desulfurization (FGD) systems at U.S. power plants[12]. SDA systems are typically utilized at smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. A SDA system captures SO_2 by using slaked lime slurry that is sprayed into the flue gas, subsequently dried by the heat of the flue gas, and the collected in a particulate control device. A SDA system is technically feasible for Nucla Unit 4.

Circulating Dry Scrubber (CDS) Systems use a circulating fluidized bed of dry hydrated lime in a separate reactor tower. The flue gas must first be humidified with a water mist. EPA noted in the Bonanza BACT analysis that CDS systems have limited application on large PC-fired boilers or CFB boilers, and can result in particulate loading rates that are high enough to create unacceptable pressure drops across fabric filters and therefore require electrostatic precipitators for particulate control.[13] The potential need to replace the existing baghouse (99.9% particulate control) with an electrostatic precipitator renders a CDS system inappropriate as an option for the Nucla station.

Hydrated Ash Reinjection (HAR) increases utilization of uncreated calcium oxide in the CFB boiler ash by collecting, hydrating and re-introducing a portion of the unit's ash in a separate vessel prior to the baghouse. HAR is technically feasible for Nucla Unit 4.

Dry Sorbent Injection (DSI) systems require injection of powdered absorbent directly into the flue gas stream. EPA identified this option as impractical for use in a CFB boiler burning low sulfur coals due to an expected SO_2 reduction of less than 50%.[14] DSI is a technically feasible option for Nucla.

Post-Combustion Controls – Wet Scrubbing: Wet Flue Gas Desulfurization (FGD) systems were identified as potentially feasible for CFB boilers in both the Bonanza and Spiritwood BACT analyses. The process involves an alkaline slurry (lime or limestone) scrubbing liquid in an absorber tower. The process produces a wet byproduct that requires dewatering. Wet scrubbing is a technically feasible option for Nucla Unit 4.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Limestone Injection Process Upgrades: The Spiritwood BACT analysis states that the control efficiency from the limestone injection process is expected to be 75%[15] (further reductions occur in a Spray Dry Absorber). EPA acknowledges in the Bonanza BACT analysis report that a control efficiency of 80 – 85% should be expected for the limestone injection process alone[16].

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[12] Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environment Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg V.
[13] Ibid., Page 92.
[14] EPA, Deseret Power Electric Cooperative…Page 93.
[15] Barr, Appendix E, Page 50
[16] EPA, Deseret Power Electric Cooperative…Page 99.

The Division believes that an expectation of 95% reduction for the Nucla station from the limestone injection process, although it may have been demonstrated during the CCTDP test project, is not appropriate as a long term operation scenario. The fluidized bed is currently optimized carefully to balance efficiency, operational and emission characteristics. Increasing the Ca/S to 4.0 in order to achieve 95% SO_2 reduction is expected to cause significant operational issues; the Division has not found any evidence of current CFB boilers in operation with Ca/S ratios near 4.0. Higher limestone injections will also result in an increase in NO_x emissions, although the quantitative relationship is not well understood.[17] For these reasons, the Division believes that an increase in SO_2 control efficiency to 85% by increasing limestone injection is a feasible option. This correlates to an approximate 39.4% decrease in comparison to current SO_2 emissions.

Spray Dry Absorber: Based on experience with other Colorado EGUs, the Division believes that a realistic achievable control efficiency for a SDA at Nucla is approximately 87%, or an approximate 0.04 lb/MMBtu (30-day rolling average). This is approximately 97% from uncontrolled SO_2 emissions. A review of the EPA's RBLC database showed two retrofit Western facilities from about 0.04 – 0.05 lb/MMBtu (30-day rolling average) with SDAs as the SO_2 control option. Please refer to the document "RBLC for CFBs – July 2010" for more information.

Limestone Injection Improvements + Spray Dry Absorber: Limestone injection improvements (85%) combined with a spray dry absorber (90%) could achieve up to approximately 94% control from current SO_2 emissions, or 98.4% from uncontrolled SO_2 emissions.

Hydrated Ash Reinjection: EPA references vendor information showing that hydrated ash reinjection could reduce the post-combustion SO_2 emissions by about 80%.[18] This results in about 95% reduction from uncontrolled SO_2 emissions.

Hydrated Ash Reinjection + Limestone Injection Improvements: It may be possible to combine HAR (80% reduction) with improvements to the limestone injection system (85% reduction). This results in a potential 87.9% decrease from current SO_2 emissions or 96.9% reduction from uncontrolled SO_2 emissions.

Post-Combustion Controls – Wet Scrubbing: EPA noted a potential SO_2 removal efficiency of 94% for the post-combustion gas in the Bonanza BACT analysis[19]. Combined with the current limestone injection system, the overall potential control efficiency is 98.4% from uncontrolled SO_2 emissions.

[17] Ibid., Page 100.
[18] Barr, Appendix E, Page 93.
[19] Ibid., Page 94.

Table 7 summarizes each available technology option and technical feasibility for SO_2 control for Nucla Unit 4.

Table 7: Nucla Unit 4 SO2 Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Fuel switching – Natural gas or alternate coal source	Natural gas: 99% Alternate coal: minimal	Natural gas – N Alternate coal – Y – will not provide further SO2 control
Fuel washing	Minimal	N
Limestone Injection Process Upgrades	~85% overall control efficiency ~40% increase from current control efficiency	Y
Dry Scrubbing (SDA)	~97% overall control efficiency ~87% increase from current control efficiency	Y
Limestone Injection Improvements + SDA	~98% overall control efficiency ~94% increase from current control efficiency	Y
Circulating Dry Scrubber	Unknown	N
Hydrated Ash Reinjection (HAR)	~95% overall control efficiency ~80% increase from current control efficiency	Y
HAR + Limestone Injection Improvements	~97% overall control efficiency ~88% increase from current control efficiency	Y
Dry Sorbent Injection (DSI)	<50% overall control efficiency	Y – will not provide further SO2 control
Wet Scrubbing	~98% overall control efficiency ~94% increase from current control efficiency	Y

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

Costs for SO_2 control options were evaluated based on analyses for similar systems proposed at other western CFB boiler units (Spiritwood and Bonanza). Refer to "Nucla APCD Cost Analysis" for more details. Depending on the control option, the Division also relied on additional submittals regarding Nucla feasibility and costs submitted on

Limestone Injection Process Upgrades: The Division relied on the U.S. Department of Energy Clean Coal Technology Demonstration Program (CCTDP) study to determine control efficiency for limestone injection upgrades. The Spiritwood BACT analysis used the cost of limestone in 2006 to determine limestone injection costs. The Division adjusted this cost using the Consumer Price Index (CPI), increasing limestone cost from $80 per ton to $87 per ton. The Division also calculated the additional amount of limestone (in tons per year) that will be needed to achieve an 85% control efficiency (or 40% increase from current control efficiency). These calculations result in an annualized cost of $914,920 per year. Refer to "Nucla APCD Cost Analysis" for more details.

Dry Scrubbing (Spray Dry Absorber)/ Limestone Injection Process Upgrades + SDA: The Division again relied on the Spiritwood BACT Analysis to determine the cost of a spray dry absorber (SDA) system. The annualized cost (2006) for the Spiritwood CFB was $2,644,412. The Division used the CPI to adjust this cost to $2,814,108 and then scaled this cost up by the ratio of potential tons SO_2 removed at the Nucla CFB compared to tons removed at the Spiritwood CFB, and then added in a retrofit factor of 50% to consider the difficulty of the retrofit at Nucla as compared to a new CFB (Spiritwood). This results in an annualized cost of $4,304,807. For limestone injection improvements combined with a SDA system, the Division combined annualized costs from both controls to result in an annualized cost of $5,219,097. Refer to "Nucla APCD Cost Analysis" for more details.

Wet Scrubbing: Although Wet FGD systems provide higher levels of SO_2 removal over dry scrubbers, their incremental cost is likely the reason that they are not identified as BACT controls on any CFB boilers. The incremental cost of using a wet scrubber versus the spray dry absorber is identified as $12,902/ton in the Spiritwood BACT analysis[20], and $10,540 per ton in the Bonanza BACT analysis.[21] A wet scrubber at the Nucla Station should be expected to have even higher costs than these examples due to the retrofit factor. Therefore, a Wet FGD option will not be considered further in this analysis.

HAR/HAR+Limestone Injection Improvements: Study-level information for potential HAR systems at Nucla or any other EGU in the western part of the country were not available for use in evaluating costs. Therefore, the Division does not consider this option to commercially available at this time, and HAR will not be considered further in this analysis. However, HAR is technically feasible and will be considered in future analyses if more information becomes available.

Table 8 illustrates resultant SO_2 emissions for each technically feasible control option. Table 9 shows the SO_2 control cost comparisons for each unit based on the detailed cost analyses. The Division used baseline emissions from Table 3. The Division analyzed both annual and 30-day rolling average limits. The Department's experience with power plants suggests that the maximum 30-day rolling average SO_2 emission rate is approximately 5% higher than the annual average emission rate.

[20] Barr, Appendix E, Page 95.
[21] EPA, Deseret Power Electric Cooperative…Page 95.

Table 8: Nucla Unit 4 Control Resultant SO_2 Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Unit 4		
		(tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,335	0.299	0.314
Limestone Injection Improvements (LII)	39.4	809	0.182	0.191
Hydrated Ash Reinjection (HAR)	80.0	267	0.060	0.063
Spray Dry Absorber (SDA)	87.0	174	0.039	0.041
HAR + LII	87.9	162	0.036	0.038
LII+SDA	93.9	81	0.018	0.019
Wet Scrubbing	94.0	80	0.018	0.019

Table 9: Nucla Unit 4 SO_2 Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
LII	526	$2,188,595	$4,161	$4,161
HAR	1,068	Not determined		
HAR+LII	1,173	Not determined		
SDA	1,162	$7,604,627	$6,547	$8,520
LII+SDA	1,254	$9,793,222	$7,808	$23,619
Wet Scrubbing	1,255	Not determined		

Factor 2: Time Necessary for Compliance

It is assumed that the Limestone Injection Improvements will not require any construction or capital improvements since the Unit has already been demonstrated at the higher Ca/S ratios during the CCTDP test project.

Based on other Colorado facility submittals, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take Tri-State approximately 3 – 5 years to implement the SDA or LII+SDA control options. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: Energy and Non-Air Quality Impacts

There are no identified energy or non-air quality impacts associated with improvements to the Limestone Injection System. Thus, this factor does not influence the selection of this control.

Wet Scrubbing: Based upon its experience, and as discussed in detail below, the Division has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including massive water usage. This is a significant issue in Colorado, where water is a costly, precious and scarce resource. In the arid West, securing sufficient water supplies to support a wet FGD control system is a difficult undertaking that precludes other beneficial uses for such water. In Colorado, water law is based upon the doctrine of prior appropriation or "first in time - first in right," and the priority date is established by the date the water was first put to a beneficial use. Thus, depending upon whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the state, particularly in the Front Range, to accommodate the added demands of wet FGD controls. At a minimum, the water demands of wet FGDs will compete for what is already a scarce resource needed for Colorado's domestic, agricultural and industrial demands.

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. Potential on-site storage of wet ash is an increasing regulatory concern, as evidenced by the recent Tennessee Valley Authority spill. The Division has received complaints regarding the more visible plumes associated with wet scrubbing; a potential irony in light of the visibility issues at the heart of the Regional Haze program. The Division largely focused its RP SO_2 control technology consideration on commercially available once-through dry FGD controls, specifically, "lime spray dryers" (LSD), that have an established record of reliable performance on boilers burning low-sulfur coal. Generally, wet FGD controls can achieve a higher level of SO_2 control on a percent capture basis that exceeds the capabilities of LSDs but, as noted above, there are a number of non-air quality and other environmental impacts including increased water usage, sludge disposal and wet plume issues that often overshadow any incremental improvement in SO_2 emission reductions. Recent PSD applications in Colorado have demonstrated lime spray dryer systems to be BACT.

The Division finds the negative environmental impacts of a traditional wet FGD control system far outweigh minimal incremental SO_2 emission reduction benefits (tons of SO_2 reduced annually) and visibility improvement (deciview improvement at nearest Class I area) when compared to a SDA system when applied to the Nucla Unit 4 CFB boiler.

Spray dry absorber (SDA): Other Colorado facility have noted that there are a number of non-air quality environmental impacts with regard to lime spray dryer systems. Application of a dry scrubber will tend to remove halogens from the flue gas (primarily chlorine) that are important to the removal of mercury from the flue gas. Several sources of speciated mercury stack test data, including EPA's own ICR stack test data, show that an unscrubbed plant with a baghouse burning western coal will remove more mercury from the flue gas when compared to a similar plant with a scrubber. There will be a greater volume of material being landfilled. A LSD scrubber consumes a tremendous amount of water. Wet scrubbers consume approximately 23% more water than LSD scrubbers, depending on boiler size.[22]

Although these non-air quality/energy impacts have been identified, the State has determined that these impacts are not significant or unusual enough to warrant elimination of this control option.

DSI: Other Colorado facility have documented additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Application of DSI would be effective in further enhancing the removal of halogenated acid gases in the baghouse. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash.

The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash at some plants,[23] which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls

Factor 4: Remaining Useful Life

Tri-State asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

[22] 2008. "Revised BART Analysis for Unit 1 & 2 Gerald Gentleman Station Sutherland, Nebraska: Nebraska Public Power District." Prepared by: HDF 701 Xenia Avenue South, Suite 600 Minneapolis, MN 55416 With control technology costs provided by: Sargent & Lundy.

[23] Department of Energy, 2001. LIFAC Sorbent Injection Desulfurization Demonstration Project: A DOE Assessment. U.S. Department of Energy: National Energy Technology Laboratory. P.O. Box 880, 3610 Collins Ferry Road Morgantown, WV 26507-0880. http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/lifac/LIFAC_PPA.pdf

Factor 5 (optional): Evaluate Visibility Results

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis.

Step 6: Select RP Determination

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, the state has determined that the existing permitted SO_2 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.

b. Filterable Particulate Matter (PM) & Particulate Matter (PM_{10})

Nucla Unit 4 is currently equipped with a four baghouse system to control PM/PM_{10} emissions from the boiler. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred micron in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

The baghouses performed over the 2006 – 2008 baseline period with PM and PM_{10} emissions of 0.013 lb/MMBtu and 0.009 lb/MMBtu, respectively. During the CCTDP test project, the unit demonstrated particulate emissions ranging between 0.0072 to 0.0125 lb/MMBtu, corresponding to a removal efficiency of 99.9%[24]. This boiler is subject to 40 CFR Part 60, Subpart Da, which requires 99% reduction (for facilities commencing construction after September 18, 1978) of the potential combustion concentration when burning solid fuel.

[24] U.S. Department of Energy, Page 5.

A Division review of the PM/PM_{10} emission limits in the current Title V permit revealed that these limits are for filterable PM/PM_{10} emissions only.

Table 10 shows the most recent *verified* stack test data (2002). Another stack test was conducted in August 2010, but is not yet available for release due to ongoing analysis by the Division and Tri-State. Real-time data demonstrates that these baghouses are meeting >95% control. The Operating Permit (96OPMO168) limit is 0.03 lb/MMBtu for PM/PM_{10} emissions (Conditions 1.1.1, 1.1.2). The most recent stack test data is used to determine compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

Table 10: Nucla Unit 4 Stack Test Results (August 2002)

Pollutant	Unit 4 (lb/MMBtu)
Filterable PM_{10}	0.014
PM_{10} Control efficiency	98.3%

A Division review of EPA's RBLC revealed recent BACT PM/PM_{10} determinations range from 0.010 – 0.10 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The current limit of 0.03 lb/MMBtu is in the range of recent BACT determinations. Please refer to "Division RBLC Analysis" for more details about recent BACT determinations.

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 control technology and 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. Therefore, a full 4-factor analysis is not needed to evaluate PM/PM_{10} for the Unit 4 boiler.

c. *Nitrogen Oxides (NO_x)*

Step 1: Identify All Available Technologies

Fuel Switching – Natural Gas or Alternate Coal Source
Selective Non-Catalytic Reduction (SNCR) system upgrades
Selective Catalytic Reduction (SCR) with flue gas reheat

Step 2: Eliminate Technically Infeasible Options

Tri-State provided an analysis of the requirements and costs associated with increasing the size of the existing SNCR system to allow for more frequent operation, and the Division has relied on this information (with some exceptions) in order to evaluate a full-time SNCR option. Due to lack of any specific feasibility or cost information related to SCR controls at Nucla Station, the Division relied on recent control evaluations performed for other CFB boilers in the western part of the country (the Spiritwood and Bonanza evaluations, noted in Section III.a. above).

Every BACT determination listed in the RACT/BACT/LAER Clearinghouse for CFB Boilers specifies SNCR; no SCR determinations or installations have been identified. This is likely due to the significantly high incremental costs of SCR systems, as discussed below.

As described above for SO_2 controls, fuel switching to natural gas or an alternative coal source is not considered technically feasible.

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SNCR is considered a technically feasible alternative is Nucla Unit 4.

SCR: SCR systems are the most widely used post-combustion NO_x control technology for PC-fired boilers. SCR control involves injecting ammonia into the flue gas stream in the presence of a catalyst, and requires a temperature range of 500°F – 800°F. SCR systems are not considered feasible for CFB boilers because the particles present in the boiler exhaust act as catalyst poisons. However, the recent BACT analyses for the Spiritwood and Bonanza Units have considered the application of SCR technology following the particulate control device on CFB boilers in order to achieve 90% NO_x reduction. Since baghouse exhaust temperatures are too low to satisfy SCR requirements, reheating of the flue gas is required. NO_x control efficiencies of 90% are expected. The Division considers SCR a technically feasible alternative for Nucla Unit 4. Please see the cost section for more details regarding SCR.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

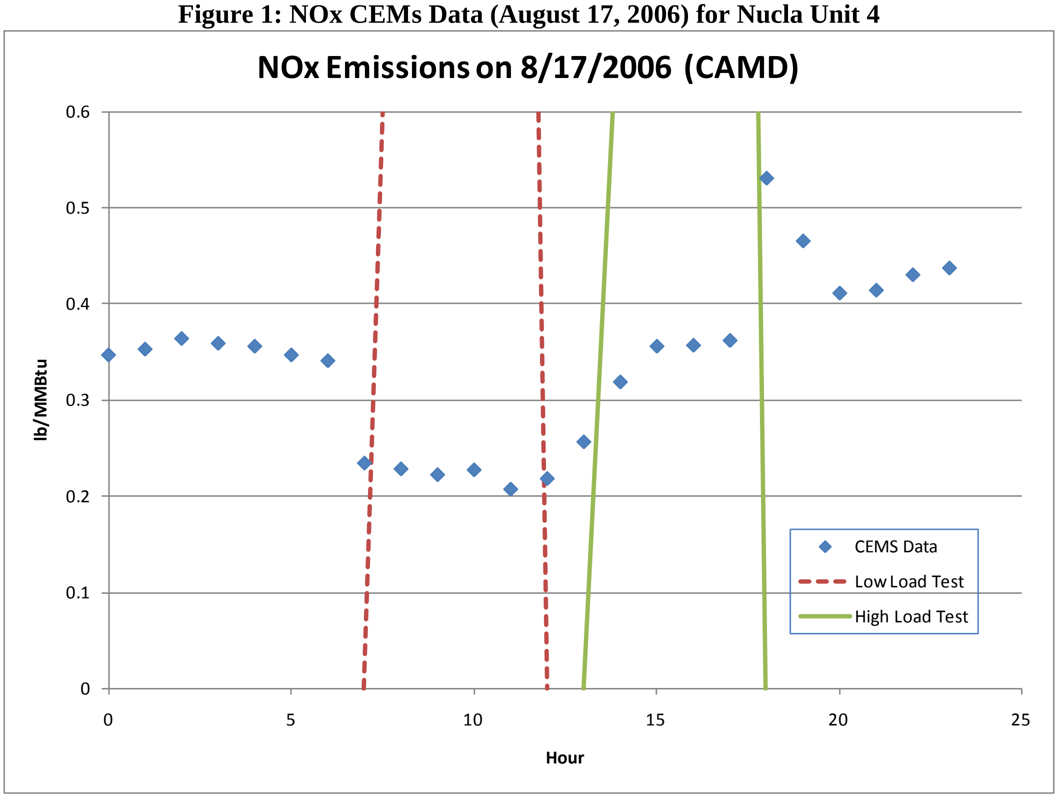
SNCR: The current SNCR system associated with Unit 4 is a small system using anhydrous ammonia injection for NO_x trim during period when emissions approach 0.4 lb/MMBtu (the permit limit is 0.5 lb/MMBtu). NO_x trim is required to ensure that the facility is able to meet the 1,987.9 ton per year permit limit on a rolling 12-month total. Tri-State notes that the unit is not in service the majority of the time. The system was designed with a 2,000 gallon tank and a flow rate during operation of around 10 gallons per hour, allowing only 8 days of continuous service. Tri-State also notes that there is such a wide variability in the effectiveness of SNCR for controlling NO_x emissions that only 10% control should be assumed, but provided no data to support this value. Note that 10% control over a baseline of 0.39 lb/MMBtu is 0.35 lb/MMBtu.

On August 17, 2006, Tri-State performed a stack test in order to ensure that ammonia slip emissions resulting from the newly installed SNCR system would not result in a significant emission increase (for PM_{10}) and trigger PSD review for the project. The test was completed at maximum and minimum boiler loads, and maximum ammonia injection rate (15.4 – 15.5 gallons per hour)[25]. The test runs occurred during the following timeframes:

Low Load (80.4 MW)	High Load (109.2 MW)
Run 1: 7:28 – 8:28	Run 1: 13:51 – 14:51
Run 2: 9:14 – 10:14	Run 2: 15:25 – 16:25
Run 3: 10:44 – 11:44	Run 3: 16:52 – 17:52

The NO_x CEMS data from CAMD for August 17, 2006 in Figure 1 shows an hourly NO_x rate during the low load test of 0.22 lb/MMBtu (corresponding to 43.6% control over the baseline), and an hourly NO_x rate during the high load test of 0.35 lb/MMBtu (corresponding to 10.3% control).

Figure 1: NOx CEMs Data (August 17, 2006) for Nucla Unit 4



The low load rate of control is more in line with estimates for the SNCR systems in the Spiritwood and Bonanza BACT analyses (58%[26] and 47%[27], respectively).

[25] Colorado Department of Public Health & Environment, November 2, 2006. "Stack Testing Report, Nucla Station"
[26] Barr, Appendix E, Page 56.
[27] EPA, Deseret Power Electric Cooperative…Page 49.

The Division conducted an analysis to determine the typical load for Nucla Unit 4 using baseline data (2006 – 2008). From 2006 – 2008, Nucla ran at 97.6% load. This high load data indicates that 10.3% control is more reasonable. However, the Division and Tri-State both note that the existing small scale SNCR system is not designed for full-scale operation and would last about 8 days in continuous service and has never operated for an extended period of time. Tri-State further notes that given the design purpose of the existing system for injection to trim emissions as needed, the system is not engineered to achieve a specific percent reduction. The Division concludes that there is a significant amount of uncertainty surrounding the application of SNCR on CFB boilers due to lack of information at this time.

Table 11 summarizes each available technology and technical feasibility for NO_x control.

Table 11: Nucla Unit 4 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Fuel switching – Natural gas or alternate coal source	Natural gas: 20 – 70% Alternate coal: minimal	Natural gas – N Alternate coal – Y – will not provide further NOx control
Low NO_x Burners (LNB)	~10%	N – CFB boiler
Overfire air (OFA)	10 – 25% (alone)	N – CFB boiler
Selective non-catalytic reduction (SNCR)	20 – 40%	Y – small scale system already installed
Selective catalytic reduction (SCR)	70 – 90%	Y

Step 4: Evaluate Factors and Present Determination

Tri-State provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[28] 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Nucla Unit 4 to determine control efficiencies and annual reductions.

[28] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

Factor 1: Cost of Compliance

SCR: Although SCR systems provide significantly higher levels of NO_x removal over SNCR systems, their incremental cost is likely the reason that they are not identified as BACT controls on any CFB boilers. The incremental cost of using SCR versus SNCR on a CFB Boiler is identified as $25,315/ton in the Spiritwood BACT analysis[29], and $40,297 per ton in the Bonanza BACT analysis[30]. A SCR system at the Nucla Station should be expected to have even higher costs than these examples due to a retrofit factor and small size. Therefore, the Division considers that costs for SCR will be excessive. Additionally, site-specific costs for SCR on Nucla are not available at this time.

SNCR: The cost associated with installation of an upgraded SNCR system is shown below. Costs are based on values submitted by Tri-State on May 14, 2010.[31] Refer to "Nucla APCD Cost Analysis" for more details. The Division used two discrete control efficiencies to demonstrate the significant uncertainty of the application of SNCR and the variation in resultant cost effectiveness.

Table 12 and Table 13 depict controlled NO_x emissions and control cost comparisons.

Table 12: Nucla Unit 4 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,675	0.387	
SNCR	10.3	1,503	0.347	0.399
SNCR	43.6	945	0.218	0.251

Table 13: Nucla Unit 4 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
SNCR	173	$2,238,592	$12,974	$12,974
SNCR	730	$2,238,592	$3,065	---

[29] Barr, Appendix E, Page 57.
[30] EPA, Deseret Power Electric Cooperative…Page 51.
[31] Tri-State, Page 3.

Factor 2: Time Necessary for Compliance
Tri-State states that the SNCR project could be implemented in a two to three year time frame, but also notes that[32]:

> "Projects of this size entailing a significant outage lasting eight weeks or more must be integrated into the long term schedule in order to coordinate with the management of the grid and for power replacement commitments. The date on which EPA SIP approval occurs is necessarily the starting point for any schedule including significant investments for engineering and design, procurement of equipment and contract commitments. In addition, the schedule would have to be integrated into the electric supply planning process."

Tri-State has also described significant constructability challenges and balance-of-plant changes that will likely affect the timeframe for reconstruction of the SNCR project[33]. Nucla station is located approximately 70 miles from the nearest interstate highway. The facility does not have rail service and is located 40 miles from the nearest commercial air terminal. Below freezing temperatures are expected seven months of the year, which affects soil excavation, structure foundations and concrete placement.

Based on other Colorado facility submittals, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take Tri-State approximately 3 - 5 years to implement any of the above control options. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: Energy and Non-Air Quality Impacts

Post-combustion add-on control technologies like SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. The cost associated with increased power needs was addressed in the cost effectiveness study provided by Tri-State and is reflected in the costs shown in the tables above.

Installing SNCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid.

[32] Ibid., Page 24.
[33] Ibid., Page 10.

With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; Tri-State has indicated that the larger quantity of on-site anhydrous ammonia storage required by the scale-up of the SNCR system will require the review and approval of new Risk Management Plans and Process Safety Management Plans. The larger tank may also trigger other state and local ordinances and requirements.

Factor 4: Remaining Useful Life
Tri-State asserts that there are no near-term limitations on the useful of this boiler, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results
Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis. Nucla has a limited, small-scale SNCR system for emissions trimming purposes already installed.

Step 6: Select RP Determination

Based upon its consideration of the five factors summarized herein, the State has determined that NOx RP for Nucla Unit 4 is 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 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, and other relevant technologies such as lime spray dryers and flue gas desulfurization. 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 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. On December 26, 2012, Tri-State submitted an updated four-factor analysis and visibility modeling to the Division, with the conclusion that limestone for SO2 control and existing SNCR for NOx reduction remained the preferred strategy.

Requirements for Nucla Station

On December 31, 2012, EPA approved Colorado's Regional Haze SIP, including Colorado's Reasonable Progress determination for Nucla Unit 4 (0.5 lb/MMBtu (30-day rolling average)). In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a Reasonable Progress review of Nucla. This review adds a requirement of a closure date on or before December 31, 2022 for Nucla Station. Additionally, an annual NO_x limit of 952 tons per year will be effective January 1, 2020 on a calendar year basis beginning in 2020.

These requirements are the result of an agreement. The 2022 closure achieves further NOx reductions and other environmental co-benefits than the 2011 RP determination. Consistent with the agreement and in lieu of being subject to stringent requirements as part of the long term strategy for the second implementation period of Regional Haze, Nucla Station will close by December 31, 2022. Additionally, an annual NOx limit of 952 tons per year will be effective on January 1, 2020 on a calendar year basis beginning in 2020. Nucla Unit 4 will still comply with the 2011 RP determination of 0.5 lb/MMBtu (30-day rolling average) until closure.

Reasonable Progress (RP) Four-Factor Analysis of Control Options
For
Platte River Power Authority – Rawhide Energy Station

I. Source Description

Owner/Operator:	Platte River Power Authority
Source Type:	Electric Utility Steam Generating Unit
SCC (EGU):	1010026
Boiler Type:	Pulverized Coal Dry-Bottom Tangentially-Fired

The Platte River Power Authority (PRPA) Rawhide Energy Station is located in Larimer County approximately 10 miles north of the town of Wellington, Colorado. The Rawhide Energy Station consists of one coal fired steam driven electric generating unit (Unit 101), with a rated electric generating capacity of 305 MW (gross), and was placed into service in 1984. The boiler is equipped with a fabric filter (baghouse) system for controlling particulate matter (PM) emissions, and a lime spray dry absorber controls sulfur dioxide (SO_2). The boiler is equipped with low nitrogen oxide (NO_x) concentric firing system (LNCFS) burners with separated overfire air (SOFA) configuration for minimization of NO_x emissions, installed in 2005.

The Rawhide Station also has five natural-gas fired combustion turbines, designed to operate in a simple cycle mode, four rated at a heat input of 831.1 MMBtu/hour (approximately 82 MW) and one rated at a heat input of 1,400 MMBtu/hour (about 150 MW). Each turbine is equipped with integral dry low NO_x combustion systems and inlet air fog cooling systems and startup and shutdown duration average NO_x and CO emission limits determined to be Best Available Control Technology (BACT)[1] since each turbine is subject to Prevention of Significant Deterioration (PSD) provisions. These turbines were placed into service starting in May 2002, with the last turbine (150 MW) started up in June 2008. The primary use of these units is to meet Platte River's energy reliability and peak load requirements. The turbines operate on limited, intermittent, and unpredictable schedules as peak loading units. Additionally, the facility includes a number of fugitive dust sources. PRPA has prepared a Reasonable Progress (RP) analysis as well as supplemental information which can be found in "PRPA RP Submittals".

For this analysis, the Division also relied on the existing Title V permit, historical information regarding the Rawhide facility, and information about similar facilities to determine RP for PM_{10} and SO_2 (available in the TSD). EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must considered in making BART and RP determinations are largely the same.

For the purposes of evaluating RP, the Division has elected to set *de minimis* thresholds for any emission unit at a subject-to-RP source with actual baseline emissions of SO_2, NO_x, or PM_{10} equal

[1] Colorado Air Pollution Control Division, 2004. Colorado Operating Permit 03OPLR261: Rawhide Energy Station. Section II: Condition 1.7, pages 10 – 13.

to or exceeding the federal Prevention of Significant Deterioration (PSD) significance levels. The Division has established *de minimis* thresholds for SO_2, NO_x and PM_{10} to focus the technical emission control analysis on significant emission sources where potential controls could provide a meaningful improvement in visibility if emission controls are determined to be cost effective.

The *de minimis* levels are applicable to individual emission units at a stationary source. The Division defines "emissions unit" as "any part or activity of a stationary source that emits or has the potential to emit any air pollutant regulated under the state or Federal Acts. This term is not meant to alter or affect the definition of the term "unit" for purposes of Title IV (acid deposition control) of the federal act, or of the term "source" for purposes of the Air Pollutant Emission Notice requirements of Regulation Number 3, Part A, Section II.B.3. [2] ." These *de minimis* levels are as follows:

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

Emissions Unit P301 serves as a detailed example of evaluating one "unit" in Table 1. As the PM10 emissions from emissions unit P301 are below the *de minimis* level of 15 tons per year, it is exempted from any further analysis under RP.

Table 1: Unit Detail Example for *de minimis* Threshold

Unit P301 Breakdown	2006 – 2008 Average PM_{10} Emissions (Baseline Actual Emissions)
Solid Wastes Silo Rotary Unloader Discharge	0.41
Solid Wastes Hauling to Landfill	1.64
Solid Wastes Haul Truck Unloading	0.02
Active/Exposed Landfill Area	0.21
Waste Landfilling/Reclamation	0.39
Bottom Ash Excavation and Loading	0.02
Solid Wastes Silo Filling	0.00
Solids Vacuum Conveying System and Silo Filling	0.17
Fly Ash and Solid Waste Silo Dry Unloading and Haul Truck Loading	0.02
Unit P301 Baseline PM_{10} Emissions	3.01 << 15 (PSD threshold)

Rawhide Unit 101 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. PRPA submitted a "Rawhide NOx Reduction Study" on January 22, 2009 as well as additional relevant information on May 5 and 6, 2010. Table 2 depicts technical information for Rawhide Unit 101.

[2] Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

Table 2: Rawhide Unit 101 RP-eligible Emission Controls and Reduction (%)

	Rawhide Unit 101
Placed in Service	1984
Boiler Rating, MMBtu/Hr for coal	3,000
Electrical Power Rating, Gross Megawatts	305
Description	Combustion Engineering tangentially fired, dry bottom steam generator/boiler firing pulverized coal.
Air Pollution Control Equipment	Fabric Filter (baghouse) for PM/PM_{10} control Spray Dryer Removal System for SO_2 control
Special Features	Low NO_x Concentric Firing System (LNCFS) with separated overfire air (SOFA) installed in 2005
Emissions Reduction (%)[1]	NO_x – 49.6% SO_2 – 83.1% PM/PM_{10} – 99.2/96.7%

[1]Emissions Reduction estimated by comparing uncontrolled AP-42 factor to actual average emission factor for PM/PM_{10}. For SO_2 estimates, CAMD data (average of 2006 – 2008) was used to calculate reduction %. The NO_x reduction is based on actual data from pre-2005 actual emissions. See "Rawhide APCD Technical Analysis" for further details. Not based on actual testing.

For the boiler, the Voluntary Emissions Reduction Agreement (VERA) permit limit for NO_x is 0.180 lbs/MMBtu on an annual average effective July 15, 2006. The Acid Rain permit limit for NO_x is currently 0.40 lbs/MMBtu on an annual average and the PSD/NSPS limit is 0.50 lbs/MMBtu on a 30-day rolling average.

In October of 2005, PRPA installed a low NO_x Concentric Firing System (LNCFS) with separated overfire air (SOFA) on Unit 101 that resulted in an approximate 50% reduction of NO_x emissions (from pre-2005 actual emissions) in accordance with the Voluntary Emissions Reduction Agreement entered into with the State of Colorado in 2002[3].

Rawhide Unit 101 was initially installed in 1984 with a baghouse for particulate emission (PM/PM_{10}) control, with control efficiency exceeding 99.9%. This system was BACT at the time of initial startup and is still considered BACT currently.

The "Spray Dryer Removal System" for Unit 101 was considered a new control technology at the time of installation in 1984 and started up at the same time as Rawhide Unit 101. This system originally reduced SO_2 emissions by approximately 80% and 0.13 lbs/MMBtu (30-day rolling average) (from AP-42 emission calculations) according to Federal PSD emission standards at that time (0.2 lbs/MMBtu annually). In 2003, PRPA entered into a Voluntary Emissions Reduction Agreement with the State of Colorado to reduce SO_2 emissions to 0.09 lbs/MMBtu (annual

[3] Colorado Air Pollution Control Division, 1992. Exhibit A: Division Evaluation of Nitrogen Oxides Emission Limitation and Regulatory Assurance Periods.

average) by upgrading the lime spray dryer system[4]. This upgraded system resulted in an approximate 30% emission rate reduction of SO_2 emissions from pre-VERA emission rates.

II. Source Emissions

Table 3 summarizes the NO_x, SO_2, and PM_{10} actual emissions averaged over the 2006 – 2008 baseline timeframe from EPA's CAMD Database for the facility. Table 4 summarizes each unit at the facility and applicable NO_x, SO_2, and PM_{10} actual emissions averaged over the 2006 – 2008 timeframe with data from Colorado's APEN's submitted by the facility and as applicable, EPA's CAMD Database (primarily for the Unit 101 boiler and the turbines).

Table 3. Summary of 2006 - 2008 Averaged Emissions - PRPA Rawhide Facility

NO_x (tons/year)	SO_2 (tons/year)	PM_{10} (tons/year)
1,885	914	125

Table 4. Summary of 2006 - 2008 Averaged Emissions by Unit - PRPA Rawhide Facility

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
Unit 101 Boiler	SO_2 (tons)	943	928	869	913
	SO_2 (lb/ MMBtu)	0.078	0.081	0.078	0.081
	NO_x (tons)	1,990	1,863	1,745	1,866
	NO_x (lb/ MMBtu)	0.163	0.162	0.173	0.166
	PM_{10} (tons)	109	113	101	108
	PM_{10} (lb/ MMBtu)	0.018	0.017	0.018	0.018
Turbine Unit A (82 MW)	*SO_2 (tons)*	*0.10*	*0.12*	*0.12*	*0.11*
	NO_x (tons)	*1.17*	*5.45*	*0.75*	*2.46*
	PM_{10} (tons)	*0.20*	*1.12*	*0.13*	*0.48*
Turbine Unit B (82 MW)	*SO_2 (tons)*	*0.09*	*0.06*	*0.11*	*0.09*
	NO_x (tons)	*3.87*	*3.17*	*5.07*	*4.04*
	PM_{10} (tons)	*0.77*	*0.58*	*0.99*	*0.78*
Turbine Unit C (82 MW)	*SO_2 (tons)*	*0.04*	*0.09*	*0.03*	*0.05*
	NO_x (tons)	*2.03*	*4.45*	*1.65*	*2.71*
	PM_{10} (tons)	*0.33*	*0.80*	*0.30*	*0.48*
Turbine Unit D (82 MW)	*SO_2 (tons)*	*0.05*	*0.10*	*0.03*	*0.06*
	NO_x (tons)	*2.53*	*4.95*	*1.50*	*2.99*
	PM_{10} (tons)	*0.45*	*0.85*	*0.26*	*0.52*
*Turbine Unit F (150 MW)***	*SO_2 (tons)*			*0.38*	*0.38*
	NO_x (tons)			*20.45*	*20.45*
	PM_{10} (tons)			*3.75*	*3.75*
P201 Train Unloading Facility	*PM_{10} (tons)*	*0.60*	*0.01*	*0.01*	*0.20*
P201 Active Coal Pile Reclaim	*PM_{10} (tons)*	*0.03*	*0.02*	*0.00*	*0.02*
P201 Coal Silo Filling and Conveyor Belt Transfer	*PM_{10} (tons)*	*0.30*	*0.00*	*0.00*	*0.10*
P201 Coal Silo Discharge to Conveyor Belt	*PM_{10} (tons)*	*0.28*	*0.00*	*0.00*	*0.10*
P201 Coal Crushing and	*PM_{10} (tons)*	*0.33*	*0.02*	*0.02*	*0.12*

[4] Colorado Air Pollution Control Division, 1992. Exhibit B: Division Evaluation of Sulfur Dioxides Emission Limitation and Regulatory Assurance Periods.

Conveying					
P201 Coal Conveyor Belt Transfer	*PM_{10} (tons)*	*0.30*	*0.00*	*0.00*	*0.10*
P201 In-Plant Silo Filling Conveyor Belt Transfer	*PM_{10} (tons)*	*0.30*	*0.00*	*0.00*	*0.10*
P201 Coal Pile Stockout	*PM_{10} (tons)*	*1.18*	*0.01*	*0.02*	*0.40*
P201 Active Coal Storage Area	*PM_{10} (tons)*	*0.93*	*1.91*	*1.96*	*1.60*
P201 Active Coal Pile Storage Area	*PM_{10} (tons)*	*0.95*	*2.56*	*2.56*	*2.02*
P201 Coal Crusher Stockout	*PM_{10} (tons)*	*0*	*0*	*0*	*0.00*
P201 Coal Conveying	*PM_{10} (tons)*	*1.81*	*1.23*	*1.09*	*1.38*
P301 Solid Wastes Silo Rotary Unloader Discharge	*PM_{10} (tons)*	*0.70*	*0.28*	*0.25*	*0.41*
P301 Solid Wastes Hauling to Landfill	*PM_{10} (tons)*	*1.82*	*1.67*	*1.44*	*1.64*
P301 Solid Wastes Haul Truck Unloading	*PM_{10} (tons)*	*0.04*	*0.02*	*0.01*	*0.02*
P301 Active/Exposed Landfill Area	*PM_{10} (tons)*	*0.19*	*0.24*	*0.19*	*0.21*
P301 Waste Landfilling/Reclamation	*PM_{10} (tons)*	*0.13*	*0.57*	*0.46*	*0.39*
P301 Bottom Ash Excavation and Loading	*PM_{10} (tons)*	*0.03*	*0.02*	*0.02*	*0.02*
P301 Solid Wastes Silo Filling	*PM_{10} (tons)*	*0.02*	*0.20*	*0.17*	*0.13*
P301 Solids Vacuum Conveying System and Silo Filling	*PM_{10} (tons)*	*0.17*	*0.18*	*0.16*	*0.17*
P301 Fly Ash and Solid Waste Silo Dry Unloading and Haul Truck Loading	*PM_{10} (tons)*	*0.02*	*0.02*	*0.01*	*0.02*
P401 Scrubber Lime Storage Silo Filling	*PM_{10} (tons)*	*0*	*0.01*	*0.01*	*0.00*
P401 Recycle Ash Storage Silo Filling	*PM_{10} (tons)*	*0.11*	*0.89*	*0.81*	*0.60*
P501 Unpaved Site Roadways and Parking Lots	*PM_{10} (tons)*	*3.14*	*3.92*	*4.23*	*3.76*
P501 PRS Soda Ash Storage Silo Filling	*PM_{10} (tons)*	*0*	*0*	*0*	*0.00*

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average. 30-day rolling averages for the Unit 101 Boiler are estimated to be 5-15% higher than the annual average emission rate (i.e. the maximum 30-day NO_x rolling average is likely about 0.190 lbs/MMBtu).
**Note that Unit F did not start up until June of 2008; therefore it was not operated in 2006 or 2007 and for only half of 2008.

Units *italicized* in Table 3 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress.

Each of the five turbines at Rawhide Station was installed with an advanced dry low-NO_x combustion system that controls NO_x emissions to less than 9 ppm @ 15% O_2 as well as a gas turbine inlet air fog cooling system designed for optimal power augmentation during hot weather operations. . Each turbine is subject to BACT under the PSD provisions. The turbines are also required to use pipeline quality natural gas as defined by the Acid Rain Provisions 40 CFR Part 72. The Title V permit enforces a compliance SO_2 emission factor of 0.0006 lb/MMBtu for each turbine. These combustion turbines are further evaluated within the source category "Combustion Turbines" in Section 8.2.3 of the Regional Haze SIP.

III. Units Evaluated for Control

As documented by PRPA, Rawhide Unit 101 fires low sulfur, high heating value Power River Basin sub-bituminous coal. The specifications for the coal are listed below in Table 5.

Table 5: Coal Specifications (2006 - 2008 Averaged APEN data)

	Specifications		
Emission Unit	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
Rawhide Unit 101	8,853	0.24	5.42

Table 4 lists the units at Rawhide that the Division examined for control to meet reasonable progress requirements. Controlled and uncontrolled emission factors and APEN data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 6.

Table 6: Uncontrolled emission factors for Rawhide Unit 101

Emission Unit	Pollutant	Fuel
		Coal (sub-bituminous) (lb/ton)
Rawhide Unit 101[5]	NO_x	7.2
	SO_2	35 x %S = 8.5*
	PM/PM_{10}	PM – 54.2** PM_{10} – 12.5

*%S = % of sulfur present in coal supply. For example, 35 x 0.24 = 8.5

**%A = % of ash present in coal supply. For example, 10 x 5.42 = 54.2

IV. Reasonable Progress Evaluation of Unit 101

a. Sulfur Dioxide

Step 1: Identify All Available Technologies

PRPA identified one SO_2 control option:

Fuel Switching – Natural Gas or Colorado Coal

The Division requested that PRPA evaluate the option below, and received relevant information for this request on May 5, 2010:

Dry FGD upgrades

As discussed in EPA's BART Guidelines[6], electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls.

[5] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[6] EPA, 2005. Federal Register, 40 CFR Part 51. Regional haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Pgs. 39133.

However, upgrades need to be considered for the scrubber if technically feasible. These upgrades include:

- -Use of performance additives
- -Use of more reactive sorbent
- -Increase the pulverization level of sorbent
- -Engineering redesign of atomizer or slurry injection system

Step 2: Eliminate Technically Infeasible Options

Fuel Switching – Natural Gas or Colorado Coal: The Division and PRPA both assert that the Unit 101 boiler at Rawhide could convert fuels from coal to natural gas with boiler modifications and natural gas pipeline construction. Conversion from coal to natural gas would reduce SO_2 emissions by about 906 tons per year, or approximately 99% (using 2006 - 2008 CAMD data average)[7]. SO_2 emissions from coal combustion are affected by the chemical and physical properties of the feed coal. Feed coal characteristics significantly affect the design and operation of combustion controls, such as the existing LNB+SOFA system. With the dry FGD – lime spray dryer system in place, Unit 101 currently achieves an emission rate of 0.07 lb/MMBtu (annual average).

PRPA notes that Unit 101 is designed to burn PRB coal and the boiler is additionally optimized through a technologically complex process to burn this coal at very tightly controlled rate. PRPA has indicated that it is infeasible as well as economically impractical to change coal supplies. The sulfur content of the Rawhide Unit 101 PRB coal supply is between 0.8 – 1.4 lb/MMBtu with most of the supply containing less than 1.2 lbs/MMBtu (based on northern Wyoming PRB coal mine reports). The average sulfur content in the coal is 0.29%. PRPA obtains coal for Rawhide Unit 101 from the Antelope Mine in Converse County, Wyoming, which has one of the lowest sulfur content of any mine in the county. PRPA additionally pays a premium to ensure higher Btu/lower sulfur coal. A review by the Colorado Geological Survey found that on average, Wyoming coal had similar sulfur content to Colorado coal[8]. Virtually all Colorado coal contains less than 1 percent sulfur and most of it contains less than half of that amount (0.5% or less)[9]. Therefore, the sulfur content of the Antelope Mine coal is similar, if not lower, than Colorado coal.

The Division has determined that fuel switching to natural gas is technically feasible for Rawhide Unit 101. However, fuel switching to Colorado coal will not further reduce SO_2 emissions from Unit 101 and will not be considered further in this analysis.

Dry Flue Gas Desulfurization (FGD) Upgrades: Dry FGD systems are commonly known as spray dry absorbers (SDA), and currently make up about 12% of FGD systems at U.S. power

[7] Colorado Air Pollution Control Division Technical Analysis – Rawhide Unit 101 Boiler – Natural Gas Switching, 2010. See Appendix D of the SIP for detailed calculations.
[8] Colorado Geological Survey: RockTalk. Volume One, Number Three. July 1998. http://geosurvey.state.co.us/pubs/rocktalk/rtv1n3.pdf
[9] Colorado Geological Survey: RockTalk. Volume One, Number Three. July 1998. http://geosurvey.state.co.us/pubs/rocktalk/rtv1n3.pdf

plants[10]. SDA systems are typically utilized at smaller units that burn lower-sulfur in the western U.S., where water resources are limited. A SDA system captures SO_2 by using a slaked lime containing slurry that is sprayed into the flue gas and reacts with the SO_2 to form calcium sulfate, and then is subsequently dried by the heat of the flue gas, and collected in a particulate control device.

Rawhide Unit 101 was installed in 1984 with a "Spray Dryer Removal System" in connection with the aforementioned baghouse for control of the resultant SDA materials. At the time, the system was a new control technology for SO_2 removal from the gaseous emission stream of a utility boiler. PRPA has since upgraded this system (in 2002) and currently achieves greater than 80% SO_2 removal, with an actual annual average of 0.07 lb/MMBtu and a permit limit of 0.09 lb/MMBtu on an annual average basis, 0.13 lb/MMBtu on a 30-day average, and 0.19 lbs/MMBtu on a 3-hour rolling average. This system exceeds EPA's presumptive limits stated in 40 CFR part 51 Appendix Y of 0.15 lb/MMBtu[11]. Lime spray dryers have been determined to be Best Available Control Technology (BACT) for new Electric Generating Unit (EGU) sources proposed in the West according to EPA's RBLC (RACT/BACT/LAER Clearinghouse) database. The RBLC database lists recent BACT determinations ranging from 0.06 – 0.167 lb/MMBtu, with an average of 0.11 lb/MMBtu on a 30-day rolling average. Refer to Appendix D for more details regarding recent RBLC BACT determinations. Additionally, an EPA Report regarding the control of SO_2 emissions found that lime spray drying processes have a range of design efficiencies from 70 – 96% and a median design efficiency of 90%; however, application conditions may differ (e.g. coal sulfur percent)[12] .

PRPA submitted a SO_2 upgrade analysis to the Division on May 6, 2010 upon request regarding potential upgrades for the dry FGD scrubber system. PRPA asserts that operating the SO2 scrubber at the 0.09 lbs/MMBtu VERA limit pushes many of the scrubber's material handling and slurry preparation sub-systems to the limits of their design capacity. As part of the VERA scrubber improvements, the recycle ash pressure feeders were upgraded and the recycle ash conveying line was replaced with larger diameter piping to increase the recycle ash conveying capacity between the solids waste silo and recycle ash storage bin/silo. Moving beyond current levels of scrubber operation would require additional equipment upgrades and would reduce the existing redundancy in some critical scrubber sub-systems. Specifically, the recycle ash blowers, bin vent filter on recycle ash silo, feed slurry preparation pumps, and feed slurry tanks are all operating at maximum throughput levels or at the margin and would need to be replaced with larger capacity equipment. While there is usually available redundancy within the lime slaking sub-system, a lower SO_2 limit would diminish this available capacity and likely also require an upgrade to ensure adequate margin.

PRPA notes that the SO_2 scrubber has three atomizer reaction compartments that provide critical operating flexibility. The scrubber generally operates with all three compartments in-service,

[10] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.
[11] Colorado Operating Permit 96OPLR142 pg. 5 – SO_2 30-day rolling average limit is 0.13 lb/MMBtu.
[12] EPA, 2000. "Controlling SO_2 Emissions: A Review of Technologies." Prepared by Ravi K. Srivastava for Office of Research and Development, Washington, D.C. 20460. Pg. 33.

which provides maximum reaction/residence time, eases SO_2 removal equipment demands, and minimize pressure drop. Though not a desirable operating mode, the scrubber is currently capable of operating at full load with only two atomizer compartments in-service. In addition to the improved scrubber performance, the current atomizer compartment redundancy provides critical atomizer operational and maintenance flexibility, ensuring environmental compliance, and providing for high SO_2 scrubber and unit availability. Achieving a lower SO_2 limit may compromise atomizer compartment redundancy, which will significantly diminish scrubber operational and maintenance flexibility. This loss of redundancy and flexibility will likely result in increase malfunctions and could also affect unit availability if load reduction is triggered.

Even with the potential scrubber equipment upgrades, additional SO_2 reductions will still present unacceptable operational challenges. SO_2 scrubbing is limited by scrubber outlet temperatures which must remain above the fluegas dew point with an adequate margin to prevent condensation and catastrophic damage to the baghouse. Over-spraying below minimum SDA outlet temperatures also results in higher moisture ash in the baghouse that is difficult to convey from the collection hoppers.

Given existing spray-down temperature constraints, reducing SO_2 emissions below 0.09 lbs/MMBtu requires additional lime to increase feed slurry reactivity. At higher SO_2 removal rates, the lime/SO_2 stoichiometry increases and more unreacted lime is carried-over with the flyash and scrubber waste to the baghouse. The higher lime content in the flyash and scrubber waste affects the fluidity of the material making it harder to pneumatically convey out of and between the baghouse hoppers, solid waste silo, and recycle ash storage bin/silo. Hopper bridging and conveying piping pluggage are significant operational and maintenance issues impacting SO_2 scrubber reliability. Lowering the SO_2 emissions below the VERA limit will increase the potential for scrubber and baghouse malfunctions.

PRPA examined BART-guideline dry scrubbing potential upgrades, with the following results:

-*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. Therefore, this upgrade is not technically feasible for the dry scrubbing system.

-*Use of more reactive sorbent*: Lime quality is critical to achieving the VERA emission limit. PRPA utilizes premium lime at higher cost to ensure compliance with the VERA limit. The lime contract requires >92% reactivity (available calcium oxide) lime to ensure adequate scrubber performance. Therefore, this upgrade is not technically feasible for the dry scrubbing system.

-*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 are designed to improve the reactivity of the slaked lime-milk slurry. Therefore, this upgrade is not technically feasible for the dry scrubbing system.

-*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. Therefore, this upgrade is not technically feasible for the dry scrubbing system.

The Division concludes that upgrades are not technically feasible for the Unit 101 Boiler.

Fuel switching to Colorado coal will not provide further SO_2 emission reductions. Rawhide Unit 101 has a SDA system for which the State has determined that no upgrades are feasible. Therefore, the Division has conducted a four-factor analysis for reasonable progress for fuel switching to natural gas regarding SO_2 reductions.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Fuel Switching – Natural Gas: Conversion from coal to natural gas would reduce SO_2 emissions by almost 100% from the boiler using EPA's AP-42 emission factors[13] and concurs with PRPA's submittal.

Table 7 summarizes each available technology options and technical feasibility for SO_2 control on Rawhide Unit 101.

Table 7: Rawhide Unit 101 SO2 Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Wet FGD	52-98%, median 90%[14]	Y – not evaluated
Dry FGD	70 – 90%	Y - installed
DSI (Trona)	60-65%	Y – not evaluated, will not provide further SO2 control
Fuel switching – different coal type	None	Y – will not provide further SO2 control
Use of performance additives	None	N
Use of more reactive sorbent	None	N
Increase the pulverization level of sorbent	None	N
Engineering redesign of atomizer or slurry injection system	None	N
Fuel switching – natural gas	99% (EPA AP-42)	Y

Step 4: Evaluate Factors and Present Determination

[13] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.4, Table 1.4-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[14] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

Factor 1: Cost of Compliance

In 2008, Platte River performed a Unit 101 Natural Gas Conversion Study. The primary objective of the study was to determine required unit modifications and associated capital costs to co-fire the unit up to 100% using natural gas. The direct capital cost of converting to 100% natural gas was estimated to be about $50 million by PRPA[15]. This results in an initial control cost, using EPA's Cost Control Manual[16] to estimate annual operating costs, of about $262,000 per ton of SO_2 removed annually[17]. Changing to natural gas would dramatically raise fuel costs given that natural gas prices are approximately nine (9) times the cost of PRB coal and are subject to significant cost variability, which was not taken into account in the 2008 study[18].

To determine annualized costs of switching to natural gas, the annual electricity cost differentials between coal and natural gas were analyzed. PRPA notes that when using natural gas, fuel use will increase 17% annually due to anticipated efficiency drops, increased heat input requirements, and drop in generation. The annual electricity cost of coal is $25.5 million compared to natural gas at about $240 million when using 2008 commercial natural gas prices reported by the U.S. Energy Information Administration[19]. Therefore, this results in a significant annualized cost increase of $233 million. Refer to Appendix D for details.

Table 8 and Table 9 illustrate the resultant emissions and costs of switching fuel to natural gas, based on the difference between costs of coal and natural gas in 2008 and AP-42 emission factors.[20]

Table 8: Unit 101 Control Resultant SO_2 Emissions

Alternative	Control Efficiency (%)*	Resultant Emissions**	
		(tons/year)	(lb/MMBtu)
Baseline	---	913	0.08
Fuel Switching - NG	99%	7.7	0.0006

* Control efficiency calculated by the Division based on PRPA submittal of projected natural gas NO_x lb/MMBtu estimate.
** Division calculated from average baseline years (2006 – 2008). This is an **annual** average.

Table 9: Unit 101 SO_2 Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)*	Cost Effectiveness ($/ton)*	Incremental Cost ($/ton)
Baseline	0	$0	$0	n/a

[15] PRPA, February 18, 2010. "Re: Rawhide Unit 101 NOx Emissions Control Cost and Technical Feasibility Information Request – Additional Details and Explanation." Contained in Appendix D.
[16] EPA, 2002. EPA Air Pollution Control Cost Manual, Sixth Edition. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, 27711.
[17] Colorado Air Pollution Control Division Technical Analysis – Rawhide Unit 101 Boiler – Natural Gas Switching, 2010. See Appendix D for detailed calculations.
[18] PRPA, February 18, 2010. "Re: Rawhide Unit 101 NOx Emissions Control Cost and Technical Feasibility Information Request – Additional Details and Explanation." Contained in Appendix D.
[19] U.S. Energy Information Administration, 2010. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm
[20] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.4, Table 1.4-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

Fuel Switching - NG	906	$237,424,331	$262,169	$262,169

* Division estimate based on PRPA submittal estimating direct capital cost at $50,000,000, current delivered coal costs at ~$20/ton, EPA Cost Control Manual, and EPA AP-42 emission factors for natural gas.

Platte River noted that the Division natural gas cost analysis does not account for replacement power for the lost generation. The Rawhide Natural Gas Conversion Study performed by B&V estimated that a 100% fuel switch would result in a loss of approximately 30 MW, in addition to the increased heat rate which was considered.

Platte River asserts that replacement power cost and associated emissions would depend on the specific source. Replacement with coal-fired sources would run in the $20 - $25/MWh range ($5.3 - $6.6 million/year), while natural gas-fired sources would run in the $60 - $125/MWh range ($15.8 – 32.8 million/year). Unaccounted NO_x emissions from the replacement power sources would likely be around 1.5 lbs/MWh (197 tons/year) for well combustion controlled coal-fired sources, and 0.36 lbs/MWh (47 tons/year) for natural gas-fired sources. The replacement power prices reflect current conditions and will need to be escalated over the 20-year 4-factor evaluation period. SO_2 emissions would likely be in the 0.7 lbs/MWh (92 tons/year) for well controlled coal-fired sources and 0.007 lbs/MWH (1 ton/year) for natural gas-fired sources. Table 7 below summarizes these costs and emissions.

Table 10: Unaccounted for Replacement Power Cost & Emissions Estimates (30 MW)

Power Source	Lower Cost ($/MWh)	Lower Cost ($ million/year)	Higher Cost ($/MWh)	Higher Cost ($ million/year)
Coal	$20	$5.26	$25	$6.57
Natural Gas	$60	$15.77	$125	$32.85
Power Source	NO_x (lbs/MWh)	NO_x (ton/year)	SO_2 (lb/MWh)	SO_2 (ton/year)
Coal	1.5	197	0.7	92
Natural Gas	0.36	47	0.007	1

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals[21], the Division anticipates that, taking into account the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval it would take PRPA approximately 2 – 3 years to convert the boiler from coal to natural gas. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

[21]Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. "Black Hills Clark Station NOx Reduction Feasibility Study." Pgs. 3-13 and 3-14.

Factor 3: Energy and Non-Air Quality Impacts

The Division has determined that there are not any negative energy or non-air quality related impacts related to fuel switching to natural gas for the Unit 101 boiler. Thus, this factor does not influence the selection of controls.

Factor 4: Remaining Useful Life

PRPA asserts that since Rawhide Unit 101 is one of the newest units in Colorado, it will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 11 shows the number of days pre- and post-control. **Error! Reference source not found.** depicts the visibility results (98^{th} percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Table 11: Visibility Results - Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO_2 Control Scenario	Unit(s)	SO2 Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hr SO_2 rates	101	0.11	RMNP	20	---	---	6	---	---
dry FGD	101	0.09	RMNP	n/a					
dry FGD	101	0.07	RMNP	20	19	1	6	4	2
Fuel Switching - NG	101	0.001	RMNP	n/a					

Table 12: Visibility Results - SO2 Control Scenarios

SO2 Control Scenario	Unit(s)	SO2 Emission Rate	Output (@ 98^{th} Percentile Impact)	98^{th} Percentile Impact Improvement	98^{th} Percentile Improvement from Maximum
		(lb/MMBtu)	(deciviews)	(deciviews)	(%)
Max 24-hr SO_2 rates	101	0.11	0.871		
dry FGD	101	0.09*	0.87	0.01	1%
dry FGD	101	0.07	0.84	0.03	3%
Fuel Switching - NG	101	0.001	0.00	0.87	100%

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "PRPA Modeling Summary" for more details.

Determination

The Division evaluated emission limit tightening based on current operations through the four-factor analysis. PRPA's average 30-day rolling emission rate during the baseline period (2006 – 2008) was 0.09 lb/MMBtu. The maximum 30-day rolling emission rate during this period was 0.13 lb/MMBtu. Please refer to "Rawhide Cost Analysis" for more detail. The Division and PRPA agree that Rawhide can meet an emission limit of 0.11 lb/MMBtu (30-day rolling average).

Based upon its consideration of the five factors summarized herein, the state has determined that SO2 RP is the following SO2 emission rate:

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

The state has determined that these emissions rates are achievable without additional capital investment. 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.

b. Filterable Particulate Matter (PM_{10})

PRPA Unit 101 is currently equipped with two twelve-compartment fabric filter baghouses to control PM/PM_{10} emissions from the boiler. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred micron in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

PRPA states that the baghouses are able to control PM/PM_{10} emissions to 0.03 lb/MMBtu and further notes that that the baghouses meet a 99.9+% control efficiency. The source was tested on November 18, 2009 and ran at 0.0023 lb/MMBtu, 92% lower than the permit limit (Method 5 – filterable portion). This boiler is subject to 40 CFR Part 60, Subpart Da, which requires 99% reduction (for facilities commencing construction after September 18, 1978) of the potential combustion concentration when burning solid fuel. A Division review of the PM/PM_{10} emission limits in the current Title V permit revealed that these limits are for filterable PM/PM_{10} emissions only.

A Division review of EPA's RBLC revealed recent BACT PM/PM_{10} determinations range from 0.010 – 0.10 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The current limit of 0.03 lb/MMBtu is well within the range of recent BACT determinations.

The State has determined that the existing Unit 101 regulatory emissions limits of 0.03 lb/MMBtu (PM/PM10) represents the most stringent control option. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouses. The unit is exceeding a PM control efficiency of 95%, and the control technology and emission limit is RP for PM/PM_{10}. Thus, as described in EPA's BART Guidelines, a full four-factor analysis for PM/PM_{10} is not needed for Rawhide Unit 101.

c. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

PRPA identified eight NO_x control options:
Fuel Switching – Natural Gas
Selective non-catalytic reduction (SCNR)
Selective catalytic reduction (SCR)
Separated overfire Air (SOFA)
Low NO_x Burners (LNB)
LNB + SOFA
ECC – Enhanced Combustion Control

The Division also identified and examined the following additional control options:
Electro-Catalytic Oxidation (ECO)®
Rich Reagent Injection (RRI)
Coal reburn +SNCR

Rotating overfire air (ROFA) was not considered in this analysis because ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load[22]. While ROFA is considered superior to SOFA alone, ROFA alone is not superior to LNB+OFA and cannot achieve the greater than 70% NO_x reduction already being achieved at Unit 101. Since ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for this unit, ROFA® technology is not considered further in this analysis.

Step 2: Eliminate Technically Infeasible Options

Fuel Switching – Natural Gas: The Unit 101 boiler at Rawhide could convert fuels from coal to natural gas with boiler modifications. NO_x emissions from coal combustion are affected by the chemical and physical properties of the feed coal. Feed coal characteristics significantly affect the design and operation of combustion controls, such as the existing LNB+SOFA system. With the LNB+SOFA system in place, Unit 101 currently achieves an emission rate of 0.17 lb/MMBtu (annual average).

PRPA notes that Unit 101 is designed to burn PRB coal and the boiler is additionally optimized through a technologically complex process to burn this coal at very tightly controlled rate. PRPA has indicated that it is infeasible and economically impractical to change coal supplies. With fuel switching to natural gas, NO_x emissions were projected to drop from the current 0.17

[22] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html

lbs/MMBtu to a rate of 0.1 lbs/MMBtu[23]. However, this reduction would be diminished by the accompanying loss in boiler efficiency, increased boiler heat input requirement, and significant loss of generation resulting from natural gas firing.

The Division has determined that fuel switching to natural gas is technically feasible for Rawhide Unit 101.

LNB/ROFA®/SOFA/LNB+SOFA: The boiler is already equipped with a tangentially-fired LNB+SOFA system that was installed in 2005. This system achieves an approximate 50% NO_x reduction (based on actual emissions).

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. The optimum temperature window for Rawhide Unit 101 will most likely occur somewhere at the top of the furnace and in the backpass of the boiler if SNCR is applied. SCNR is considered a technically feasible alternative for Unit 101.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. There are three different types of SCR arrangements – high-dust, low-dust, and tail-end. The pre-dominant arrangement applied in the United States has been high-dust. In most circumstances, a high-dust SCR system is the most economical arrangement alternative and would likely be the arrangement for Unit 101 if applicable. For high- and low-dust arrangements, the catalyst, because of its location directly downstream of the boiler and upstream of the air heater, can impact the boiler through its effect on the air heater. The magnitude of this effect is dependent on the power plant configuration, air quality control components, type of fuel, and overall emission control requirements. For retrofit applications, adequate space between the economizer outlet and the air heater inlet to allow boiler outlet and air heater return duct is a prerequisite for the installation of a high-dust system and is the case at the Rawhide Station. Therefore, high-dust SCR is a technically feasible alternative for Rawhide Unit 101.

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[23] PRPA, February 18, 2010. "Re: Rawhide Unit 101 NOx Emissions Control Cost and Technical Feasibility Information Request – Additional Details and Explanation." Contained in Appendix D.

ECC: The enhanced combustion control system option for Rawhide Unit 101, submitted by PRPA, consists of a neural-net based combustion optimization subsystem (software and hardware) and companion real-time boiler combustion constituents and temperature measurement system. These system components are interfaced with the boiler's standard coordinated combustion control system (CCS). The ECC system continuously measures and monitors the dynamic boiler combustion constituents, temperatures and other process parameters. The ECC system then commands the CCS to manipulate variables such as combustion air damper positions, burner tilts, coal feeder speeds, and other process parameters to optimize fuel combustion and boiler efficiency, while controlling NO_x and CO emissions within targeted ranges. Optimizing the ECC requires periodic combustion testing and CCS tuning. ECC is a technically feasible option for Rawhide Unit 101.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[24] and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[25] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Unit 101.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu[26]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Fuel Switching – Natural Gas: The Unit 101 boiler at Rawhide could convert fuels from coal to natural gas with boiler modifications. Conversion from coal to natural gas would reduce NO_x emissions by about 545 tons per year, or approximately 29% (using 2006 - 2008 CAMD data average)[27].

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[24] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[25] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php
[26] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf
[27] Colorado Air Pollution Control Division Technical Analysis – Rawhide Unit 101 Boiler – Natural Gas Switching, 2010. See Appendix D for detailed calculations.

SNCR: Other Colorado facilities have noted a variety of control ranges for SNCR. The Division used a variety of information, including a similar Colorado facility estimates, EPA's SNCR Air Pollution Control Fact Sheet and a recent AWMA study[28] to conservatively approximate that Rawhide Unit 101 can achieve up to 30% control when SNCR is applied. PRPA asserts that NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. However, if ammonia slip is controlled closer to 2 ppm then achievable NO_x reduction efficiencies will be closer to 20 percent.

*SCR:*PRPA approximates that SCR can achieve an approximate 64% NO_x reduction from the current low 0.17 lb/MMBtu baseline emission rate. PRPA asserts that while a lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for PRPA, a retrofit SCR, the 0.07 lb/MMBtu controlled NO_x value is more expected. This control efficiency is slightly lower than EPA's AP-42 emission factor discussion, which estimates SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction from an assumed baseline emission rate of 0.5 lb/MMBtu.[29,30] However, in the Division's experience and national CAMD emissions data (2009) reflect that an emission limit of no lower than 0.07 lb/MMBtu is realistically achievable for a retrofit SCR.

Table 13 summarizes each available technology and technical feasibility for NO_x control.

Table 13: Rawhide Unit 101 NOx Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO_x Burners (LNB)	10-30%	Y – installed
LNB + OFA	25-45%	Y – installed
Air Staging – overfire air (OFA)	5-40%	Y – installed
Rotating overfire air (ROFA)	45-65%	Y – will not increase current NO_x reductions
SCNR	20 – 40%	Y
SCR – HTSCR	Up to 90%	Y-high-dust arrangement
SCR – LTSCR		
SCR – RSCR		
Fuel switching – Natural gas	20-70%	Y
Electro-Catalytic Oxidation (ECO)®	n/a	N
Rich Reagent Injection (RRI)	n/a	N
Coal reburn+SNCR	n/a	N
ECC	15-25%	Y

[28] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.
[29] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[30] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

SNCR: A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.[31] The PRPA-estimated SNCR costs for operating expenses is 44% for Unit 1. Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. The cost effectiveness for SNCR on Unit 1 is $3,168 per ton NO_x reduced. Recent NESCAUM studies estimate SNCR retrofits achieving NO_x emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[32,33] EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NO_x reduced.[34]

Platte River relies on Black and Veatch's (B&V) expertise and cost estimates on major projects. Platte River contracted with B&V to perform a detailed study to provide capital costs for NOx emissions reduction alternatives for the Rawhide Unit 101. The *Rawhide NOx Reduction Study, January 2009* noted that the SNCR costs were based on actual B&V engineering, procurement, and contracting projects. Rawhide specific SNCR project cost considerations were:

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- Rawhide's geographic location, economies of scale and small size of Rawhide Unit 101
- Three levels of automatic injection lances with retract system to accommodate SNCR reaction temperature and boiler turndown requirements.
- Computer flow/temperature modeling to establish optimum ammonia injection locations and flow patterns,
- Boiler waterwall modifications for injector lances and steam piping modifications for performance optimization,
- Electrical Motor Control Center switch gear upgrades and modifications to support urea system and ammonia delivery system,
- Reagent storage tank,
- Digital Control System (DCS) computer system hardware and control logic upgrades,
- Fluegas temperature and NOx and ammonia continuous emission monitoring, data acquisition, alarming and reporting system,
- Interest costs during construction, and
- Use of a more expensive urea reagent system rather than anhydrous ammonia due to safety and transport concerns.

[31] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.
[32] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[33] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.
[34] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

Platte River notes that the SNCR cost effectiveness ($/ton removed) remains comparatively high due to Rawhide's low baseline NO_x emission rates for the above reasons.

There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[35] Although PRPA's estimates are greater than these ranges, the reasons above lead the Division to the conclusion that PRPA's cost estimates for SNCR are reasonable.

SCR: SCR reagent materials, such as urea and/or ammonia, primarily use a limited resource, natural gas. Therefore, future costs for these materials may fluctuate widely. These costs are not included in the overall $/ton projections.

EPA's regulations recommend using the EPA's Office of Air Quality Planning and Standards' Air Pollution Cost Control Manual (Sixth Edition, January 2002) for estimating costs of compliance. This Manual provides guidance and methodologies for developing accurate and consistent estimates of cost for air pollution control devices. The costs that may be estimated include capital costs, operation and maintenance (O&M) expenses, and other annual costs.

In reviewing PRPA's estimate, the Division found that the ratio of annual costs to the total capital costs for all control technologies projected by PRPA to be slightly lower than those projected by other facilities that were amortized over the same 20 year time frame. For example, the annualized costs for SCR for Unit 101 are 10.5% of the total capital investment. The EPA found that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments[36]. Therefore, the Division concurs that PRPA's estimate is consistent with annual costs estimated by other facilities.

Platte River relies on Black and Veatch's (B&V) expertise and cost estimates on major projects. Platte River contracted with B&V to perform a detailed study to provide capital costs for NOx emissions reduction alternatives for the Rawhide Unit 101. The *Rawhide NOx Reduction Study, January 2009* noted that the SCR costs were based on actual B&V engineering, procurement, and contracting projects. Rawhide specific SCR project cost considerations were:

- Vertical oriented high-dust SCR reactor configuration,
- Construction crane access constraints due to north-side coal conveyor and ACI silo, and south-side underground 84 inch circulating water line,
- Preliminary design and layout analyses including foundations, structural columns, cantilevered support steel, and main trusses support structures,
- Modification to existing structures including demolition of ductwork between the economizer and the air heater inlet,
- Rawhide's geographic location, economies of scale and small size of Rawhide Unit 101,

[35] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
[36] Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.

- Induced draft (ID) fan higher hp motor replacement and retrofit issues,
- Auxiliary power and switch gear upgrades and modifications to support two new ID fan motors,
- Digital Control System (DCS) computer system hardware and control logic upgrades including new electrical and controls building located adjacent to SCR,
- NOx and ammonia continuous emission monitoring, data acquisition, alarming and reporting system,
- Three layer (two catalyst and one initial spare) reactor sizing for maximizing catalyst utilization,
- Reactor design to accommodate both ceramic honeycomb and plate type catalyst products to insure future procurement flexibility,
- Rerouted underground utilities (bottom-ash sluice trench and drain piping) due to SCR foundation requirements,
- Added superstructure costs due to fully enclosed plant, including boiler and air heater areas for cold-weather concerns requiring roof and wall penetrations and modifications,
- Higher structural costs due to high wind loading ,
- High gas temperature design issues (>800°F economizer gas temperature results in higher grade catalyst and steel issues), and
- Use of a more expensive urea reagent system rather than anhydrous ammonia due to safety and transport concerns,
- Interest costs during construction, and
- Lost generation revenue costs during outage.

Platte River notes that the SCR cost effectiveness ($/ton removed) remains comparatively high due to Rawhide's low baseline NO_x emission rates for the above reasons. The Division asserts that $/KW is not an appropriate metric when a detailed cost estimate has be developed. $/KW is rough estimate of controls for back of the envelope discussions and should not serve as cost estimate in light of more refined estimates. Therefore, the Division did not adjust PRPA's estimates for capital costs.

Fuel Switching – Natural Gas: In 2008, Platte River performed a Unit 101 Natural Gas Conversion Study. The primary objective of the study was to determine required unit modifications and associated capital costs to co-fire the unit up to 100% using natural gas. The direct capital cost of converting to 100% natural gas was estimated to be about $50 million. Conversion from coal to natural gas would reduce NO_x emissions by about 545 tons per year (using 2006 - 2008 CAMD data average). This results in an initial control cost, using EPA's Cost Control Manual to estimate annual operating costs, of about $436,000 per ton of NO_x removed annually[37]. Changing to natural gas would dramatically raise fuel costs given that natural gas prices are approximately nine (9) times the cost of PRB coal and are subject to significant cost variability. Tables 9 and 10 illustrate the resultant emissions and costs of switching fuel to natural gas, based on the difference between costs of coal and natural gas in 2008 and AP-42 emission factors. The annual cost to control was determined using a capital

[37] Colorado Air Pollution Control Division Technical Analysis – Rawhide Unit 101 Boiler – Natural Gas Switching, 2010. See Appendix D SIP for detailed calculations.

recovery factor based on an approximate 8% interest rate. Refer to “Rawhide Cost Analysis” for more details.

To determine annualized costs of switching to natural gas, the annual electricity cost differentials between coal and natural gas were analyzed. PRPA notes that when using natural gas, fuel use will increase 17% annually due to anticipated efficiency drops, increased heat input requirements, and drop in generation. The annual electricity cost of coal is $25.5 million compared to natural gas at about $240 million when using 2008 commercial natural gas prices reported by the U.S. Energy Information Administration[38]. Therefore, this results in a significant annualized cost increase of $233 million. Refer to Appendix D for details.

ECC: PRPA worked with three different vendors on an enhanced combustion control pilot system. The cost estimates provided are from this pilot project. The annualized cost of approximately $288,500 is much lower than SNCR, which achieves about the same amount of control. This is little available cost information regarding this type of boiler modification. Since the costs are comparable or lower than other pre-combustion technologies, the Division concurs that PRPA’s cost estimate is reasonable.

Table 14 and Table 15 depict controlled NO_x emissions and control cost comparisons.

Table 14: Unit 101 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,866	0.166	
ECC	24.0	1,418	0.126	0.145
SNCR	27	1,362	0.121	0.140
Fuel Switching - NG	29.2**	1,321	0.118	0.135
SCR	63.5	681	0.061	0.070

* Control efficiency calculated by the Division based on PRPA submittal of projected natural gas NO_x lb/MMBtu estimate.
** Control efficiency provided in PRPA’s analysis based on 0.17 lb/MMBtu NO_x input, equivalent to 2006 – 2008 baseline conditions. Refer to “Rawhide Cost Analysis” for more information.

Table 15: Unit 101 NO_x Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---

[38] U.S. Energy Information Administration, 2010. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm

ECC	448	$ 288,450	$644	$644
SNCR	504	$1,596,000	$3,168	$23,357
Fuel Switching - NG	545	$237,424,331	$435,681	$5,735,260
SCR	1,185	$12,103,000	$10,214	($352,073)

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals[39], the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take PRPA approximately 2 – 3 years to convert the boiler from coal to natural gas. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

PRPA anticipates that the time necessary for completing design, permitting, procurement, control equipment installation, and system startup and shakedown, after SIP approval, would be approximately 2-3 years for SNCR and 3-4 years for SCR. These timeframes may also vary somewhat to schedule the necessary major maintenance outage with other regionally affected utilities. The ECC option timeframe is much shorter due to the fact that PRPA has already been working with independent vendors on this system. Therefore, this system could be functional within 6 months of SIP approval.

Factor 3: Energy and Non-Air Quality Impacts

SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR and SNCR reagent injection system have minimal power requirements.

Post-combustion add-on control technologies like SCR and SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. In particular, SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer. 100 – 300 kW is less than 0.5% of the power generated by the Unit 101 boiler annually, or enough energy to power about 10 homes for a year. These energy requirements are minimal.

Installing SNCR or SCR increases levels of ammonia, and may create a ‘blue plume’, if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in

[39] Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. “Black Hills Clark Station NOx Reduction Feasibility Study.” Pgs. 3-13 and 3-14.

the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas. PRPA has indicated to the Division that they would prefer to use urea instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on a urea reagent versus an ammonia reagent. Refer to Appendix D for more information.

Factor 4: Remaining Useful Life

PRPA asserts that since Rawhide Unit 101 is one of the newest units in Colorado, it will remain in service for the 20-year amortization period. Thus, this factor doesn't influence the selection of controls.

Factor 5 (optional): Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 16 shows the number of days pre- and post-control. Table 17 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

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.

Table 16: Visibility Results - Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Boiler	NOx Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hr NOx rate	101	0.302	Rocky Mountain National Park	20	---	---	6	---	---
ECC	101	0.126		20	6	14	6	1	5
SNCR	101	0.121*		n/a					
Fuel Switching - NG	101	0.118*		n/a					
SCR	101	0.061		20	1	19	6	0	6

Table 17: Visibility Results - NOx Control Scenarios

NOx Control Scenario	Boiler	NOx Emission Rate (lb/MMBtu)*	Output (@ 98th Percentile Impact)	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	($/dv)
Max 24-hr NOx rate	101	0.302	0.87	---	---	---
ECC	101	0.126	0.42	0.45	52%	$642,428
SNCR	101	0.121*	0.41	0.46	53%	$3,469,565
Fuel Switching - NG	101	0.118*	0.41	0.47	54%	$509,494,272
SCR	101	0.061	0.28	0.59	68%	$20,548,387

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “PRPA Modeling Summary” for more details.

Determination

Based upon its consideration of the five factors summarized herein, 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, 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.

RECIPROCATING INTERNAL COMBUSTION ENGINE (RICE) SOURCE CATEGORY

NOx Emission 4-Factor Analysis for Reasonable Progress (RP)

I. Source Description

The review of potential RP sources involved an evaluation 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. There were one-hundred-thirteen (113) sources identified as exceeding the 100 tons/year threshold for any of the three pollutants which were further analyzed, using ArcGIS mapping, to determine the exact distance from the centroid of the source to the nearest Class I Area (CIA) boundary. The Q/d was calculated for each source, where "Q" is the sum of the SO2, NOx and PM10 emissions in tons per year and "d" is the source distance from the nearest CIA in kilometers; which resulted in the identification of seventeen (17) point sources with a $Q/d \geq 20$. The Q/d threshold was determined based on conducting a sensitivity analysis of previous subject-to-BART CALPUFF modeling of BART eligible sources that indicated a value of 20 represented about 0.3 deciview of change in visibility impairment.

An evaluation of the 17 RP sources identified only one source directly associated with RICE equipment, a compressor station (Ignacio B Plant) that uses natural gas-fired RICE. The Ignacio B compressor station is located southeast of Durango on Southern Ute Indian Tribal land which is outside the jurisdiction of the State of Colorado; consequently the Division is unable to provide a 4-factor NOx control evaluation and associated determination for this particular RP source.

In addition to individual point sources with a $Q/d \geq 20$, the Division evaluated categories of sources that were determined to be significant and subject to evaluation under RP. The Colorado point source emission inventory indicates that stationary internal combustion engines (see below table), particularly large industrial natural gas fired reciprocating internal combustion engines (RICE), are a significant source category of NOx emissions that represents about 16% of statewide point source NOx emission inventory[1].

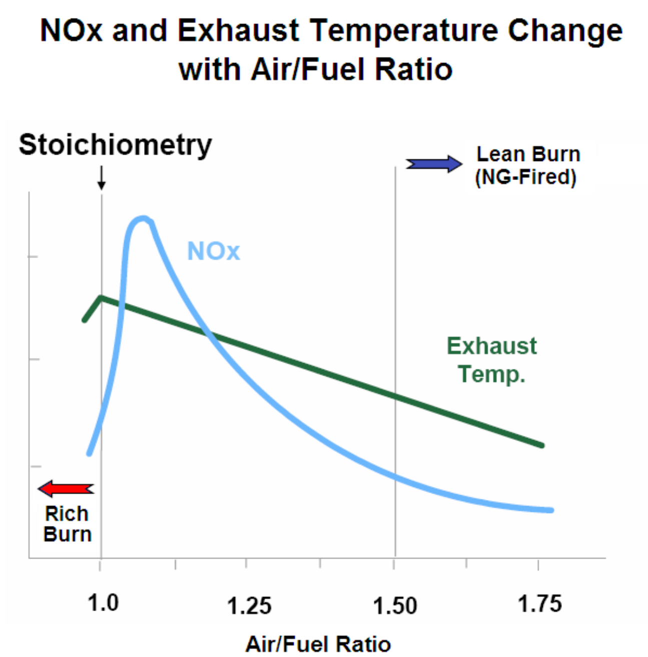
Colorado Internal Combustion Engine NOx Emissions from the PRP 2018b Emission Inventory

Category	Subcategory	2018 NOx Emissions (tpy)
Industrial	Natural Gas Fired	16,199
	Large Bore Engine	256
	Distillate Oil (Diesel)	225
	Liquefied Petroleum Gas	27
	Gasoline	24
Electric Generation	All	4,323
Commercial/Institutional	All	1,152
Engine Testing	All	5
	Total:	22,210

[1] Total 2018 Statewide Point Source NOx is projected at 101,818 tons per year based on the WRAP PRP2018b emission inventory.

The majority of the RICE operating in Colorado are associated with the oil and gas industry. The power generated by these RICE is generally used to compress natural gas for line transmission 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 document.

Stationary RICE produce power by combustion of fuel and are operated at various air-to-fuel ratios (AFR). If the stoichiometric ratio is used, the air and fuel are present at exactly the ratio to have complete combustion. An air-to-fuel ratio controller uses exhaust O_2 to control the combustion ratio. RICE that are operated with fuel-rich ratios (exhaust $O_2 < 0.05\%$) at or near stoichiometric, are called rich-burn engines (RB), or alternatively RICE that operate with air-rich ratios (exhaust $O_2 > 7$ to 8%) above stoichiometric, are called lean-burn engines (LB). The undesirable combustion emissions from natural gas fired RICE are primarily nitrogen oxides (NOx, consisting of primarily nitric oxide and nitrogen dioxide), carbon monoxide (CO), and volatile organic compounds (VOCs). Oxides of nitrogen are formed by thermal oxidation of nitrogen from the air. CO and VOCs are byproducts of incomplete combustion.



There are site specific considerations for using either type of engine, depending on the parameters that are most important for the operator. RB engines have lower oxygen levels and higher temperatures in the engine exhaust, which allows for the use of a 3-way catalyst (non-selective catalyst) which is effective at reducing NOx, CO, and VOCs in the exhaust. Because the air-to-fuel ratio is rich with fuel, more fuel is used, which results in increased combustion temperatures, increased engine power, and decreased engine efficiency. Higher temperatures result in more NOx being formed during the combustion process. Conversely, LB engines have higher oxygen levels in the combustion chamber, which decreases the combustion temperature thereby reducing how much NOx is formed. Because the air-to-fuel ratio is lean with fuel, less fuel is used, which results in decreased combustion temperatures, decreased engine power, and increased engine efficiency. The use of an oxidation catalyst on a lean burn engine similarly results in decreases in CO and VOC emissions but the performance for controlling NOx emissions is very low because LB engine exhaust temperatures are below the optimum temperature range for effective NOx control due to reduced catalyst reactivity. The above chart provides the relative change in NOx emissions and engine exhaust temperature as a function of air-to-fuel ratio.

II. Natural Gas-Fired RICE Source Category Emissions - Statewide

Since natural gas-fired RICE comprise over 73% of the NOx emissions in statewide RICE source category, the analysis will focus exclusively on NG-fired RICE. In 2018, the statewide NG-fired RICE source category is projected to contribute the following emissions:

Statewide Natural Gas Fired RICE Source Category Emissions*

Total Number of Sources with NG-fired RICE	Pollutant	Number Sources with RICE > 100 tpy	Number Sources with RICE > 40 tpy	Number Sources with RICE < 2 tpy	2018 Emissions (tpy)
497	NOx	40	85	82	16,199
	SO_2	0	0	486	115

* *Point Source Natural Gas Fired RICE Emissions based on APEN report data supplied to the WRAP for the PRP2018b Emission Inventory.*

Based on the PRP 2018b emission inventory, statewide there are about 497 sources using NG-fired RICE and about 40 sources that emit NOx emissions greater than 100 tons per year. During a recent 2008 rulemaking, the Division conducted a detailed analysis of RICE outside the 9-county metro area (referenced as "statewide") and determined that there are about 1,340 NG-fired RICE statewide[2], which includes about 593 NG-fired RICE over 500 hp as indicated in the below table.

Statewide Natural Gas-Fired RICE Over 500 Horsepower Outside the 9-County Metro Area

SCC Description	Number of RICE
2-CYCLE LEAN BURN (NG)	84
4-CYCLE LEAN BURN (NG)	204
4-CYCLE RICH BURN (NG)	305
Total:	593

In addition to the 593 RICE listed above, the 2004 Denver Early Action Compact rulemaking identified 139 NG-fired RICE[3] over 500 hp that were subject to control requirements of non-selective catalytic reduction on 79 RB RICE and oxidation catalyst on 60 LB RICE in the 9-county metro area. Consequently, there are a total of 732 NG-fired RICE over 500 hp in Colorado.

It is difficult to readily determine the exact number of NG-fired RICE below 500 hp but over 100 hp because engines were sometimes grouped together in a single permit. However, a preliminary review of APEN data indicates that there are approximately 234 NG-fired RICE below 500 hp but over 100 hp. The remaining 513 NG-fired RICE have design capacities under 100 hp.

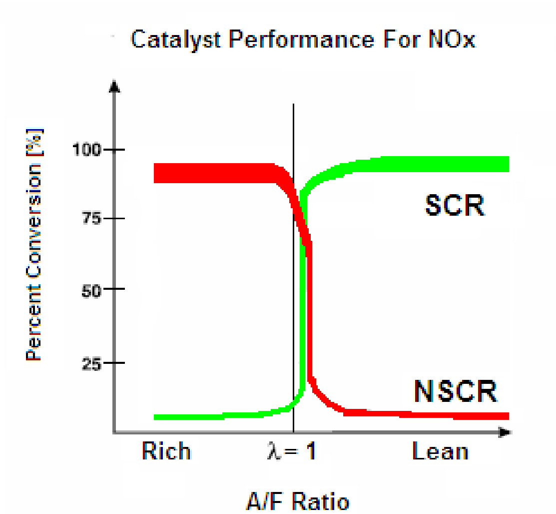
[2] The Statewide RICE count does not include RICE in the 9-county metro area which was subject to an earlier rulemaking, thus the actual number of total RICE in the State of Colorado is higher.

[3] Reference Final Economic Impact Analysis – Revisions to Regulation No. 7, February 11, 2004.

III. NOx Control Technology Evaluation

Step 1: Identify All Available Technologies

Generally in retrofit applications, NOx emissions from engines can be reduced either through combustion controls or adding post combustion emission controls (e.g., catalysts) to the engine exhaust. Catalysts are designed to speed up desired reactions. The rate of chemical reaction is a function of several parameters, including air-to-fuel ratio, engine load and exhaust temperature. Catalysts have specific temperature ranges that must be achieved for optimum NOx reduction. The below diagram roughly depicts the catalyst performance for conversion of NOx emissions using a NSCR and SCR on rich and lean burn engines.



Six retrofit technologies have been identified to lower NOx emissions from rich/lean burn natural gas-fired internal combustion engines.

1. Lean Burn – Air/Fuel Ratio Adjustment
2. Lean Burn – Ignition or Spark Timing Retard
3. Rich Burn – Non Selective Catalytic Reduction (NSCR) Catalyst (3-way)
4. Rich/Lean Burn – Selective Non-Catalytic Reduction (SNCR)
5. Lean Burn – Selective Catalytic Reduction (SCR)
6. Replacement with electric motors

Colorado requires that emissions from rich burn RICE (applicable statewide[4]) be controlled using a 3-way catalyst (NSCR) with air/fuel controller if control costs are below $5,000 per ton. Few of the statewide rich burn RICE demonstrated control costs exceeding the $5,000 cost off-ramp. Consequently, the state concludes that such NSCR controls are installed on the majority of rich burn RICE over 500 HP statewide. Therefore, the following analysis does not evaluate lower benefit NOx controls such as air/fuel adjustment or ignition/spark timing adjustment for rich burn RICE despite the technical feasibility of such controls.

[4] Reference Colorado Regulation Number 7, see section XVII.E.3.a

It is important to clarify that lean burn RICE are not subject to NOx retrofit controls because Regulation 7 requires statewide lean burn RICE over 500 HP to install retrofit oxidation catalyst control, which is only effective for control of VOC and CO, if the VOC control cost is under $5,000 per ton. This Regulation was effective as of July 1, 2010.

Step 2: Eliminate Technically Infeasible Options

Technology #1 - LB (Air/Fuel Ratio Adjustment): This technology is technically feasible.

Technology #2 - LB (Ignition/Spark Timing Retard): This technology is technically feasible.

Technology #3 – RB (3-way NSCR Catalyst): This technology is technically feasible.

Technology #4 – RB/LB (SNCR): This technology is technically feasible.

Technology #5 – LB (SCR): This technology is technically feasible.

Technology #6 – Replace RICE with electric motors: This technology is technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Technology #1 - Lean Burn (Air/Fuel Ratio Adjustment): In lean burn engines, increasing the air to fuel ratio decreases the NOx emissions. Extra air dilutes the combustion gases, thus lowering peak flame temperature and reducing thermal NOx formation. In order to avoid de-rating, combustion air to the engine must be increased at constant fuel flow, requiring a turbocharger. An automatic air-to-fuel ratio controller also will be required. This control method is most effective on fuel-injected engines. Typically, for lean burn engines the air/fuel ratios are increased from normal levels of 50% excess air up to excess air levels of 240%. The upper limit is constrained by the onset of misfiring at the lean limit. This condition also increases CO and VOC emissions. Naturally aspirated engines and engines with fuel injected into the intake manifold plenum do not have identical air-to-fuel ratios in each cylinder, this results in limited ability to vary the A/F ratio. To maintain acceptable engine performance at lean conditions, high energy ignition systems (HEIS) have been developed that promote flame stability at very lean conditions. On lean burn RICE, air/fuel ratio adjustment generally achieves about 5-30% reduction[5] in NOx emissions but is very specific to each engine and typical loading.

Technology #2 - Lean Burn (Ignition/Spark Timing Retard): This adjustment lowers NOx emissions by moving the ignition event to later in the power stroke. Because the combustion chamber volume is not at its minimum, the peak flame temperature will be reduced, thus reducing thermal NOx formation. Ignition timing retard is applicable to all engines. It is implemented in spark ignition engines by changing the timing of the spark, and in compression ignition engines by changing the timing of the fuel injection. For variable loads, an electronic ignition/injection control system is required. On lean burn RICE, ignition/spark timing retard generally achieves about 20% reduction in NOx emissions.

Technology #3 - Rich Burn NSCR: This technology uses three-way catalysts to promote the reduction of NOx to nitrogen and water. CO and hydrocarbons are simultaneously oxidized to carbon dioxide and water. NSCR is applicable only to rich burn engines (i.e. those with exhaust oxygen concentration below about one percent). NSCR, in addition to the catalysts and catalyst

[5] Reference – State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines, State of New Jersey Department of Environmental Protection, 2003.

housing, require an oxygen sensor and automatic air to fuel ratio controller to maintain an appropriate air to fuel ratio. Some ammonia can be produced particularly as the catalyst ages. The simplified reactions governing NSCR are as follows:

$NOx + CO \rightarrow CO_2 + N_2$
$NOx + HC \rightarrow CO_2 + H_2O + N_2$

The exhaust passes over a catalyst, usually a noble metal (platinum, rhodium or palladium) which reduces the reactants to N2, CO2 and H20. Typical exhaust temperatures for effective removal of NOx are 800-1200 degrees Fahrenheit. An oxidation catalyst using additional air can be installed downstream of the NSCR catalyst for additional CO and VOC control. This includes 4-cycle naturally aspirated engines and some 4-cycle turbocharged engines. Engines operating with NSCR require air/fuel control to maintain high reduction effectiveness typically around 80 to 90 percent NOx control. Extremely tight control of the air to fuel ratio operating range is accomplished with an electronic air to fuel ratio controller.

Technology #4 - Rich/Lean Burn SNCR: SNCR is applicable to both lean burn natural gas and diesel engines. SNCR involves injecting ammonia or urea into regions of the exhaust with temperatures greater than 1200 – 2000 degrees Fahrenheit. The nitrogen oxides in the exhaust are reduced to nitrogen and water vapor. Additional fuel is required to heat the engine exhaust to the correct operating temperature. Heat recovery from the engine exhaust can limit the additional fuel requirement and concurrent additional emissions from heating exhaust gases. Ten parts per million of ammonia (slip) is considered reasonable for SNCR. Temperature is the operational parameter affecting the reaction - as well as degree of contaminant mixing with reagent and residence time. Additional control of particulate matter (up to 85% diesel particulate matter), volatile organic compounds (up to 90 percent) and carbon monoxide (up to 70 percent) may be realized by the afterburning effect of this technology. On both rich burn and lean burn RICE, SNCR generally achieves about 50 to 95% reduction in NOx emissions.

Technology #5 – Lean Burn SCR: SCR uses catalyzed reduction of NOx with injected ammonia or urea solution. This technology is applicable to lean burn engines only (i.e., those with greater than about one percent exhaust oxygen, as oxygen is a reagent in the selective reduction reaction.) SCR may be used with lean burn (SI), dual fuel or diesel engines (CI). SCR produces unreacted ammonia (slip) and monitors are necessary to provide correct control of ammonia injection rates to minimize slip. When used with diesel engines, it is important to use a low sulfur fuel and sulfur resistant catalyst. Sulfur dioxide in the exhaust can be oxidized over the SCR catalyst to sulfuric acid mist, and when combined with unreacted ammonia, produces sulfate particulate.

For an SCR system using urea, the first stage of the catalyst bed is the hydrolysis catalyst, which converts the urea to ammonia. In the second stage of the catalyst, the ammonia and NOx react to form nitrogen gas and water with some unreacted ammonia passing through. Base metal catalysts, typically vanadium and titanium, are used for exhaust gas temperatures between 450^{o}F and 800 ^{o}F. For higher temperatures (675 ^{o}F to 1100 ^{o}F), zeolite catalysts may be used. Both the base metal and zeolite catalysts are sulfur tolerant for diesel engine exhaust. Precious metal SCR catalysts are useful for low temperatures (350 ^{o}F to 550 ^{o}F). When using precious metal SCR catalysts, attention should be paid to the fuel sulfur content and the appropriate formulation selected. This is not a concern with RICE fired with natural gas.

Reactions of NOx over SCR catalyst:

$$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O$$
$$6NO + 4NH_3 \rightarrow 5N_2 + 6H_2O$$
$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO + 4NH_3 + 2O_2 \rightarrow 3N_2 + 6H_2O$$

An SCR system consists of reagent storage, feed and injection system, and a catalyst and catalyst housing. Predictive mapping of engine operating parameters can be used to monitor and control the SCR reaction. Precious metal catalysts can reduce NOx by 80%. Zeolite catalysts can reduce NOx by 90% with minimal sulfur dioxide to sulfur trioxide conversion. Exhaust gas temperatures greater than the upper limit (850 F) will pass the NOx and ammonia unreacted through the catalyst.

Technology #6 – Replace RICE with electric motors: This control technology results in complete reduction of NOx emissions at the RICE location, although the electric power provided to the motor must be supplied by a power plant located at some distant location. There is a net reduction in NOx emissions from consolidating operations although the amount of reduction depends on the distance from the power plant as transmission line losses reduce the effectiveness of this control. Another consideration is the proximity to high voltage lines which may limit the practically of this control option in rural areas.

The below table summarizes each available technology and the technical feasibility for NOx Control.

NG-Fired RICE – NOx Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Lean Burn (Air/Fuel Ratio Adjustment)	~5-30%	Y
Lean Burn (Ignition/Spark Timing Retard)	~20%	Y
Rich Burn NSCR	~80-90%	Y
Rich/Lean Burn SNCR	~50-95%	Y
Lean Burn SCR	~80-90%	Y
Replace RICE with electric motors	~60-100%	Y

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

Technology #1 - Lean Burn (Air/Fuel Ratio Adjustment): In naturally aspirated LB engines and LB engines where fuel is injected into the intake manifold plenum, each cylinder does not have an identical air-to-fuel ratio, thus changes in the A/F ratio are very limited and therefore of little benefit, although the cost of such adjustment is minimal. Additional NOx emission reduction benefit is gained through the addition of a turbocharger and an automatic air-to-fuel ratio controller. The cost of adding these controls is very specific to the engine size and design but generally ranges between \$320 to \$8,300 per ton[6] of NOx reduced.

[6] Reference – Supplementary Information for Four Factor Analysis by WRAP States, EC/R Incorporated, May 4, 2009, see table 3-3.

Technology #2 - Lean Burn (Ignition/Spark Timing Retard): Based on a general analysis of NG fired RICE for the WRAP states[4], the cost of this control ranges between $310 to $2,000 per ton of NOx depending on engine size and firing design.

Technology #3 - Rich Burn NSCR: Regulation Number 7 requires rich burn RICE over 500 HP to install retrofit NSCR controls if the cost of control is under $5,000 per combined ton (NOx and VOC) statewide. This Regulation was effective as of July 1, 2010. None of the operators of rich burn RICE outside the metro-area ozone non-attainment area submitted information demonstrating control costs in excess of $5,000 per ton cost threshold, consequently, the majority of natural-gas fired RB RICE over 500 HP must operate an NSCR with an AFR controller.

Emission Reduction from NSCR Retrofit of RICE > 500 hp

Statewide RICE Category*	Count**	NO_x Reduction (tpy)
Lean Burn ≥ 500 HP	288	minimal***
Rich Burn ≥ 500 HP	305	5,800

Notes:

* This data represents statewide RICE, excluding the 9-county metro area (ozone non-attainment area) which was addressed in an earlier rulemaking for the Early Action Compact.

** Data obtained from 2008 APENs

*** Retrofit NSCR for lean burn RICE was not required because of minimal NOx reduction

Annualized Costs for Rich Burn RICE Control Device

Item	Capital Costs (one time)	O&M (recurring)	Total Annualized Cost (15 yrs)
NSCR with AFR Controller*	$35,000	-	
Operating	-	$6,000	
Subtotal Costs:	$35,000	$6,000	
Annualized Costs:	$4,851	$6,000	**$10,851**

Notes:

* Cost estimates obtained from "Denver Early Action Compact Analysis of Stationary Sources" Nov. 3, 2003

Costs Associated with Statewide Retrofit of Natural Gas-fired RB RICE ≥ 500 HP

Category	Number of Devices	Annualized Cost per Device	Total Device Cost	NO_x Reduction [tpy]	$/ton
NSCR & AFR Controller	305	$10,851	$3,309,555	5,800	$571

Technology #4 - Rich/Lean Burn SNCR: SNCR usually requires reheating of the exhaust to achieve the proper temperature range for effective NOx conversion; this is particularly true for lean burn RICE where excess oxygen results in exhaust temperatures well below the required levels. The Division was unable to acquire cost information for this control option, thus no cost estimates have been provided. The scarcity of SNCR data on NG-fired RICE may suggest other post combustion NOx controls are preferred, particularly SCR which has more reliable control effectiveness under a variety of load conditions.

Technology #5 – Lean Burn SCR: Depending on the engine size, catalyst used and the level of sophistication of the control system, SCR costs generally range about $430 to $4,900 per ton of NOx reduced.

Technology #6 – Replace RICE with electric motors: Depending on the engine size, length and capacity of the power line required, the costs generally range from $100 to $4,700 per ton of NOx reduced[7]. These costs do not include any potential impact from increases in electrical load at the power plant. The true cost of replacing RICE with electric motors is dependent on the distance from the power plant and the amount of compression power required. In actuality, larger compressor stations with multiple large engines would produce significant increased demands at a nearby power plant and possibly significant demands on the line transmission system that would escalate the costs to levels much higher than the $4,700 control cost. Colorado has about 40 large compressor stations, thus the estimation of costs would require a case-by-case analysis which was not done for this RP evaluation. Although, if all statewide RICE (above 500 horsepower) were converted to electric motor compression, then a minimum of approximately 600 MW of extra generating capacity would be required. Realistically, the actual generating capacity required is probably much higher when transmission losses and peak demand cycles are factored into the load demands.

Factor 2: Time Necessary for Compliance

Technology #1, 2, 4, 5 and 6: If Colorado was to decide to adopt a particular control strategy, up to 2 years will be needed to develop the necessary rules and undergo Legislative review. Subject sources may then require up to a year to procure the necessary capital to purchase control equipment. The Institute of Clean Air Companies (ICAC) has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NOx control[8]. However, the time necessary will depend on the type and size of the unit being controlled. For instance, in past rulemakings, typically 18 months may be required to install a particular control technology on hundreds of engines. Additional time, up to 12 months may be required for staging the installation process if multiple sources are to be controlled at a single facility. Based on these figures, the total time required achieve the NOx emission reductions for reciprocating engines is estimated at about 5 years.

Technology #3: This control option is implemented and was effective on July 1, 2010.

Factor 3: Energy Impacts and Non Air-Quality Impacts

In general, air-to-fuel-ratio adjustments and ignition retarding technologies have been found to increase fuel consumption by up to 5%, with a typical value[9] of about 2.5%. This increased fuel consumption would result in increased CO_2 emissions. Installation of SCR on any type of engine would cause a small increase in fuel consumption, about 0.5%, in order to force the exhaust gas through the catalyst bed. This would produce an increase in CO_2 emissions. In addition, spent

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[7] Bar-Ilan, Amnon, Ron Friesen, Alison Pollack, and Abigail Hoats (2007), *WRAP Area Source Emissions Inventory Protection and Control Strategy Evaluation - Phase II*, Western Governors Association, Denver, Colorado, Chpt 4.

[8] Institute of Clean Air Companies (2006), Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources.

[9] Center for Alternative Fuels, Engines & Emissions (2005), Alice Austen Ferry Emissions Tests, M.J. Bradley & Associates, Manchester, NH, Page 13.

catalyst would have to be changed periodically, producing an increase in solid waste disposal[10]. Replacing RICE with electric motors may require construction of additional power plants to accommodate increased power demands.

Factor 4: Remaining Useful Life:

Generally the operational life of a catalyst is approximately 5 to 15 years, depending upon factors such as how it is maintained and the particular duty cycle of the engine.

Step 5: Select Reasonable Progress Control

The state has determined that control technology #3, rich burn NSCR w/air-fuel controller, represents reasonable progress for the natural gas-fired RICE source category in this planning period. The estimated reduction of 5,800 tons/year represents about 36% of the NG RICE total NOx emissions.

The State of Colorado regulates RICE under Colorado Air Quality Control Commission Regulation No. 7 (Reg. 7) Section XVII. Further NOx emission reduction benefits are anticipated in the future because of tighter NOx emission standards in Regulation 7 that require emissions from RICE shall not exceed the following emission performance standards:

Colorado Emission Standards Natural Gas-Fired RICE

RICE Horsepower	Construction or Relocation Date	Emission Standards (grams/hp-hr)		
		NOx	CO	VOC
< 100	Any	NA	NA	NA
≥ 100 and ≤ 500	On or after 1/1/08	2.0	4.0	1.0
	On or after 1/1/11	1.0	2.0	0.7
> 500	On or after 7/1/07	2.0	4.0	1.0
	On or after 7/1/10	1.0	2.0	0.7

RICE that are subject to an emissions control requirement in a federal Maximum Achievable Control Technology (MACT) standard under 40 CFR Part 63, a Best Achievable Control Technology (BACT) limit, or a New Source Performance Standard under 40 CFR Part 60 are not subject to Reg. 7 Section XVII.

[10] EPA (2002), EPA Air Pollution Control Cost Manual, 6th ed., EPA/452/B-02-001, U.S. EPA, Office of Air Quality Planning and Standards, RTP.