

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Craig Unit 1

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Order No. 202-25-14

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit L: NERC, *2025-2026 Winter Reliability Assessment* (Nov. 2025)

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2025–2026 Winter Reliability Assessment

November 2025



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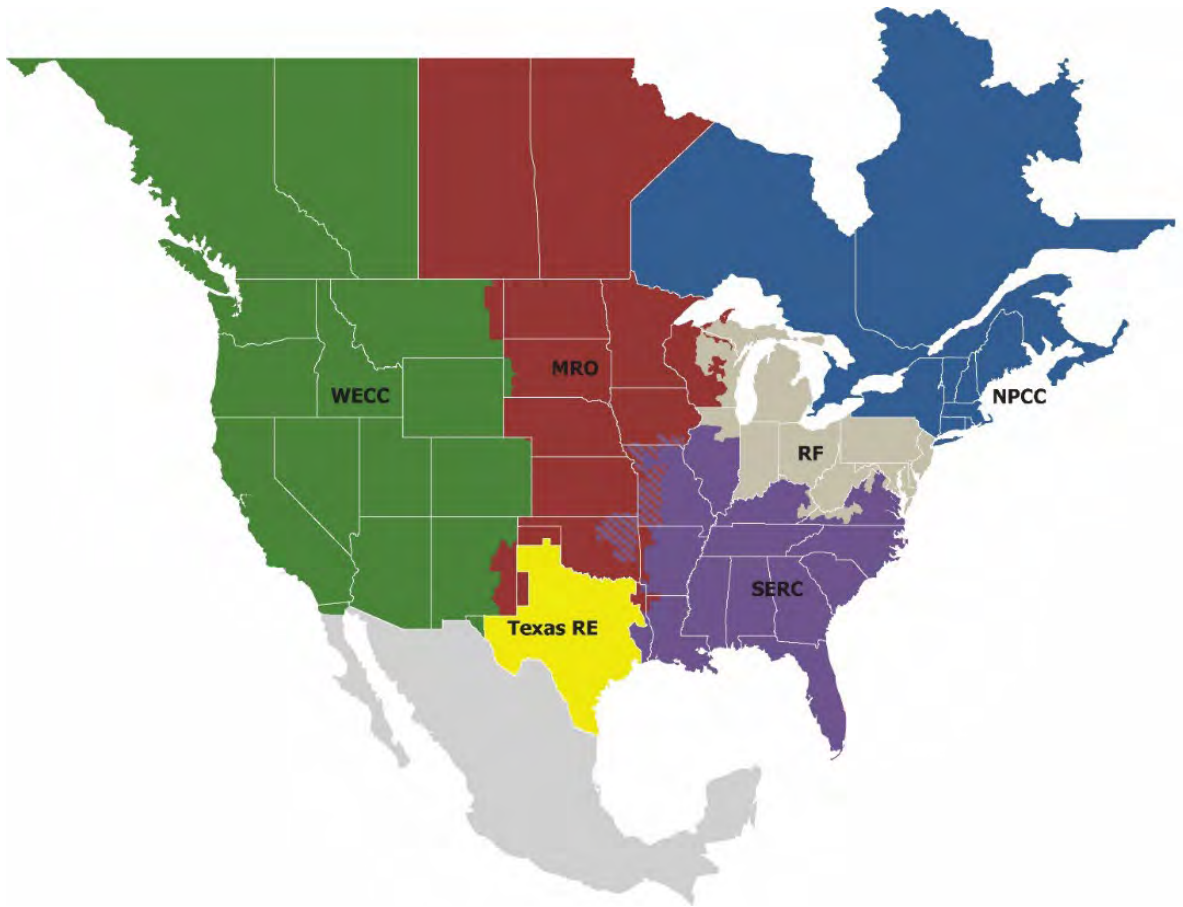
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Preface

Electricity is a key component of the fabric of modern society, and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

About this Assessment

NERC's *2025–2026 Winter Reliability Assessment* (WRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the WRA presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS.

The reliability assessment process is a coordinated evaluation between the Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas.

This report reflects an independent assessment by the ERO Enterprise (i.e., NERC and the six Regional Entities) and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

This WRA covers the upcoming three-month (December–February) winter period, providing an evaluation of the generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional risks. The following findings are the ERO Enterprise’s independent evaluation of electricity generation and transmission capacity as well as the potential operational concerns that may need to be addressed for the upcoming winter.

Two trends affecting resource adequacy across the BPS for the upcoming winter are rising electricity demand forecasts and a continued shift in the resource mix characterized by the retirement of thermal generators and growth in battery resources. After years of flat or low (~1%) peak demand growth, the aggregate peak demand for all NERC assessment areas has risen by 20 GW (2.5%) since the previous winter. Nearly all assessment areas are reporting year-on-year demand growth; some are forecasting increases near 10%. Total BPS resources have also increased since last winter, but by a smaller amount of 9.4 GW. This number includes the net change in generating capacity as well as additional demand response. These demand and resource changes are described in [Escalating Winter Demand](#) and [Resource Trends](#) sections.

The following findings are derived from NERC and the ERO Enterprise’s independent evaluation of electricity generation and transmission capacity as well as potential operating concerns that should receive attention for Winter 2025–2026:

1. **All areas are assessed as having adequate resources for normal winter peak-load conditions (i.e., the area’s 50-50 peak forecast). However, more extreme winter conditions extending over a wide area could result in electricity supply shortfalls.** Prolonged, wide-area cold snaps can drive sharp increases in electricity demand and threaten reliable BPS generation and the availability of fuel supplies for natural-gas-fired generation. Four severe arctic storms have descended to cover much of North America since 2021, causing regional demand for electricity and heating fuel to soar and exposing generation and fuel infrastructure in temperate areas to freezing conditions.¹ The following areas face risks of electricity supply shortfalls during periods of more extreme conditions this winter (see [Figure 1](#)):
 - **NPCC-Maritimes:** The peak demand forecast has fallen slightly (-1.6%) in the NPCC-Maritimes assessment area, contributing to higher reserves compared to the 2024–2025 winter. Maritimes is projected to have an Anticipated Reserve Margin (ARM) of 16.9%, which is 270 MW below the area’s Reference Margin Level of 20% . New Brunswick has long-term energy contracts that can be used to mitigate resource adequacy challenges

through the purchase of energy on a day-ahead basis. NPCC’s all-hours probabilistic assessment for the NPCC Region included the simulation of both a base case (i.e., normal 50/50 demand) and highest peak load scenario (having an approximate 7% chance of occurring), for both an expected and a low-likelihood, reduced-resource condition. The preliminary results of this assessment indicate that operators in Maritimes are likely to require emergency operating mitigations and/or energy emergency alerts (EEA) during above-normal demand or low-resource output conditions.

- **NPCC-New England:** A lower peak demand forecast and additional resources from demand response and firm imports offset recent generator retirements, resulting in little change to the NPCC-New England ARM for this winter. New England continues to closely monitor regional energy adequacy, particularly during extended cold snaps where constrained natural gas pipelines contribute to rapid depletion of stored fuel supplies. ISO-NE’s deterministic winter scenario analysis shows limited exposure to energy shortfalls this winter. In New England, winter energy concerns are highest in scenarios when stored fuels are rapidly depleted; during these periods, timely replenishment is critical to minimizing the potential for energy shortfalls.
- **SERC-East:** The winter peak demand forecast has increased by 700 MW (1.6%) since last winter, while winter firm capacity has declined, resulting in lower reserves. SERC-East has changed from a summer-peaking area to potentially peaking during both summer and winter. This is due to the continued addition of solar photovoltaic (PV) generation that shaves off summer peak demand and a trend toward electrification of heating that drives up winter peak demand. All-hours probabilistic analysis from SERC found some load-loss hours (<0.1 hrs) and small amounts of expected unserved energy, with the highest risk occurring during above-normal peak demand and early morning hours when solar output is absent.
- **SERC-Central:** Additional demand response and flat load growth since last winter is offsetting declining resource capacity (down 1,120 MW), resulting in little change to the ARM at 30.5%. There are adequate resources for normal winter peak demand; however, higher levels of demand that can occur during extreme cold temperatures can result in insufficient reserves that operators would need to manage with non-firm imports and potential energy emergencies.
- **Texas RE-ERCOT:** Strong load growth from new data centers and other large industrial end users is driving higher winter electricity demand forecasts and contributing to continued risk of supply shortfalls. For the upcoming winter season, Texas RE-ERCOT is expected to continue facing reserve shortage risks during the peak load hour and high-

¹ See detailed reports on the [January 2024 and January 2025 Arctic Storms, Winter Storm Elliott, and Winter Storm Uri](#).

net-load hours, particularly under extreme load conditions that accompany freezing temperatures. Elevated forced outage of thermal resources and reduced output from intermittent resources during these conditions exacerbates the risk of supply shortfalls. In winter, peak demands typically occur before sunrise and after sunset coinciding with the unavailability of solar generation making the system dependent on wind generation and dispatchable resources. Data centers are altering the daily load shape due to their round-the-clock operating pattern, lengthening peak demand periods. Additional battery storage and demand-response resources since last winter help mitigate shortfall risks. However, with the continued flattening of the load curve, maintaining sufficient battery state of charge will become increasingly challenging for extended periods of high loads, such as a severe multi-day storm like Winter Storm Uri.

- **WECC-Basin:** There is sufficient capacity in the area for expected peak conditions; however, Balancing Authorities (BA) are likely to require external assistance during extreme winter weather that causes thermal plant outages, adverse wind turbine conditions, and natural gas fuel supply issues for area internal resources. External assistance may not be available during region-wide extreme winter conditions. With an expected winter peak demand of 11.1 GW, under an extreme combination of generator derates and outages, the region could be short 1.6 GW before imports. Forecasted net internal demand has increased 1% since last year, with little change in winter capacity. Note that the WECC-Basin assessment area includes Utah, southern Idaho, and a portion of western Wyoming. In prior WRA reports, this part of the BPS was included as part of the WECC-NW assessment area. The 2025–2026 WRA includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.
- **WECC-NW:** Like WECC-Basin, there is sufficient capacity in the area for expected peak conditions; however, BAs are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year. Over 3 GW of new resources have been in development for the assessment area this year, primarily battery storage, solar PV, and wind resources. Delays that threaten timely completion of these resource additions will make the area more reliant on imports to meet peak demand.

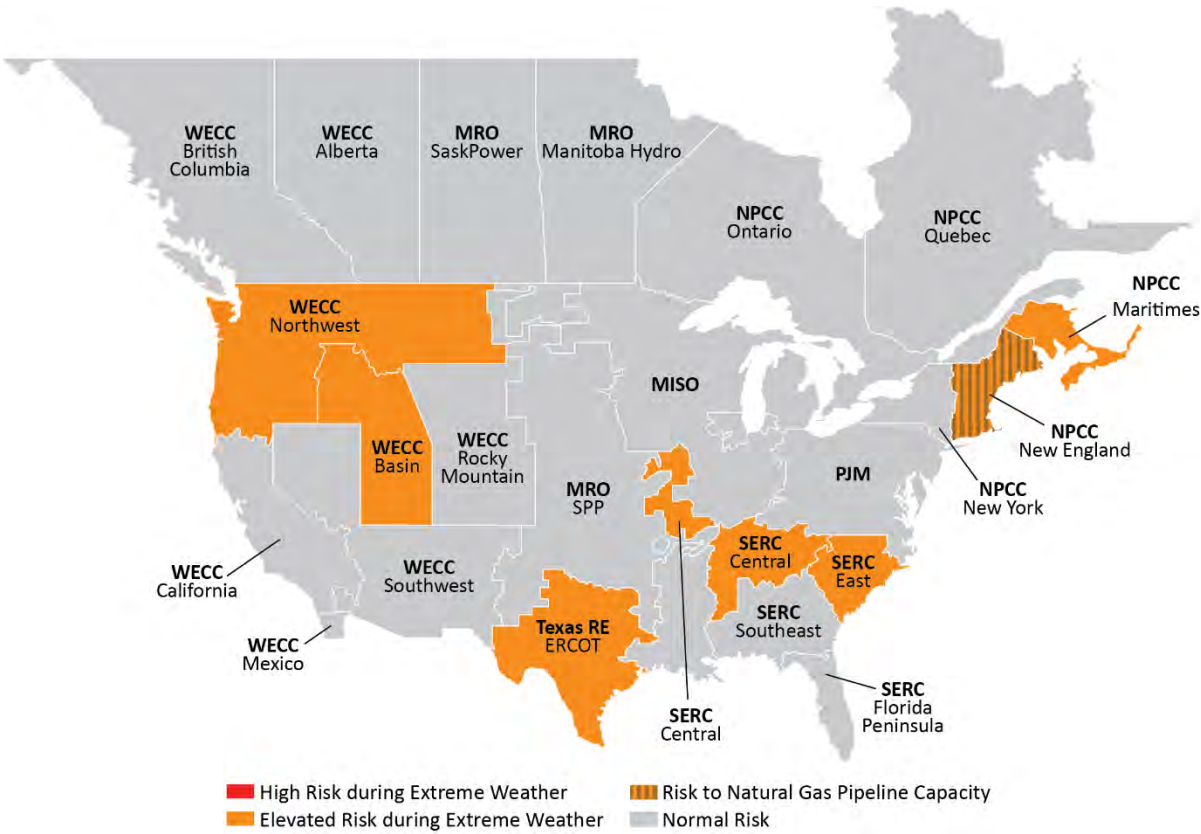


Figure 1: Winter Reliability Risk Area Summary

2. **The performance of natural gas production and supply infrastructure during peak winter conditions will again have a significant effect on BPS reliability.** Natural gas is an essential fuel for electricity generation in winter. Winter fuel supplies for thermal generators must be readily available during the periods of high electricity and natural gas demand that accompany extreme cold weather. Yet these periods are the most challenging for natural-gas-fired Generator Operators to obtain sufficient fuel and delivery. Natural gas production often falls off in extreme winter temperatures as supply infrastructure is affected by freezing issues, and Generator Operators that fail to secure firm fuel delivery are frequently unable to access fully subscribed pipelines. Evidence from the past two winters indicates notable improvement in the delivery of natural gas to BPS generators since winter storms Elliott and Uri with overall less natural gas production decline during cold weather and fewer natural gas infrastructure

force majeures.² Still, natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America, resulting in uneven application of protections and continued supply risks during extreme conditions. Furthermore, timing misalignments between the natural gas and electric markets continue to challenge generator fuel procurement in advance of severe winter conditions that occur over winter holiday weekends. As winter approaches, NERC encourages all entities across the gas-electric value chain—from production to the burner tip—to take all necessary preparations for extreme cold and keep natural gas flowing and the lights on.

3. **Cold weather Reliability Standards first introduced in 2023 have been improved prior to the upcoming winter and address recommendations from winter storms Elliott and Uri.** In September 2025, the Federal Energy Regulatory Commission (FERC) approved EOP-012-3 with an effective date of October 1, 2025, concluding the development of Reliability Standards for generator cold weather preparedness.³ The EOP-012 Reliability Standard contains requirements for generator freeze protection measures, cold weather preparedness plans, and operator training. Among the improvements in the new version are enhanced and expanded requirements to ensure that Generator Owners (GO) are implementing corrective actions to address known issues affecting their ability to operate in cold weather in a timely manner. NERC collects data on the winterization of generating units, which, in conjunction with NERC’s monitoring of BPS performance and analysis of cold weather events, helps determine the effectiveness of Reliability Standards. NERC submitted to FERC its first annual *Cold Weather Data and Analysis* informational filing in October 2025.⁴ Based on the data reported this year, 96% of the total net winter capacity reported extreme cold weather temperatures (ECWT) at or below 32 degrees Fahrenheit, triggering winter preparedness measures under the Cold Weather Preparedness Standard, and 99% of total net winter capacity in the continental US reporting the ability to operate at the calculated ECWT. As the first such report, this *Cold Weather Data and Analysis* filing provides a benchmark for future analysis.

Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

- Reliability Coordinators (RC), BAs, and Transmission Operators (TOP) in the elevated risk areas identified in the key findings should review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially high generator outages and extreme demand levels. Operators should review NERC’s Resources on Cold Weather Preparations.
- GOs should complete winter readiness plans and checklists prior to December, deploy weatherization packages well in advance of approaching winter storms, and frequently check and maintain cold weather mitigations while conditions persist.
- BAs should be cognizant of the potential for short-term load forecasts to underestimate load in extreme cold weather events and be prepared to take early action to implement protocols and procedures for managing potential reserve deficiencies. Proactive issuance of winter advisories and other steps directed at generator availability contributed to improved reliability during cold weather events of the past two winters.
- RCs and BAs should implement generator fuel surveys to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- Generator Owners/Operators of natural-gas-fired units should maintain awareness of potential extreme cold weather developing over holiday weekends and the implications for fuel planning and procurement that may result given the natural gas purchase close dates that precede long holiday weekends.
- State and provincial regulators can assist grid owners and operators in advance of and during extreme cold weather by maintaining awareness of BA, natural gas pipeline, and gas local distribution company (LDC) operational public announcements and notices, amplifying public appeals for electricity and natural gas conservation, and supporting requested environmental and transportation waivers.

² See [January 2025 Arctic Events | A System Performance Review](#), April 2025

³ See NERC’s [Statement on FERC September Open Meeting](#) for summary and link to FERC’s order.

⁴ See [2025 Cold Weather Data Collection and Analysis Informational Filing](#)

Risk Highlights

Escalating Winter Demand

Winter electricity demand is rising at the fastest rate in recent years, particularly in areas where data center development is occurring. After several years of low (~1%) growth, total internal demand for the BPS is forecast to increase by 20.2 GW (2.5%) over last winter’s forecast. The changes in forecasted net internal demand for each assessment area are shown in [Figure 2](#) below.⁵ Assessment areas develop these forecasts based on historical load and weather information as well as future projections. Most assessment areas are projecting an increase in peak demand. SaskPower, PJM, the U.S. Southeast, and parts of the U.S. West have the largest increase in peak demand forecasts.

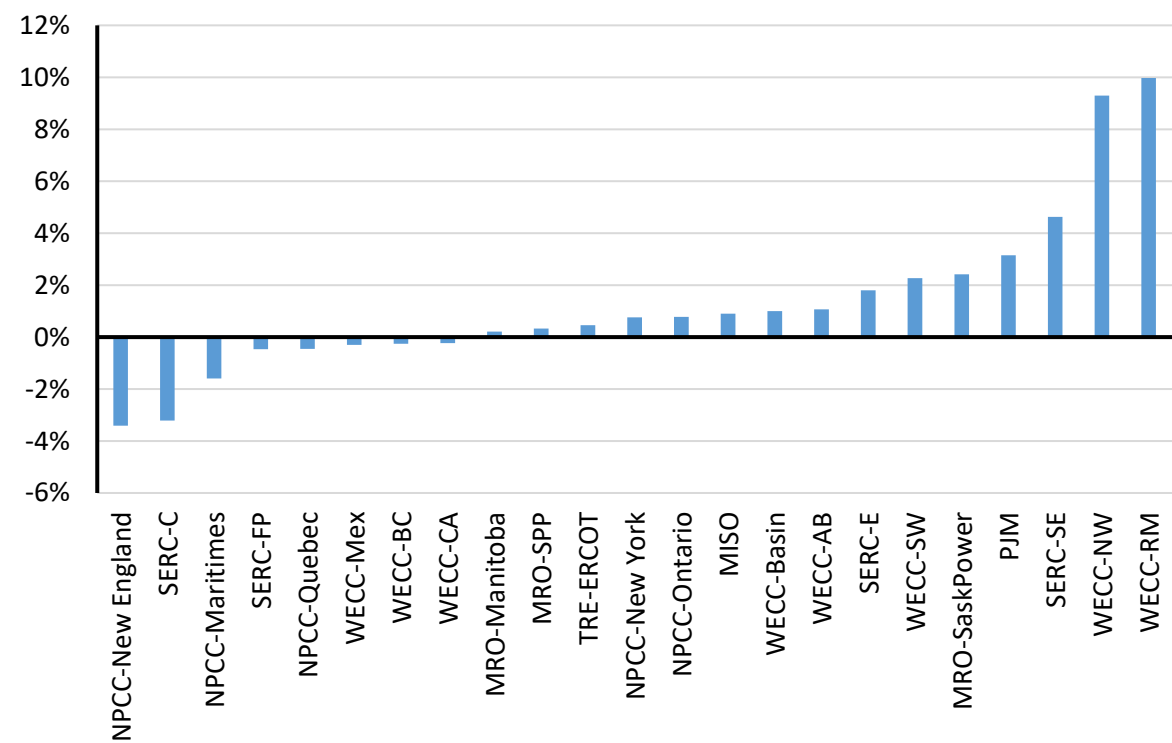


Figure 2: Change in Net Internal Demand—Winter 2025–2026 Forecast Compared to Winter 2024–2025 Forecast

⁵ See [Data Concepts and Assumptions](#) section for demand definitions.

Resource Trends

BPS resources are growing, but at a slower rate than demand is rising. Battery and solar facilities were the leading resource types added to the BPS since last winter. Solar resources, however, often do not supply output during hours of peak winter demand. Growth in demand response is also contributing to BPS resources for the upcoming winter. [Table 1](#) shows the total change in BPS resources since last winter. For battery, solar, and wind resources, the table includes change in both nameplate (installed) capacity as well as the change in on-peak demand capacity, which is the capacity that resources are expected to provide in their area during the time of peak demand. For assessment-area specific information see [Variable Energy Resource Contributions](#) section.

Table 1: BPS Resource Change from Winter 2024–2025 to Winter 2025–2026		
Resource	Net Change Nameplate Capacity (MW)	Net Change Peak Demand Capacity (MW)
Total Generator Capacity		1,335
Battery	19,659	11,121
Solar	11,097	1,176
Wind	-562	-14,238
Thermal and Hydro		3,276
Demand Response		8,112
Total Resources		9,447

Total BPS resources for serving winter peak demand, including generating capacity and demand response, have increased since last winter by 9,447 MW. Sizeable additions in battery resources and some new natural gas-fired generators contribute to the increase in resource capacity. However, the increase is offset by lower on-peak capacity values for wind resources, which are the result of revised valuations of wind resource capability at peak demand hours in some areas.⁶ As a result, BPS generator capacity for winter peak demand makes up only a small portion of the total BPS increase. Generation accounts for 1,335 MW of the total 9,445 MW increase, while the larger share comes from demand response programs. Area specific information on demand response is provided in the [Demand and Resource Tables](#).

The recent trend in resource additions is contributing to higher risk of electricity supply shortfalls in winter. BA operators are likely to face higher winter demand without a comparable increase in supply resources. Furthermore, the types of resources that are growing the most-- battery resources and

⁶ Since last winter, ERCOT and MISO have implemented new methods for determining capacity contributions that result in lower wind and solar resources contributions at peak demand. See ERCOT’s [Resource Adequacy page](#) and MISO’s [Planning Year 2025-2026 Wind and Solar Capacity Credit Report](#).

demand response—have unique characteristics that operators will need to account for and could limit the use of these resources in extreme winter conditions. Battery energy is reliable when it can be dispatched and has sufficient charge for the period it is needed, yet little time to recharge can be expected during extreme winter weather. System operators will need good visibility on battery state of charge and should anticipate that some extreme winter events will cause these resources to become depleted when needed. Demand response is limited by contract terms, which typically specify how often and for how long the resource may be used. Other resource types are also challenged in winter (see [Thermal Generator Fuel Adequacy and Security](#)). As BAs grapple with higher demand in most parts of the BPS, they will do so with resources that are becoming increasingly complex to dispatch especially in winter.

Thermal Generator Fuel Adequacy and Security

The performance of the thermal generator fleet remains critical to winter BPS operations. Winter fuel supplies for thermal generators must be readily available during periods of high demand and extreme cold weather. Generally, fuel adequacy for the thermal generating fleet is bolstered through strategic infrastructure investments and fuel stockpiling that increases the certainty of having fuel on hand that can be converted to electricity when needed. Because of this, winter performance of thermal generators is inextricably linked to extraction, processing, storage, and delivery infrastructure for a variety of fuels. Fuel supply risks have been noted in recent years’ WRAs related to coal and natural gas availability and illustrate the interconnected nature of these critical energy infrastructure systems.

BPS stakeholders across North America note multiple fuel-related issues that are being monitored entering the winter season. For example, while coal represents a waning share of the overall resource mix, it continues to play an important role in meeting demand during extreme winter weather events, and oil inventories at dual-fuel gas-oil generators lessen risks related to natural gas deliverability in infrastructure-constrained regions, especially during the winter. Notably, it is infeasible or prohibitively costly to stockpile natural gas locally at power plants, and this exposes the BPS to the risk profile of the constituent systems that comprise the supply and delivery of this just-in-time fuel.

Natural Gas Generator Fuel Supplies

Natural gas generators remain a crucial part of on-peak resources meant to meet winter electricity demand across much of North America. While many Generator Owners and Operators secure backup fuel supplies at critical gas-fired generators, particularly in the northeastern United States and Florida, large contributions to the on-peak winter resource mix by single-fuel natural-gas-fired generators remain across North America (see [Figure 3](#)).

Natural gas generator performance can be threatened when natural gas supplies are insufficient or when natural gas infrastructure is unable to maintain the flow of fuel to critical generators. Grid operators continue to acknowledge and enhance their winter planning processes to firm up their fuel supplies and guard against natural gas disruptions, but winter storms Uri and Elliott demonstrated that combinations of natural gas flow restrictions and supply insufficiency can occur regardless of whether cold temperatures are common or uncommon in the region and can affect more than one BA area concurrently.

Many BPS areas that regularly experience cold weather events, like New England, have adopted mitigating technologies to lessen the impact of natural gas shortages through generator dual-fuel capability and stored backup fuel. In those areas, prolonged cold weather events present a risk of rapid depletion of stored backup fuel. Robust regional and distributed storage investments and winter planning for timely fuel replenishment are critical to minimizing potential energy shortfalls in the operational time frame in these areas.

Natural gas and electricity infrastructures have the added complexity of interdependence. Electricity is used to power some facilities, such as compressor stations and processing plants that make up natural gas infrastructure. These interdependencies mean that reliability events that originate on one system have the potential to affect the other and worsen the overall event magnitude or duration.

Natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America. Texas is an exception, where the Railroad Commission of Texas adopted rules to require critical natural gas facilities to implement weather-related emergency preparation measures.⁷ Lack of consistent standards for natural gas infrastructure protections will result in uneven application of freeze protections and continued supply risks during extreme conditions in many areas.

These considerations have driven higher levels of coordination to ensure sustained reliable operation of the natural gas and electricity systems. While a FERC and ERO staff review of system performance during the January 2025 arctic events⁸ details improvements in electric and natural gas coordination since winter storms Uri and Elliott, the review also identifies continuing gaps between the electricity and natural gas industries that remain entering the 2025–2026 Winter season. These include natural gas scheduling challenges during winter holiday weekends, market time frame and process incompatibility, and electric power entities’ lack of visibility into operational impact data from natural gas producers and suppliers.

⁷ See [Railroad Commission of Texas weatherization rule](#).

⁸ [FERC, NERC Issue Report on System Performance During the January 2025 Arctic Weather | Federal Energy Regulatory Commission](#)

The U.S. Energy Information Administration (EIA)⁹ anticipates a slightly milder winter than last year across much of the United States, especially in the Northeast, leading to a projection that households will consume approximately 2% less natural gas than last winter. Working natural gas storage inventories are about 5% above the previous five-year average in the United States heading into the winter season. The EIA attributes this relative surplus in part to robust production this summer and lower-than-expected natural gas consumption by power generators.

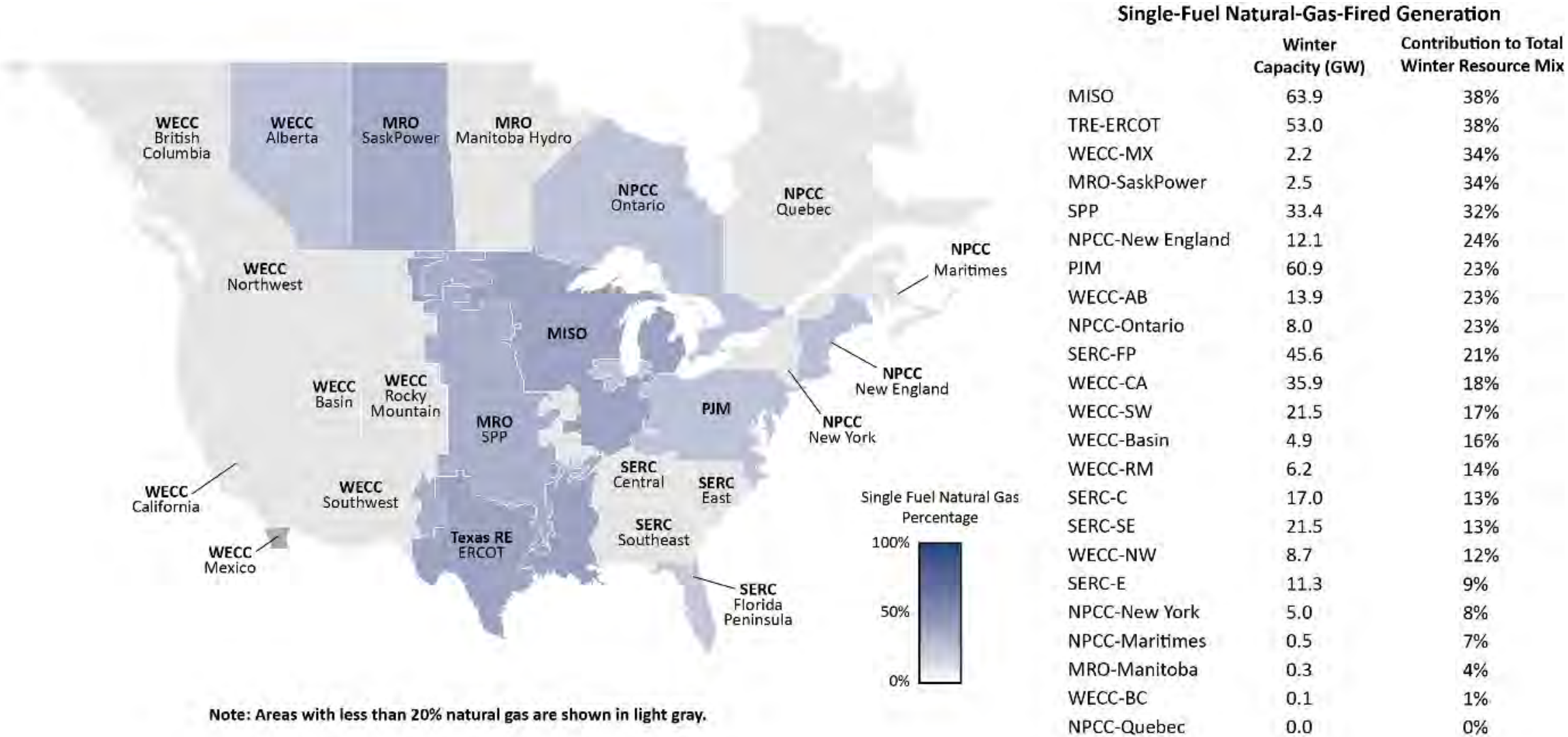


Figure 3: Single-Fuel Natural-Gas-Fired Generation Capacity Contribution to the 2025–2026 Winter Generation Mix

⁹ See the U.S. Energy Information Administration’s [Winter Fuels Outlook 2025–26](#)

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in [Table 2](#).

Table 2: Seasonal Risk Assessment Summary	
Category	Criteria ¹
High	- Planning Reserve Margins do not meet Reference Margin Levels (RML); or - Probabilistic indices exceed benchmarks, e.g., loss of load hours (LOLH) of 2.4 hours over the season; or - Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under normal peak-day demand and outage scenarios²
Potential for insufficient operating reserves in normal peak conditions	
Elevated	- Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season); or - Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under extreme peak-day demand with normal resource scenarios (i.e., typical or expected outage and derate scenarios for conditions);² or - Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under normal peak-day demand with reduced resources (i.e., extreme outage and derate scenarios)³
Potential for insufficient operating reserves in above-normal conditions	
Normal	- Probabilistic indices are negligible - Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios⁴
Sufficient operating reserves expected	
Table Notes: ¹ The table provides general criteria. Other factors may influence a higher or lower risk assessment. ² Normal resource scenarios include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand. ³ Reduced resource scenarios include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted. ⁴ Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.	

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins (ARM), which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins with typical forced outage levels and for the most extreme seasonal risk scenarios are provided in [Table 3](#).

Table 3: Seasonal Risk Scenario On-Peak Reserve Margins			
Assessment Area	Anticipated Reserve Margin	Reserve Margin with Typical Outages	Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	49.5%	22.3%	3.7%
MRO-Manitoba	13.7%	11.4%	6.1%
MRO-SaskPower	35.1%	29.0%	16.1%
MRO-SPP	56.5%	29.4%	16.9%
NPCC-Maritimes	16.9%	12.5%	-4.7%
NPCC-New England	58.9%	45.4%	8.7%
NPCC-New York	78.2%	52.4%	16.2%
NPCC-Ontario	28.6%	21.8%	13.2%
NPCC-Québec	15.2%	15.1%	5.0%
PJM	35.6%	24.8%	15.6%
SERC-C	30.5%	22.4%	-0.9%
SERC-E	21.9%	17.5%	3.0%
SERC-FP	41.7%	28.3%	25.6%
SERC-SE	39.7%	24.7%	17.7%
TRE-ERCOT	36.0%	25.2%	-20.0%
WECC-AB	35.2%	32.4%	10.0%
WECC-Basin	29.6%	19.7%	-21.1%
WECC-BC	25.9%	25.8%	15.4%
WECC-CA	82.3%	73.7%	57.9%
WECC-Mex	83.1%	79.4%	52.9%
WECC-NW	30.9%	29.5%	-8.5%
WECC-RM	61.7%	53.2%	10.0%
WECC-SW	104.4%	90.1%	50.1%

Seasonal risk scenarios for each assessment area are presented in the [Regional Assessments Dashboards](#) section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential winter peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year’s assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the [Data Concepts and Assumptions](#) section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In [Table 3](#), each assessment area’s ARMs are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Areas highlighted in orange in [Figure 1](#) above have been identified as having resource adequacy or energy risks for the winter and are included in the [Key Findings](#) section’s discussion that follows. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced-outage margin is the same as the ARM, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area’s scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the winter season. Results are summarized in [Table 5](#). The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include loss of load expectation (LOLE), loss of load hours (LOLH), expected unserved energy (EUE), and the probabilities of energy emergency alert (EEA) declarations (see [Table 4](#) for a description of EEA levels).

Table 4: Energy Emergency Alert Levels		
EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	- The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required operating reserves. - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	- The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. - An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. - An energy-deficient BA is still able to maintain minimum operating reserve requirements.
EEA 3	Firm load interruption is imminent or in progress	The energy-deficient BA is unable to meet minimum operating reserve requirements.

Energy Emergency Alerts

The combination of above-normal generation outages, low resource output, and peak loads as occurred during the extreme cold weather events of Winter Storm Uri in 2021 and Winter Storm Elliott in 2022 are ongoing winter reliability risks. When supply resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ EEAs to maintain balance between available capacity and energy and real-time demand. A description of each EEA level is provided above.

Table 5: Probability-Based Risk Assessment

Area	Type of Assessment	Results and Insight from Assessment
MISO	Deterministic	MISO does not provide a probabilistic assessment for the WRA. MISO applies a <u>deterministic</u> look at expected system conditions, looking at generation availability under typical and extreme outages and looking at a typical 50/50 load forecast and an extreme 90/10 load forecast. For the upcoming winter season, under an extreme outage and extreme 90/10 load forecast, this is the riskiest scenario for the MISO footprint. This scenario produces the shortest actual reserve margin for January.
MRO-Manitoba	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic analysis for the 2024 ProbA summarized in NERC’s 2024 <i>Long-Term Reliability Assessment</i> (LTRA) found no load-loss or unserved energy hours for 2026.
MRO-SaskPower	Probability-based capacity adequacy assessment	SaskPower’s probabilistic assessment for the 2025–2026 Winter indicates that risk of shortfalls is lower than the previous winter. LOLH for an elevated risk scenario for the 2025–2026 Winter season is 0.08 hours. The month with the highest LOLH is December (0.05 hours).
MRO-SPP	NERC 2024 ProbA	Probabilistic analysis for the 2024 ProbA summarized in NERC’s 2024 LTRA found no load-loss or unserved energy hours for 2026.
NPCC	NPCC conducted an all-hour probabilistic reliability assessment that included detailed neighbor modeling and consisted of a base case and severe case examining low resources, reduced imports, and higher loads. The assessment evaluates the probabilistic indices of LOLE, LOLH, and EUE. The highest peak load scenario has an approximately 7% probability of occurring.	
NPCC-Maritimes	The Maritimes Area low-likelihood resource case assumed: wind derated by 50% for every hour in December through February and a 50% natural gas capacity curtailment for December through February (dual-fuel units assumed reverting to oil) and reduced transfer capabilities.	The preliminary assessment indicates that established operating procedures are not sufficient to maintain a balance between electricity supply and demand. Under highest peak load levels, the Maritimes Area shows a notable likelihood of utilizing its operating procedures such as reducing 30-minute reserves, initiating interruptible loads, and reducing 10-minute reserves to maintain system reliability during the upcoming winter period.
NPCC-New England	The New England Area low-likelihood resource case assumed: 500 MW of additional maintenance outages, ~4,513 MW of gas-fired generation unavailable due to fuel supply constraints, and 50% reduced import capabilities of external ties.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand
NPCC-New York	The New York Area low-likelihood resource case assumed: ~500 MW of extended maintenance in southeastern New York, 600 MW of cable transmission reduction across HVdc facilities, and ~5,000 MW of generation unavailable due to fuel delivery issues.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period, for all the scenarios modeled.
NPCC-Ontario	An energy assessment for the Ontario Assessment Area was conducted for two scenarios: firm resources and firm demand with expected weather, and planned resources with planned demand with expected weather.	No cumulative LOLH or EUE risks were identified over the entire November-to-April winter season for both scenarios modeled.

Table 5: Probability-Based Risk Assessment

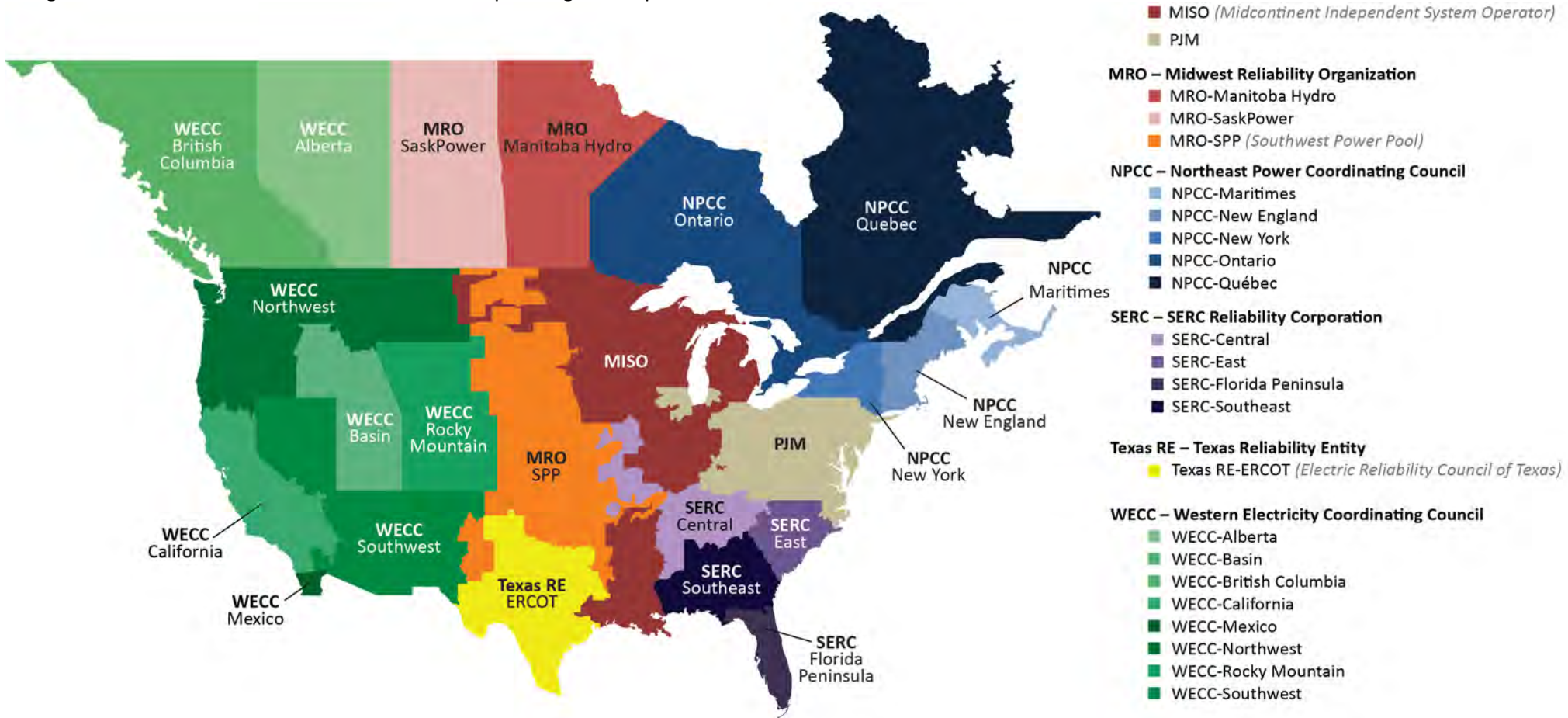
Area	Type of Assessment	Results and Insight from Assessment
NPCC-Québec	The Québec Area low-likelihood resource case assumed 1,000 MW of generation reductions.	The preliminary results of this assessment indicate that established operating procedures are sufficient to maintain a balance between electricity supply and demand if needed. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period for all the scenarios modeled
PJM	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic study for 2025–2026 Winter is not provided for the WRA. PJM performed probabilistic analysis for 2026-2027 winter as part of the 2024 ProbA summarized in NERC’s 2024 LTRA. The results of this study indicate risk of load loss (<0.1 hours) and unserved energy during winter months. For the upcoming winter, load-loss hours are expected to be less than this value because forecasted load is lower and anticipated resource capacity is higher than the case studied for the 2024 ProbA.
SERC	Based on the 2024 NERC Probabilistic Assessment (ProbA) base-case result. SERC’s assessment used 38 years of historical load shapes to assess the resource adequacy of years 2026 and 2028, primarily based on data from the 2024 Long Term Reliability Assessment (LTRA).	
SERC-Central		Probabilistic analysis for the 2024 ProbA summarized in NERC’s 2024 LTRA found no load-loss or unserved energy hours for 2026.
SERC-East		Probabilistic analysis for the 2024 ProbA summarized in NERC’s 2024 LTRA found a small number of load-loss hours (<0.1) and EUE (61 MWh / 1 ppm) for 2026.
SERC-Florida Peninsula		Probabilistic analysis for the 2024 ProbA summarized in NERC’s 2024 LTRA found negligible load-loss hours and EUE.
SERC-Southeast		Probabilistic analysis for the 2024 ProbA summarized in NERC’s 2024 LTRA found no load-loss or unserved energy hours for 2026.
Texas RE-ERCOT	ERCOT Probabilistic Reserve Risk Model	ERCOT’s probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
WECC	The resource adequacy work performed at WECC used the Multi-Area Variable Resource Integration Convolution (MAVRIC) model for the 2025 LTRA. The MAVRIC model is a convolution-based probabilistic model and is WECC’s chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC’s seasonal assessments, LTRA, and ProbA.	
WECC-AB		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Basin		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-BC		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

Table 5: Probability-Based Risk Assessment

Area	Type of Assessment	Results and Insight from Assessment
WECC-CA		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Mexico		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Rocky Mountain		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-NW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026. Results for a case where new resource additions are not completed for the upcoming winter found some EUE and LOLH.
WECC-SW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the [Data Concepts and Assumptions](#) table. On-Peak Reserve Margin bar charts show the ARM compared to a reference margin level (RML) that is established for each area to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the [Demand and Resource Tables](#)), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the [Demand and Resource Tables](#)) and the extreme winter peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the WRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods vary by assessment area and provide further insights into the risk conditions forecasted for this upcoming winter period.





MISO

The Midcontinent Independent System Operator, Inc. (MISO) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery of electricity to approximately 45 million people by managing regional transmission operations as well as energy and ancillary services markets and advising on long-term resource planning. The MISO footprint includes 39 Local BAs and more than 550 market participants. MISO operates one of the world’s largest organized electricity markets, with its members operating a system that consists of over 77,000 miles of transmission lines and approximately 1,888 generating units. The peak electricity demand on the MISO system currently occurs during the summer season. MISO’s footprint lies across three regional entities (MRO, RF, and SERC), but MRO is responsible for coordinating data and information submitted for NERC’s reliability assessments.

- MISO expects limited risk in the 2025–26 Winter season as MISO was able to procure 6.1% more resources through the annual planning reserve auction than required by its minimum resource adequacy target. A further 3.3 GW of resources were available but not chosen to be committed for the winter season.
- Some risk has been identified for this upcoming winter season. In a high generation outage and high winter load scenario reliability is expected to be maintained by reliance upon operational mitigations that include non-firm energy transfers into the system, energy-only resources not subject to a must-offer requirement that may still offer into the energy markets, load-modifying resources, and internal transfers that exceed the Sub-Regional Import/Export Constraint (SRIC/SREC) between the MISO North/Central and South areas.
- MISO continues to coordinate with neighboring RCs and BAs to improve situational awareness and vet any needs for energy transfers to address extreme system conditions.
- MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency.
- MISO has implemented a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons.

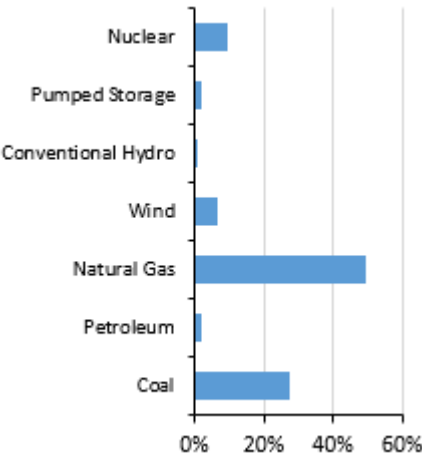
On-Peak Reserve Margin¹⁰



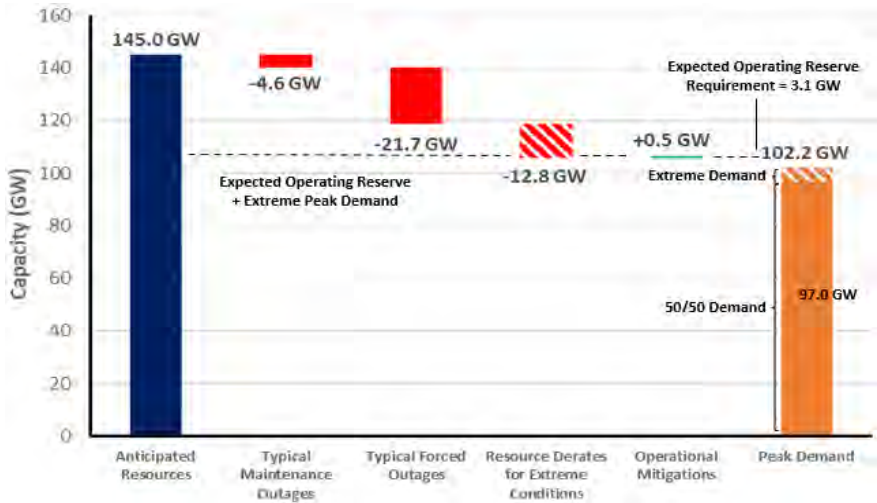
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with generator outages from freezing or fuel supply issues and low wind output result in the need to employ operating mitigations (i.e., demand response and transfers).

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

- Risk Period:** Highest risk for unserved energy at peak demand hour
- Demand Scenarios:** 50/50 net internal demand and additional demand during extreme weather conditions (e.g., Winter Storm Enzo) using member submitted data and historical load data
- Typical Maintenance Outages:** Rolling three-year winter average of peak-day maintenance and planned outages
- Typical Forced Outages:** Three-year average of all peak-day outages that were not planned
- Resource Derates for Extreme Conditions:** Represents derates aligning with the most extreme hour of each of the past 3 years,
- Operational Mitigations:** Non-firm energy transfers into the system, energy-only resources that do not have a must-offer requirement, or internal transfers that exceed the SRIC/SREC between the MISO North/Central and South regions

¹⁰ The MISO Risk Scenario Assessment for the 2025-26 Winter Season is not directly comparable to that for the 2024-25 Winter Season as methodology improvements have been implemented.



MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter-peaking. Manitoba Hydro is its own Planning Coordinator (PC) and Balancing Authority (BA). Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

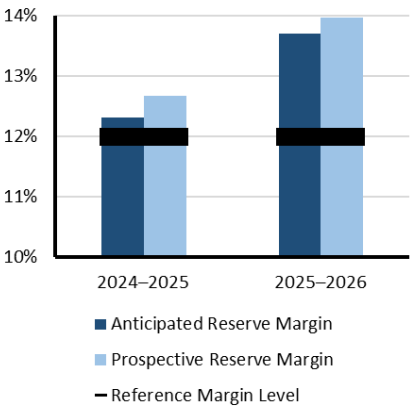
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Winter 2025–2026.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even under continued drought conditions.
- Manitoba Hydro is experiencing well below-average water supply conditions; however, the Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought.
- The ARM for Winter 2025–26 exceeds the 12% RML.

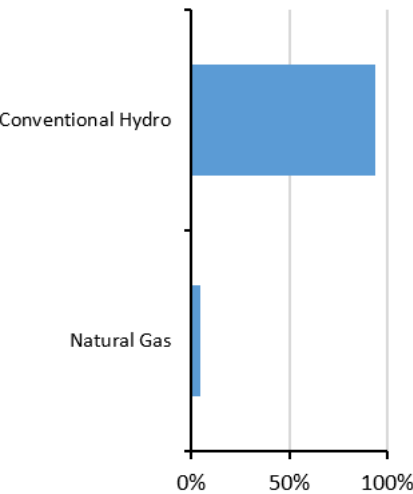
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

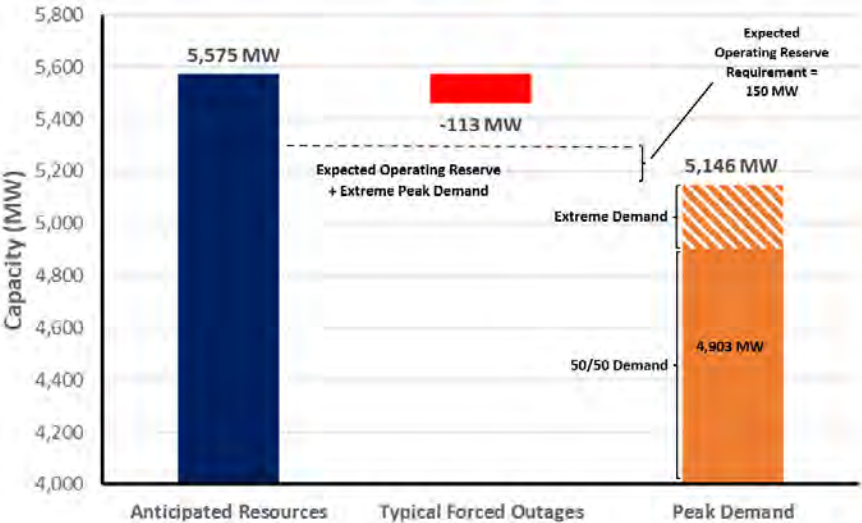
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of weather data

Typical Forced Outages: Accounts for average forced outages



MRO-SaskPower

MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections. Overall, SaskPower operates nearly 14,816 circuit-km of transmission lines, 65 high-voltage switching stations, and 191 distribution substations. Peak electricity demand on the SaskPower system currently occurs during the winter season.

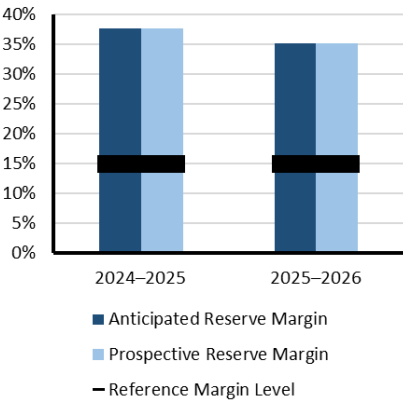
Highlights

- Saskatchewan experiences its peak load during the winter months due to extreme cold weather.
- Based on the planned maintenance, typical forced outages from historical data, and expected renewable generation under the normal and extreme demand conditions, SaskPower does not anticipate any reliability issues during the 2025–2026 Winter.
- During extreme winter conditions, SaskPower would utilize available demand-response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions to manage the situation.

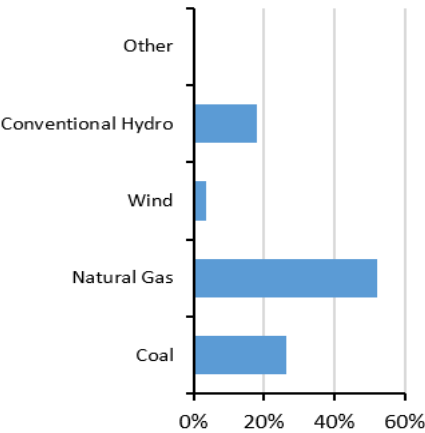
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

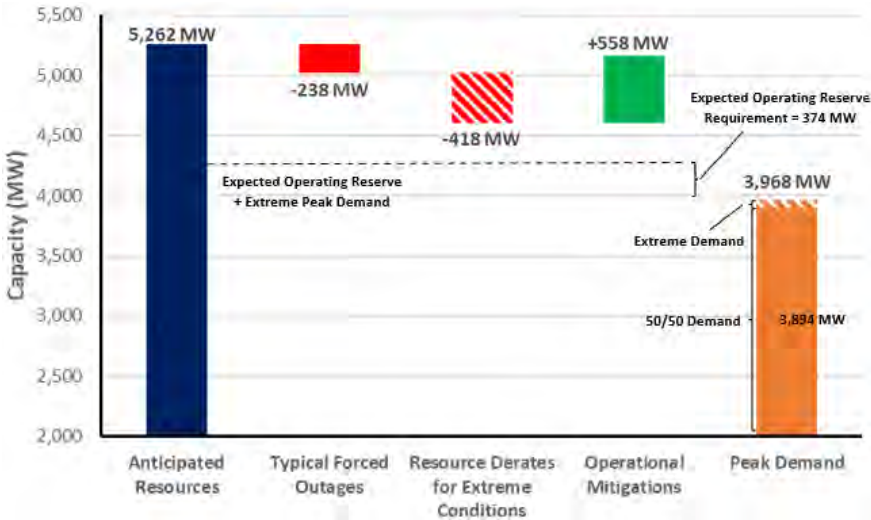
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Based on the historical load variability, SaskPower calculates a probability density function for load to simulate various scenarios that include extreme conditions.

Typical Forced Outages: Estimated using SaskPower forced outage model

Resource Derates for Extreme Conditions: Wind capacity is derated by 96% due to the cut-out of most wind farms below -30°C. Solar generation is expected to be fully unavailable under extreme conditions.

Operational Mitigations: Includes the non-firm import capability (360 MW) and generators in layup status (167 MW) that can be brought online with one to five days’ notice; additional demand-side resources are estimated based on other demand response programs and non-firm loads that require 15 minutes to 2 hours of notification



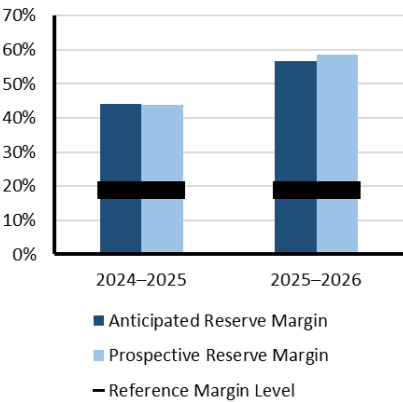
MRO-SPP

SPP’s footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Highlights

- SPP anticipates that planning reserves are adequate for the upcoming winter season even as SPP continues to set new winter season load records.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2025–2026 Winter season but realizes that interruptions to fuel supply combined with higher penetration of variable energy resources could create unique operation challenges.
- SPP continues to work at enhancing communications and operator preparedness with neighboring regions to address potential electric deliverability issues associated with extreme weather events.
- To minimize conservative operations, EEAs, and mid-range forecast error uncertainty response in wind forecasts, SPP implemented several new operational mitigation processes and procedures to deal with high-impact real-time areas of reliability concern.
- SPP has proposed numerous resource adequacy initiatives, including addressing EUE standards, fuel assurance, winter planning reserve margins, outage policies, demand response, and accreditation; all were recently approved by FERC.

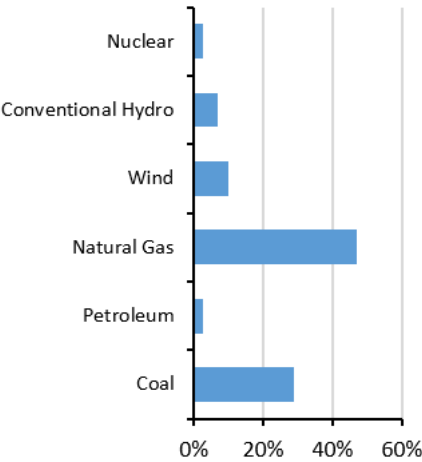
On-Peak Reserve Margin



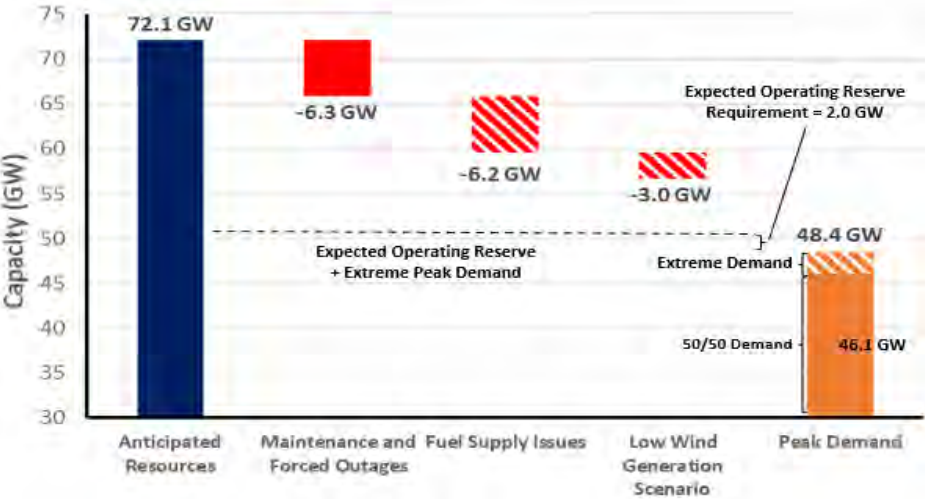
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast using historical data

Maintenance and Forced Outages: A capacity derate of 6.3 GW for maintenance outages, forced outages, and performance in extreme weather based on historical data

Fuel Supply Issues: BA derate of 6.2 GW based on MW capacity of gas-fired generators experiencing fuel supply issues in winter storm Elliott.

Low Wind Generation Scenario: 3 GW of wind potentially off-line when temperatures fall below their cold weather performance packages



NPCC-Maritimes

NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. state of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 1.9 million people. The New Brunswick Power Corporation (NB Power) is the balancing authority for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the balancing authority for Nova Scotia. NB Power’s system is electrically interconnected with NPCC-Québec and NPCC-New England, and the electric systems in the provinces of Nova Scotia and Prince Edward Island have ties with New Brunswick but no direct ties with other assessment areas. Peak electricity demand in NPCC-Maritimes occurs during the winter season.

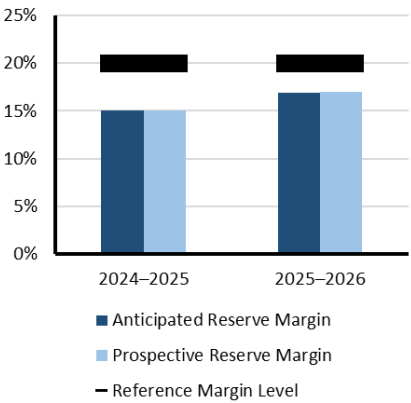
Highlights

- The Maritimes has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind, dual-fuel oil/gas, tie benefits, and biomass with no one type making up more than about 27% of the total capacity in the area.
- The Maritimes has long-term energy contracts in place for its winter supply and can purchase additional energy in the day-ahead and in real time as required.
- As part of the winter planning and preparation process, dual-fueled units will have sufficient supplies of heavy fuel oil stored on site to enable sustained operation in the event of natural gas supply interruptions.

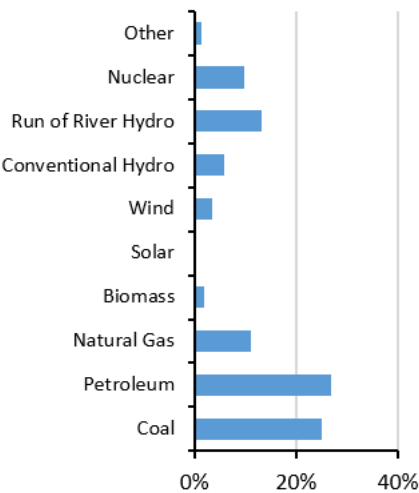
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates some risk of unserved energy and LOLH under high demand or low resource scenarios.

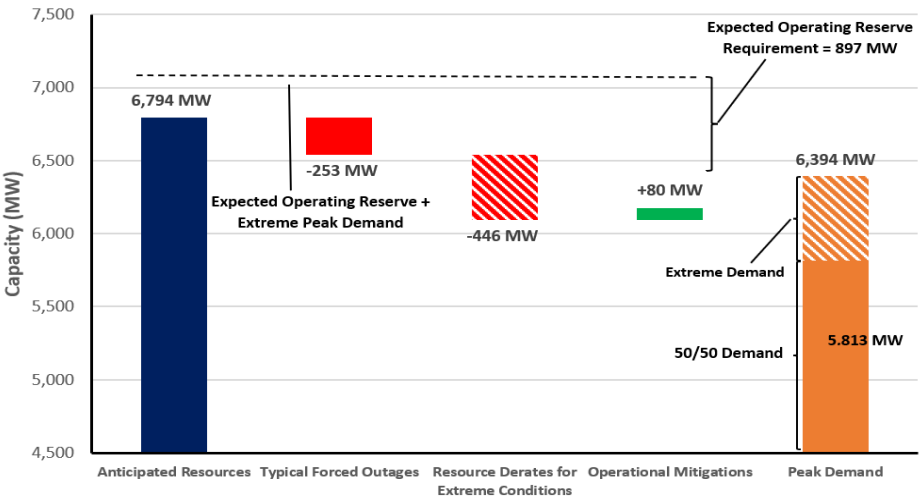
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Scenario peak load with adjustment calculated by adding a 10% margin of error to the peak internal demand forecast taken from the *Long-Term Reliability Assessment* (LTRA) for the 2025–2026 Winter period (aligns with the all-time winter peak, which occurred on February 4, 2024)

Typical Forced Outages: Based on historical operating experience

Resource Derates for Extreme Conditions: Based on ambient temperature thermal derates, wind derated to zero, as well as natural gas capacity derated by 50% due to supply issues

Operational Mitigations: Based on emergency operations and planning procedures in place including fuel switching



NPCC-New England

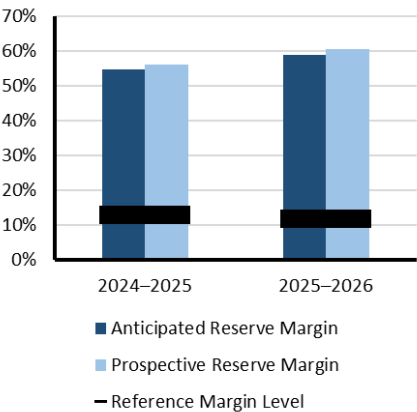
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England’s bulk power generation and transmission system, administration of the area’s wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- ISO-NE expects to meet its regional resource adequacy requirements this 2025–2026 Winter operating period without calling upon operating procedures to maintain a balance between electricity supply and demand.
- A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold spell given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and liquefied natural gas (LNG)).
- ISO-NE expects to have sufficient capacity resources to meet the 2025–2026 50/50 and 90/10 winter peak demand forecast of 19,616 MW and 21,125 MW, respectively, for the weeks beginning January 10, January 17, and January 24.
- ISO-NE has recently developed the Regional Energy Shortfall Threshold (REST) as an effort to quantify the tolerable risk of energy shortfall during extreme events. Within the 0.25% highest-risk scenarios, the REST thresholds are 3.0% normalized EUE over 72-hour periods and 18.0 hours over 21-day periods.
 - ISO-NE does not anticipate exceeding the REST criteria for Winter 2025–2026.

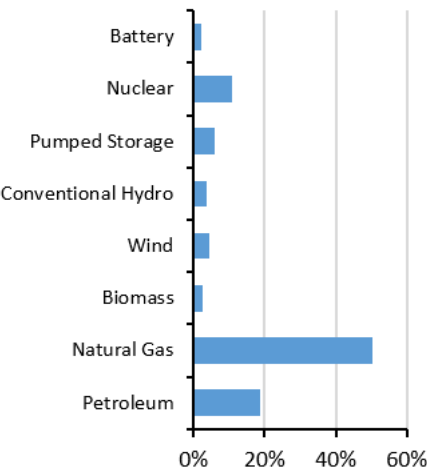
On-Peak Reserve Margin



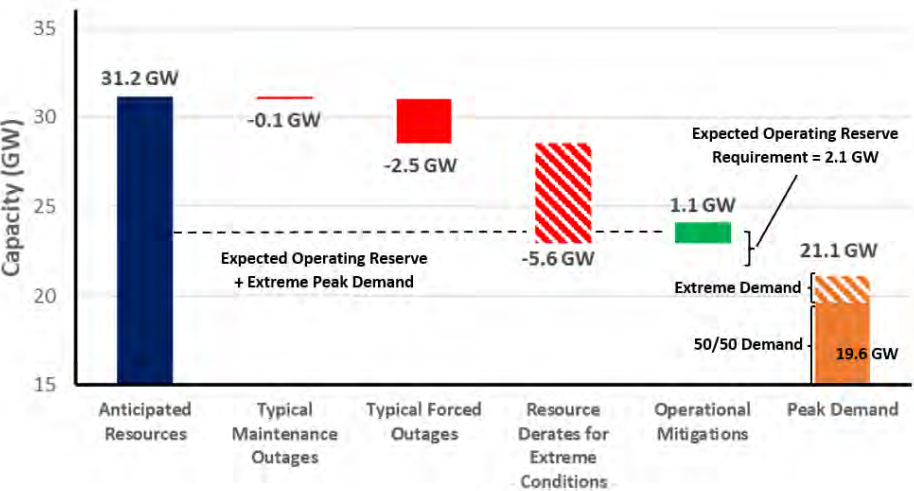
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with high generator outages could result in the need for operating mitigations (i.e., demand response and transfers). Prolonged extreme cold weather events that result in depletion of stored fuels can lead to resource shortfalls.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast capturing the region’s coldest day in the last 30 years using current and future load models

Typical Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Resource Derates for Extreme Conditions: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather-related outages

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York’s BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this WRA, the established RML is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2025–2026 IRM at 24.4%.

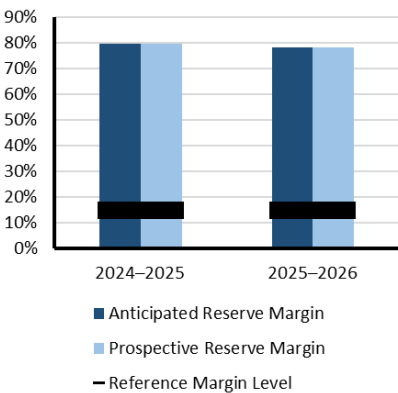
Highlights

- New York is presently a summer-peaking area, and no emerging reliability issues are anticipated during the 2025–26 Winter assessment period.
- Expected resources meet operating reserve requirements under the assessed demand and resource scenarios. A scenario involving an extended cold snap that causes above-normal demand and diminished natural gas supplies would result in low but sufficient reserves.
- The preliminary results of the NPPCC winter probabilistic assessment indicate that operating procedures are not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period for all the scenarios modeled.

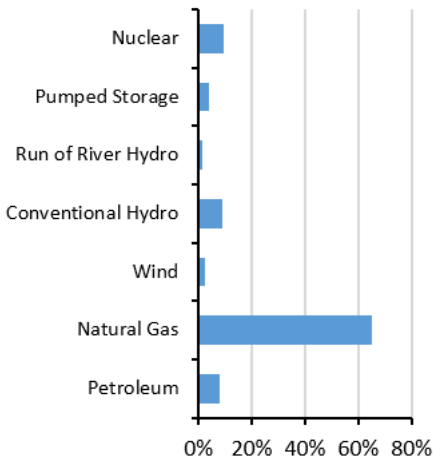
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed demand and resource scenarios.

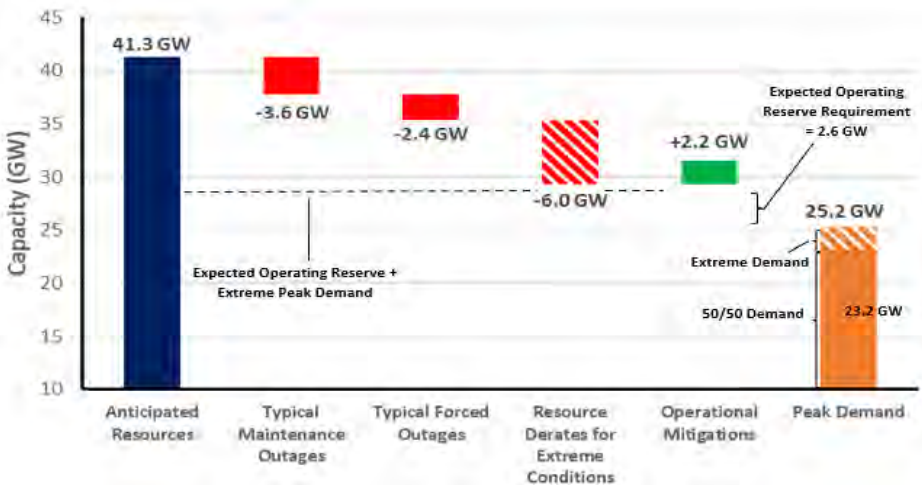
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Maintenance Outages: Based on planned scheduled maintenance

Typical Forced Outages: Based on 5–year averages from GADS data.

Resource Derates for Extreme Conditions: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather. Based on a 2025 analysis, approximately 6,307 MW of gas generation with non-firm fuel supplies could be unavailable.

Operational Mitigations: Based on NYISO operating procedures



NPCC-Ontario

NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of almost 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

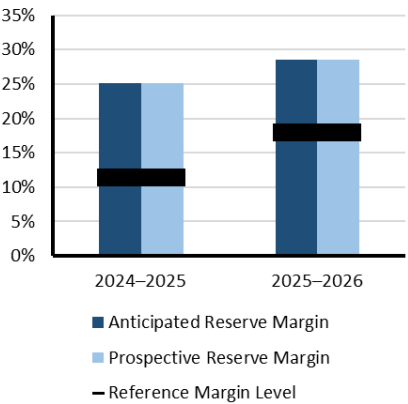
Highlights

- As Ontario is a summer-peaking province, there is typically a lower risk of reliability issues during the winter than the summer. However, Ontario regularly experiences extreme cold weather in the winter.
- NPCC-Ontario is well prepared for Winter 2025–2026, and IESO expects that the electric system will remain reliable with reserve margins well above required levels.
- Operators and forecasters in Ontario work closely with neighboring jurisdictions to manage extreme weather events.
- Natural-gas-fired generators in Ontario are supplied by pipelines with access to the Enbridge Gas Dawn Hub and its associated storage facilities, which significantly reduces natural gas deliverability and reliability concerns by connecting those systems to several major gas transportation corridors, enabling access to multiple supply basins.

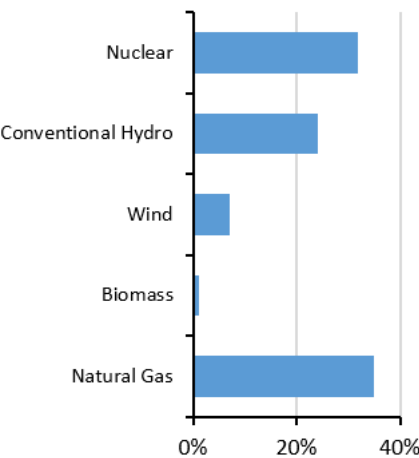
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

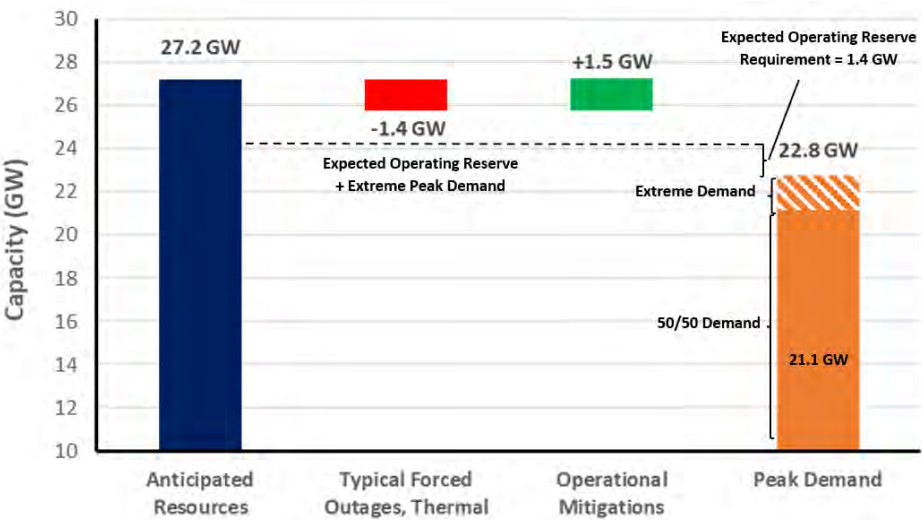
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand from 31 years of winter demand history

Typical Forced Outages, Thermal: Based on analysis of a rolling five-year history of actual forced outage data.

Operational Mitigations: Imports anticipated from **neighbors** during emergencies



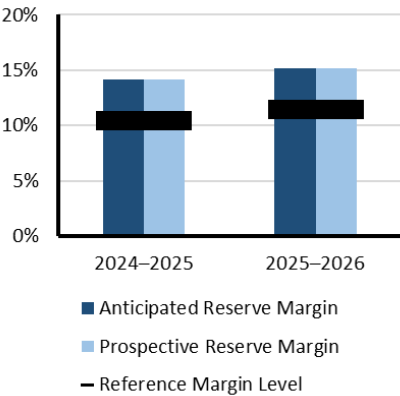
NPCC-Québec

NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the four electric Interconnections in North America. It is a predominately hydroelectric-generation-based system that is electrically interconnected with NPCC-Ontario, NPCC-New York, NPCC-New England, and NPCC-Maritimes. Peak electricity demand in NPCC-Québec occurs during the winter season.

Highlights

- NPCC-Québec projects adequate capacity margins above its reference reserve requirements and that system resource adequacy will be maintained for the province for the 2025–26 Winter assessment period.
- No hydropower performance issues are expected during extreme cold because of design criteria for cold weather.
- No fuel supply or transportation issues are anticipated for the upcoming winter season.
- While a slight decrease in net firm transfers has occurred since last winter (-89 MW), significant increases in demand-side management programs (+450 MW year-over-year) have been realized over the same period and are expected to compensate for this winter’s modest expected load growth.

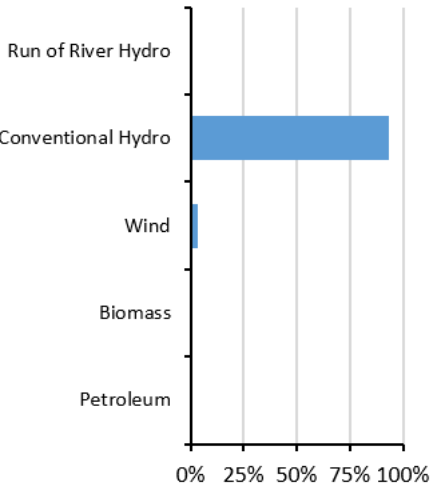
On-Peak Reserve Margin



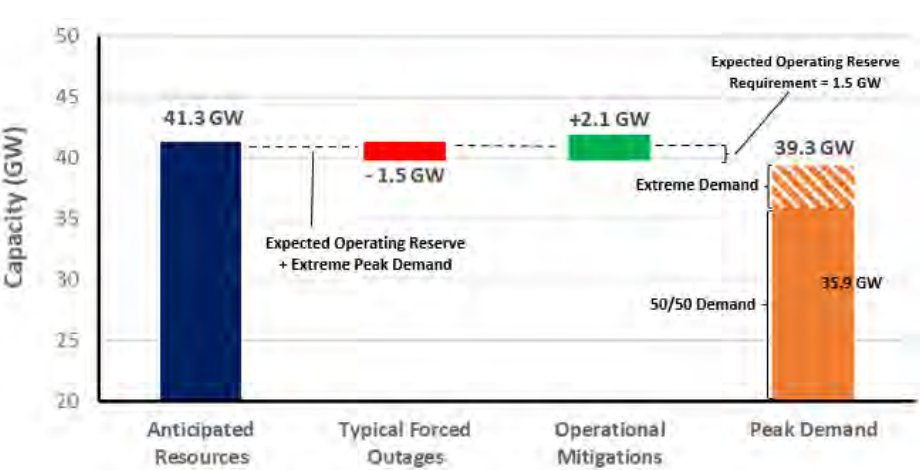
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 8:00 a.m.

Demand Scenarios: Demand forecasts include demand-side resources. The demand side resources are the same for the 50/50 and extreme demand scenarios. The extreme load forecast is determined at two standard deviations higher than the mean, which has a 6.06% probability of occurrence.

Extreme Derates: Maintenance outages and other deratings are already included in existing-certain capacity calculation. Wind capacity is 64% derated

Typical Forced Outages: Unplanned outages are 1,500 MW.

Operational Mitigations: Operational mitigations include imports from neighboring areas and reduction of reserves



PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM’s footprint covers approximately 369,054 square miles and with an approximate population of 67 million people. PJM is the area’s BA, Transmission and Resource Planner, interchange authority, TOP, transmission service provider, and RC. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

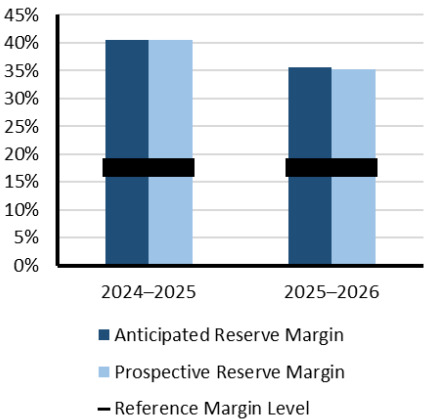
Highlights

- Due to the low penetration of limited and variable resources in PJM relative to PJM’s peak load, the hour with highest loss-of-load risk remains the hour with highest forecasted demand.
- PJM is expecting little capacity adequacy risk during Winter 2025–2026 and expects around 35% installed reserves, which is above the target IRM of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- Last winter, PJM hit a new all-time winter peak, but generator preparations anticipating congestion and tight capacity projections led to sufficient reserves throughout the demand event and PJM’s transmission system performed well.
- The decrease in reserves from Winter 2024–2025 is due to load increases and retirement of generation without like (non-solar dispatchable) replacement generation.

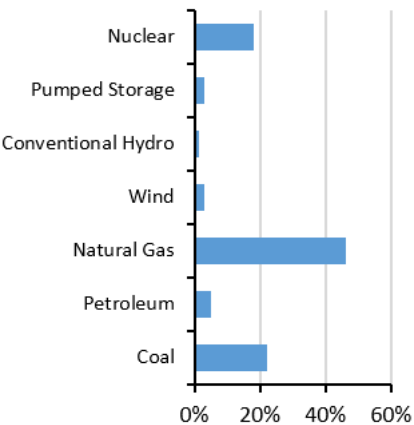
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

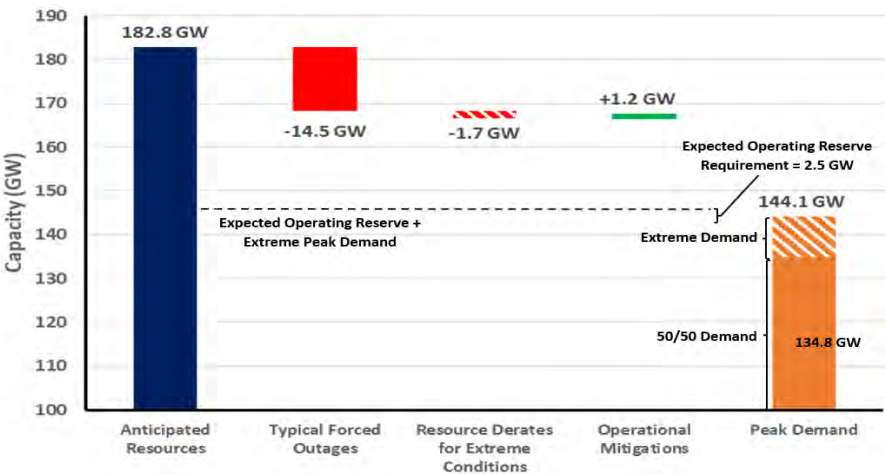
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Based on historical data and trending

Resource Derates for Extreme Conditions: Reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: accounts for an estimated value based on operational / emergency procedures



SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

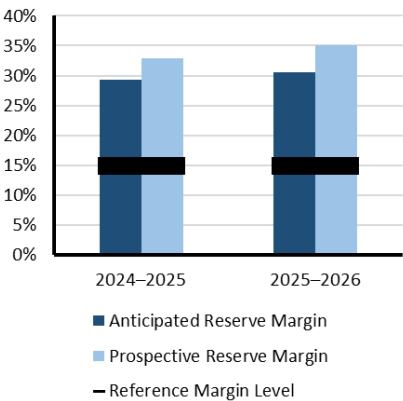
Highlights

- SERC-Central is transitioning from a summer-peaking area to a dual-peaking system.
- For the 2025–2026 Winter, SERC-Central projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProBA base-case results.
- Most entities across SERC-Central report that fuel security is strong since it is supported by firm natural gas contracts, storage resources, and reliable pipeline capacity. Coal inventories are projected to remain within operational ranges necessary to meet winter demand.
- Following lessons from Winter Storm Elliott, one SERC-Central entity raised its winter Planning Reserve Margin target to 26% and updated preparedness programs with improved heat trace capabilities.

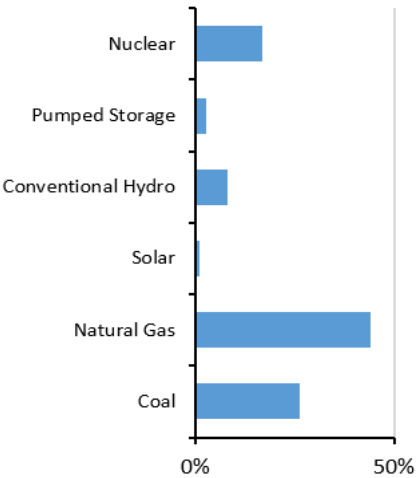
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand. A severe cold weather event that extends to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

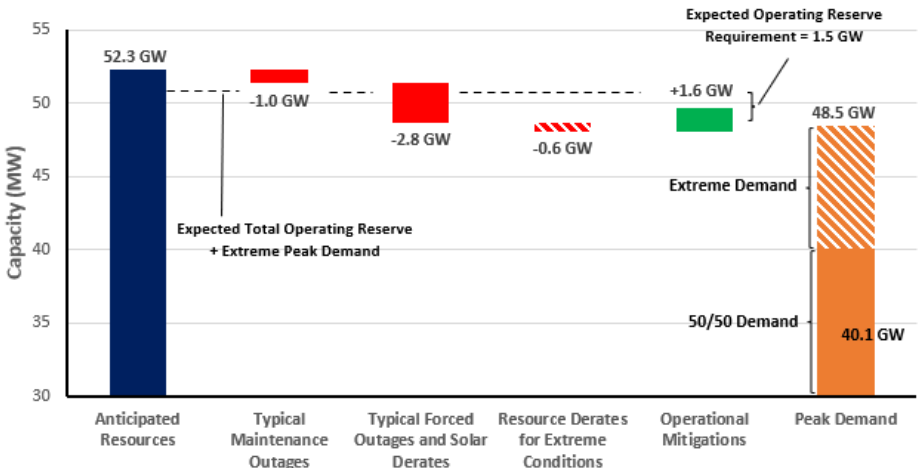
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for expected outages during December through February

Typical Forced Outages and Solar Derate: Includes any weighted average forced-outage rates on-peak that are not factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood extreme conditions

Operational Mitigations: A total of over 1.6 GW based on operational/emergency procedures



SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six Regional Entities across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

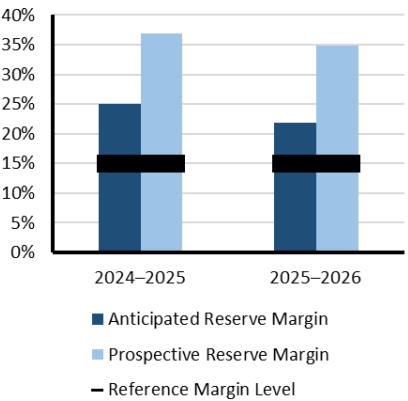
Highlights

- SERC-East is transitioning from a summer-peaking area to potentially peaking during both summer and winter. This shift is attributed to the continued addition of solar PV generation, which reduces summer peak demand, and a trend toward electrification of heating, which drives up winter peak demand.
- For the 2025–2026 Winter, the SERC-East region projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Fuel supplies and transportation remain stable, and entities anticipate maintaining adequate coal and oil inventories with no reported changes to fuel procurement or operator plans for the upcoming winter.
- Probabilistic Base Case Results (Median Weather): EUE is 61.95 MWh and LOLH is 0.06 hours/year. EUE values are likely due to higher winter peaks and/or lower supply of capacity that can meet early winter morning demand.
- Mitigation measures for extreme conditions include voltage reduction (25–50 MW) and load-shedding programs that cover up to 30% of system load.

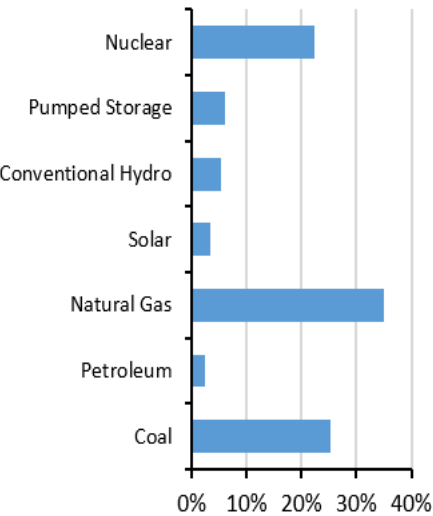
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal demand scenarios. A severe cold weather event extending to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

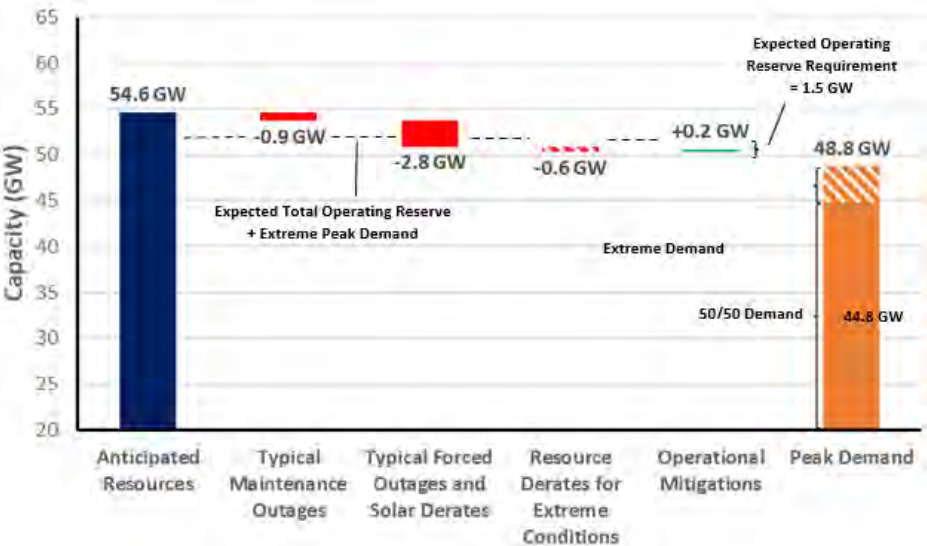
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages (excluding 2022–2025)

Operational Mitigations: A total of 0.2 GW based on operational/emergency procedures



SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity area covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

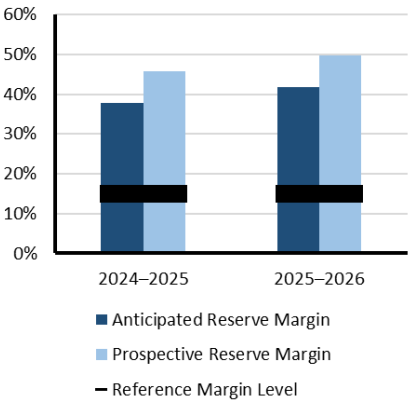
Highlights

- SERC-Florida Peninsula is a summer-peaking assessment area.
- Florida Peninsula entities have not identified any emerging reliability issues for the upcoming 2025–26 Winter season with an ARM projected at 39%, well above the RML, while the 2024 NERC ProbA base-case results project a sufficient level of resources to serve the expected load under median weather and typical system operating conditions (EUE is 1.09 MWh and LOLH is 0.00 hours/year).
- Many entities report strong fuel security, supported by firm natural gas contracts, storage resources, reliable pipeline capacity, and actively managed coal and oil inventories, which are projected to remain within operational ranges to meet winter demand.
- Florida Peninsula entities do not assume non-firm external assistance from neighboring areas during extreme conditions.

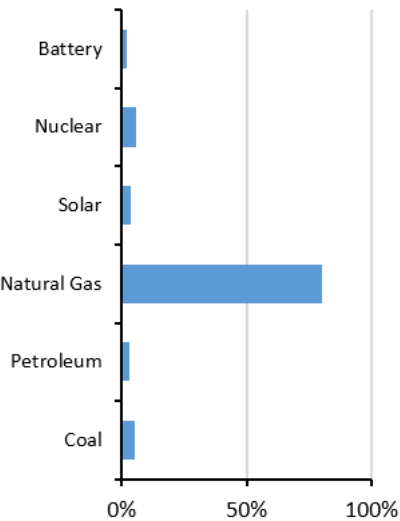
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

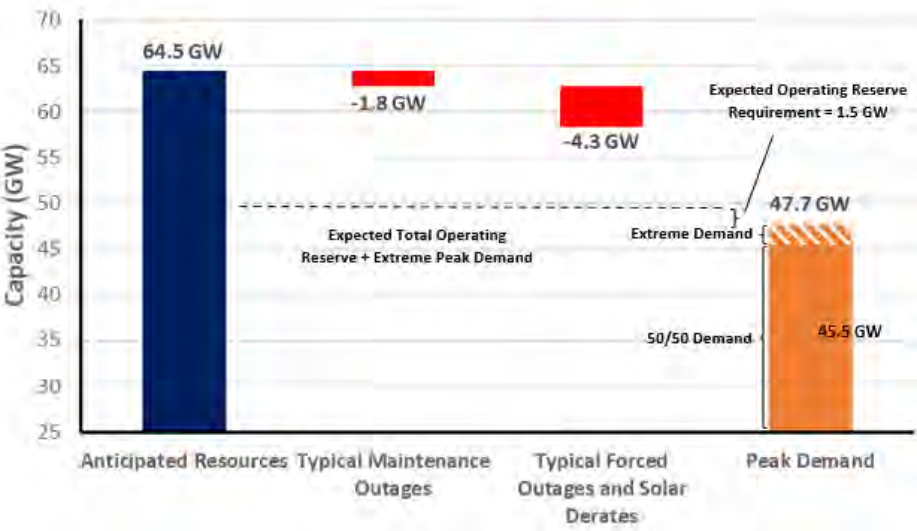
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood extreme conditions



SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

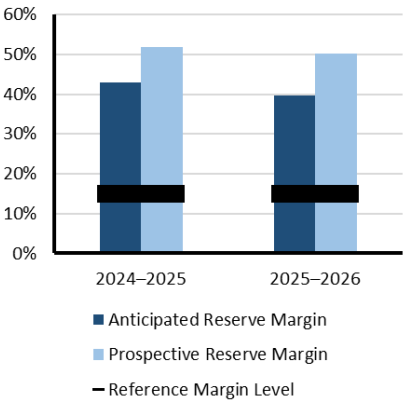
Highlights

- SERC-Southeast is trending towards becoming slightly winter-peaking.
- For the 2025–2026 Winter, SERC-Southeast entities report no emerging reliability concerns and expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories to serve the expected load under typical system operating conditions. The 2024 NERC ProbA base-case results in EUE and LOLH are both 0.00.
- While most SERC-Southeast BAs expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories, one BA highlights potential risks related to natural gas transportation capacity, citing high pipeline utilization, competition for delivered gas, and ratable flow requirements. Mitigation strategies include securing third-party gas supply, adding dual-fuel capability, and implementing coal inventory management.
- Entities have made refinements such as replacing specific 230 kV circuit breakers and increasing monitoring frequencies for critical plant systems after January 2025 winter events.

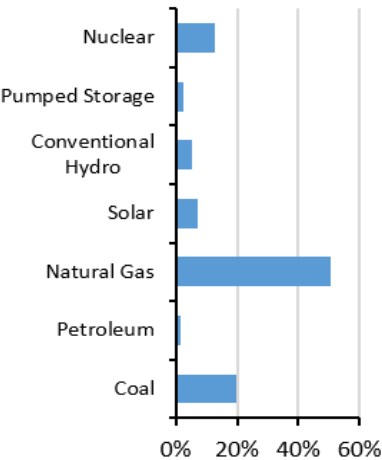
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

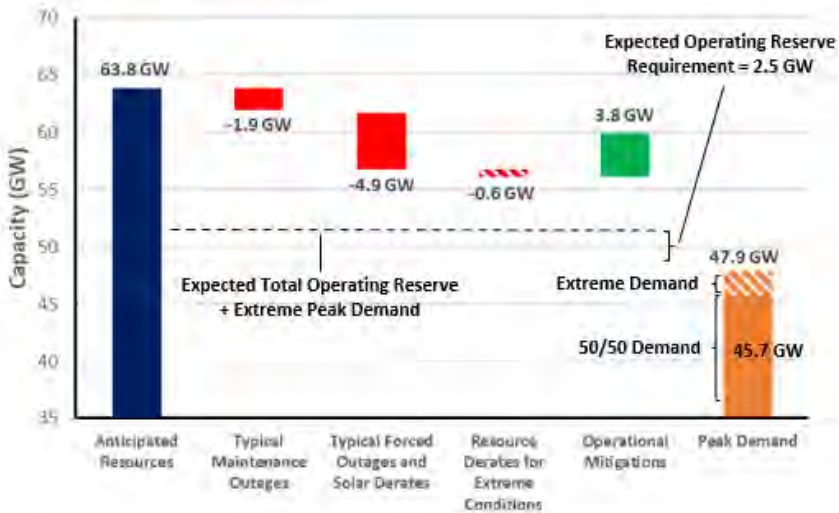
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages

Operational Mitigations: A total of 3.8 GW based on operational/emergency procedures



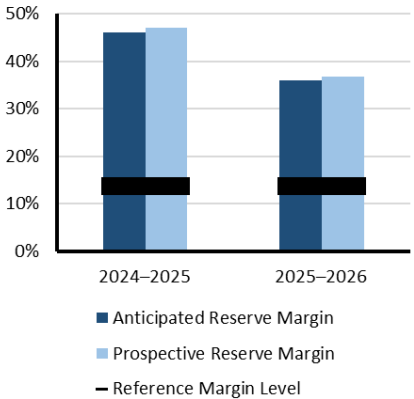
Texas RE-ERCOT

ERCOT is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking and covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas power grid.

Highlights

- Given expected system conditions, an ARM of 36% and RML of 13.75%, ERCOT expects to have sufficient operating reserves for the peak hour ending 8:00 a.m.
- ERCOT does not expect any significant fuel supply issues for the winter.
- ERCOT has conducted 2,028 generation resource and transmission service provider (TSP) winter weatherization inspections since Winter 2021–2022.
- Winter peak demands typically occur before sunrise and after sunset when solar generation is not available. Significant battery storage mitigates these risks.
- ERCOT’s probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
- Increased load growth in west Texas combined with “no solar” and low wind conditions can cause transmission lines into this area to become heavily loaded. ERCOT has introduced improved dynamic line ratings that allow for greater transfers at colder temperatures and periods of low irradiance.

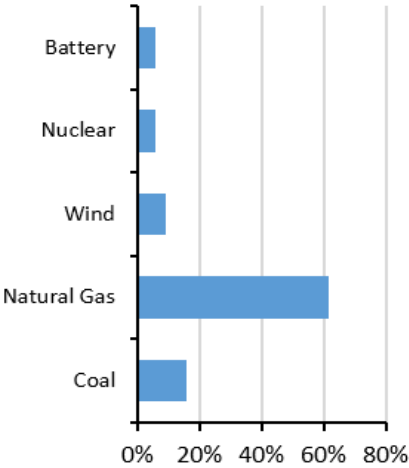
On-Peak Reserve Margin



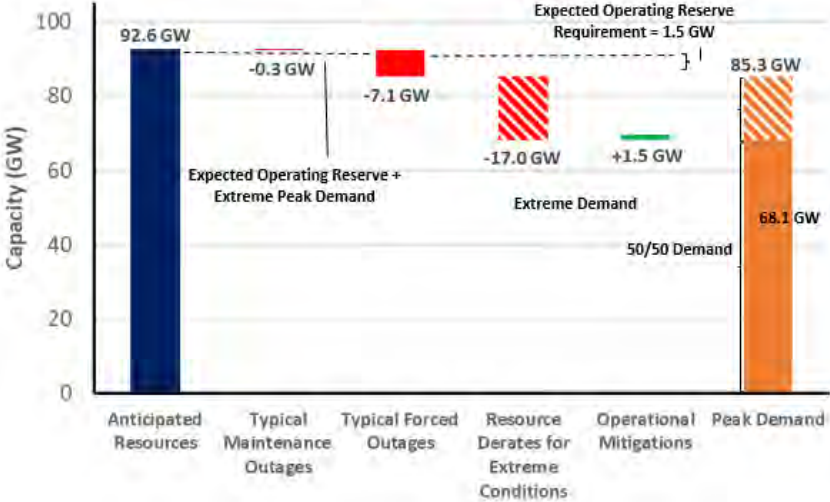
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour
Demand Scenarios: Presumes weather conditions comparable to Winter Storm Uri. The adjustment is calculated as the difference between the 100th percentile and 50th percentile values from ERCOT’s Probabilistic Reserve Risk Model (PRRM) simulated load outcome distribution for hour ending 8:00 a.m.
Typical Maintenance Outages: Based on historical winter data and consideration of ERCOT’s allowed maximum system daily planned outage capacity
Typical Forced Outages: Based on a probability distribution created using historical ERCOT Outage Scheduler data for the last three Januaries.
Resource Derates for Extreme Conditions: Weather-related thermal and wind outages based on Winter Storm Uri levels, adjusted for reductions due to weatherization standards. Also includes high non-weather-related outages.
Operational Mitigations: Additional potential capacity from switchable generation and imports



WECC-Alberta

WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province’s Planning Entity and RC responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta’s transmission system has three interties with neighboring areas: Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

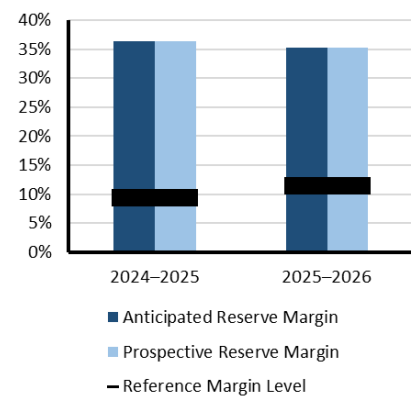
Highlights

- At an extreme winter peak of 12,982 MW, with extreme forced outages at 530 MW and derates for extreme conditions bringing wind energy availability down by 1,800 MW and hydroelectricity by 88 MW, the required reserves are 759 MW and are sufficiently met, even with low availability.
- Demand is expected to increase 1.1% from last winter with the existing-certain installed capacity having increased 23%.
- Solar availability is down because 1,000 MW of PV moved from originally expecting to come on-line in 2024 as Tier 1 resources to Tier 2s mostly anticipated to come on-line in 2025, but with less certainty.

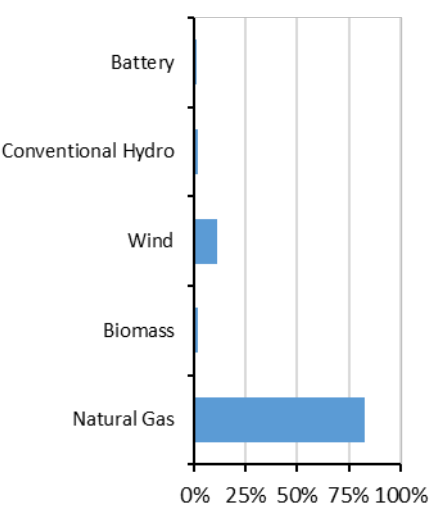
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

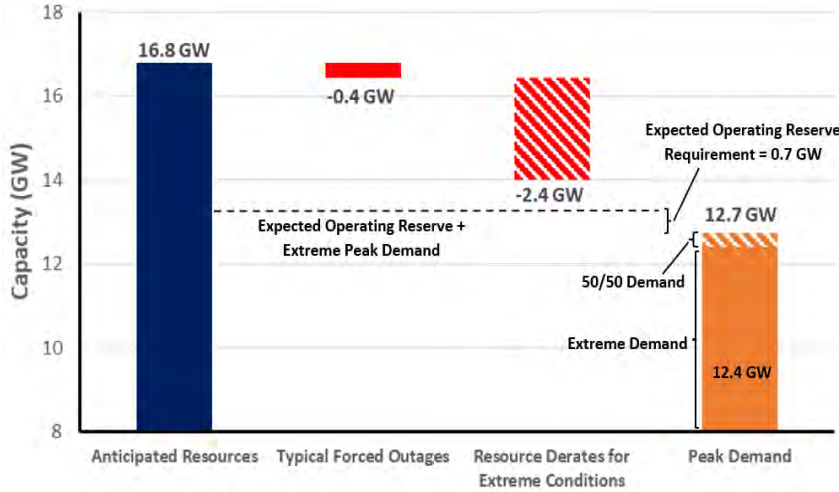
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS data

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves’ probability distributions’ 10th percentiles for the risk period



WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp’s eastern BA area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC’s 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025-26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

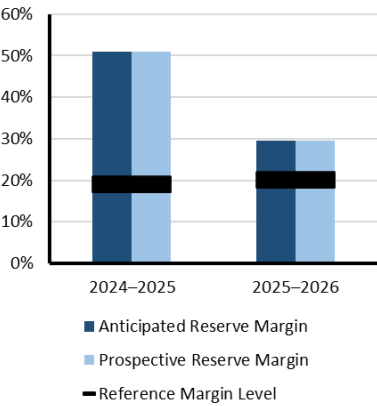
Highlights

- At an extreme winter peak of 11.1 GW under an extreme combination of derates and outages, the region could be short 1.0 GW before imports and is expected to need to rely on transfers.
- Net internal demand is expected to increase 1% since last year, with total internal demand up 1.8% being offset by a doubling of controllable and dispatchable demand response.
- Tier 1 resources have declined and do not appear to be offset by increases in existing-certain generation resource capacity. Nameplate wind has increased by almost 18% and solar by almost 30%. Hydro is also up over 7% in total installed capacity.
- Reliance on imports is expected to be required to maintain resource adequacy during extreme peak demand and extreme derate conditions.

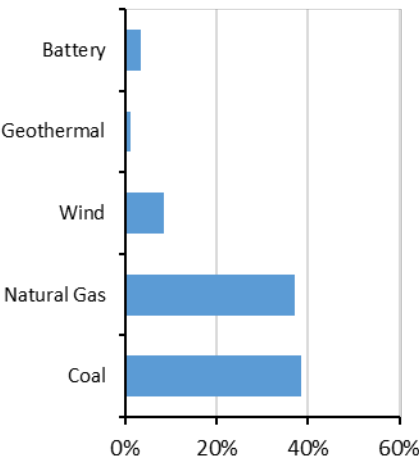
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

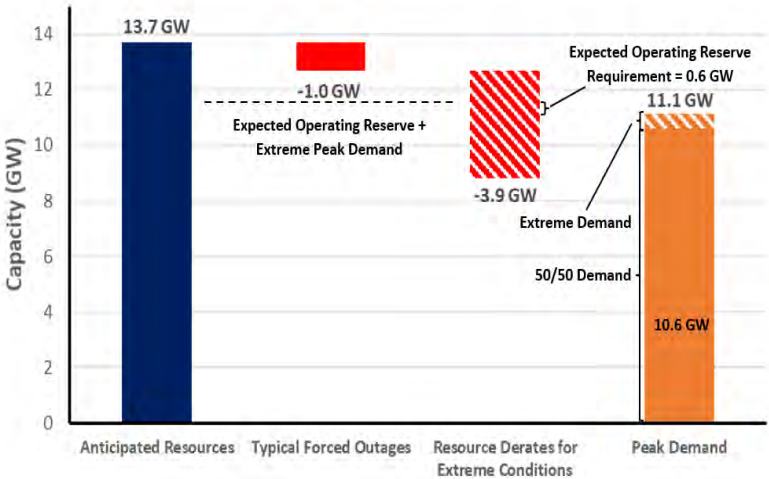
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Extreme Derates: Thermal, wind, and solar are based on the hourly energy availability curves’ probability distributions’ 10th percentiles for the risk period



WECC-British Columbia

WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and RC for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia BES and its interconnections. BC Hydro operates an integrated system supported by 30 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro’s transmission system has two interties with neighboring areas: the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during winter.

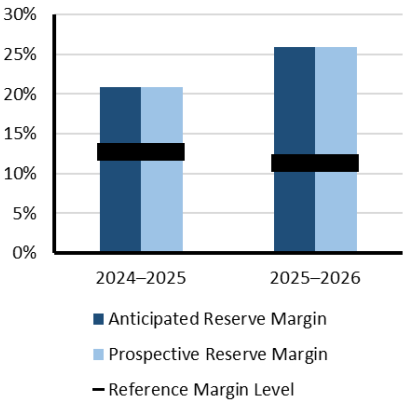
Highlights

- Peak demand is expected to remain about the same as last winter.
- There are about 200 MW more (47%) planned Tier 1 resources for this winter than last.
- Solar nameplate capacity has increased from 2 MW to 17 MW since last winter and hydroelectric nameplate capacity is up more than 5%, or 1,366 MW.

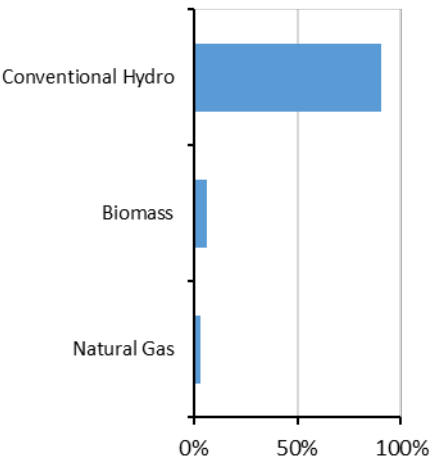
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme demand scenarios.

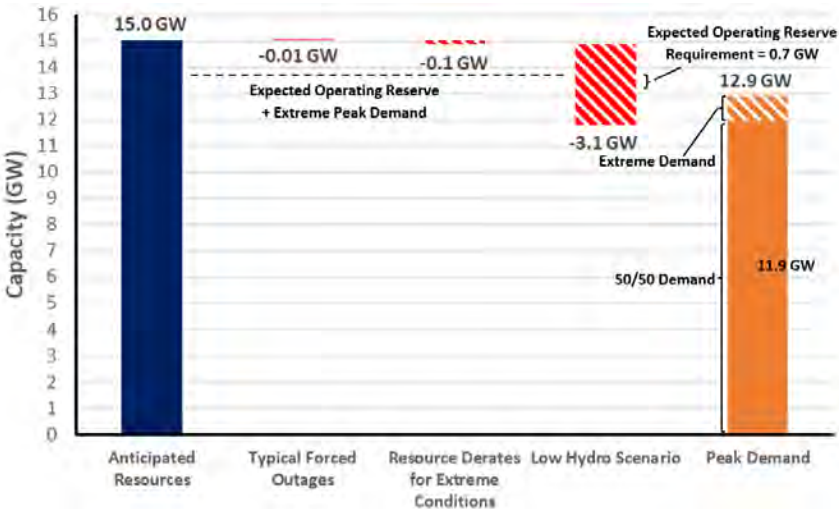
On-Peak Reserve Margin



On-Peak Resource Mix



2025-2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves’ probability distributions’ 10th percentiles for the risk period

Low Hydro Scenario: Estimated derate for lower hydro output



WECC-California

WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, the Los Angeles Department of Water and Power, the Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC’s 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

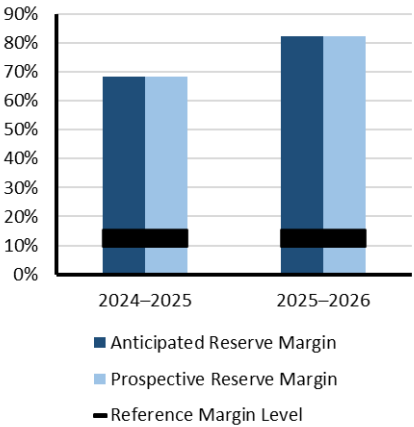
Highlights

- Operating reserve margins are met before imports in all winter resource availability scenarios.
- On-peak demand is expected to remain about the same as last winter. Demand-side management is down about 10%.
- Existing-certain capacity is up almost 5%, while planned Tier 1 resources are up more than 2 GW. The total wind nameplate capacity is up almost 27% and solar almost 13%. Hydro is down 4%.
- No reliance on imports is expected to be required to maintain resource adequacy for Winter 2025–2026.

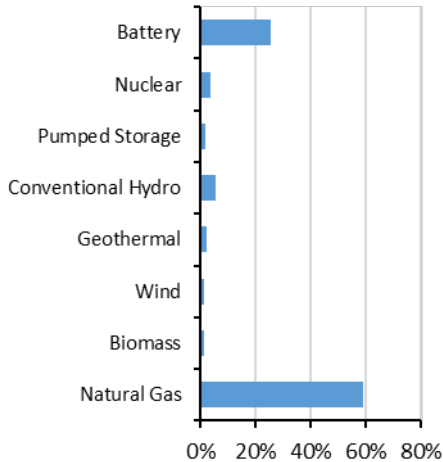
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

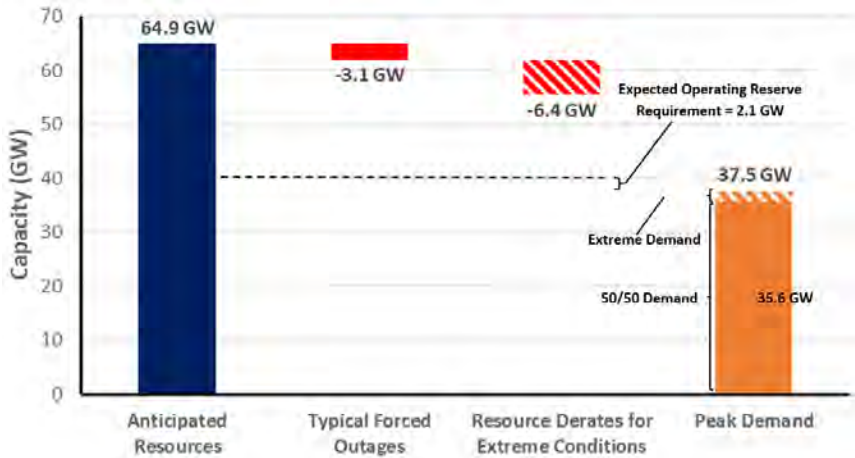
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves’ probability distributions’ 10th percentiles for the risk period



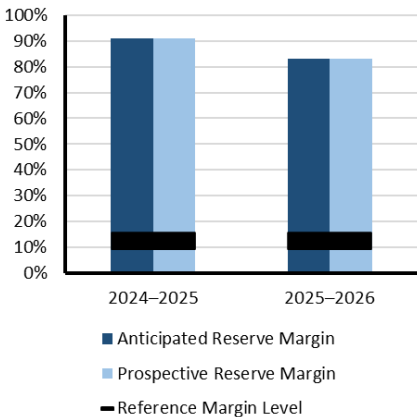
WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC’s 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

Highlights

- As a summer-peaking region, operating reserve margins are met before imports in all scenarios.
- Planned Tier 1 resources are down 100% to zero as expected resources have either been brought on-line to move into existing or, in the case of some natural gas, have been delayed until 2026 and moved into Tier 2.
- The existing-certain on peak reserve margin is down by 5.2%, and the anticipated and prospective reserve margins are down by 7.8%; however, since Mexico is heavily summer-peaking, the 83% reserve margin still exceeds the RML of 12.5%, which remains unchanged.

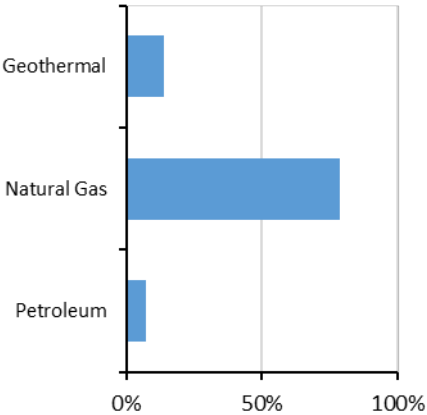
On-Peak Reserve Margin



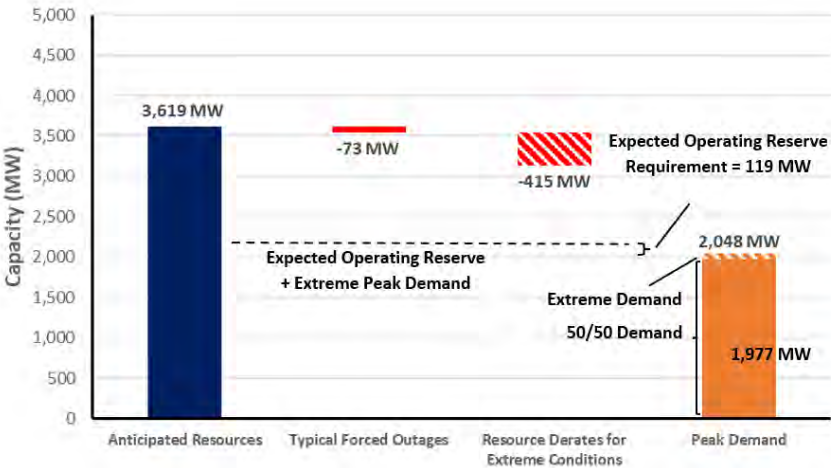
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves’ probability distributions’ 10th percentiles for the risk period



WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC’s 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

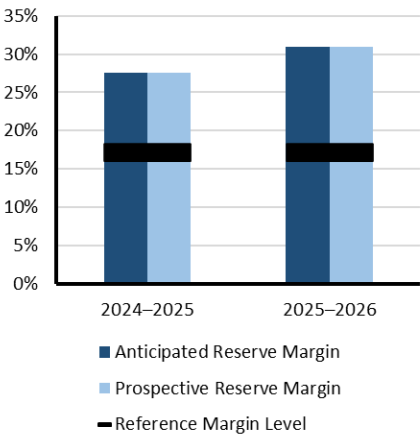
Highlights

- The Northwest has historically been a mixed season-peaking region.
- Operating reserve margins are expected to be met after imports in all winter scenarios.
- Total and net internal demand are up 9.3% with the primary drivers being data centers, residential electrification, transportation electrification, and semiconductor manufacturing.
- Large coal unit retirements and conventional hydro unit retirements are attributable to the reduction in existing certain capacity of 10.5%; however, planned Tier 1 resources have soared over 580%, from 463 MW to over 3 GW.
- Nameplate wind capacity is up over 3 GW (26%) and solar nameplate capacity is up nearly 2,690 MW (134%), which has also increased the solar availability on the peak hour.
- An increase in firm imports is seen in the model, 6.1 GW, absorbing the reduction in existing certain capacity of 4 GW.

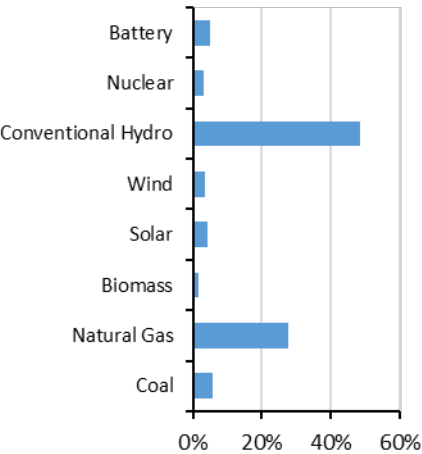
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

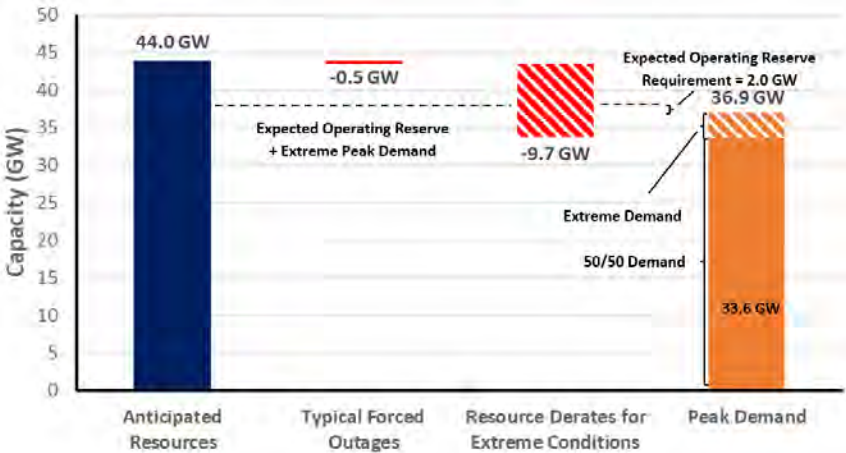
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves’ probability distributions’ 10th percentiles for the risk period. This value includes 6.8 GW of hydro derates.



WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration’s Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC’s 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

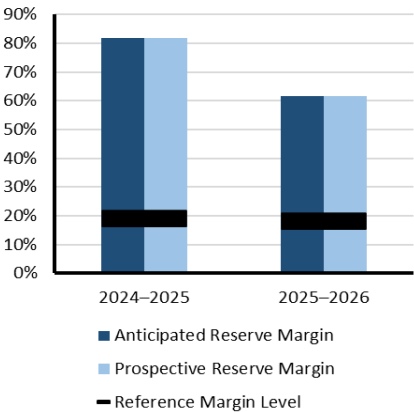
Highlights

- In Rocky Mountain, operating reserve margins are expected to be met before imports in all winter scenarios.
- Total and net internal demand are up almost 1%. The primary drivers are data centers and commercial and industrial customer growth.
- Planned Tier 1 resources are up over 84%, from almost 200 MW to over 365 MW. Solar nameplate capacity is up 27%; however, on-peak solar energy availability is down 100% due to the shift to after sunset. Expected hydro on peak energy availability is also down by around a quarter on the peak hour. Existing-Certain, Anticipated, and Prospective Reserve Margins are all down by over 20% on the peak hour; however, the region still maintains resource adequacy with margins hovering around 60% compared to the RML of 18%.
- No reliance on imports is expected to be required to maintain resource adequacy under combined extreme peak and extreme derated conditions.

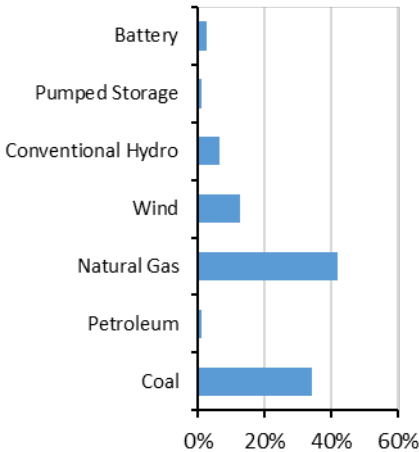
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

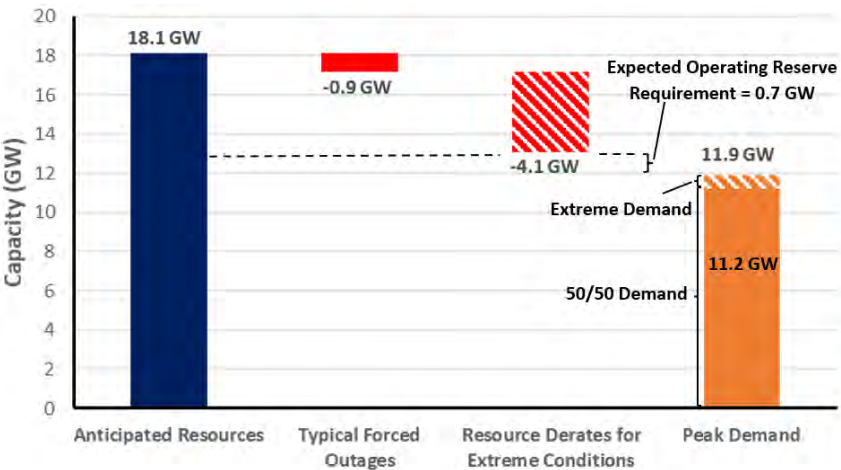
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves’ probability distributions’ 10th percentiles for the risk period



WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC’s 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

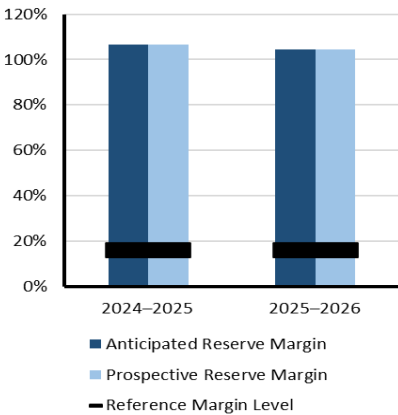
Highlights

- The Southwest is anticipated to be resource adequate under all winter expected and extreme energy availability and demand scenarios before imports.
- Total internal demand is expected to be up 1.5% and net internal demand up 2.3% since last winter. The primary drivers for load growth are data centers and industrial and residential electrification. Controllable and dispatchable demand response is down nearly half, by 163 MW.
- Planned Tier 1 resources are down over 19% as some have moved into existing certain, which is up almost 3%, over 1 GW, and other projects have experienced delays.
- Wind nameplate is up 12%, 470 MW, correlating to on-peak energy availability from wind increasing almost 11%, by 114 MW, while solar nameplate is up 27% or over 2.5 GW.

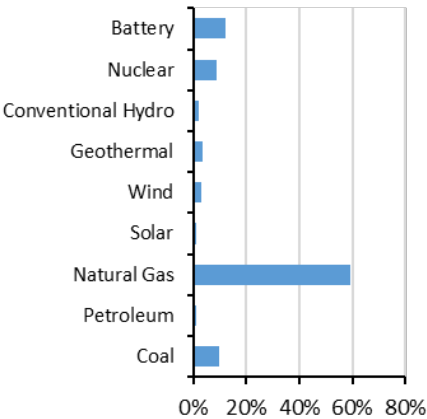
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves’ probability distributions’ 10th percentiles for the risk period

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
- Reliability of the interconnected BPS is comprised of both adequacy and operating reliability: - Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components. - Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components. - The reserve margin calculation is an important industry planning metric used to examine future resource adequacy. - All data in this assessment is based on existing federal, state, and provincial laws and regulations. - Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments. - A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
- Electricity demand projections, or load forecasts, are provided by each assessment area. - Load forecasts include peak hourly load¹¹ or total internal demand for the summer and winter of each year.¹² - Total internal demand projections are based on normal weather (50/50 distribution)¹³ and are provided on a coincident¹⁴ basis for most assessment areas. - Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (VER) (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: Existing-Certain Capacity: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. Tier 1 Capacity Additions: This category includes capacity that either is under construction or has received approved planning requirements. Net Firm Capacity Transfers (Imports minus Exports): This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

¹¹ https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

¹² The summer season represents June–September and the winter season represents December–February.

¹³ Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

¹⁴ Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the [Regional Assessments Dashboards](#). The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The ARM, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.¹⁵ Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. NPCC-Maritimes marginally does not meet its RML for the upcoming winter. Other than NPCC-Maritimes, all assessment areas have sufficient ARMs to meet or exceed their RML for the 2025 winter as shown in [Figure 4](#).

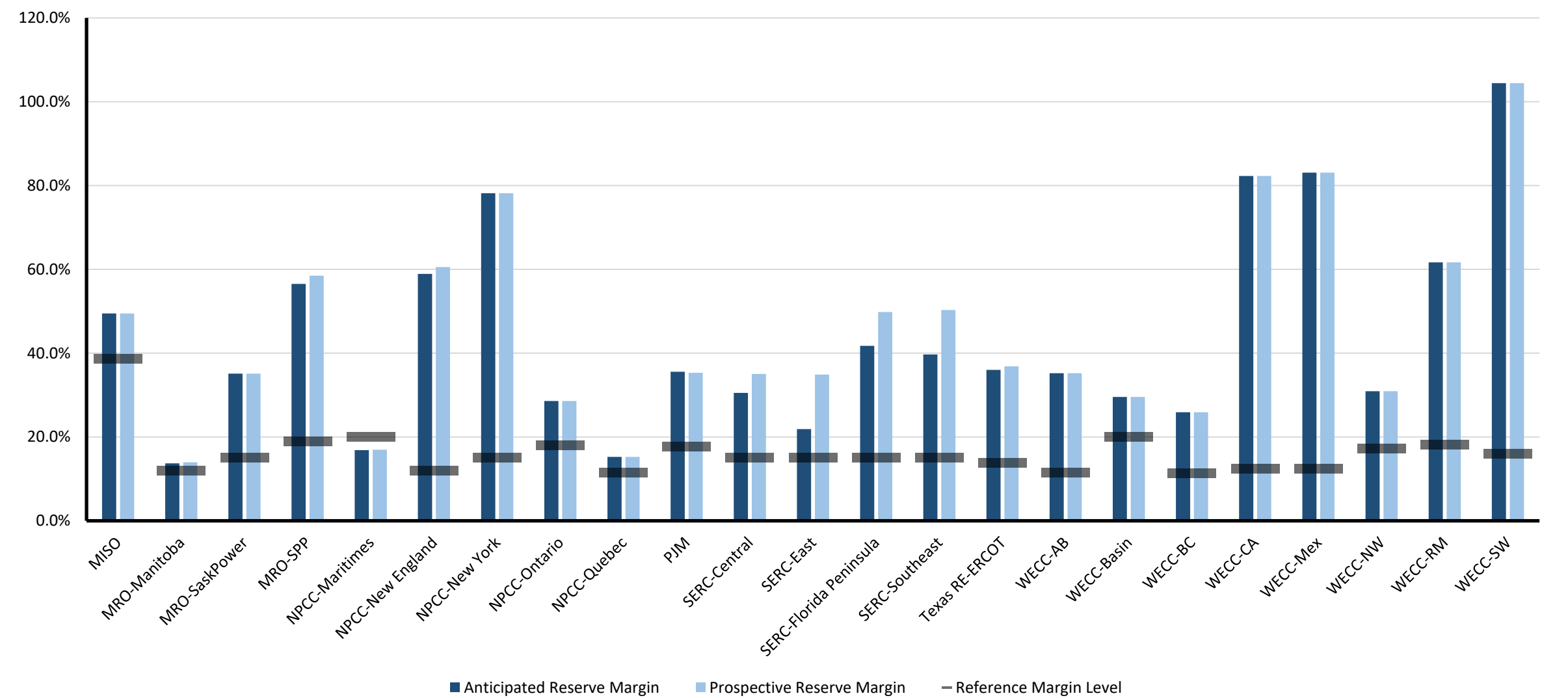


Figure 4: Winter 2025–2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

¹⁵ Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the [Data Concepts and Assumptions](#) section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast ARMs from the 2024–2025 Winter to the 2025–2026 Winter. All areas except NPCC-Maritimes remain above their RMLs for 2025–2026 Winter. The Canadian winter-peaking systems, which include MRO-Manitoba, MRO-SaskPower, NPCC-Maritimes, NPCC-Québec, WECC-Alberta, and WECC-British Columbia, may have reserve margins that are near RMLs but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the [Data Concepts and Assumptions](#) section.

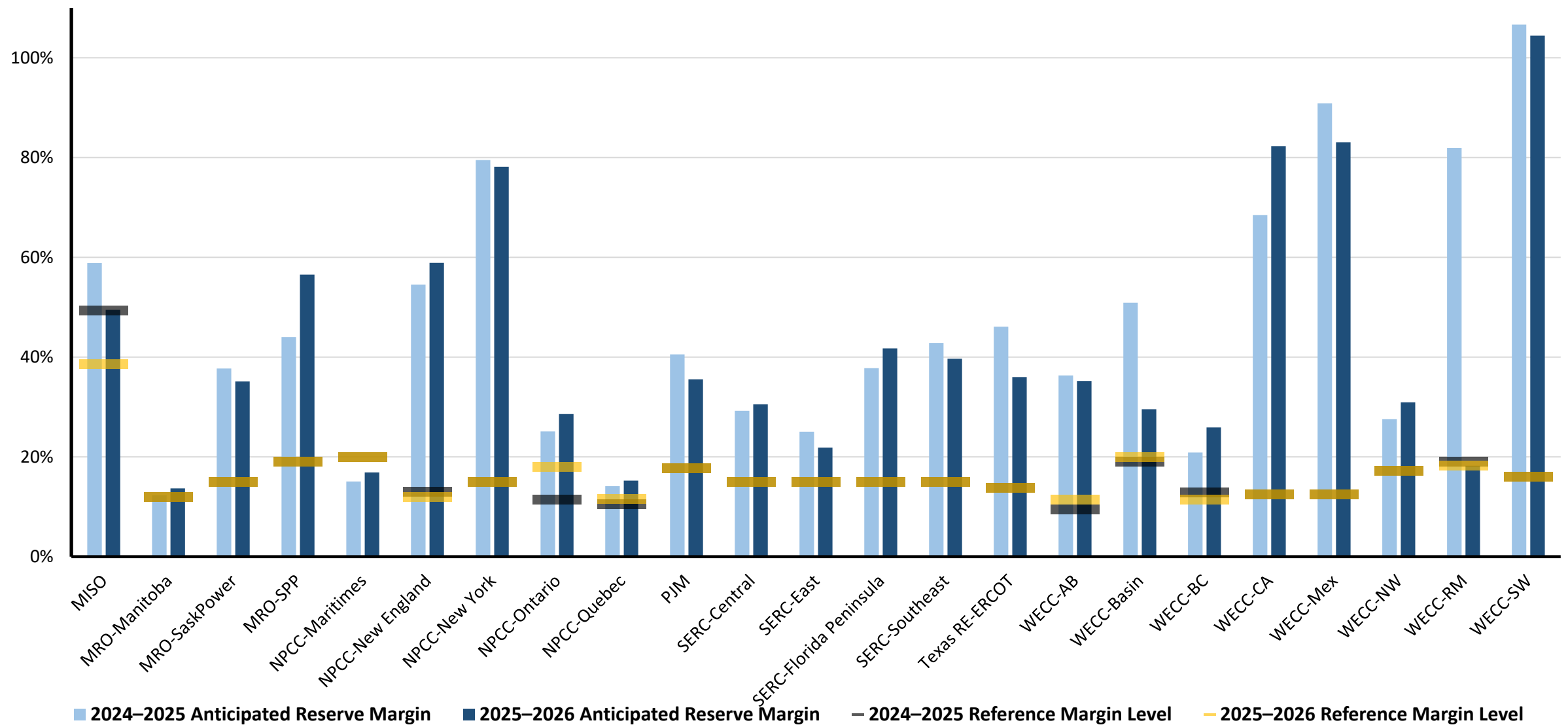


Figure 5: Winter 2024–2025 and Winter 2025–2026 Anticipated Reserve Margins Year-to-Year Change

Demand and Resource Tables

Peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area are as follows in each table.

MISO			
Demand, Resource, and Reserve Margins	2024–2025 WRA ¹⁶	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	102,353	105,249	2.8%
Demand Response: Available	6,219	8,250	32.7%
Net Internal Demand	96,134	96,999	0.9%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	150,407	142,880	-5.0%
Tier 1 Planned Capacity	122	0	0.0%
Net Firm Capacity Transfers	2,310	2,113	-8.5%
Anticipated Resources	152,717	144,993	-5.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	152,839	144,993	-5.1%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	58.9%	49.5%	-9.4
Prospective Reserve Margin	59.0%	49.5%	-9.5
Reference Margin Level	49.4%	38.6%	-10.8

MRO-SaskPower			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	3,852	3,944	2.4%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,802	3,894	2.4%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	4,946	4,972	0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	5,236	5,262	0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,236	5,262	0.5%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	37.7%	35.1%	-2.6
Prospective Reserve Margin	37.7%	35.1%	-2.6
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	45,788	47,168	3.0%
Demand Response: Available	1,128	1,091	-3.3%
Net Internal Demand	45,926	46,077	0.3%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	67,252	71,074	5.7%
Tier 1 Planned Capacity	0	1087	0.0%
Net Firm Capacity Transfers	-1,116	-32	-97.1%
Anticipated Resources	66,136	72,129	9.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	66,090	73,029	10.5%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	44.0%	56.5%	12.5
Prospective Reserve Margin	43.9%	58.5%	14.6
Reference Margin Level	19.0%	19.0%	0.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	4,814	4,903	1.8%
Demand Response: Available	0	0	0.0%
Net Internal Demand	4,814	4,903	1.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	5,924	5,688	-4.0%
Tier 1 Planned Capacity	10	0	-100.0%
Net Firm Capacity Transfers	-527	-113	-78.5%
Anticipated Resources	5,407	5,575	3.1%
Existing-Other Capacity	18	13	-26.8%
Prospective Resources	5,425	5,588	3.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	12.3%	13.7%	1.4
Prospective Reserve Margin	12.7%	14.0%	1.3
Reference Margin Level	12.0%	12.0%	0.0

¹⁶ MISO-provided updated data post 2024-25 WRA publication.

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	6,167	6,061	-1.7%
Demand Response: Available	259	248	-4.4%
Net Internal Demand	5,907	5,813	-1.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	6,647	6,704	0.9%
Tier 1 Planned Capacity	6	88	0.0%
Net Firm Capacity Transfers	145	1	-99.0%
Anticipated Resources	6,798	6,794	-0.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	6,798	6,800	0.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	15.1%	16.9%	1.8
Prospective Reserve Margin	15.1%	17.0%	1.9
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	23,800	24,200	1.7%
Demand Response: Available	802	1,027	28.1%
Net Internal Demand	22,998	23,173	0.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	40,522	40,080	-1.1%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	759	1,203	58.5%
Anticipated Resources	41,281	41,283	0.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	41,281	41,283	0.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	79.5%	78.2%	-1.3
Prospective Reserve Margin	79.5%	78.2%	-1.3
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	20,651	20,056	-2.9%
Demand Response: Available	343	440	28.2%
Net Internal Demand	20,308	19,616	-3.4%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	30,030	29,935	-0.3%
Tier 1 Planned Capacity	194	0	-100.0%
Net Firm Capacity Transfers	1,161	1,235	6.4%
Anticipated Resources	31,385	31,170	-0.7%
Existing-Other Capacity	306	322	5.2%
Prospective Resources	31,691	31,492	-0.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	54.5%	58.9%	4.4
Prospective Reserve Margin	56.1%	60.5%	4.5
Reference Margin Level	13.0%	12.0%	-1.0

NPCC-Ontario			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	21,898	22,013	0.7%
Demand Response: Available	915	868	-5.2%
Net Internal Demand	20,982	21,146	0.9%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	26,652	27,319	2.5%
Tier 1 Planned Capacity	0	294	#DIV/0!
Net Firm Capacity Transfers	-450	-420	-6.7%
Anticipated Resources	26,202	27,193	3.8%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	26,202	27,193	3.8%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	25.1%	28.6%	3.5
Prospective Reserve Margin	25.1%	28.6%	3.5
Reference Margin Level	11.5%	18.0%	6.5

NPCC-Québec			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	40,512	40,799	0.8%
Demand Response: Available	4,451	4,902	10.9%
Net Internal Demand	36,061	35,897	-0.4%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	41,560	41,698	0.3%
Tier 1 Planned Capacity	73	61	0.0%
Net Firm Capacity Transfers	-479	-390	-18.6%
Anticipated Resources	41,154	41,368	0.5%
Existing-Other Capacity	-479	0	0.0%
Prospective Resources	41,154	41,368	0.5%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	14.1%	15.2%	1.1
Prospective Reserve Margin	14.1%	15.2%	1.1
Reference Margin Level	10.5%	11.5%	1.0

SERC-Central			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	42,895	42,875	0.0%
Demand Response: Available	1,497	2,809	87.6%
Net Internal Demand	41,397	40,067	-3.2%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	51,578	50,454	-2.2%
Tier 1 Planned Capacity	0	0	0%
Net Firm Capacity Transfers	1,922	1,847	-3.9%
Anticipated Resources	53,500	52,301	-2.2%
Existing-Other Capacity	1,498	1,810	20.8%
Prospective Resources	54,998	54,111	-1.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	29.2%	30.5%	1.3
Prospective Reserve Margin	32.9%	35.1%	2.2
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	136,328	140,827	3.3%
Demand Response: Available	5,616	5,998	6.8%
Net Internal Demand	130,712	134,829	3.1%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	179,216	178,335	-0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	4,502	4,448	-1.2%
Anticipated Resources	183,718	182,783	-0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	183,718	182,452	-0.7%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	40.6%	35.6%	-5.0
Prospective Reserve Margin	40.6%	35.3%	-5.2
Reference Margin Level	17.7%	17.7%	-12.3

SERC-East			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	45,005	45,703	1.6%
Demand Response: Available	982	888	-9.6%
Net Internal Demand	44,023	44,815	1.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	54,379	54,460	0.1%
Tier 1 Planned Capacity	72	11	-84.3%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	55,045	54,622	-0.8%
Existing-Other Capacity	5,209	5,832	12.0%
Prospective Resources	60,254	60,453	0.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	25.0%	21.9%	-3.2
Prospective Reserve Margin	36.9%	34.9%	-2.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	48,494	48,628	0.3%
Demand Response: Available	2,780	3,127	12.5%
Net Internal Demand	45,714	45,501	-0.5%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	62,579	63,502	1.5%
Tier 1 Planned Capacity	15	692	4510.0%
Net Firm Capacity Transfers	400	300	-25.0%
Anticipated Resources	62,994	64,494	2.4%
Existing-Other Capacity	3,673	3,671	0.0%
Prospective Resources	66,667	68,165	2.2%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	37.8%	41.7%	3.9
Prospective Reserve Margin	45.8%	49.8%	4.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	45,308	47,056	3.9%
Demand Response: Available	1,638	1,365	-16.7%
Net Internal Demand	43,670	45,691	4.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	62,805	63,339	0.9%
Tier 1 Planned Capacity	765	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	62,378	63,828	2.3%
Existing-Other Capacity	3,920	4,847	23.7%
Prospective Resources	66,298	68,675	3.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	42.8%	39.7%	-3.1
Prospective Reserve Margin	51.8%	50.3%	-1.5
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	73,193	77,387	5.7%
Demand Response: Available	5,447	9,330	71.3%
Net Internal Demand	67,746	68,057	0.5%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	98,712	89,977	-8.8%
Tier 1 Planned Capacity	239	1351	464.9%
Net Firm Capacity Transfers	20	1,235	6075.0%
Anticipated Resources	98,971	92,562	-6.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	99,691	93,137	-6.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	46.1%	36.0%	-10.1
Prospective Reserve Margin	47.2%	36.9%	-10.3
Reference Margin Level	13.75%	13.8%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	12,280	12,411	1.1%
Demand Response: Available	0	0	0.0%
Net Internal Demand	12,280	12,411	1.1%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	13,535	16,658	23.1%
Tier 1 Planned Capacity	3206	124	-96.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	16,740	16,782	0.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	16,740	16,782	0.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	36.3%	35.2%	-1.1
Prospective Reserve Margin	36.3%	35.2%	-1.1
Reference Margin Level	9.5%	11.5%	2.0

WECC-Basin			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	10,568	10,758	1.8%
Demand Response: Available	85	170	100.0%
Net Internal Demand	10,483	10,588	1.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	13,213	13,183	-0.2%
Tier 1 Planned Capacity	2,605	533	-79.5%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	15,817	13,717	-13.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	15,817	13,717	-13.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	50.9%	29.6%	-21.3
Prospective Reserve Margin	50.9%	29.6%	-21.3
Reference Margin Level	19.0%	20.0%	1.0

WECC-BC			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	11,966	11,936	-0.3%
Demand Response: Available	0	0	0.0%
Net Internal Demand	11,966	11,936	-0.3%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	13,870	14,389	3.7%
Tier 1 Planned Capacity	433	637	47.0%
Net Firm Capacity Transfers	164	0	-100.0%
Anticipated Resources	14,467	15,026	3.9%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	14,467	15,026	3.9%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	20.9%	25.9%	5.0
Prospective Reserve Margin	20.9%	25.9%	5.0
Reference Margin Level	12.8%	11.4%	-1.5

WECC-CA			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	36,441	36,281	-0.4%
Demand Response: Available	743	666	-10.4%
Net Internal Demand	35,698	35,615	-0.2%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	55,380	57,923	4.6%
Tier 1 Planned Capacity	4,757	6,997	47.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	60,138	64,920	8.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	60,138	65,920	8.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	68.5%	82.3%	13.8
Prospective Reserve Margin	68.5%	82.3%	13.8
Reference Margin Level	12.5%	12.5%	0.0

WECC-Mexico			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–2025 vs. 2025–2026
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	1,983	1,977	-0.3%
Demand Response: Available	0	0	0%
Net Internal Demand	1,983	1,977	-0.3%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	3,733	3,619	-3.0%
Tier 1 Planned Capacity	52	0	-100.0%
Net Firm Capacity Transfers	0	0	0%!
Anticipated Resources	3,784	3,619	-4.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	3,784	3,619	-4.4%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	90.8%	83.1%	-7.8
Prospective Reserve Margin	90.8%	83.1%	-7.8
Reference Margin Level	12.5%	12.5%	0

WECC-Northwest			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–25 vs. 2025–26
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	30,748	33,604	9.3%
Demand Response: Available	30	30	0.0%
Net Internal Demand	30,718	33,574	9.3%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	38,729	34,671	-10.5%
Tier 1 Planned Capacity	463	3,152	581.5%
Net Firm Capacity Transfers	0	6,136	100%!
Anticipated Resources	39,192	43,959	12.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	39,192	43,959	12.2%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	27.6%	30.9%	3.3
Prospective Reserve Margin	27.6%	30.9%	3.3
Reference Margin Level	17.2%	17.2%	0.0

WECC-Southwest			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–25 vs. 2025–26
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	20,844	21,147	1.5%
Demand Response: Available	340	177	-47.9%
Net Internal Demand	20,504	20,970	2.3%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	38,991	40,135	2.9%
Tier 1 Planned Capacity	3,381	2,733	-19.2%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	42,372	42,868	1.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	42,372	42,868	1.2%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	106.6%	104.4%	-2.2
Prospective Reserve Margin	106.6%	104.4%	-2.2
Reference Margin Level	16.0%	16.0%	0.0

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	2024–2025 WRA	2025–2026 WRA	2024–25 vs. 2025–26
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	10,481	11,501	9.7%
Demand Response: Available	282	285	1.1%
Net Internal Demand	10,199	11,216	10.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	18,356	17,768	-3.2%
Tier 1 Planned Capacity	199	366	84.3%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	18,555	18,134	-2.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	18,555	18,134	-2.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	81.9%	61.7%	-20.3
Prospective Reserve Margin	81.9%	61.7%	-20.3
Reference Margin Level	19.0%	18.2%	-0.8

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity and may vary widely year to year based on the identified risk hour. In many areas, winter demand peaks in the early morning hours or early evening resulting in little or no electrical resource output from solar PV resources and wide variability in wind availability. The following table shows the capacity contribution of existing wind and solar PV resources at the identified risk hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS.

BPS Variable Energy Resources On-Peak Capacity Contributions by Assessment Area									
	Wind			Solar			Run of River Hydro		
Assessment Area/ Interconnection (* - includes all hydro)	Nameplate Wind (MW)	Expected Wind (MW)	Expected Share of Nameplate (%)	Nameplate Solar PV (MW)	Expected Solar (MW)	Expected Share of Nameplate (%)	Nameplate Hydro (MW)	Expected Hydro (MW)	Expected Share of Nameplate (%)
MISO	30,247	8,772	29%	13,726	686	5%	2,351	1,404	60%
MRO-Manitoba Hydro	259	52	20%	0	0	0%	202	0	0%
MRO-SaskPower	816	433	53%	30	0	13%	884	703	80%
MRO-SPP	35,714	7,198	20%	1,197	457	38%	114	72	63%
NPCC-Maritimes	1,635	241	15%	155	10	6%	1,357	1,283	95%
NPCC-New England	2,675	455	17%	3,620	0	0%	3,742	1,453	39%
NPCC-New York	2,586	737	29%	627	0	0%	974	596	61%
NPCC-Ontario	4,943	1,971	40%	478	0	0%	0	0	0%
NPCC-Québec	4,024	1,426	35%	10	0	0%	445	445	100%
PJM*	13,318	5,463	41%	15,732	1	0%	8,134	7,900	97%
SERC-Central	1,324	370	28%	1,576	455	29%	4,991	4,027	81%
SERC-East	0	0	0%	7,068	1,792	25%	3,010	2,951	98%
SERC-Florida Peninsula	0	0	0%	12,058	2,151	18%	0	0	0%
SERC-Southeast	0	0	0%	8,670	4,461	51%	3,258	3,258	100%
Texas RE-ERCOT	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC-AB*	5,712	1,919	34%	2,206	0	0%	894	285	32%
WECC-Basin*	5,932	1,148	19%	3,853	62	2%	2,667	1,473	55%
WECC-BC*	747	85	11%	17	0	0%	17,752	13,560	76%
WECC-CA*	9,382	682	7%	28,328	0	0%	15,740	4,572	29%
WECC-Mex	40	4	11%	350	0	0%	0	0	0%
WECC-NW*	14,744	1,319	9%	4,695	1,556	33%	32,915	18,502	56%
WECC-RM*	5,681	2,265	40%	3,521	0	0%	3,251	1,327	41%
WECC-SW*	4,303	1,182	27%	12,139	391	3%	3,117	948	30%
EASTERN INTERCONNECTION	93,517	25,692	27%	64,937	10,013	15%	29,017	23,647	81%
QUÉBEC INTERCONNECTION	4,024	1,426	35%	10	0	0%	445	445	100%
TEXAS INTERCONNECTION	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC INTERCONNECTION	46,541	8,605	19%	55,108	2,008	4%	76336	40667	53%
INTERCONNECTION TOTAL:	184,711	43,556	23%	155,664	12,685	8%	106,377	65,325	61%

Review of Winter 2024–2025 Capacity and Energy Performance

The [meteorological winter](#) across the contiguous United States had an average temperature of 34.1 degrees F—1.9 degrees above average—ranking in the warmest third of NOAA’s historical record. Total winter precipitation in the US was 5.87 inches, 0.92 of an inch below average, ranking in the driest third of the December–February climate record.¹⁷ Most of Canada experienced temperatures at least 2°C above the baseline average with the Maritime provinces, southern Ontario, and the Canadian west coast recording temperature departures nearer the baseline average while a small region in southern Saskatchewan recorded temperatures just slightly below the baseline average.¹⁸

In February 2025, FERC and NERC and its Regional Entities launched a joint review of the BPS’ performance during the January 2025 arctic events, which comprised Winter Storms Blair, Cora, Demi, and Enzo.¹⁹ The week of January 19–25, 2025 was the third coldest winter week (spanning Sunday through Saturday) across the United States since 2000. Between January 21 and 22, 2025, natural gas demand peaked at 150 Bcf/day, electric demand peaked at 683 GW, and unplanned outages peaked at 71,022 MW. Nevertheless, during the January 2025 arctic events, manual load shed was not required. The January 2025 arctic events had lower observed hourly wind chill temperatures in pockets of the Northeast, the Louisiana Gulf, California, and the Southwest compared to Winter Storms Uri, Elliott, Gerri, and Heather. During the January 2025 arctic events, the most extreme storm relative to typical weather was Winter Storm Enzo—a Gulf and Southern storm. On January 20, 2025, a burst of snow, sleet, and freezing rain developed across Texas and Louisiana late in the day. A mixture of sleet and freezing rain fell from Austin to San Antonio and to the southernmost point of Texas. By the early morning hours of January 21, 2025, for the first time in history, a blizzard warning was issued for southwest Louisiana and the southeastern-most point of Texas. Snow fell in Gulf cities in Texas, southern Mississippi, southern Alabama, and western Florida. On January 21, 2025, Baton Rouge recorded 7.6 inches of snowfall, making it the city’s snowiest day since recordkeeping began in 1892, while New Orleans saw its snowiest day on record, with a total of 8.0 inches. Temperatures plunged to single digits in Louisiana. Temperatures in some parts of the state fell to levels not seen in more than 125 years.

The review team engaged with 10 electric entities across the Eastern and Texas Interconnections to gather the information necessary to provide a high-level overview of the BPS’ performance during the cold weather events. Based on the data and interviews that the team reviewed, electric generators appear to have performed better during the January 2025 arctic events because of additional generator commitments, improved preparedness, increased situational awareness, and the implementation of lessons learned from previous extreme cold weather events and prior report recommendations. The natural gas system also performed better overall, serving record levels of natural gas demand and experiencing only minor production declines and short-duration force majeure events.

On October 1, 2025, NERC submitted to the Federal Energy Regulatory Commission its first *Cold Weather Data Annual Report*. This report includes a review of forced outage data from GADS for the winter 2024–2025 period indicating performance consistent with historical performance as reported in NERC’s annual *State of Reliability* report. This is within the normal range of capacity that occurs across the fleet. During the Winter 2024–2025 period, the highest amount of capacity in a forced outage state for all reasons occurred on January 20, 2025, with 68,519 MW across all regions. The outages occurring over January 20, 2025, were analyzed as part of the joint FERC, NERC, and Regional Entity *2025 System Performance Review*. The joint FERC, NERC, and Regional Entity *2025 System Performance Review* found a reduction in peak coincident unplanned generator outages for the four 2025 winter storms reviewed compared to past winter storms; however, this review also noted that it was not an exact comparison due to prior winter storms having different characteristics.

Eastern Interconnection–Canada and Québec Interconnection

No EEAs were needed during the previous winter season. One entity plans to make a slight increase to the demand-response program based on last winter’s operations.

¹⁷ [Despite Arctic air outbreaks, U.S. had warm, dry winter on average | National Oceanic and Atmospheric Administration](#)

¹⁸ [Climate Trends and Variations Bulletin – Winter 2024/2025 - Canada.ca](#)

¹⁹ <https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional>

Eastern Interconnection–United States

Several entities indicated that generators performed better during the January 2025 arctic events than in previous winter storms. For example, TVA stated that generator performance within its footprint was stable, with minimal natural gas delivery issues. Southeastern RC detailed that no major fuel-related outages occurred. FRCC noted that generator performance was strong during this period. The significant characteristics of Winter Storm Enzo in the Southern and Gulf states were freezing precipitation and snow accumulation, especially in regions where those conditions rarely occur. In FRCC, only the northern portion of Florida experienced severe arctic weather including freezing precipitation and snowfall (record-setting, in some cities) that were abnormal for the region even though certain northern cities have faced cold temperatures in the past. In Florida, entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events. ISO-NE, NYISO, and PJM all generally described the January 2025 arctic events as having cold temperatures but overall weather conditions that were similar to a winter without a major storm.

MISO emerged from Winter 2024–2025 without turning to emergency procedures despite the wide-ranging winter storms from January 6 to 9 and again from January 20 to 22. Generators continue to prioritize scheduling planned or maintenance outages to the shoulder seasons of fall and spring to maximize unit availability for the winter season. Also, extreme cold weather outage adders were added to the LOLE model to make sure that winter storm risks are included in planning. In PJM, demand reached a new all-time winter peak on January 22, 2025, of 143,714 MW with sufficient reserves. PJM did call an EEA1 on January 22, 2025, however reserves remained adequate. PJM had less than 3% load forecast error over the peak days of the January cold weather events. Reliability cases were conducted, and units with extended start times were evaluated and started early to ensure units were on-line before extreme cold weather settled in. PJM had a 9.24% forced outage rate on the peak day, a relatively low forced outage rate for the weather experienced. There were also very few gas production problems; however, market issues prevented proper scheduling because of the four-day holiday weekend.

In SERC-Central, entities reported only limited impacts from Winter 2024–2025 coldest weather and made minor adjustments. One entity declared conservative operations ahead of peak conditions but experienced no emergencies. One entity raised its winter Planning Reserve Margin target to 26% following lessons learned from Winter Storm Elliott. Corrective actions were implemented due to isolated equipment issues, including improved heat trace capabilities and adding heat trace equipment to the cold weather critical component list. During the previous winter season, some SERC-Florida Peninsula entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Despite these challenges, entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events.

Texas Interconnection–ERCOT

There were no energy emergencies for the Texas RE-ERCOT region last winter and no conditions that prompted changes in operating procedures. Winter Storm Kingston, which occurred in February 2025, was the only storm where ERCOT utilized firm fuel supply service resources (FFSS), a firm-fuel product that provides additional grid reliability and resiliency during extreme cold weather and compensates generation resources that meet a higher resiliency standard. A maximum FFSS deployment of 470 MW occurred on February 19 between the hours 13:10 and 17:02. Two other storms, Enzo and Cora, impacted ERCOT in January 2025, but these storms did not cause any system reliability issues.

Western Interconnection

Between January 11 and 17, 2024, a prolonged Arctic outbreak impacted British Columbia, Alberta, and the U.S. Pacific Northwest, driving record electricity demand and widespread reliability challenges. Four U.S. Northwest BAs and one Canadian BA declared energy emergencies, underscoring two core vulnerabilities: Inadequate capacity during evening peak hours (4 to 8 p.m.) and Insufficient fuel supply (limited hydro availability) across multiple days.

Although temperatures were comparable to the December 2022 cold snap, WECC-Northwest peak demand rose two percentage points to 6% over then, with BC Hydro and AESO both setting new all-time records. The U.S. Northwest relied heavily on imports—averaging 4,745 MW during peaks and 5,241 MW across all hours, mostly from the Southwest and Rockies. California remained a net importer, providing little relief. Market prices in the Northwest reached or neared caps across most hours, indicating persistent scarcity rather than short-term peaks. Overall, the January 2024 event illustrated capacity alone does not ensure resilience. Sustained energy availability with interregional flexibility (both physical and market-based) will be key to maintaining reliability through the 2025–2026 and future winter seasons.

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	Peak Demand Date	Peak Demand Hour	Demand ¹ (MW)	WRA Peak Demand Scenarios ² (MW)	Generation ¹ (MWh)	Transfers ¹ (MW)	Wind – Actual ¹ (MWh)	Wind – Expected ³ (MW)	Solar – Actual ¹ (MWh)	Solar – Expected ³ (MW)	Forced Outages Summary ⁴ (MW)
MISO	Jan. 21	18:00	108,888*	96,134	101,655	-977	18,468	16,761	0	519	17,010
				100,395							
MRO- Manitoba Hydro	Jan. 20	08:00	5.132	4,814	5,292	-277	142	52	N/A	0	146
				5,060							
MRO- SaskPower	Dec. 18	18:00	3,785	3,802	3,641	-231	664	368	0	3	0
				3,897							
MRO-SPP	Feb. 20	08:00	47,981	45,926	40,898	-1,424	4,886	4,783	255	36	9,272
				47,054							
NPCC- Maritimes	Jan. 22	07:00	5,810	5,907	4,266	-1,174	368	261	3	5	*
				6,498							
NPCC-New England	Jan. 21	18:00	19,607	20,308	17,686	-1,896	285	329	4	23	624
				21,814							
NPCC-New York	Jan. 22	19:00	23,521	22,998	18,932	-4,589	654	728	0	0	4,835
				24,023							

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	Peak Demand Date	Peak Demand Hour	Demand ¹ (MW)	WRA Peak Demand Scenarios ² (MW)	Generation ¹ (MWh)	Transfers ¹ (MW)	Wind – Actual ¹ (MWh)	Wind – Expected ³ (MW)	Solar – Actual ¹ (MWh)	Solar – Expected ³ (MW)	Forced Outages Summary ⁴ (MW)
NPCC-Ontario	Jan. 22	18:00	21,940	20,951	24,250	2,990	3,693	1,914	0	0	*
				22,179							
NPCC-Québec	Jan. 22	08:00	37,178	36,061	39,514	-766	1,463	1,449	0	0	*
				39,545							
PJM	Jan. 22	09:00	144,420	130,712	152,142	7,731	3,704	3,620	3,076	1	8,663
				144,939							
SERC-C	Jan. 22	08:00	47,815	41,397	40,898	-6,921	563	176	214	455	1,538
				47,062							
SERC-E	Jan. 23	08:00	47,130	44,023	41,810	-5,323	0	0	145	2,526	1,830
				47,662							
SERC-FP	Jan. 25	08:00	43,974	45,714	41,702	-557	0	0	362	1,684	2,824
				54,239							
SERC-SE	Jan. 22	08:00	46,490	43,670	48,227	1,741	0	0	592	3,861	2,210
				45,116							

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	Peak Demand Date	Peak Demand Hour	Demand ¹ (MW)	WRA Peak Demand Scenarios ² (MW)	Generation ¹ (MWh)	Transfers ¹ (MW)	Wind – Actual ¹ (MWh)	Wind – Expected ³ (MW)	Solar – Actual ¹ (MWh)	Solar – Expected ³ (MW)	Forced Outages Summary ⁴ (MW)
TRE-ERCOT	Feb. 20	08:00	80,560	73,193 ⁵	79,960	-191	9,397	15,697	1,586	15	5,742
				90,405 ⁵							
WECC-AB	Dec. 18	17:00	12,241	12,280	12,711	-470	3,175	1,867	4	0	*
				12,635							
WECC-BC	Feb 3	18:00	11,359	11,996	11,415	44	70	279	0	0	839
				12,749							
WECC-CA/MX	Dec. 12	15:00	35,555	35,359	31,925	-4,669	4,021	569	11,547	0	1,627
				36,823							
WECC-NW	Feb. 12	08:00	54,278	58,001	48,437	-920	2,607	7,876	1,494	2,198	3,281
				62,230							
WECC-SW	Feb. 13	16:00	22,969	16,177	25,087	2,117	2,741	1,065	1,599	182	1,496
				17,777							
Highlighting Notes:			Actual peak demand in the highlighted areas met or exceeded extreme scenario levels				Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	Peak Demand Date	Peak Demand Hour	Demand ¹ (MW)	WRA Peak Demand Scenarios ² (MW)	Generation ¹ (MWh)	Transfers ¹ (MW)	Wind – Actual ¹ (MWh)	Wind – Expected ³ (MW)	Solar – Actual ¹ (MWh)	Solar – Expected ³ (MW)	Forced Outages Summary ⁴ (MW)

Table Notes:											
¹ Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data . For areas in Canada, this data was provided to NERC by system operators and utilities.											
² See NERC 2024–2025 WRA demand scenarios for each assessment area. Values are the normal winter peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.											
³ Expected values of wind and solar resources from the 2024–2025 WRA.											
⁴ Values from NERC Generator Availability Data System for the 2024–2025 winter hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024–2025 winter risk period scenarios in the 2024–2025 WRA.											
⁵ Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (5.4 GW for winter 2024-2025) to the demand scenarios found on p. 29 of the 2024-2025 WRA.											
*Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.											

Errata

December 2025

- Corrections made to the VER Table (page 50): Hydro values for WECC NW, Western Interconnection Total, and Total

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-25-14
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit LL: Division, *Technical Review Document for
Operating Permit 96OPMF155* (Jan. 2005)

TECHNICAL REVIEW DOCUMENT
for
OPERATING PERMIT 96OPMF155
to be issued to:

Tri-State Generation & Transmission Association
Craig Station
Moffat County
Source ID 0810018

Cathy Rhodes
May, 2002
Revised January, 2005

I. PURPOSE:

This document will establish the basis for decisions made regarding the applicable requirements, emissions factors, monitoring plan and compliance status of emission units covered by the operating permit proposed for this site. It is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. This narrative is intended only as an adjunct for the reviewer and has no legal standing. The conclusions made in this report are based on information provided in the original application submittal of February 23, 1996 and the revised application submittal of January 4, 1999, and additional information received on October 21, 1999 and August 31, 2001.

Any revisions made to the underlying construction permits associated with this facility in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or an additional or revised Construction Permit.

II. SOURCE DESCRIPTION:

This facility is located in Craig, Moffat County, Colorado. The area is classified as an attainment area for all pollutants. Wyoming is an affected state within 50 miles of the facility. There are two Federal Class I areas within 100 kilometers of the facility: Mount Zirkel National Wilderness Area and Flattops National Wilderness Area. Dinosaur National Monument, although not a Class I area, is within 100 kilometers of the facility, and has been designated by the State to have the same sulfur dioxide increment as Federal Class I areas.

The entire plant is categorized as a major stationary source for the Prevention of Significant Deterioration (PSD) provisions. The EPA issued a PSD permit for Unit 3 on March 26,

1980. Future modifications at this facility resulting in a significant net emissions increase (see Colorado Regulation No. 3, Part A, Section I.B.37 and 58) for any pollutant listed in Colorado Regulation No. 3, Part A, Section I.B.58 or a modification which is major by itself may result in the application of the PSD review requirements.

The Craig Station consists of three coal fired steam driven electric generating units (Units 1, 2, and 3). Total net electric generating capacity is 1264 MW. Natural gas, propane and fuel oil are used as secondary fuels for flame stabilization, startup and shutdown. All three units are subject to the provisions of Title IV, the Acid Rain Program, of the Clean Air Act. Units 1 & 2 PM emissions were controlled by ESPs and wet limestone scrubbers control SO₂ emissions. Under a January 10, 2001 Consent Order, the ESPs have been replaced with baghouses and the wet scrubbers were upgraded. A baghouse controls PM emissions, and a spray dry scrubber controls SO₂ emissions from Unit 3. All three units have low-NO_x burners to control NO_x emissions. Overfire air and related NO_x control upgrades are now in place for Unit 1 and Unit 2. This permit currently only covers Units 1 and 2 and associated equipment. This permit does not currently cover Unit 3 or its associated equipment (except for coal handling, which may at times also serve Units 1 and 2). Associated activities covered by the permit include two cooling towers, coal handling systems, ash handling systems, limestone handling system, and the staging/landfilling area, as well as numerous insignificant activities.

Unit 3 is currently operating under the provisions of an EPA-issued PSD permit (issued on March 26, 1980, revised January 12, 1981, and August 14, 1992) and State-issued Construction permits 12MF322(1-4) and 98MF0141. The draft version of this permit that went to Public Comment on May 17, 2001 as well as the Proposed version of the permit that went to EPA on September 13, 2004 covered all three boilers. Prior to the Public Comment period, EPA, the Division, and Tri-State had discussions regarding the interpretation of several conditions of the EPA PSD permit. Following Public Comment, discussions continued on two issues: Range Z and the applicability of the BACT limits during periods of startup, shutdown, and malfunction (s/s/m). The root of the issues lies with imprecise and confusing language that was put into the PSD permit when it was issued some 25 years ago. Some of the issues were not resolved, and EPA sent a formal objection letter to the Division on October 22, 2004, citing the remaining unresolved issues.

Under the provisions of Regulation No. 3, Part C, § VI.H, the Division has 90 days in which to submit a revised permit to EPA after a formal objection letter is received. During the 90 day period, Tri-State indicated that they were planning on submitting an application to the Division for a major PSD modification to Unit 3 sometime in April 2005. State statutes and Federal regulations provide for the Air Pollution Control Division ("APCD") to issue PSD permits for major modifications made after September 2, 1986. Section 25-7-210 C.R.S. states:

Sections 25-7-201 and 25-7-203 to 25-7-206 shall apply only to applications for proposed new major stationary sources and major modifications which are submitted on or after the date of approval by the United States

environmental protection agency of the program for prevention of significant deterioration embodied in the state implementation plan.

Thus the March application will result in a new PSD Construction permit for Unit 3 and associated activities. The new permit will replace the existing PSD permit, and will address the provisions upon which the EPA's objection was based.

Since a new PSD permit will be issued in the near future, the Division and the EPA have agreed that the Division will at this time issue a revised Operating Permit which contains only the requirements for Units 1 and 2. The Unit 3 requirements will be added to this operating permit once the new PSD permit is issued. The EPA and the Division believe that this is the best and most expedient method to resolve the existing PSD permit concerns and the EPA objections regarding the initially proposed operating permit. The new PSD permit will be issued using the appropriate procedures in Regulation No. 3, including public notice and participation requirements. Under Regulation No. 3, Part C provisions, the applicant must apply for a modification to incorporate the new PSD permit requirements into their operating permit within twelve months of startup of the modified Unit 3. The revised Operating Permit will be issued using the Significant Modification procedures of Regulation No. 3, Part C, including public notice and participation requirements and EPA review.

The following Potential-to-Emit and actual 1997 emissions data are based on information supplied in the Title V application (rounded figures – includes all three units and all associated activities).

	POTENTIAL TO EMIT, TONS PER YEAR					
	PM	PM ₁₀	SO ₂	NO _x	VOC	CO
B001 - Unit 1	1891	435	22695	13239	60	498
B002 - Unit 2	1891	435	22695	13239	60	498
B003 - Unit 3	566	130	3770	9426	58	484
P101 - Coal Handling Units 1 & 2	41	18				
P102 - Coal Handling Unit 3	2	1				
P201 - Limestone Handling Units 1 & 2	14	3				
P202 - Lime Handling Unit 3	23	6				

P203 - Ash Handling Units 1 & 2	neg	Neg				
P204 - Ash Handling and Ash Haul Roads Unit 3	115	30				
P205 – Landfill	4	1				
P401 - Unit 1 CT	14	14			5	
P402 - Unit 2 CT	14	14			5	
P403 - Unit 3 CT	14	14			5	
Total	4588	1101	49160	35904	194	1479
FACILITY 1997 ACTUAL EMISSIONS TPY	772	250	10094	15750	133	1110

CT = Cooling Tower

III. EMISSION SOURCES

The following sources are specifically regulated under terms and conditions of the Operating Permit for this site:

B001 - Unit #1 - Babcock & Wilcox Boiler

B002 – Unit #2- Babcock & Wilcox Boiler

Applicable Requirements - Final Approval Construction Permit 10MF579 was issued for Units 1 and 2. Applicable requirements are as follows.

Construction Permit 10MF579

- This source is subject to the requirements of the New Source Performance Standards for Fossil Fuel Fired Steam Generators, as in effect May 1, 1973.

Construction Permit 10MF579 indicates that the Units are subject to the NSPS as it existed on May 1, 1973. This is because the units were permitted when Subpart D was in the proposal process, and had not been finalized by the EPA. Subsequently, the EPA finalized the rule, and it applies to all sources constructed, reconstructed, or modified after August 17, 1971. The rule does not provide for any exceptions for sources constructed prior to final promulgation, therefore, Units 1

and 2 are subject to the most current version of Subpart D. This revision to the Construction Permit is incorporated directly into this operating permit through a combined Construction Permit/Operating Permit procedure. Note: The EPA did not promulgate startup, shutdown, and malfunction provisions until October 15, 1973.

- Emissions of sulfur dioxide shall not exceed 1.2 pounds per million Btu heat input, maximum 3 hour average.
- Visible emissions shall not exceed 20 percent opacity.
- Emissions of particulate matter shall not exceed 0.1 pounds per million Btu heat input, maximum 2 hour average. *On June 14, 1974, the EPA revised Subpart D to change the sampling time requirements for PM from a minimum of 2 hours to a minimum of 60 minutes per run, to make the provision consistent with 60.8(f). The sampling interval specified in 60.46 was shortened to be consistent with the 60-minute-per-run requirement. The preamble to this revision states that these actions are intended for clarification and for maintaining consistency throughout the regulations. They are not intended to alter the substantive content of the regulations. Thus, the 2 hour averaging time no longer applies to Units 1 and 2.*
- Emissions of nitrogen oxides shall not exceed 0.7 pounds per million Btu heat input, maximum 3 hour average.
- This source shall comply with all applicable monitoring, notification, and record keeping requirements of the New Source Performance Standards (Regulation 6) and Regulation 1. IV.
- This source is subject to the requirements of Regulation 6. Section I., including Section I.4 which states: At all times, including periods of start-up, shutdown, and malfunction, the facility and control equipment shall, to the extent practicable, be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operating and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

- A Revised Air Pollutant Emission Notice shall be filed when a significant change in emissions occurs, as required by Regulation No.3.II.B.

Colorado Regulation No. 1

- Except as provided in Section II.A.4, opacity shall not exceed 20% (Section II.A.1)
- Opacity shall not exceed 30%, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or cleaning of control equipment (Section II.A.4)
- Particulate emissions shall not exceed 0.1 lbs/mmBtu heat input (Section III. A.1.c)
- Continuous emission monitoring (Section IV)
- Continuous Opacity Monitor (COM) requirements (Section IV.B.1)
- Continuous Emission Monitor (CEM) for SO₂ or fuel sampling (Section IV.B.2)
- If CEM for SO₂ then CEM for either O₂ or CO₂ (Section IV.B.3)
- Calibration of CEMs (Section IV.F)
- Notification and Recordkeeping (Section IV.G)
- Recordkeeping duration (Section IV.H)
- Reporting requirements - if fuel sampling (Section IV.I)
- Sulfur dioxide emissions shall not exceed 1.2 lbs/mmBtu heat input (Section VI.A.3.a.(ii)), based on a 3 hour rolling average

Colorado Regulation No. 8, Part C

- Lead (Pb) emissions shall not be such that emissions result in an ambient lead concentration exceeding 1.5 µg/scm averaged over a one-month period (Reg 8, Part C) - This is a **State-only** requirement

NSPS Subpart D Requirements (40 CFR, Part 60, Subpart D as adopted by reference in Colorado Regulation No. 6, Part A)

- Emissions of Particulate Matter shall not exceed 0.1 lbs/mmBtu heat input
- Opacity shall not exceed 20%, except for one six-minute period of not more than 27% - does not apply during start-up, shutdown and malfunction
- SO₂ emissions shall not exceed 1.2 lbs/mmBtu heat input when burning coal, 3 hour average
- NO_x emissions shall not exceed 0.70 lbs/mmBtu heat input when burning coal, 3 hour average

- Source shall install, calibrate, maintain and operate continuous monitoring systems for measuring opacity, SO₂ and NO_x emissions and either O₂ or CO₂

PM, SO₂, and NO_x emission limits do not apply during startup, shutdown, or malfunction. (See October 15, 1973 Federal Register)

Acid Rain (Title IV) Requirements

- The Code of Federal Regulations lists 8153 (Unit 1) and 7785 (Unit 2) SO₂ allowances (as listed in 40 CFR 73.10(b)) for these sources. Note that additional allowances can be obtained as needed per 40 CFR Part 75. The units will be allocated 8153 and 7785 allowances per year from 2000 to 2009 (as listed in the EPA's "Allowances Held Report," January 4, 1999).
- NO_x emissions of 0.50 lbs/mmBtu heat input, on an annual average basis (source opted to comply with Phase I limits (§76.5(a)(2) by early election (§ 76.8), which went into effect January 1, 1997).
- Acid rain permitting requirements per 40 CFR Part 72.
- Continuous emission monitoring requirements per 40 CFR Part 75.
- The source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emissions (40 CFR Part 77).

January 10, 2001 Consent Decree Requirements

- Requires replacement of ESPs at Units 1 and 2 with baghouses, FGD upgrades, and installation of NO_x emission control upgrades by certain dates
- PM emissions from Units 1 and 2 shall not exceed 0.03 lb/mmBtu heat input by certain dates
- SO₂ emissions from Units 1 and 2 shall not exceed 0.160 lb/mmBtu heat input, on a 30 day rolling average and 0.130 lb/mmBtu heat input on a 90 day rolling average, by certain dates
- SO₂ emissions from Units 1 and 2 shall be controlled by either 86% on a 30 day rolling average, or 90% on a 90 day rolling average, by certain dates, unless a "showing" is made
- NO_x emissions from Units 1 and 2 shall not exceed 0.30 lb/mmBtu heat input on an annual average basis, by certain dates
- Limits opacity as follows: (1) 20% averaged over each separate 6-minute period at all times when air pollutants are being discharged into the atmosphere, but does not apply when the boiler and all fans that move flue gas in the unit are off. Under this limit, during periods of a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, opacity shall not exceed 30% for more than 6 minutes in any 60 consecutive minutes; (2) 30% for more than 6 minutes during any 60 consecutive minutes during any startup; (3) 20% during any

shutdown, unless excused by an upset condition; (4) 20% except for one six minute period per hour of not more than 27% opacity as averaged over each separate 6-minute period with an hour, beginning each hour on the hour. Emissions during startup, shutdown and malfunction are excused under this opacity limit.

- Requires stack testing for PM
- Requires installation and operation of continuous opacity monitors and continuous monitors for SO₂ emissions, NO_x emissions, CO₂, and flow
- Requires permittee to operate Units 1 and 2 using good operating practices

Note: Since this permit went to public notice, the milestones for various Consent Decree requirements have passed. The permit is therefore revised to delete those due dates and obsolete requirements related to the ESPs.

Consent Decree Requirements as a Pollution Control Project

Typically, the Division does not consider the addition of a control device to be a modification for purposes of permitting. The installation of the baghouses and the FGD upgrades do not result in an increase in emissions. The NO_x emission control upgrades may decrease NO_x emissions substantially but increase CO emissions slightly. In the case of Craig Units 1 and 2, the addition of control equipment is required by the consent decree and qualifies as an environmentally beneficial pollution control project. No additional permitting or testing requirements were included in the consent decree for the potential increase in CO emissions from the low NO_x emission control upgrades. Therefore, the Division does not believe it is appropriate to include any other permitting requirements or emission limitations for a possible increase of CO emissions due to the NO_x emission control upgrades.

Effect of Incorporation of Consent Decree into the Operating Permit

The Consent Decree requirements were approved by the EPA as part of the Colorado State implementation Plan and are applicable requirements which must be included in the operating permit. Under terms of the Consent Decree, upon issuance of this operating permit, the Division assumes certain compliance/enforcement provisions of the Decree. As for any applicable requirement incorporated into an operating permit, nothing in the permit is intended to have the effect of relaxing any requirement in the Consent Decree or to change or modify any rights of the parties to that decree.

Voluntary Emission Reduction Agreement (VERA)

In 2001, a VERA was completed for Units 1 and 2, to reduce emissions which affect visibility and air quality related values. VERA's normally include specific emission limits and related requirements, and are included as applicable requirements in operating permits. In this case, the VERA states that the Division finds and determines that the provisions of the Consent Decree meet the requirements for a VERA for Units 1 and 2. Therefore, this VERA

is not incorporated into the operating permit, since the Consent Decree requirements are incorporated.

Emission Factors - The combustion of coal in the boilers results in emissions of NO_x, SO₂, PM, PM₁₀, CO, VOC, and Pb. CEMs are used to determine compliance with emission standards and to estimate annual emissions of NO_x and SO₂. For PM and PM₁₀, stack test results and monitored heat content of the fuel are used to determine compliance and estimate annual emissions. Standard factors from the AP-42 manual, or other emission factors/procedures acceptable to the Division (see Regulation No. 3, Part A, II.B.1 for acceptable alternative methods) along with appropriate removal efficiencies for control equipment, are used to estimate CO, VOC, HAP and Pb emissions.

Monitoring Plan - CEMs are used to demonstrate compliance with the NO_x and SO₂ lb/mmBtu limits. Stack testing and a baghouse and wet scrubber maintenance plan are used to demonstrate compliance with the PM limits. The required frequency for PM stack testing will be reduced, if the source meets criteria based on the test results in relation to the emission standard, as set forth in the permit. The heat content of the fuel is needed for these determinations. The heat input can be calculated from the carbon dioxide CEM required under the Acid Rain Program, or measured through a coal sampling plan, or vendor information.

Compliance with opacity limits is demonstrated using a COM.

Scales are used to measure the amount of coal combusted in the boiler. These data are used to estimate PM, PM₁₀, CO, VOC, and HAP emissions.

The permittee performed a one-time modeling exercise which demonstrated compliance with the Regulation No. 8 lead requirements.

Compliance Status - The Division accepts these Units were in compliance at the time the Title V application was submitted. In addition, the most recent inspection report indicates the Units were in compliance at the time of inspection.

B001 - Unit #1 - Babcock & Wilcox Boiler
- Natural Gas, Propane, and Fuel Oil
B002 - Unit #2 - Babcock & Wilcox Boiler
- Natural Gas, Propane, and Fuel Oil

Coal is the primary fuel for these boilers. Secondary fuels (natural gas, propane, or fuel oil) are used during non-routine periods such as startup and shutdown, adding to or removing coal pulverizers from service, or other flame stability efforts.

Applicable Requirements - The Construction Permit did not address secondary fuels. The NSPS, Subpart D sets forth emission limits when fuels are combined for combustion. The

permittee submitted information which indicates that, for the past five years, "alternative" fuel use has comprised less than 1% of total heat input. By calculation, the Subpart D emission limits for this amount of natural gas, propane or fuel oil remain essentially unchanged from the coal emission limit. The Division therefore assumes the source is in compliance with Subpart D emission limits whenever alternate fuel use comprises less than 5% of total heat input. If alternate fuel use comprises more than 5% of total heat input on an annual basis, the permit must be reopened to include Subpart D requirements for combined fuel combustion. In addition, this source is subject to Regulation No. 1 emission limits, which are equal to or less stringent than Subpart D provisions. The Division therefore also assumes the source is in compliance with Regulation No. 1 requirements whenever alternate fuel use comprises less than 1% of total heat input.

Alternate Operating Scenarios

The permittee requested the ability to dispose of spent boiler tube cleaning waste as an alternate operating scenario. Circulation of water through the boiler tubes results in an accumulation of mineral deposits over time. The mineral deposition decreases the efficiency of the heat transfer from the boiler tube to the circulating water. Periodically, the tubes are cleaned to recover the heat transfer efficiency. The cleaning is accomplished by circulating cleaning solutions, generally acid and detergent mixtures, through the tubing. Commonly, the accumulated spent materials are slowly injected into an operating boiler for disposal. The permittee had previously requested to dispose of cleaning waste in the boiler, in March of 1993. At that time the Division agreed to the proposal, and determined a modification to the Construction Permit was not necessary. The permittee provided information regarding studies performed by the Electric Power Research Institute which indicates that disposal of cleaning wastes does not have a significant effect on operations or emissions. This has been an on-going practice for boilers operated by utilities, and has not been cited by the Division as a compliance issue.

In addition, the permittee indicates that on a sporadic basis, they wish to combust non-hazardous petroleum contaminated soils and materials in the boiler. These materials are generated on occasions at the Craig Station when accidental spills of petroleum liquids (lube oils and fuel) occur. Because of the expected small quantity of non-hazardous petroleum contaminated soils and materials generated, it is expected that introduction of such materials into the boiler for combustion will not cause the exceedance of any applicable emission limit or emission of pollutants not generated by routine operation of these boilers.

Provisions for these two alternate operating scenarios are provided for in the Operating Permit.

P101 – Coal Handling – Units 1 & 2

The Unit 1 and 2 coal handling system transfers coal delivered by trucks on unpaved haul roads to Craig Station to the Unit 1, 2, and 3 coal storage piles and silos. On occasion, coal is deposited in a coal surge pile prior to being transferred to the crusher. The coal is

crushed and conveyed to the coal transfer building, where it is sent either to the stockpiles or coal silos. Coal destined for the storage pile is conveyed to the stackout tower and then to telescoping chutes for loadout to the storage pile. Coal is reclaimed underground from storage and is transferred to generation building coal silos. Bagfilters and enclosed conveyors control PM emissions from all sources except coal delivery unloading, the coal pile stackout and the storage piles. Telescopic chutes are used to control PM emissions from the coal pile stackout. Coal unloading and stackout is controlled with water spray containing a surfactant, on an as-needed basis. Note that water sprays may not be operable during cold weather. The coal haul road is treated with a resinous adhesive, or equivalent, as often as necessary.

Applicable Requirements - Final Construction Permit 11MF276 was issued for these activities. Applicable requirements are as follows.

Construction Permit 11MF276

- Limits process throughput to 3,900,000 tons per year
- Limits opacity to 20%
- Sets forth measures for minimizing fugitive particulate matter emissions

Requested revisions:

"The coal being loaded to live storage will be sprayed with water with a surfactant added," is revised to read: "The coal being loaded to live storage will be sprayed with water with a surfactant added, on an as-needed basis." This is consistent with other Tri-State construction permits.

"The haul road used by coal trucks on the Craig Station property shall be treated with a resinous adhesive (or equivalent) to control dust. The treatment material shall be bladed into the soil according to the manufacturer's specification and shall be reapplied as often as necessary to remain viable as a control measure." Is revised to read: "The haul road used by coal trucks on the Craig Station property shall be treated with magnesium chloride (or equivalent) to control dust. The treatment material shall be applied according to the manufacturer's specification and shall be reapplied as often as necessary to remain viable as a control measure."

The requirement for water spray bars at the unloading station is revised to indicate that the spray bars will be used *as needed*.

Regulation No.1.II.A.1 & 4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes

(Note: These limits do not apply to fugitive particulate emissions (Colorado Regulation No. 1, II.8(iii)) - Colorado Regulation No. 3 defines "fugitive emissions" as "those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening." The Division has determined that the emissions from the coal pile stackout telescopic chute are fugitive.) Other fugitive sources include the storage piles, unloading to the grizzly, unloading to the coal surge pile, and the haul road.

40 CFR Part 60 Subpart Y, NSPS for Coal Preparation Plants

- Opacity not to meet or exceed 20% for all sources except the storage piles, unloading to coal surge pile, coal pile stackout and coal stackout building, coal reclaim A & B, coal tripper deck and silos, common coal drive house, and haul roads - Not applicable during startup, shutdown, or malfunction

Emission Factors - AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM₁₀ emissions.

Monitoring Plan - As-fired and as-received belt scales continuously weigh the coal as it moves from the truck unloading hoppers to the units or stockpile, and from the stockpile to the coal silos. These monitoring records can be used to identify compliance with the coal handling limits. The emissions are calculated based on the amount of coal being processed.

For those sources subject to an opacity standard, a U.S. EPA Reference Method 9 opacity observation is performed by a certified observer at least semi-annually. An operation and maintenance plan shall be implemented for the baghouses.

A quarterly inspection is performed to ensure PM Emission Control Plan measures are in place.

Compliance Status - The Division accepts this process was in compliance at the time the Title V application was submitted.

P102 – Coal Handling – Unit 3

The Unit 3 coal handling system transfers coal delivered by rail car to the Unit 1,2, and 3 coal piles and silos. Coal drops from the railcars into underground hoppers and is conveyed to the crusher building. After crushing, coal is conveyed to the stackout building, where it is either sent to the stockpile or to the transfer building. Coal in the transfer building is conveyed to the coal silos in the generation building. Bagfilters control PM emissions from all sources except coal delivery unloading, the coal pile stackout and the storage piles.

Telescopic chutes are used to control PM emissions from the coal pile stackout. Water is sprayed at the coal train unloading to control PM emissions. Note that water sprays may not be operable during cold weather. Water, compaction or chemicals are used, as necessary, to control PM emissions at the coal storage piles. Since the Unit 3 system handles coal which may be delivered to Units 1 and 2, the system is included in the Operating Permit at this time.

Applicable Requirements - Final Construction Permit 12MF322(2) was issued for these sources. Applicable requirements are as follows.

Construction Permit 12MF322(2)

- Limits opacity to 20%
- Sets forth measures for minimizing fugitive PM emissions
- Requires emissions from crushing, transferring, and coal reclaiming to be controlled by fabric filter baghouses

Colorado Regulation No.1.II.A.1&4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes (*Note: These limits do not apply to fugitive particulate emissions (Colorado Regulation No. 1, II.8(iii)) - Colorado Regulation No. 3 defines "fugitive emissions" as "those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening." Fugitive sources include coal train unloading, coal stackout, and storage piles.*)

40 CFR Part 60 Subpart Y, NSPS for Coal Preparation Plants

- Opacity not to meet or exceed 20% - Not applicable during startup, shutdown, or malfunction - Does not apply to coal stackout, common coal transfer building extension, common coal drive house, coal tripper deck and silos, to the storage pile, or to the open coal storage pile

Other

The Construction Permit does not contain a specific processing limit, however, records of the amount of coal processed are necessary for estimating emissions.

Emission Factors - AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM₁₀ emissions.

Monitoring Plan - As-fired and as-received belt scales continuously weigh the coal as it moves from the rail cars unloading hoppers to the Units or stockpile, and from the stockpile to the coal silos. The emissions are calculated based on the amount of coal being processed. A U.S. EPA Reference Method 9 opacity observation is performed by a certified observer every six months and a baghouse operating and maintenance plan is required.

A quarterly inspection is performed to ensure PM Emission Control Plan measures are in place.

Compliance Status - The Division accepts the process was in compliance at the time the Title V application was submitted.

P201 – Limestone Handling and Storage Facility – Units 1 & 2

The Unit 1 & 2 limestone handling system provides for receiving, transferring, storage, and preparation of limestone before it is introduced to the Units 1 & 2 wet limestone scrubbers. Limestone is delivered by trucks, and unloaded to a receiving hopper. Limestone is then transferred to the silos. Bagfilters are used to control PM emissions at the silo and unloading.

Applicable Requirements - Final Construction Permit 11MF415 was issued for these activities. Applicable requirements are as follows.

Construction Permit 11MF415

- Limits opacity to 20%
- Requires unloading facilities emissions to be controlled by baghouse
Construction Permit requirement is revised from: "All process equipment shall be maintained and operated so that there is no leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system." To: "All process equipment shall be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system."

Colorado Regulation No. 1, II.A.1 & 4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes
Does not apply to fugitive emission sources: limestone hauling.

Other

The Construction Permit does not specifically limit the amount of limestone delivered, however, the amount is needed to calculate emissions estimates

Emission Factors - AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM₁₀ emissions

Monitoring Plan -Semi-annual U.S. EPA Reference Method 9 opacity observations will be performed on the baghouses and a baghouse operation and maintenance plan is required.

Compliance Status - The Division accepts the units were in compliance at the time the Title V application was submitted.

P203 – Ash Handling System – Units 1 & 2

The Unit 1 and 2 ash handling and processing system provides for transferring ash from the boilers and ESPs to ash silos for temporary storage before it is transported for off-site disposal or commercial sale. The Unit 1 and 2 boilers generate both bottom ash and fly ash. The bottom ash handling system transfers all materials using water, thus there are no particulate emission sources associated with bottom ash handling. Fly ash is pneumatically transported to the silos. Bagfilters are used to control PM emissions for the silos and the dry ash unloading for commercial sale. Water and dustless unloaders are used to control PM for truck loading operations for ash disposal.

Applicable Requirements - Final Construction Permit 11MF332 was issued for these activities. Applicable requirements are as follows.

Construction Permit 11MF332

- Limits opacity to 20%
- Requires bagfilter control of ash silos
- Sets forth measures for minimizing fugitive dust emissions

Construction Permit requirement is revised from: "All process equipment shall be maintained and operated so that there is no leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system." To: "All process equipment shall be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system."

Colorado Regulation No. 1, II.A.1&4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control

equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes
Does not apply to fugitive emission sources: truck loading for disposal

Other

The Construction Permit does not specifically limit the amount of ash processed, however, the amount is needed to calculate emissions estimates.

Emission Factors - Standard AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM₁₀ emissions.

Monitoring Plan - For those sources subject to an opacity standard, semi-annual U.S. EPA Reference Method 9 opacity observations will be performed and a baghouse operation and maintenance plan is required. The dry ash unloader on silo A discharges directly into silo A. Therefore, there is not a separate source of emissions. The dry ash unloading on silo B discharges to a bagfilter which discharges inside the silo B building adjacent to a piperack, therefore, a Method 9 reading is not required, and absent credible evidence to the contrary, the Division assumes the opacity standard is being met. The word "credible" as it is used in the term "credible evidence" shall be applied under the provisions of the permit as defined by Colorado and Federal Rules of Evidence. Quarterly inspections will be performed to ensure the bagfilters and PM emission minimization measures are in place.

Compliance Status - The Division accepts the process was in compliance at the time the Title V application was submitted.

P204 – Ash Handling System and Ash Haul Road Ash Haul Road for Units 1, 2 and 3 (Ash and Scrubber Sludge Hauling)

The Unit 3 ash handling and processing system provides for transferring of ash from the Unit 3 boiler, baghouse hoppers, and ash collection locations in the scrubber building to an ash silo or the recycle ash tank for temporary storage before it is transported offsite for disposal or commercial sale. The boiler generates both bottom ash and fly ash. The bottom ash handling system transfers all materials using water, thus there are no particulate emission sources associated with bottom ash handling. Flyash is pneumatically conveyed to the silo. Baghouses control PM emissions for the silo, day tank and dry ash unloading for commercial sale. Water and dustless unloaders control PM for the ash unloading operations for disposal. Magnesium chloride is applied to the unpaved portion of the ash haul road, as necessary, to control PM emissions.

Applicable Requirements - Final Construction Permit 12MF322(3) was issued for these activities. Applicable requirements are as follows.

Construction Permit 12MF322(3)

- Limits opacity to 20%

- Sets forth measures for minimizing fugitive dust emissions
(Note: Construction Permit Condition 3. States "Ash deposited in trucks for transport to disposal areas shall be sufficiently wet to maintain a moisture content greater than 12% and/or a control of visible emissions equal to that of an enclosed cargo box originally permitted." The Division believes requiring a specific moisture content is not practical. In addition, it is not practical to attempt to compare current visible emissions to the now removed cargo box. This condition is therefore revised as follows: "Ash deposited in trucks for transport to disposal areas shall be sufficiently moist to minimize fugitive emissions." This is consistent with minimization measures set forth in the Construction Permit 11MF332 for Units 1 & 2 ash handling.

PSD Permit

- Requires magnesium chloride to be used on the ash haul road according to manufacturer's specifications

Colorado Regulation No. 1, II.A.1 & 4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes
Not applicable to fugitive emission sources: truck loading for disposal and haul roads.

Other

The Construction Permit does not specifically limit the amount of ash processed, however, the amount is needed to calculate emissions estimates.

Emission Factors - Standard AP-42 factors and equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM₁₀ emissions

Monitoring Plan - For those sources subject to an opacity standard, semi-annual U.S. EPA Reference Method 9 opacity observations will be performed and a baghouse operation and maintenance plan is required. The dry ash unloading baghouse is located inside a building, therefore a Method 9 reading is not required, and absent credible evidence to the contrary, the Division assumes the opacity standard is being met. A quarterly inspection will be performed to ensure the bagfilters and PM emission minimization measures are in place.

Compliance Status - The Division accepts the process was in compliance at the time the Title V application was submitted.

P205 – Staging/Landfilling

Wet and dry waste products are hauled to the staging/landfilling area, where they are unloaded. The staged wastes are then subsequently loaded in a truck for final disposal at Trapper Mine. The staging/landfilling activities are considered to have negligible emissions.

Applicable Requirements - Final Construction Permit 11MF994(F) was issued for these activities. Applicable requirements are as follows.

Construction Permit 11MF994(F)

- Sets forth a Particulate Emissions Control Plan
(Note: The Construction Permit indicates that Mining activities are subject to the 20% opacity guideline, under Regulation No. 1. This activity is not “mining,” but consists of construction (land clearing and leveling) and storage and handling of materials, which are also subject to the 20% opacity guideline. The permit language is revised to delete the reference to mining activities. The 20% is a guideline, as stated in Regulation No. 1 and its Statement of Basis and Purpose. The regulation shifted the use of opacity observations from an enforceable standard for area sources to a guideline in determining when the adequacy of applied control methods should be reviewed. U.S. EPA Method 9 readings are not required for these sources.)

Other

The Construction Permit does not specifically limit the amount of waste processed, however, the amount is needed to calculate emissions estimates.

Emission Factors - Standard AP-42 equations, or other emission factors/procedures acceptable to the Division, and appropriate control measure/equipment control efficiencies are used to estimate PM and PM₁₀ emissions.

Monitoring Plan - A quarterly inspection will be performed to ensure PM emission minimization measures are in place.

Compliance Status - The Division accepts the process was in compliance at the time the Title V application was submitted.

P206 - Soda Ash Addition System

This system was for addition of soda ash to coal for Boiler Units #1 and #2. Due to the Consent Decree changes to the scrubber system, the soda ash addition system has been dismantled and is not longer included in this operating permit.

P401 – Unit 1 Cooling Tower

P402 – Unit 2 Cooling Tower

The cooling towers are used to dissipate waste heat from the boilers circulating water system. Pollutants expected to be emitted include PM and small quantities of chloroform produced by the introduction of chlorine in the recirculating cooling tower water to control biological growth. The cooling towers were not permitted at the time of the initial Operating Permit application submittal. The application documents for a construction permit were submitted and Initial construction permits were subsequently issued.

Applicable Requirements - Initial Construction Permits 98MF0141 and 96MF195 were issued for these sources. The source has demonstrated compliance under the provisions of Regulation No. 3, Part B, Section IV.H for initial approval construction permit 98MF0141 but not yet received a final approval construction permit. Under the provisions of Regulation No. 3, Part C, Section V.A.3, the Division will not issue a final approval construction permit and is allowing the initial approval construction permit to continue in full force and effect. The appropriate provisions of the initial approval construction permit have been directly incorporated into this operating permit.

Construction Permits 98MF0141 and 96MF195

- Limit the design and maximum circulating water rates.
- Limit the total dissolved solids content of the water.
- Limit the drift loss and set forth schedules for retrofitting drift eliminators (at the time of Construction Permit issuance, the cooling towers equipped with older style drift eliminators. New, more efficient drift eliminators are considered to represent "BACT" for cooling towers, and the schedule was developed to implement the new style drift eliminators.) The Construction Permits require progress reports by March 31 of the following year. The Operating Permit requires reports by April 30, to be consistent with APEN reporting requirements. (*Note: Construction of the new drift eliminators is completed, therefore the schedule is not included in this operating permit.*)
- Limits PM, PM₁₀, and VOC emissions

Colorado Regulation No. 1, II.A.1&4

- Limits opacity to 20%, except as provided for below
- New fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment - not to exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes

Emission Factors - PM emissions are estimated using EPA factors. VOC emissions are estimated using factors from a report by Michelletti. A copy of the report is included in the Operating Permit application.

Monitoring Plan - Measurements of TDS will be made and recorded monthly.

Compliance Status - The applicant has submitted the documents needed to obtain a construction permit and permits were issued. The Division accepts the cooling towers are now in compliance.

Miscellaneous

Emission Factors - From time to time published emission factors and/or other emission estimating methods are changed based on new or improved data. A logical concern is what happens if the use of the new factors/methods in a calculation results in a source being out of compliance with a permit limit. For this operating permit, the emission factors, equations, and/or other emission estimating methods included in the permit are considered to be fixed until changed by the permit. Obviously, emission factors dependent on the fuel sulfur content or heat content of the fuel can not be fixed and will vary with the test results. The method for determining the emissions is, however, fixed. It is the responsibility of the permittee to be aware of changes in the factors, etc. and to notify the Division in writing of impacts on the permit requirements when there is a change. Upon notification, the Division will work with the permittee to address the situation. In addition, the Division will review the factors, etc. as appropriate during permit modifications and renewals.

APEN Reporting for Insignificant Activities - Some sources permitted under the issued Construction Permits are insignificant sources because the uncontrolled actual emissions for recent years are below APEN de minimis levels. (Note: Those sources with emissions below de minimis levels, but which are subject to an NSPS requirement are still subject to APEN reporting requirements.) These sources are listed in the Operating Permit as permitted sources, in the event emissions should increase above the de minimis level in the future.

Accidental Release Program – 112(r)

Section 112(r) of the Clean Air Act mandates a new federal focus on the prevention of chemical accidents. Sources subject to these provisions must develop and implement risk management programs that include hazard assessment, a prevention program, and an emergency response program. They must prepare and implement a Risk Management Plan (RMP) as specified in the Rule.

Based on the information provided by the applicant, this facility is subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act).

Compliance Assurance Monitoring (CAM)

The following emission points at this facility use a control device to achieve compliance with an emission limitation or standard to which they are subject and have pre-controlled emissions that exceed or are equivalent to the major source threshold. They are therefore subject to the provisions of the CAM program as set forth in 40 CFR Part 64 as adopted by reference into Colorado Regulation No. 3, Part C, Section XIV:

None.

(The Title V application was deemed administratively complete prior to April 20, 1998.)

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-25-14
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit M: Department, *Resource Adequacy Report: Evaluating the Reliability and
Security of the United States Electric Grid* (July 2025)



U.S. DEPARTMENT
of ENERGY

Resource Adequacy Report

Evaluating the Reliability and Security of the United States Electric Grid

July 2025

Acknowledgments

This report and associated analysis were prepared for DOE purposes to evaluate both the current state of resource adequacy as well as future pressures resulting from the combination of announced retirements and large load growth.

It was developed in collaboration with and with assistance from the Pacific Northwest National Laboratory (PNNL) and National Renewable Energy Laboratory (NREL). We thank the North American Electric Reliability Corporation (NERC) for providing data used in this study, the Telos Corporation for their assistance in interpreting this data, and the U.S. Energy Information Administration (EIA) for their dissemination of historical datasets. In addition, thank you to NREL for providing synthetic weather data created by Evolved Energy Research for the Regional Energy Deployment System (ReEDS) model.

DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience.

Historically, the nation's power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued. Thus, one of the key takeaways from this study process is the underscored "call to action" for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security.

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List of Acronyms

AI	Artificial Intelligence
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EO	Executive Order
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITCS	Interregional Transfer Capability Study
LBL	Lawrence Berkeley National Laboratory
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LTRA	Long-Term Reliability Assessment
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PJM	PJM Interconnection, LLC
PNNL	Pacific Northwest National Laboratory
ReEDS	Regional Energy Deployment System
RTO	Regional Transmission Organization
SERC	SERC Reliability Corporation
TPR	Transmission Planning Region
USE	Unserved Energy

Background to this Report

On April 8, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid." EO 14262 builds on EO 14156, "Declaring a National Emergency (Jan. 20, 2025)," which declared that the previous administration had driven the Nation into a national energy emergency where a precariously inadequate and intermittent energy supply and increasingly unreliable grid require swift action. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy and the integrity of our Nation's electrical grid.

EO 14262 mandates the development of a uniform methodology for analyzing current and anticipated reserve margins across regions of the bulk power system regulated by the Federal Energy Regulatory Commission (FERC). Among other things, EO 14262 requires that such methodology accredit generation resources based on the historical performance of each generation resource type. This report serves as DOE's response to Section 3(b) of EO 14262 by delivering the required uniform methodology to identify at-risk region(s) and guide reliability interventions. The methodology described herein and any analysis it produces will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States.

Executive Summary

Our Nation possesses abundant energy resources and capabilities such as oil and gas, coal, and nuclear. The current administration has made great strides—such as deregulation, permitting reform, and other measures—to enable addition of more energy infrastructure crucial to the utilization of these resources. However, even with these foundational strengths, the accelerated retirement of existing generation capacity and the insufficient pace of firm, dispatchable generation additions (partly due to a recent focus on intermittent rather than dispatchable sources of energy) undermine this energy outlook.

Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation. A failure to power the data centers needed to win the AI arms race or to build the grid infrastructure that ensures our energy independence could result in adversary nations shaping digital norms and controlling digital infrastructure, thereby jeopardizing U.S. economic and national security.

Despite current advancements in the U.S. energy mix, this analysis underscores the urgent necessity of robust and rapid reforms. Such reforms are crucial to powering enough data centers while safeguarding grid reliability and a low cost of living for all Americans.

Key Takeaways

- **Status Quo is Unsustainable.** The status quo of more generation retirements and less dependable replacement generation is neither consistent with winning the AI race and ensuring affordable energy for all Americans, nor with continued grid reliability (ensuring “resource adequacy”). Absent intervention, it is impossible for the nation's bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens.
- **Grid Growth Must Match Pace of AI Innovation.** The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. The situation necessitates a radical change to unleash the transformative potential of innovation.
- **Retirements Plus Load Growth Increase Risk of Power Outages by 100x in 2030.** The retirement of firm power capacity is exacerbating the resource adequacy problem. 104 GW of firm capacity are set for retirement by 2030. This capacity is not being replaced on a one-to-one basis and losing this generation could lead to significant outages when weather conditions do not accommodate wind and solar generation. In the “plant closures” scenario of this analysis, annual loss of load hours (LOLH) increased by a factor of a hundred.
- **Planned Supply Falls Short, Reliability is at Risk.** The 104 GW of retirements are projected to be replaced by 209 GW of new generation by 2030; however, only 22 GW would come from firm baseload generation sources. Even assuming no retirements, the model found increased risk of outages in 2030 by a factor of 34.

- **Old Tools Won't Solve New Problems.** Antiquated approaches to evaluating resource adequacy do not sufficiently account for the realities of planning and operating modern power grids. At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude, and duration of power outages; move beyond exclusively analyzing peak load time periods; and develop integrated models to enable proper analysis of increasing reliance on neighboring grids.

This report clearly demonstrates the need for rapid and robust reform to address resource adequacy issues across the Nation. Inadequate resource adequacy will hinder the development of new manufacturing in America, slow the re-industrialization of the U.S. economy, drive up the cost of living for all Americans, and eliminate the potential to sustain enough data centers to win the AI arms race.

Developing a Uniform Methodology

DOE's resource adequacy methodology assesses the U.S. electric grid's ability to meet future demand through 2030. It provides a forward-looking snapshot of resource adequacy that is tied to electricity supply and new load growth, systematically exploring a range of dimensions that can be compared across regions. As detailed in the methodology section of this report, the model is derived from the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study (ITCS) which leverages time-correlated generation and outages based on actual historic data.¹ A deterministic approach² simulates system stress in all hours of the year and incorporates varied grid conditions and operating scenarios based on historical events:

- **Demand for Electricity – Assumed Load Growth:** The methodology accounts for the significant impact of data centers, particularly those supporting AI workloads, on electricity demand. Various organizations' projections for incremental data center electricity use by 2030 range widely (35 GW to 108 GW). DOE adopted a national midpoint assumption of 50 GW by 2030, aligning with central projections from Electric Power Research Institute (EPRI)³ and Lawrence Berkeley National Laboratory (LBNL).⁴ This 50 GW was allocated regionally using state-level growth ratios from S&P's forecast,⁵ reflecting infrastructure characteristics, siting trends, and market activity; and, mapped to NERC Transmission Planning Regions (TPRs).

1. This model differs from traditional peak hour reliability assessments in that it explicitly simulates grid performance hour-by-hour across multiple weather years with finer geographic detail and optimized inter-regional transfers, and explores various retirement and build-out scenarios. Furthermore, the DOE approach integrates weather-synchronized outage data.

2. Deterministic approaches evaluate resource adequacy using relatively stable or fixed assumptions about the representation of the power system. Probabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty that require more computing power. Deterministic was chosen for this analysis for transparency and to model detailed historic system conditions.

3. EPRI, "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption," March 2024, <https://www.epri.com/research/products/3002028905>.

4. Shehabi, A., et al., "2024 United States Data Center Energy Usage Report," <https://escholarship.org/uc/item/32d6m0d1>.

5. S&P Global – Market Intelligence, "US Datacenters and Energy Report," 2024.

An additional 51 GW of non-data center load was modeled using NERC data, historical loads (2019-2023), and simulated weather years (2007-2013), adjusted by the Energy Information Administration's (EIA) 2022 energy forecast, with interpolation between 2024 and 2033 to estimate 2030 demand.

- **Supply of Electricity – Assumed Generation Retirements and Additions:** Between the current system and the projected 2030 system, the model considers three scenarios for generator retirements and additions. These scenarios were selected to describe the metrics of interest and how they change during certain assumptions of generation growth and retirements.

The resource adequacy standard (or criterion) is the measure that defines the desired level of adequacy needed for a given system. Conceptually, a resource adequacy criterion has two components—metrics and target levels—that determine whether a system is considered adequate. Comprehensive resource adequacy metrics⁶ are incorporated in this analysis to capture the magnitude and duration of system stress events:

- **Magnitude of Outages – Normalized Unserved Energy (NUSE):** Measures the amount of unmet electrical energy demand because of insufficient generation or transmission, typically measured in megawatt hours (MWh).

While USE describes the absolute amount of energy not delivered, it is less useful when comparing systems of different size or across different periods. Normalizing, by dividing by total load over a whole period (for example, a year) allows comparison of these metrics across different system sizes, demand levels, and periods of analysis. For example, 100 MWh of USE in a small, isolated microgrid can be more impactful than 100 MWh of USE in a larger regional grid that serves millions of people. USE is normalized by dividing by total load:

$$\frac{100 \text{ MWh (of unserved energy)}}{10,000,000 \text{ MWh (of total energy delivered in a year)}} \times 100 = 0.001 \text{ percent}$$

Although the use of NUSE is not standardized in the U.S. today,⁷ several system operators domestically and across the world have begun using NUSE as a useful metric.

- **Duration of Outages – Loss of Load Hours (LOLH):** Measures the expected duration of power outages when a system's load exceeds its available generation capacity. At the core, LOLH helps assess how frequently and for how long the power system is likely to experience insufficient supply, providing a picture of reliability in terms of time. LOLH is calculated as both a total and average value per year, in addition to the maximum percentage of load lost in any given hour per year.

6. In the interest of technical accuracy, and separate from their contextualization in the main text, NUSE is more precisely a measure of volume that is expressed as a percentage. Similarly, 2.4 hours of LOLH represents the cumulative sum of distinct periods of load loss, not a singular, continuous duration.

7. There is no common planning criterion for this metric in North America. NERC's Long-Term Reliability Assessment employs a normalized expected unserved energy (NEUE) metric to define target risk levels for each region. Grid operators, such as ISO-NE, have also considered NUSE in energy adequacy studies. For example, see ISO-NE, "Regional Energy Shortfall Threshold (REST): ISO's Current Thinking Regarding Tail Selection," April 2025, https://www.iso-ne.com/static-assets/documents/100022/a09_rest_april_2025.pdf.

Reliability Standard

DOE's methodology recognizes that the traditional 1-in-10 loss of load expectation (LOLE) criterion is insufficient for a complete assessment of resource adequacy and risk profile. This antiquated criterion is not calculated uniformly and fails to adequately account for crucial factors such as the duration and magnitude of potential outages.⁸ To provide a comprehensive understanding of system reliability and, specifically, to complement current resource adequacy standards while informing the creation of new criteria, the methodology uses the following reliability standard:

- **Duration of Outages:** No more than 2.4 hours of lost load in an individual year.⁹ This translates into one day of lost load in ten years to meet the 1-in-10 criteria.
- **Magnitude of Outages:** No more than an NUSE of 0.002%.¹⁰ This means that the total amount of energy that cannot be supplied to customers is 0.002% of the total energy demanded in a given year.

Achieving Reliability Standard

- **Perfect Capacity Surplus/Deficit:** Defined as the amount of generation capacity (in MW) a region would need to achieve specified threshold conditions. Based on these thresholds, this standard helps answer the hypothetical question of how much more (or less) power plant capacity is needed for a power system to be considered "perfectly reliable" according to pre-defined standards. This methodology employs this perfect capacity metric to identify the amount of capacity needed to remedy potential shortfalls (or excesses) in generation.

Key Results Summary

This analysis developed three separate cases for 2030. The "**Plant Closures**" case assumes all announced retirements occur plus mature generation additions based on NERC's Tier 1 resources category,¹¹ which encompasses completed and under-construction power generation projects, as well as those with firm-signed and approved interconnection service or power purchase agreements. The "**No Plant Closures**" case assumes no retirements plus mature additions. A "**Required Build**" case further compares the impacts of retirements on perfect capacity additions needed to return 2030 to the current system level of reliability.

8. While 1-in-10 analyses have evolved, industry experts have raised concerns about its effectiveness to address future system risks. Concerns include energy constraints that arise from intermittent resources, increasing battery storage, limited fuel supplies, and the shifting away of peak load periods from times of supply shortfalls.

9. The "1-in-10 year" reliability standard for electricity grids means that, on average, there should be no more than one day (24 hours) of lost load over a ten-year period. This translates to a maximum of 2.4 hours of lost load per year.

10. This analysis targets NUSE below 0.002% for each region because this is the target NERC uses to represent high risk in resource adequacy analyses. Estimates used in industry and analyzed recently range from 0.0001% to 0.003%.

11. Mature generation additions are based on NERC's 2024 LTRA Tier 1 resources, which assume that only projects considered very mature in the development pipeline will be built. For example, Tier 1 additions are those with signed interconnection agreements or power purchase agreements, or included in an integrated resource plan, indicating a high degree of certainty in their addition to the grid. Full details of the retirement and addition assumptions can be found in the methodology section of this report.

DOE ran simulations using 12 different years of historical weather. Every hour was based on actual data for wind, solar, load, and thermal availability to stress test the grid under a range of realistic weather conditions. The benefit of this approach is that it allows for transparent review of how actual conditions manifest themselves in capacity shortfalls. For all scenarios, LOLH and NUSE are calculated and used to compare how they change based on generation growth, retirements, and potential weather conditions.

- **Current System:** Supply of power (generation) and demand for power (load) consistent with 2024 NERC Long-Term Reliability Assessment (LTRA), including 2023 actual generation plus Tier 1 additions for 2024.
- **Plant Closures:** This case assumes 104 GW of announced retirements based on NERC estimates including approximately 71 GW of coal and 25 GW of natural gas, which closely align with retirement numbers in EIA's 2025 Annual Energy Outlook. In addition, this case assumes 100% of 2024 NERC LTRA Tier 1 additions totaling 209 GW are constructed by 2030. This includes 20 GW of new natural gas, 31 GW of additional 4-hour batteries, 124 GW of new solar and 32 GW of incremental wind. Details of the breakdown can be found in Appendix A.
- **No Plant Closures:** This case adds all the Tier 1 NERC additions but assumes no retirements.
- **Required Build:** To understand how much capacity may need to be added to reach reliability targets, the analysis adds hypothetical perfect capacity (which is idealized capacity that has no outages or profile) until a NUSE target of 0.002% is realized in each region. This scenario includes the same assumptions about retirements as our Plant Closures scenario described above.

As shown in the figures and tables below, the model shows a significant decline in all reliability metrics between the current system scenario and the 2030 Plant Closures scenario. Most notably, there is a hundredfold increase in annual LOLH from 8.1 hours per year in the current case to 817 hours per year in the 2030 Plant Closures. In the worst weather year assessed, the total lost load hours increase from 50 hours to 1,316 hours.

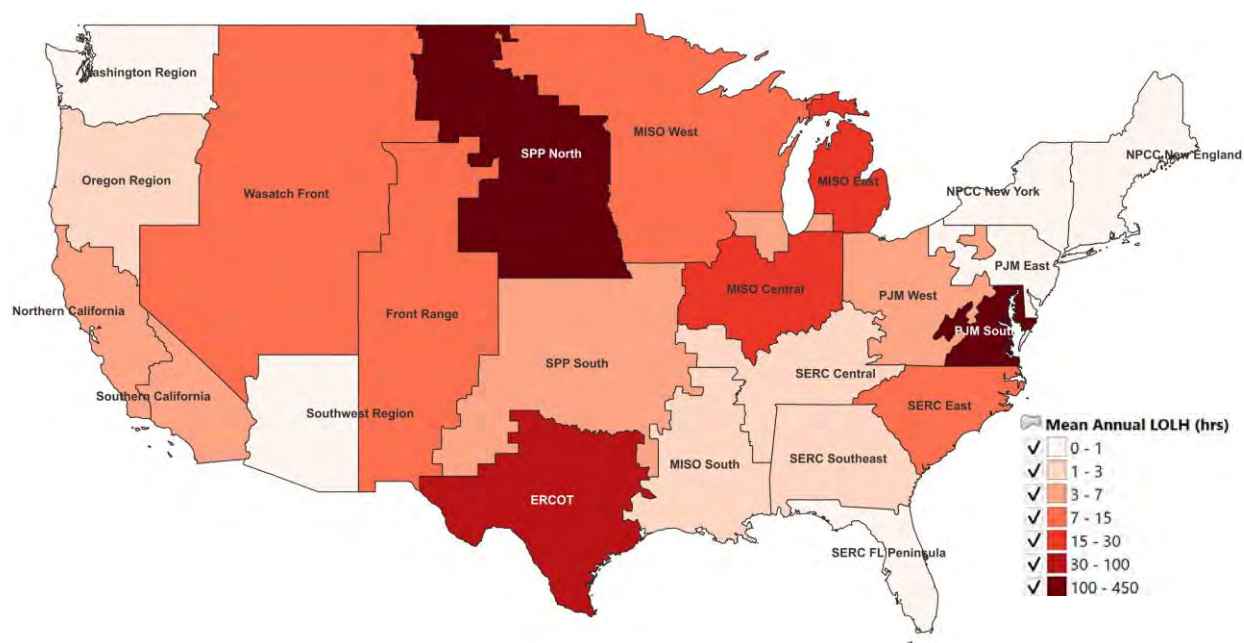


Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures

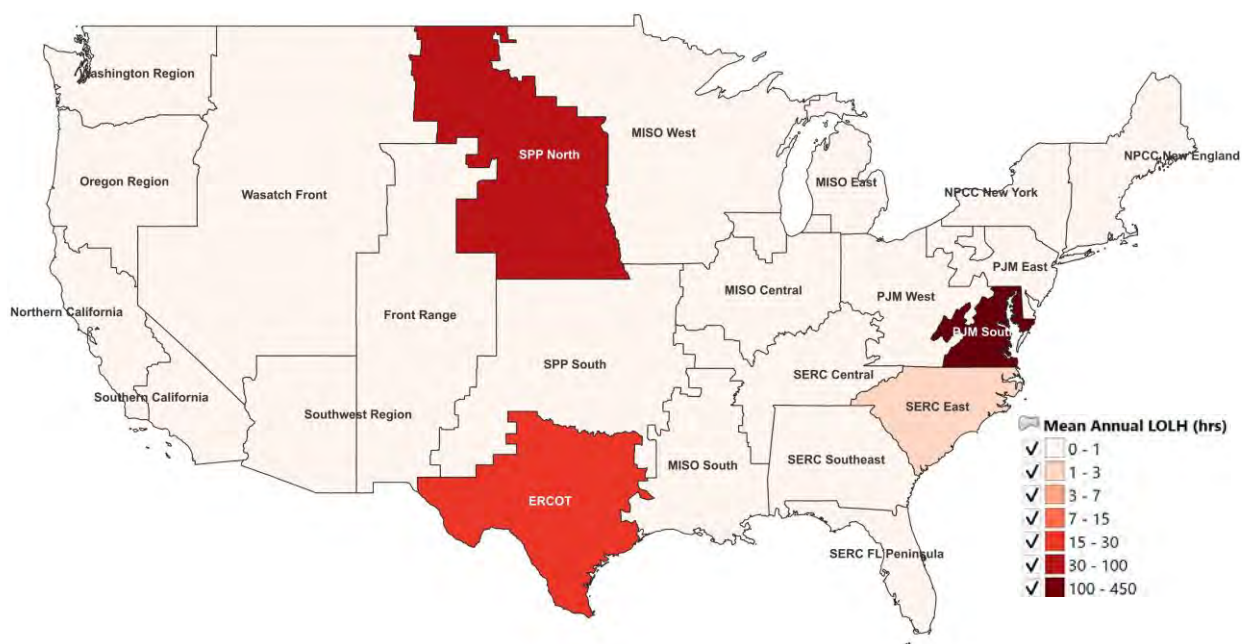


Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures

Table 1. Summary Metrics Across Cases

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	8.1	817.7	269.9	13.3
Normalized Unserved Energy (%)	0.0005	0.0465	0.0164	0.00048
WORST WEATHER YEAR				
Annual Loss of Load Hours	50	1316	658	53
Normalized Unserved Load (%)	0.0033	0.1119	0.0552	0.002

Current System Analysis

Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE. This indicates relative reliability for most regions based on the average indicators of risk used in this study. In the current system case, ERCOT would be expected to experience on average 3.8 LOLH annually going forward and a NUSE of 0.0032%. When looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour.

However, PJM, ERCOT,¹² and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load. This results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load. It is worth noting that in the case of PJM and SPP, the current system model shortfalls occurred within subregions rather than for the entire ISO footprint.

12. ERCOT has since winterized its generation fleet and did not suffer any outages during Winter Storm Elliot.

2030 Model Results

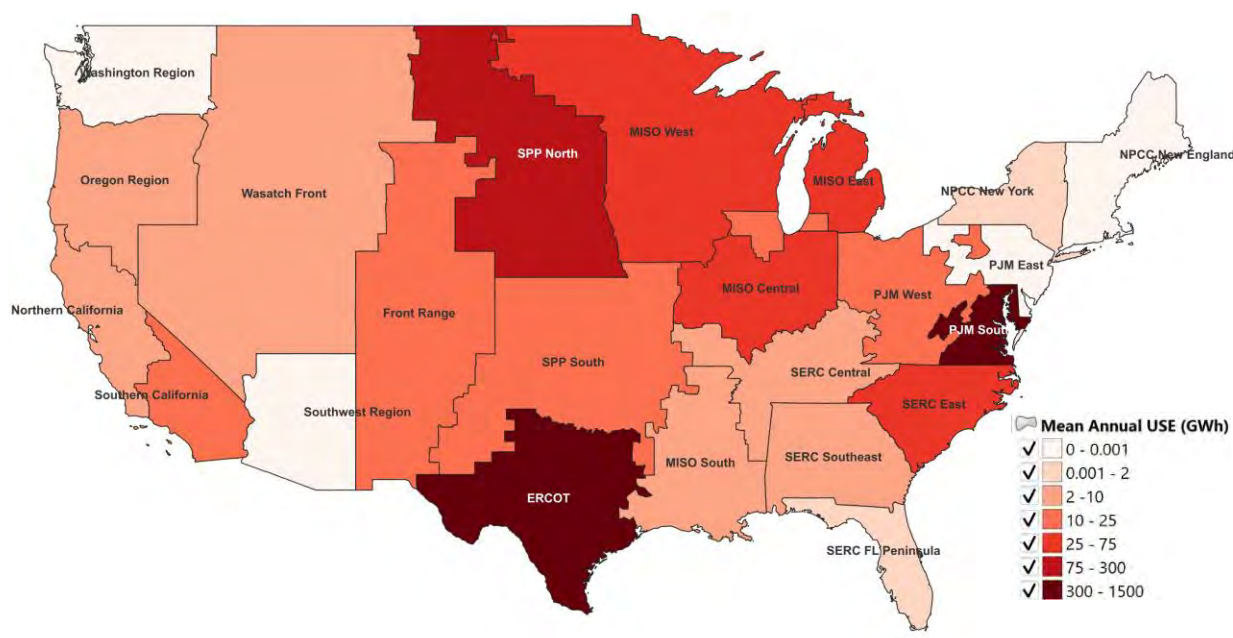


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

Key Findings – Plant Closures Case:

- **Systemwide Failures:** All regions except ISO-NE and NYISO failed reliability thresholds. These two regions did not have additional AI/data center (AI/DC) load growth modeled.
- **Loss of Load Hours (LOLH):** Ranged from 7 hours/year in CAISO to 430 hours/year in PJM.
- **Load Shortfall Severity:** Max shortfall reached as high as 43% of hourly load in PJM; 31% in CAISO.
- **Normalized Unserved Energy:** Normalized values ranged from 0.0032% (non-CAISO West) to 0.1473% (PJM), far exceeding thresholds of 0.002%.
- **Extreme Events:** Most regions experienced ≥ 3 hours of unserved load in at least one year. PJM had 1,052 hours in its worst year.
- **Spatial Takeaways:** Subregions in PJM, MISO, and SERC met thresholds—indicating possible benefits from transmission—but SPP and CAISO failed in all subregions.

Key Findings – No Plant Closures Case:

- **Improved System Performance:** Most regions avoided loss of load events. PJM, SPP, and SERC still experienced shortfalls.
- **Regional Failures:**

- o **PJM:** 214 hours/year average, 0.066% normalized unserved energy, 644 hours in worst year, max 36% of load lost.
- o **SPP:** 48 hours/year average, 0.008% normalized unserved energy, max 19% load lost.
- o **ERCOT:** 20 average hours, 0.028% normalized unserved energy, 101 max hours/year, peak shortfall of 27%.
- o **SERC-East:** Generally adequate (avg. 1 hour/year, 0.0003% NUSE), but Elliot storm in 2022 caused 42 hours of shortfall.

The overall takeaway is that avoiding announced retirements improves grid reliability, but shortfalls persist in PJM, SPP, ERCOT, and SERC, particularly in winter.

Required Build

This required build analysis quantifies "hypothetical capacity," defined as power that is 100% reliable and available that is needed to resolve the shortfalls. Known in industry as "perfect capacity," this metric is utilized to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations. Nevertheless, it serves as a valuable indicator, illustrating either the magnitude of a resource gap or the scale of large load that will be unable to interconnect. For the Required Build case, this hypothetical capacity was calculated by adding new generating resources to each region until a target of 0.002% of NUSE is reached.

The table below shows the tuned perfect capacity results. For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year. By 2030, without considering any generation retirements, an additional 12.5 GW of generating capacity is needed across PJM, SPP, and SERC to reduce shortfalls.

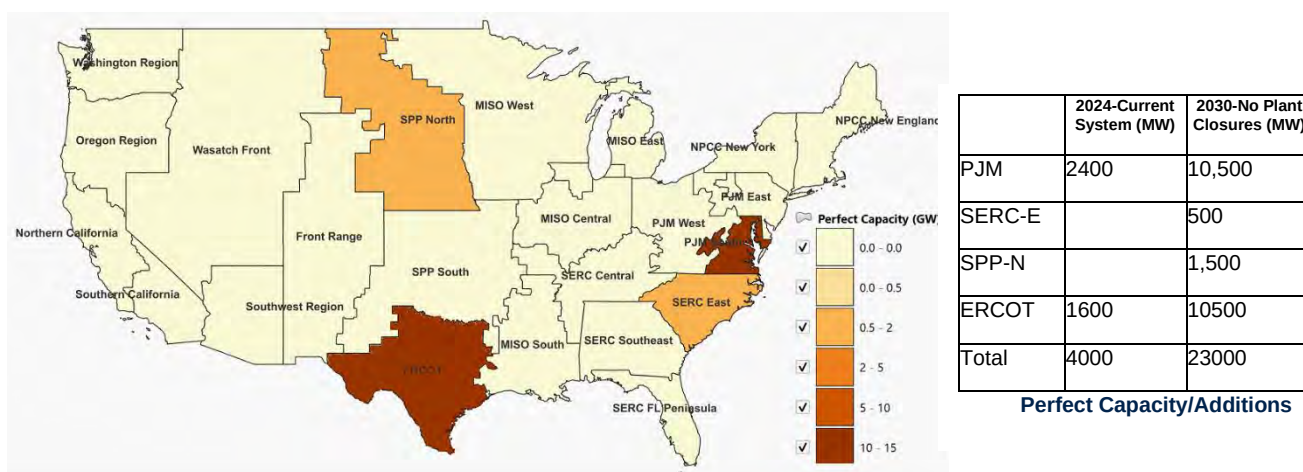


Figure 4. Tuned Perfect Capacity (MW) By Region

1 Modeling Methodology

The methodology uses a zonal PLEXOS¹³ model with hourly time-synchronous datasets for load, generation, and interregional transfer for the 23 U.S. subregions (referred to as TPRs in this study)¹⁴ including ERCOT (see Figure 5 below). While ERCOT operates outside of FERC's general jurisdiction,¹⁵ it provides a valuable case for understanding broader reliability and resource adequacy challenges in the U.S. electric grid, and FPA Section 202(c) allows DOE to issue emergency orders to ERCOT.

We base this analysis on actual weather and power plant outage data from 2007 to 2023 using NERC's ITCS¹⁶ base dataset. DOE specifically decided to start this analysis with the ITCS dataset since it is a complete representation of the interconnected electrical system for the lower 48 and it has been thoroughly reviewed by industry experts in a public and transparent process. DOE has in turn made modifications to the dataset to fit the needs of this study. The contents of this section focus on those modifications which DOE implemented for purposes of this study.

PLEXOS is an industry-trusted simulation tool used for energy optimization, resource adequacy, and production cost modeling. This study leverages PLEXOS' ability to exercise an hourly production cost model to determine the balance between loads, generation, and imports for each region. Modeling was carried out using a deterministic approach that evaluates whether a power system has sufficient resources to meet projected demand under a pre-defined set of conditions which correspond to the past few years of real-world events. The model ultimately determines the amount of unmet load if generation resources and imports are not sufficient for meeting the load in each discrete time period.

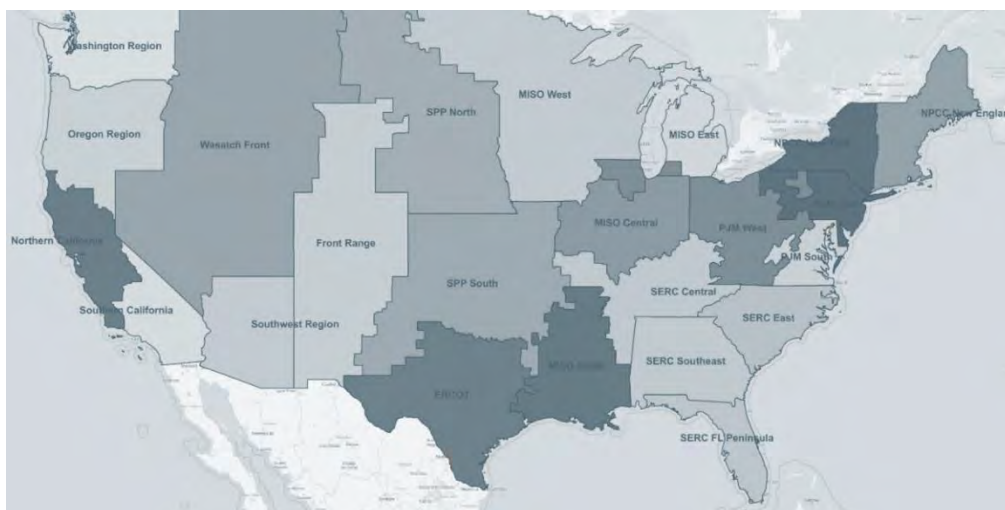


Figure 5. TPRs used in NERC ITCS

13. Energy Exemplar, "PLEXOS," <https://www.energyexemplar.com/plexos>.

14. The TPRs match the regional subdivisions in the NERC ITCS study, itself based on FERC's transmission planning regions.

15. Transmission within ERCOT is intrastate commerce. 16 U.S.C. § 824(b)(1) (provisions applying to "the transmission of electric energy in interstate commerce").

16. NERC "Integrated Transmission and Capacity System (ITCS)," accessed June 25, 2025, <https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx>.

This methodology developed a current model and series of scenarios to explore how different assumptions impact resource adequacy. This sensitivity analysis includes assumptions regarding load growth, generation build-outs and retirements, and transfer capabilities. By comparing the results of the current model with the scenario results, we can assess how generation retirements and load growth affect future generation needs.

The assessment uses data from 2007–2013 (synthetic weather data) and 2019–2023 (historical data). A brief summary of the methodological assumptions is provided here, with additional details available in the relevant appendixes.

- **Solar and Wind Availability** – Created from historical output from EIA 930 data, with bias correction of any nonhistorical data to match regional capacity factors, as calibrated to EIA 930 data.¹⁷ Synthetic years used 2018 technology characteristics from NREL based on the Variable Energy Potential (reV) model, then mapped to synthetic weather year data. See Appendix A for more details.
- **Thermal Availability** – Calculated according to NERC LTRA capacity data, adjusted for historical outages and derates, primarily with GADS data. GADS data does not capture historical outages caused by fuel supply interruptions.¹⁸
- **Hydroelectric Availability** – Historical outputs are processed by NERC to establish monthly power rating limits and energy budgets, but energy budgets are not enforced in alignment with how they were treated in the ITCS. The team evaluated performance under different energy budget restrictions, but did not find significant differences during peak hours, justifying NERC ITCS assumptions that hydroelectric resources could generally be dispatched to peak load conditions. Later work may benefit from exploring drought scenarios or combinations of weather and hydrological years, where energy budgets may be significantly decreased.
- **Outages and Derates** – Data for the actual data period (2019–2023) are based on historical forced outage rates and deratings. Outage and deratings data for the synthetic period (2007–2013) are based on the historical relationships observed between temperature and outages (see Appendix G of the NERC ITCS Final Report for more information).
- **Load Projections and AI Growth** – Load growth through 2030 is assumed to match NERC 2024 ITCS projections, scaling the 12 weather years to meet 2030 projections. Additional AI and data center load is then added according to reports from EPRI and S&P regarding potential futures.
- **Transfer Capabilities and Imports/Exports** - Each subregion is treated as a “copper plate,” with the transfer capacity between each subregion defined by the availability of transmission pathways. It is an approximation that assumes all resources are connected to a single point, simplifying the transmission system within the model. Subregions are generally assumed to exhaust their own capacity before utilizing capacity available from their neighbors. Once the net remaining capacity is at or below 10 percent of load, the subregion begins to use capacity from a neighbor.

17. See ITCS Final Report, Appendix F, for the method that was implemented to scale synthetic weather years 2007–2013.

18. See ITCS Final Report, Appendix G, for outage and derate methods.

- o Imports are assumed to be available up to the minimum total transfer capacity and spare generation in the neighboring subregion.
- o To the extent the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario, the model projects an energy shortfall. See “Outputs” in the appendix for more details.
- o To ensure that transfers are dispatched only after local resources are exhausted, a wheeling charge of \$1,000 is applied for every megawatt-hour of energy transferred between regions through transmission pathways.
- **Storage** – In alignment with the NERC ITCS methodology, storage was split into pumped hydro and battery storage. Pumped hydro was assumed to have 12 hours duration at rated capacity with 30% round-trip losses, while battery storage was assumed to have four hours and 13% round-trip losses. Storage is dispatched as an optimization to minimize USE and demand response usage under various constraints and is recharged during periods of surplus energy.
- **Demand Response** – Demand Response (DR) is treated as a supply-side resource and dynamically scheduled after all other regional resources and imports are exhausted. It is modeled with both capacity (MW) and energy (MWh) limitations and assumed to have three hours of availability at capacity but could be spread across more than three hours up to the energy limit. DR capacity was based on LTRA Form A data submissions for “Controllable and Dispatchable Demand Response – Available”, or firm, controllable DR capacity.
- **Retirements** – Retirements as per the NERC LTRA 2024 model. To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant level data are used to tabulate generation retirement or addition capacity for each ITCS region and NERC assessment area. Disaggregation fractions are then calculated by technology based on planned retirements through 2030. See Appendix B for further information. Retirements are categorized into two categories:
 1. *Announced Retirements*: Includes both confirmed retirements and announced retirements. Confirmed retirements are generators formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date. To go from LTRA regions to ITCS regions, weighting factors are derived in the same way as in the generation set, based on EIA retirement data. In addition to confirmed retirements, announced retirements are generators that have publicly stated retirement plans that have not formally notified system operators and initiated the retirement process. This disaggregation method for announced retirements mirrors used for confirmed retirements.¹⁹
 2. *None*: Removes all retirements (after 2024) for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirement contributes to some of the adequacy challenges in some regions.
- **Additions** – Assumes only projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built. This data is based on projects

19. If announced retirements were less than or equal to confirmed retirements, the model adjusted the announced retirement to equal confirmed.

designated as Tier 1 in the NERC 2024 LTRA and are mapped to ITCS regions with EIA 860-derived weighting factors similar to those described for the retirements above. See Appendix A for further information.

- **Perfect Capacity Required** - Estimates perfect capacity (which is idealized capacity that has no outages or profile and is described in Section 2) until we reach a pre-defined reliability target. We used a metric of NUSE given the deterministic nature of the model, to be consistent with evolving metrics, and to be consistent with NERC's recent LTRAs. We targeted NUSE of below 0.002% for each region.

1.1 Modeling Resource Adequacy

This model calculates several reliability metrics to assess resource adequacy. These metrics were calculated using PLEXOS simulation outputs, which report the USE (in MWh) for all 8,760 hourly periods in each of the 12 weather years:

- **USE** refers to the amount of electricity demand that could not be met due to insufficient generation and/or transmission capacity. Several USE-derived indicators were considered:
 - o *Normalized USE (percentage %)*: The total amount of unserved load over 12 years of weather data, normalized by dividing by total load, and reported as a percentage.²⁰
 - o *Mean Annual USE (GWh)*: The 12-year average of each region's total USE in each weather year. This mean value represents the average annual USE across weather variability.
 - o *Mean Max Unserved Power (GW)*: The 12-year average of each region's maximum USE value in each weather year. This mean value characterizes the typical non-coincident peak stress on system reliability.
 - o *% Max Unserved Power*: The Mean Max Unserved Power expressed as a percentage of the average native load during those peak unserved hours for each region. This percentage value provides a normalized measure of the severity of peak unserved events relative to demand.
 - o *Total number of customers without power*. The Mean Max Unserved Power expressed as the equivalent number of typical U.S. persons assuming a ratio of 17,625 persons/MW lost. This estimation contextualizes the effects of the outage on average Americans.
- **Loss of Load Hours (LOLH)** refers to the number of hours during which the system experiences USE (i.e., any hour with non-zero USE). Two LOLH-based indicators were considered:

20. NUSE can be reported as parts per million or as a percentage (or parts per hundred); though for power system reliability, this would include several zeros after the decimal point.

- o *Mean Annual LOLH*: for each weather year and *TPR*, we count the total number of hours with USE across all 8,760 hours, and we then take the average of those 12 totals. *Annual LOLH Distribution* is represented in box and whisker plots for 12 samples, each sample corresponding to a unique weather year.
- o *Max Consecutive LOLH (hours)*²¹: The longest continuous period with reported USE in each weather year.

It should be noted that USE is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system. Rather, it represents the unrealizable AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth. These numbers are used as indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need.

This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.

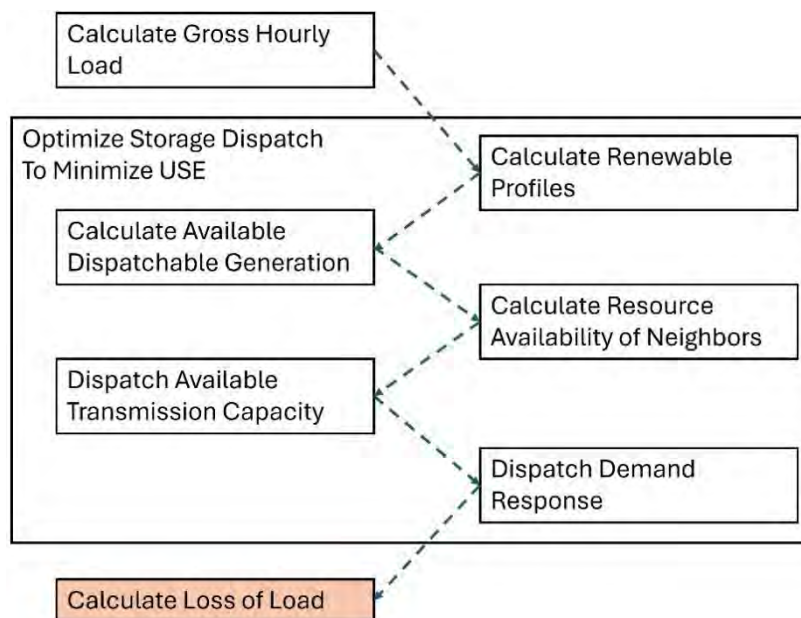


Figure 6. Simplified Overview of Model

21. One caveat on the maximum consecutive LOLH and max USE values is in how storage is dispatched in the model. Storage is dispatched to minimize the overall USE and is indifferent to the peak depth or the duration of the event. This may construe some of the max USE and max consecutive LOLH values to be higher than if storage was dispatched to minimize these values.

1.2 Planning Years and Weather Years

For the planning year (2030), historical weather year data are applied based on conditions between 2007 and 2024 to calculate load, wind and solar generation, and hydro generation. Dispatchable capacity (including dispatchable hydro capacity) is calculated through adjustment of the 2024 LTRA capacity data for historical outages from GADS data. Storage assets are scheduled to arbitrage hourly energy margins or else charge during periods of high energy margins (surplus resources) and discharge during periods of lower energy margins.

1.3 Load Modeling

Data Center Growth

Several utilities and financial and industry analysts identify data centers, particularly those supporting AI workloads, as a key driver of electricity demand growth. Multiple organizations have developed a wide range of projections for U.S. data center electricity use through 2030 and beyond, each using distinct methodologies tailored to their institutional expertise.

These datasets were used to explore reasonable boundaries for what different parts of the economy envision for the future state of AI and data center (AI/DC) load growth. For the purposes of this study, rather than focusing on any specific analysis, a more generic sweep was performed across AI/DC load growth and the various sensitivities that fit within those assumptions, as summarized below:

- McKinsey & Company projects ~10% annual growth in U.S. data center electricity demand, reaching 2,445 TWh by 2050. Their model blends internal scenarios with public signals, including announced projects, capital investment, server shipments, and chip-level power trends, supported by third-party market data.
- Lawrence Berkeley National Laboratory (LBNL) uses a bottom-up approach based on historical and projected IT equipment shipments, paired with assumptions on power draw, utilization, and infrastructure efficiency (PUE, WUE). Their projections through 2028 account for AI hardware adoption, operational shifts, and evolving cooling technologies.
- EPRI combines public data, expert input, and historical trends to define four national growth scenarios, low to higher, for 2023–2030, reflecting data processing demand, efficiency improvements, and AI-driven load impacts.
- S&P Global merges technology and power-sector models, evaluating grid readiness and facility growth under varying demand scenarios. Their forecasts consider AI adoption, efficiency trends, grid and permitting constraints, on-site generation, and offshoring risk, resulting in a wide range of outcomes.

These projections show wide variation, with 2030 electricity demand ranging from approximately 35 GW to 68 GW of average load. Given this uncertainty, including differences in hardware intensity, thermal management, siting assumptions, and behind-the-meter generation, the modeling team adopted a national midpoint assumption of approximately 50 GW by 2030.

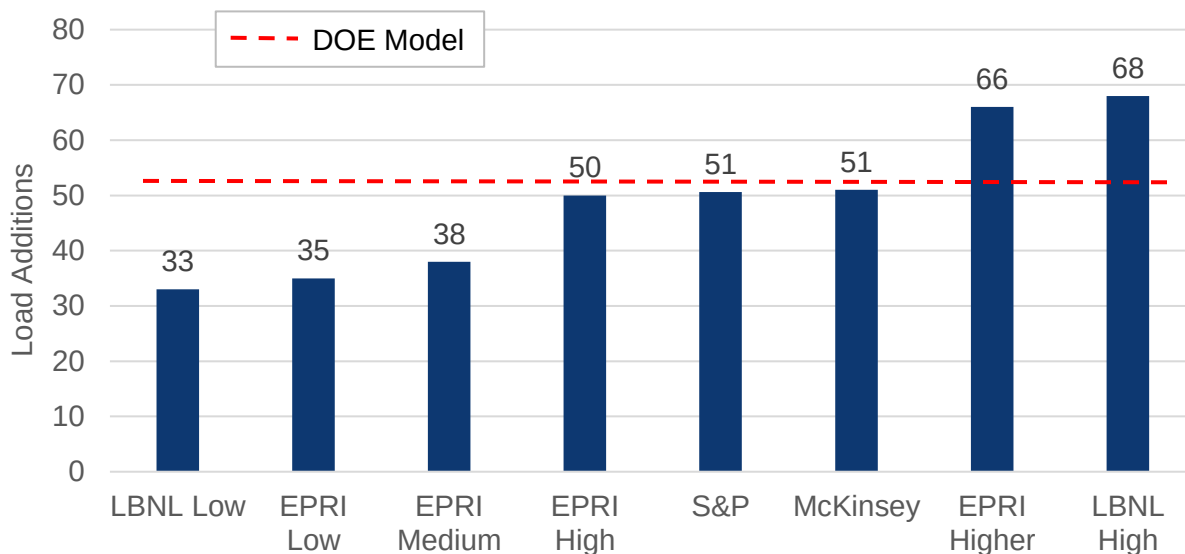


Figure 7. 2024 to 2030 Projected Data Center Load Additions

Figure 7 above displays a benchmark reflecting roughly the median across major studies and aligns with central projections from EPRI and LBNL. Using a single planning midpoint avoids double counting and enables consistent load allocation across national transmission and resource adequacy models. [Note: this figure was updated on October 27, 2025 to address a correction to the S&P projection.]

Data Center Allocation Method

To allocate the 50 GW midpoint regionally, the team used state-level growth ratios from S&P's forecast. These ratios reflect factors such as infrastructure, siting trends, and projected market activity. The modeling team mapped the state-level projections to NERC TPRs, ensuring transparent and repeatable regional allocation. While other methods exist, this approach ensured consistency with the broader modeling framework.

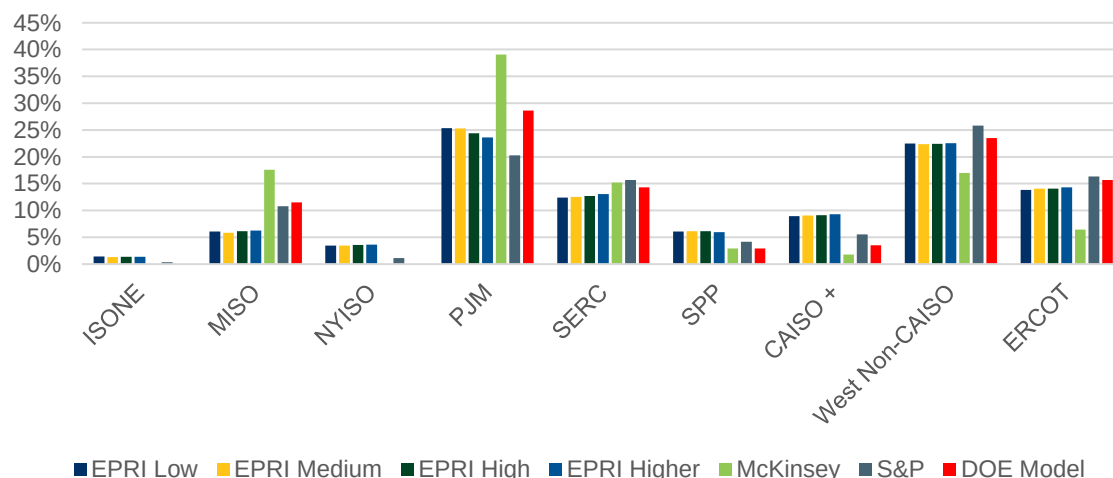


Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated)

Non-Data Center Load Modeling

The current electricity demand projections were built from NERC data, using historical load (2019–2023) and simulated weather years (2007–2013). These were adjusted based on the EIA's 2022 energy forecast. To estimate 2030 demand, the team interpolated between 2024 and 2033, scaling loads to reflect energy use and seasonal peaks. NERC provided datasets to address anomalies and include behind-the-meter and USE.

Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC LTRA forecast, for example, the 2024 LTRA saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.

Overall Impact on Projected Peak Load

As a result of the methods applied above, the average year co-incident peak load is projected to grow from a current average peak of 774 GW to 889 GW in 2030. This represents a 15% increase or 2.3% growth rate per year. Excluding the impact of data centers, this would amount to a 51GW increase from 774 GW to 826 GW which represents a 1.1% annual growth rate.

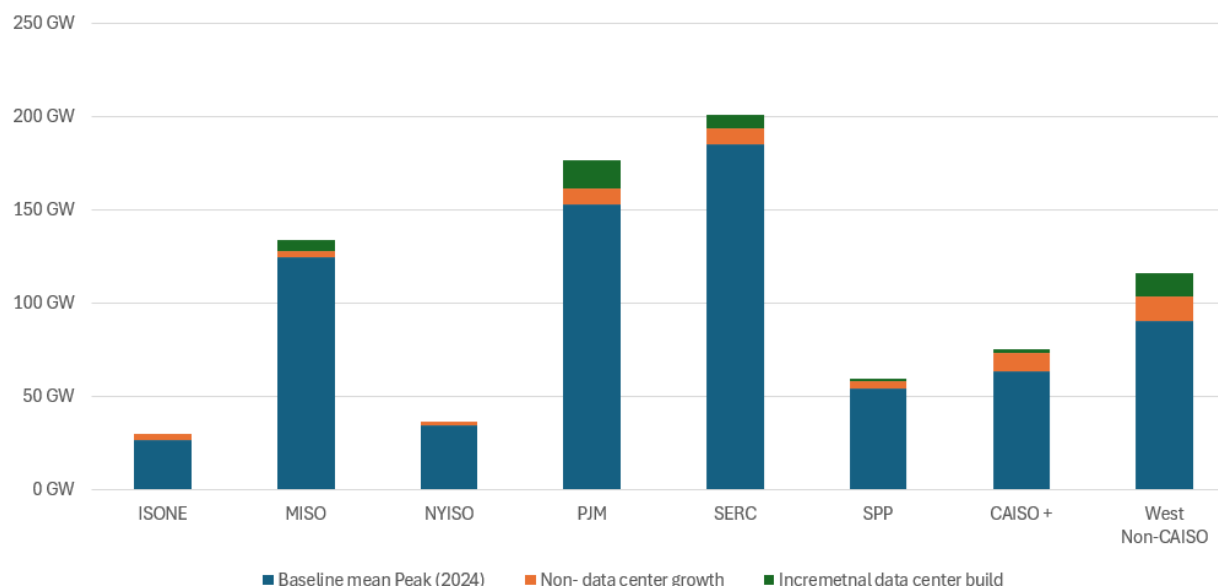


Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)

1.4 Transfer Capabilities and Import Export Modeling

The methodology assumes electricity moves between subregions, when conditions start to tighten. Each region has a certain amount of capacity available, and the methodology determines if there is enough to meet the demand. When regions reach a “Tight Margin Level” of 10% of capacity, i.e., if a region’s available capacity is less than 110% of load, it will start transferring from other regions if capacity is available. A scarcity factor is used to determine which regions to transfer from and at what fraction – those with a greater amount of reserve capacity will transfer more. A region is only allowed to export above when it is above the Tight Margin Level.

Total Transfer Capability (TTC) was used and is the sum of the Base Transfer Level and the First Contingency Incremental Transfer Capability. These were derived from scheduled interchange tables or approximated from actual line flows. It should be noted that the TTC does not represent a single line, but rather multiple connections between regions. It is similar to path limits used by many entities but may have different values.

Due to data and privacy limitations, the Canadian power system was not modeled directly as a combination of generation capacity and demand. Instead, actual hourly imports were used from nearly 20 years of historical data, along with recent trends (generally less transfers available during peak hours), to develop daily limits on transfer capabilities. See Appendix B for more details on Canadian transfer limits.

1.5 Perfect Capacity Additions

To understand how much capacity may need to be added to reach approximate reliability targets, we tuned two scenarios by adding hypothetical perfect capacity to reach the reliability threshold based on NUSE.²² Today, NERC uses a threshold of 0.002% to indicate regions are at high risk of resource adequacy shortfalls. In addition, several system operators, including the Australia Energy Market Operator and Alberta Electric System Operator, are using NUSE thresholds in the range of 0.001% to 0.003%. Several U.S. entities are considering lower thresholds for U.S. power systems in the range of 0.0001% to 0.0002%.²³

For this analysis, we target NUSE below 0.002% for each region to align with NERC definitions. We iteratively ran the model, hand-tuning the “perfect capacity” to be as small as possible while reaching NUSE values below 0.002% in all regions.²⁴ As the work was done by hand with a limited number of iterations (15), this should not be considered the minimum possible capacity to accomplish these targets. Further, because the perfect capacity can be located in various places, there would be multiple potential solutions to the problem. These scenarios represent the approximate quantity of perfect capacity each region would require (beyond announced retirements and mature generation additions only) that would lead to Medium or Low risk based on the NERC metrics for USE.

Due to some regions with zero USE, the tuned cases do not reach the same level of adequacy, where the national average is 0.00045% vs. 0.00013%. Due to transmission and siting selection of perfect capacity, there could be many solutions.

22. We are not using the standard term “expected unserved energy” because we are not running a probabilistic model, so we do not have the full understanding of long-term expectations

23. MISO, “Resource Adequacy Metrics and Criteria Roadmap,” December 2024.
<https://cdn.misoenergy.org/Resource%20Adequacy%20Metrics%20and%20Criteria%20Roadmap667168.pdf>.

24. NERC, “Evolving Criteria for a Sustainable Power Grid,” July 2024.
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Evolving_Planning_Criteria_for_a_Sustainable_Power_Grid.pdf.

2 Regional Analysis

This section presents more regional details on resource adequacy according to this analysis. For each of the nine Regional Transmission Organizations (RTOs) and sub-regions, comprehensive summaries are provided of reliability metrics, load assumptions, and composition of generation stacks.

2.1 MISO²⁵

In the current system model and the No Plant Closures cases, MISO did not experience shortfall events. MISO's minimum spare capacity in the tightest year was negative, showing that adequacy was achieved by importing power from neighbors. In the Plant Closures case, MISO experienced significant shortfalls, with key reliability metrics exceeding each of the threshold criteria defined for the study.

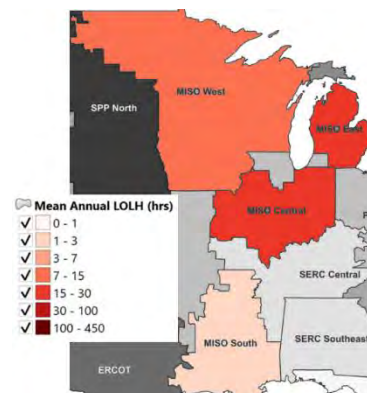


Table 2. Summary of MISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	37.8	-	-
Normalized Unserved Energy (%)	-	0.0211	-	-
Unserved Load (MWh)	-	157,599	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	124	-	-
Normalized Unserved Load (%)	-	0.0702	-	-
Unserved Load (MWh)	-	524,180	-	-

Load Assumptions

MISO's peak load was roughly 130 GW in the current model and projected to increase to roughly 140 GW by 2030. Approximately 6 GW of this relates to new data centers being installed (12% of U.S. total).

25. Following the initial data collection for this report, MISO issued its 2025 Summer Reliability Assessment. Based on that report, NERC revised evaluations from its 2024 LTRA and reclassified the MISO footprint from being an 'elevated risk' to 'high risk' in the 2028–2031 timeframe, depending on new resource additions/retirements. While DOE's analysis is based on the previously reported figures, DOE is committed to assessing the implications of updated data on overall resource adequacy and providing technical updates on findings, as appropriate.

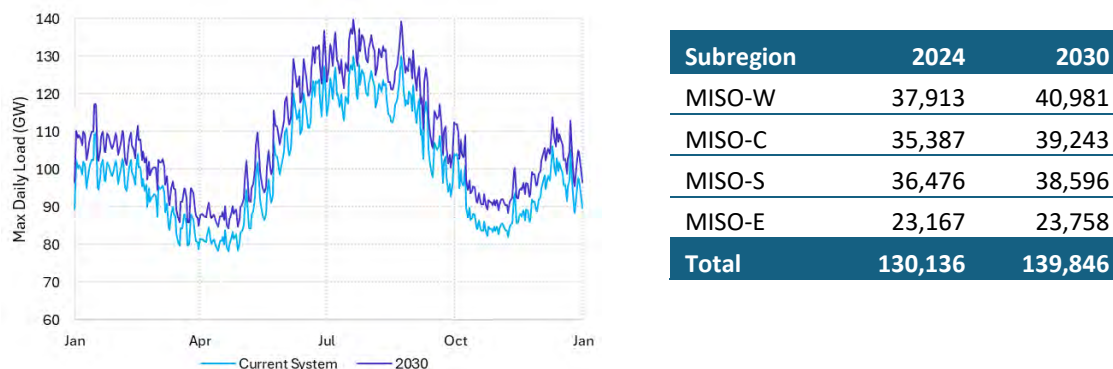


Figure 10. MISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 207 GW.²⁶ In 2030, 21 GW of new capacity was added leading to 228 GW of capacity in the No Plant Closures case. In the Plant Closures case, 32 GW of capacity was retired such that net retirements in the Plant Closures case were -11 GW, or 196 GW of overall installed capacity on the system.

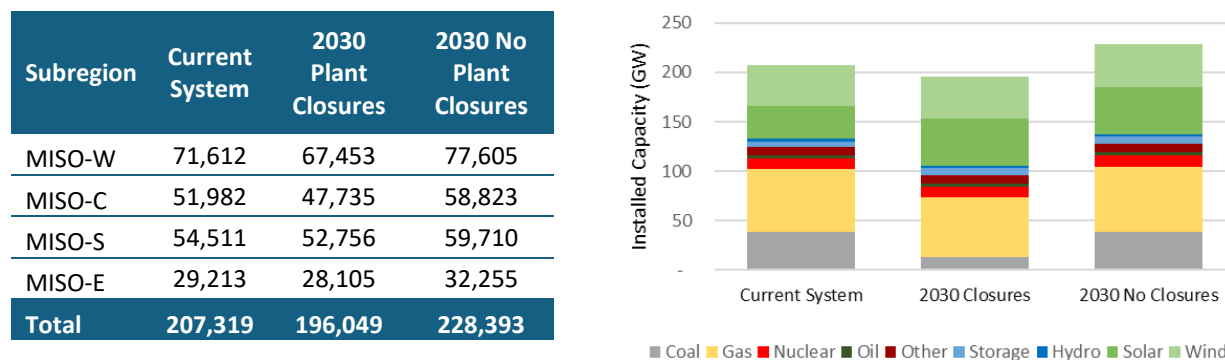


Figure 11. MISO Generation Capacity by Technology and Scenario

MISO's generation mix was comprised primarily of natural gas, coal, wind, and solar. In 2024, natural gas comprised 31% of nameplate, wind comprised 20%, coal 18%, and solar 14%. In 2030, most retirements come from coal and natural gas while additions occur for solar, batteries, and wind. In addition, the model assumed 3 GW of rooftop solar and 8 GW of demand response.

26. The total installed capacity numbers reported in this regional analysis section do not reflect the generating capability of all resources during stress conditions.

Table 3. Nameplate Capacity by MISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	37,914	64,194	11,127	2,867	8,717	5,427	2,533	32,826	41,715	207,319
MISO-W	12,651	13,608	2,753	1,491	2,613	200	777	8,109	29,411	71,612
MISO-C	15,050	10,307	2,169	494	2,211	1,272	769	12,361	7,350	51,982
MISO-S	5,493	31,052	5,100	589	2,469	54	845	8,315	596	54,511
MISO-E	4,720	9,227	1,105	292	1,424	3,901	143	4,042	4,359	29,213
Additions	0	2,535	0	330	0	1,929	0	14,354	1,926	21,074
MISO-W	0	537	0	172	0	374	0	3,552	1,358	5,993
MISO-C	0	407	0	57	0	934	0	5,103	339	6,841
MISO-S	0	1,226	0	68	0	9	0	3,868	27	5,199
MISO-E	0	364	0	34	0	611	0	1,831	201	3,042
Closures	(24,913)	(6,597)	0	(324)	(140)	(16)	(83)	0	(272)	(32,345)
MISO-W	(8,313)	(1,398)	0	(168)	(56)	0	(25)	0	(192)	(10,152)
MISO-C	(9,889)	(1,059)	0	(56)	(7)	(3)	(25)	0	(48)	(11,088)
MISO-S	(3,609)	(3,191)	0	(67)	(55)	(0)	(28)	0	(4)	(6,954)
MISO-E	(3,102)	(948)	0	(33)	(21)	(13)	(5)	0	(28)	(4,150)

2.2 ISO-NE

In the current system model and the No Plant Closures case, ISO-NE did not experience shortfall events. The region maintained adequacy throughout the study period through reliance on imports. In the Plant Closures case, ISO-NE still did not exceed any key reliability thresholds, despite moderate retirements. This finding is partly due to the absence of additional AI or data center load growth modeled in the region. Accordingly, no additional perfect capacity was deemed necessary by 2030 to meet the study's reliability standards.

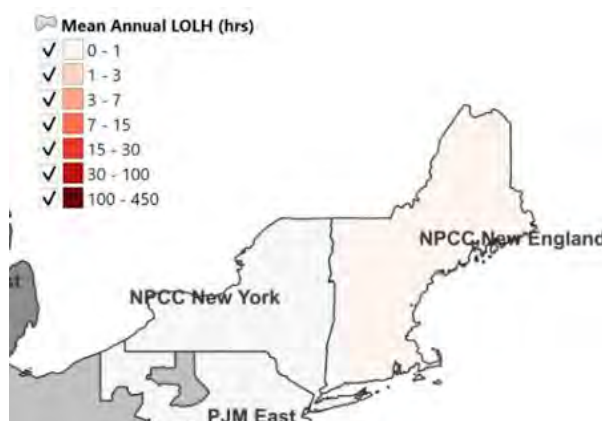
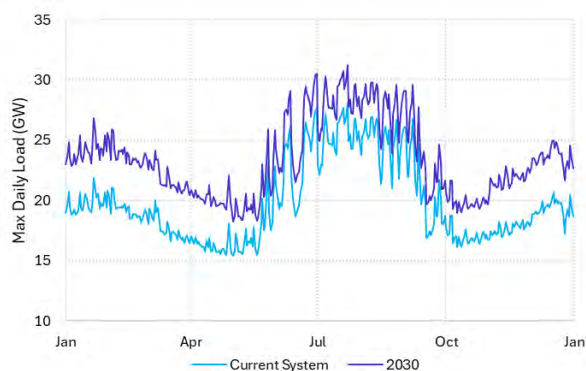


Table 4. Summary of ISO-NE Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	-	-	-
Normalized Unserved Energy (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	-	-	-
Normalized Unserved Load (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
Max Unserved Load (MW)	-	-	-	-

Load Assumptions

ISO-NE's peak load was roughly 28 GW in the current model and projected to increase to roughly 31 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
ISO-NE	28,128	31,261
Total	28,128	31,261

Figure 12. ISO-NE Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 40 GW. In 2030, 5.5 GW of new capacity was added leading to 45.5 GW of capacity in the No Plant Closures case. In the Plant Closures case, 2.7 GW of capacity was retired such that net generation change in the Plant Closures case was +11 GW, or 42.8 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ISO-NE	39,979	42,845	45,534
Total	39,979	42,845	45,534

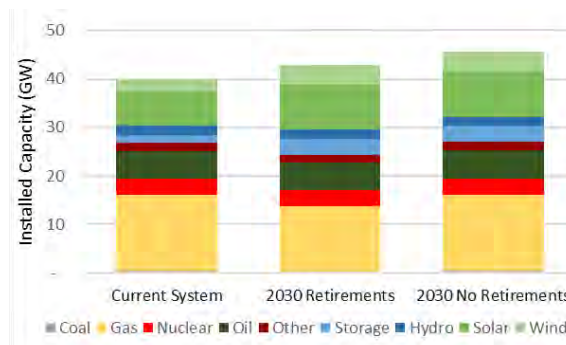


Figure 13. ISO-NE Generation Capacity by Technology and Scenario

ISO-NE's generation mix was comprised primarily of natural gas, solar, oil, and nuclear. In 2024, natural gas comprised 39% of nameplate, solar comprised 17%, oil 14%, and nuclear 8%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed nearly 2 GW of rooftop solar and 1.6 GW of energy storage.

Table 5. Nameplate Capacity by ISO-NE Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	541	15,494	3,331	5,710	1,712	1,628	1,911	7,099	2,553	39,979
ISONE	541	15,494	3,331	5,710	1,712	1,628	1,911	7,099	2,553	39,979
Additions	0	90	0	181	0	1,607	0	2,183	1,495	5,555
ISONE	0	90	0	181	0	1,607	0	2,183	1,495	5,555
Closures	(534)	(1,875)	0	(203)	(77)	0	0	0	0	(2,690)
ISONE	(534)	(1,875)	0	(203)	(77)	0	0	0	0	(2,690)

2.3 NYISO

In both the current system model and the No Plant Closures case, NYISO maintained reliability and did not exceed any shortfall thresholds. Adequacy was preserved through reliance on imports. In the Plant Closures case, NYISO experienced shortfalls but average annual LOLH remaining well below the 2.4-hour threshold and NUSE under the 0.002% standard. The worst weather year produced only 6 hours of lost load and a peak unserved load of 914 MW. Given the modest impact of retirements and no additional AI/data center load modeled, the study concluded that NYISO would not require additional perfect capacity to remain reliable through 2030.

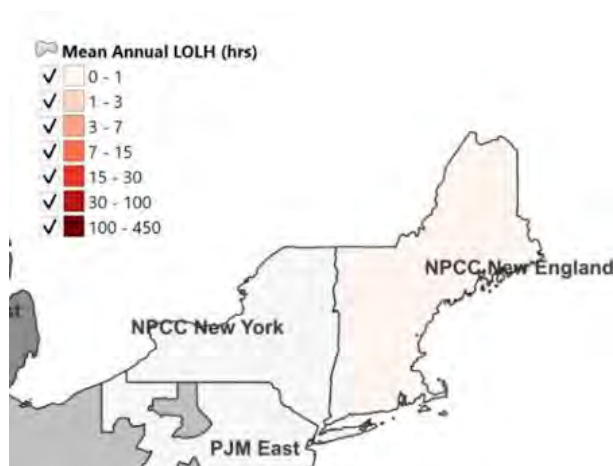


Table 6. Summary of NYISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.2	0.5	-	-
Normalized Unserved Energy (%)	0.00001	0.0001	-	-
Unserved Load (MWh)	18	209	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	2	6	-	-
Normalized Unserved Load (%)	0.0001	0.0013	-	-
Unserved Load (MWh)	216	2,505	-	-
Max Unserved Load (MW)	194	914	-	-

Load Assumptions

NYISO's peak load was roughly 36 GW in the current system model and projected to increase to roughly 38 GW by 2030. No additional AI/DCs were projected to be installed.



Figure 14. NYISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 46 GW. In 2030, 5.5 GW of new capacity was added leading to 51 GW of capacity in the No Plant Closures case. In the Plant Closures case, 1 GW of capacity was retired such that net generation in the Plant Closures case was +4 GW, or 50 GW of overall installed capacity on the system.

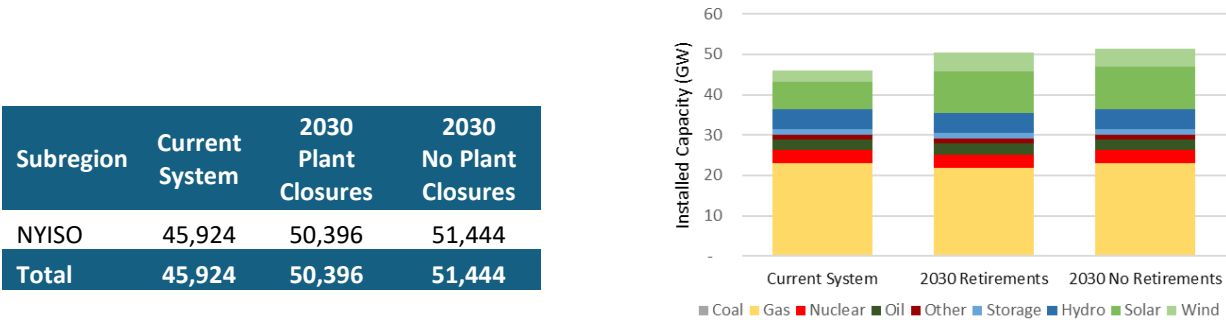


Figure 15. NYISO Generation Capacity by Technology and Scenario

NYISO’s generation mix was comprised primarily of natural gas, solar, and hydro. In 2024, natural gas comprised 50% of total nameplate generation, solar comprised 14%, and hydro 11%. In 2030, most retirements come from natural gas while additions occur for solar and wind. The model assumed 6 GW of rooftop solar and nearly 1 GW of demand response.

Table 7. Nameplate Capacity by NYISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	0	22,937	3,330	2,631	1,194	1,460	4,915	6,749	2,706	45,924
NYISO	0	22,937	3,330	2,631	1,194	1,460	4,915	6,749	2,706	45,924
Additions	0	0	0	15	0	0	0	3,604	1,902	5,521
NYISO	0	0	0	15	0	0	0	3,604	1,902	5,521
Closures	0	(1,030)	0	(19)	0	0	0	0	0	(1,049)
NYISO	0	(1,030)	0	(19)	0	0	0	0	0	(1,049)

2.4 PJM

In the current system model, PJM experienced shortfalls, but they were below the required threshold. In the No Plant Closures case, shortfalls increased dramatically, with 214 average annual LOLH and peak unserved load reaching 17,620 MW, indicating growing strain even without retirements. In the Plant Closures case, reliability metrics worsened significantly, with annual LOLH surging to over 430 hours per year and NUSE reaching 0.1473%—over 70 times the accepted threshold. During the worst weather year, 1,052 hours of load were shed. To restore reliability, the study found that PJM would require 10,500 MW of additional perfect capacity by 2030.

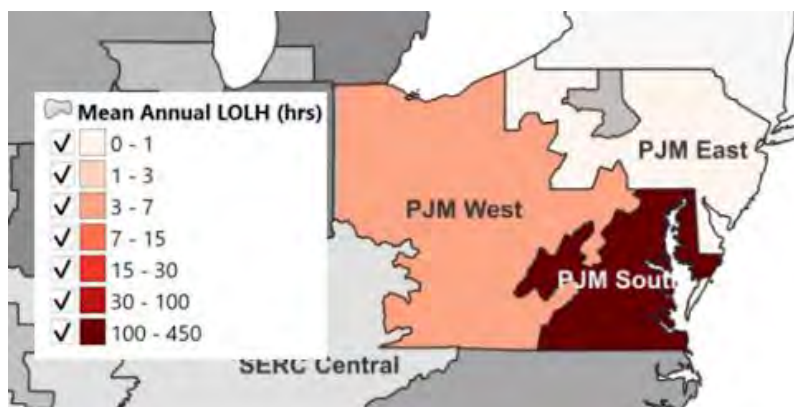
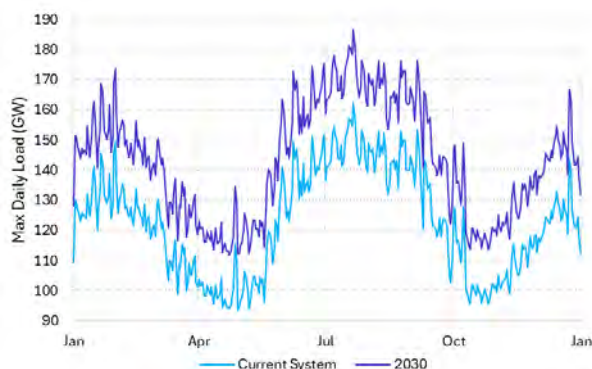


Table 8. Summary of PJM Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	2.4	430.3	213.7	1.4
Normalized Unserved Energy (%)	0.0008	0.1473	0.0657	0.0003
Unserved Load (MWh)	6,891	1,453,513	647,893	2,536
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	29	1,052	644	17
Normalized Unserved Load (%)	0.0100	0.4580	0.2703	0.0031
Unserved Load (MWh)	82,687	1,453,513	647,893	2,536
Max Unserved Load (MW)	4,975	21,335	17,620	4,162

Load Assumptions

PJM's peak load was roughly 162 GW in the current system model and projected to increase to roughly 187 GW by 2030. Approximately 15 GW of this relates to new AI/DC being installed (29% of U.S. total), primarily in PJM-S.



Subregion	2024	2030
PJM-W	81,541	92,378
PJM-S	39,904	51,151
PJM-E	41,003	43,118
Total	162,269	186,627

Figure 16. PJM Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 215 GW. In 2030, 39 GW of new capacity was added leading to 254 GW of capacity in the No Plant Closures case. In the Plant Closures case, 17 GW of capacity was retired such that net generation in the Plant Closures case was +22 GW, or 237 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
PJM-W	114,467	123,100	135,810
PJM-S	39,951	48,850	50,667
PJM-E	60,221	64,848	67,027
Total	214,638	236,798	253,504

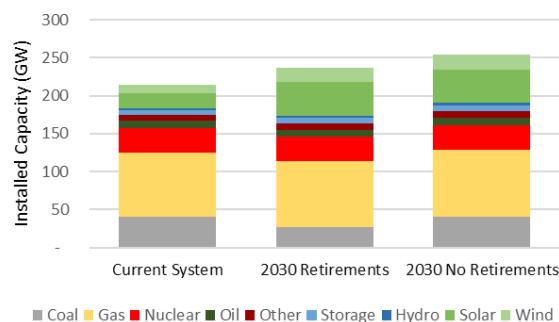


Figure 17. PJM Generation Capacity by Technology and Scenario

PJM's generation mix was comprised primarily of natural gas, coal, and nuclear. In 2024, natural gas comprised 39% of nameplate, coal comprised 19%, and nuclear 15%. In 2030, most retirements come from coal and some natural gas and oil while significant additions occur for solar plus lesser additions of wind, storage, and natural gas. The model assumed 9 GW of rooftop solar and 7 GW of demand response.

Table 9. Nameplate Capacity by PJM Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	39,915	84,381	32,535	9,875	8,248	5,400	3,071	19,495	11,718	214,638
PJM-W	34,917	39,056	16,557	1,933	3,926	383	1,252	6,379	10,065	114,467
PJM-S	2,391	15,038	5,288	3,985	2,303	3,085	1,070	6,430	360	39,951
PJM-E	2,608	30,287	10,690	3,956	2,019	1,932	749	6,686	1,294	60,221
Additions	0	4,499	0	32	317	1,938	0	24,991	7,089	38,866
PJM-W	0	2,082	0	6	135	855	0	12,176	6,089	21,343
PJM-S	0	802	0	13	102	726	0	8,856	218	10,717
PJM-E	0	1,615	0	13	81	357	0	3,958	783	6,806
Closures	(13,253)	(1,652)	0	(1,790)	(11)	0	0	0	0	(16,706)
PJM-W	(11,593)	(765)	0	(350)	(1)	0	0	0	0	(12,710)
PJM-S	(794)	(294)	0	(722)	(6)	0	0	0	0	(1,817)
PJM-E	(866)	(593)	0	(717)	(3)	0	0	0	0	(2,179)

2.5 SERC

In the current system model and the No Plant Closures case, SERC maintained overall adequacy, though some subregions—particularly SERC-East—faced emerging winter reliability risks. In the Plant Closures case, shortfalls became more severe, with SERC-East experiencing increased unserved energy and loss of load hours during extreme cold events, including 42 hours of outages in a single winter storm. The analysis identified that planned retirements, combined with rising winter load from electrification, would stress the system. To restore reliability in SERC-East, the study found that 500 MW of additional perfect capacity would be needed by 2030. Other SERC subregions performed adequately, but continued monitoring is warranted due to shifting seasonal peaks and fuel supply vulnerabilities.

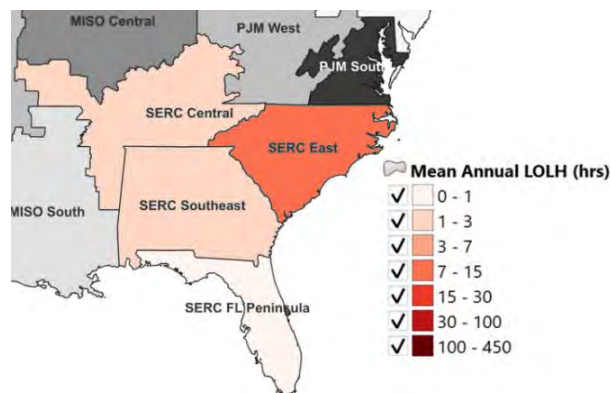
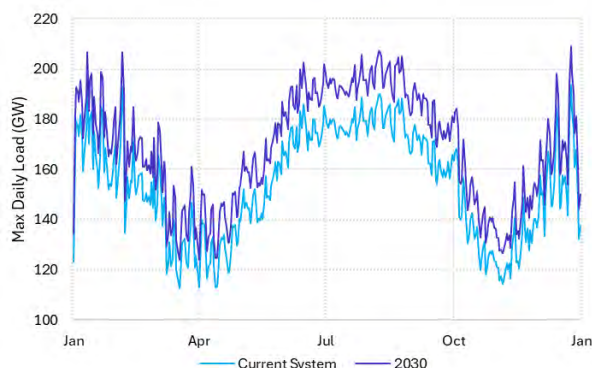


Table 10. Summary of SERC Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.3	8.1	1.2	0.8
Normalized Unserved Energy (%)	0.0001	0.0041	0.0004	0.0002
Unserved Load (MWh)	489	44,514	3,748	2,373
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	4	42	14	10
Normalized Unserved Load (%)	0.0006	0.0428	0.0042	0.0026
Unserved Load (MWh)	5,683	465,392	44,977	2,373
Max Unserved Load (MW)	2,373	19,381	6,359	5,859

Load Assumptions

SERC's peak load was roughly 193 GW in the current system model and projected to increase to roughly 209 GW by 2030. Approximately 7.5 GW of this relates to new AI/DCs being installed (14% of U.S. total).



Subregion	2024	2030
SERC-C	50,787	52,153
SERC-SE	48,235	54,174
SERC-FL	58,882	62,572
SERC-E	51,693	56,313
Total	193,654	209,269

Figure 18. SERC Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 254 GW. In 2030, 26 GW of new capacity was added leading to 279 GW of capacity in the No Plant Closures case. In the Plant Closures case, 19 GW of capacity was retired such that net generation change in the Plant Closures case was +7 GW, or 260 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SERC-C	53,978	54,014	59,660
SERC-SE	67,073	64,768	69,478
SERC-FL	72,714	83,127	86,173
SERC-E	59,914	58,513	63,973
Total	253,680	260,423	279,285

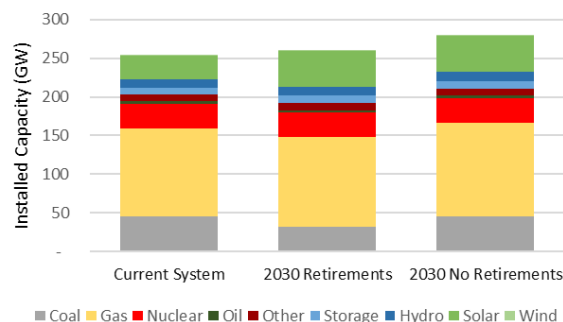


Figure 19. SERC Generation Capacity by Technology and Scenario

SERC's generation mix was comprised primarily of natural gas, coal, nuclear, and solar. In 2024, natural gas comprised 45% of nameplate, coal comprised 18%, nuclear 12%, and solar 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar and some storage. The model assumed 3 GW of rooftop solar and 8 GW of demand response.

Table 11. Nameplate Capacity by SERC Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	45,747	113,334	31,702	4,063	8,779	7,469	11,425	30,180	982	253,680
SERC-C	13,348	20,127	8,280	148	1,887	1,884	4,995	2,328	982	53,978
SERC-SE	13,275	29,866	8,018	915	2,493	1,662	3,260	7,584	0	67,073
SERC-FL	4,346	47,002	3,502	1,957	3,198	538	0	12,172	0	72,714
SERC-E	14,777	16,340	11,902	1,044	1,202	3,384	3,170	8,096	0	59,914
Additions	0	6,898	0	0	381	2,254	0	16,073	0	25,606
SERC-C	0	4,831	0	0	0	80	0	771	0	5,682
SERC-SE	0	906	0	0	19	0	0	3,135	0	4,059
SERC-FL	0	1,161	0	0	218	1,670	0	10,410	0	13,459
SERC-E	0	0	0	0	144	504	0	1,757	0	2,405
Closures	(14,075)	(4,115)	0	(672)	0	0	0	0	0	(18,862)
SERC-C	(4,465)	(1,181)	0	0	0	0	0	0	0	(5,646)
SERC-SE	(5,160)	(124)	0	(176)	0	0	0	0	0	(5,460)
SERC-FL	(1,495)	(1,071)	0	(480)	0	0	0	0	0	(3,046)
SERC-E	(2,955)	(1,739)	0	(16)	0	0	0	0	0	(4,710)

2.6 SPP

In the current system model, SPP experienced shortfalls, but they were below the required threshold. Adequacy was preserved through reliance on imports. In the No Plant Closures case, SPP experienced persistent reliability challenges, with average annual LOLH reaching approximately 48 hours per year and peak hourly shortfalls affecting up to 19% of demand. In the Plant Closures case, system conditions deteriorated further, with unserved energy and outage hours increasing substantially. These shortfalls were concentrated in the northern subregion, which lacks the firm generation and import capacity needed to meet peak winter demand. The analysis determined that 1,500 MW of additional perfect capacity would be needed in SPP by 2030 to restore reliability.

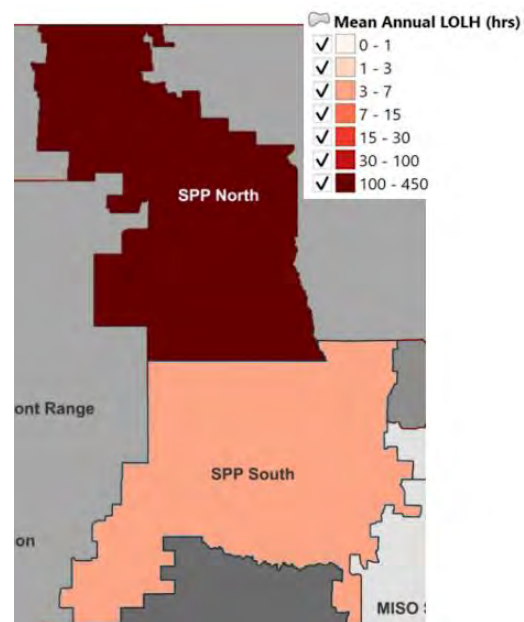


Table 12. Summary of SPP Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	1.7	379.6	47.8	2.4
Normalized Unserved Energy (%)	0.0002	0.0911	0.0081	0.0002
Unserved Load (MWh)	541	313,797	27,697	803
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	20	556	186	26
Normalized Unserved Load (%)	0.0022	0.2629	0.0475	0.0027
Unserved Load (MWh)	6,492	907,518	163,775	9,433
Max Unserved Load (MW)	606	13,263	2,432	762

Load Assumptions

SPP's peak load was roughly 57 GW in the current system model and projected to increase to roughly 63 GW by 2030. Approximately 1.5 GW of this relates to new AI/DCs being installed (3% of U.S. total).

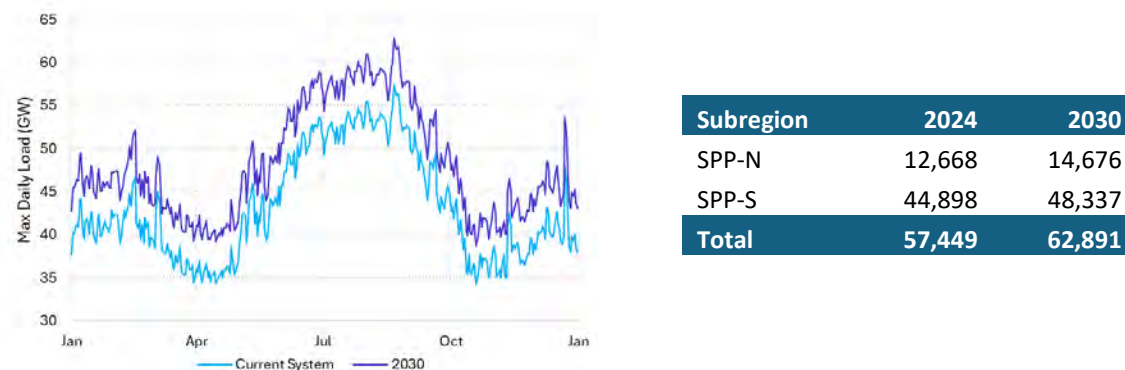


Figure 20. SPP Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 95 GW. In 2030, 15 GW of new capacity was added leading to 110 GW of capacity in the No Plant Closures case. In the Plant Closures case, 7 GW of capacity was retired such that net generation change in the 2030 Plant Closures case was +8 GW, or 103 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SPP-N	20,065	20,679	22,385
SPP-S	75,078	82,451	88,064
Total	95,142	103,130	110,449

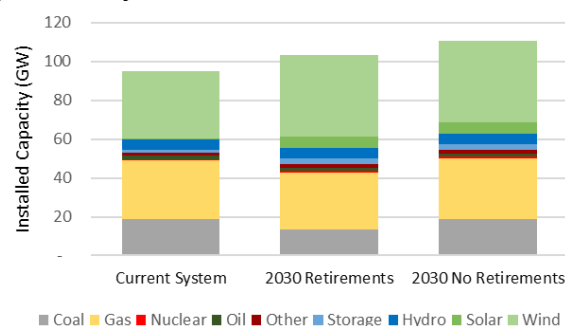


Figure 21. SPP Generation Capacity by Technology and Scenario

SPP's generation mix was comprised primarily of wind, natural gas, and coal. In 2024, wind comprised 36% of nameplate, natural gas comprised 32%, and coal 20%. In the 2030 case, most retirements come from coal and natural gas while additions occur for wind, solar, storage, and natural gas. The model assumed almost no rooftop solar and 1.3 GW of demand response.

Table 13. Nameplate Capacity by SPP Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	18,919	30,003	769	1,626	1,718	1,522	5,123	774	34,689	95,142
SPP-N	5,089	3,467	304	504	519	8	3,041	91	7,041	20,065
SPP-S	13,829	26,536	465	1,121	1,199	1,514	2,082	683	27,649	75,078
Additions	0	1,094	0	7	462	1,390	0	5,288	7,066	15,306
SPP-N	0	126	0	2	114	11	0	633	1,434	2,320
SPP-S	0	968	0	5	348	1,379	0	4,655	5,632	12,987
Closures	(5,530)	(1,732)	0	(56)	0	0	0	0	0	(7,318)
SPP-N	(1,488)	(200)	0	(17)	0	0	0	0	0	(1,705)
SPP-S	(4,042)	(1,532)	0	(39)	0	0	0	0	0	(5,613)

2.7 CAISO+

In the current system and No Plant Closures cases, CAISO+ did not experience major reliability issues, though adequacy was often maintained through significant imports during tight conditions. In the Plant Closures case, however, the region faced substantial shortfalls, particularly during summer evening hours when solar output declines. Average LOLH reached 7 hours per year, and the worst-case year showed load shed events affecting up to 31% of demand. The NUSE exceeded reliability thresholds, signaling the system’s vulnerability to high load and low renewable output periods.

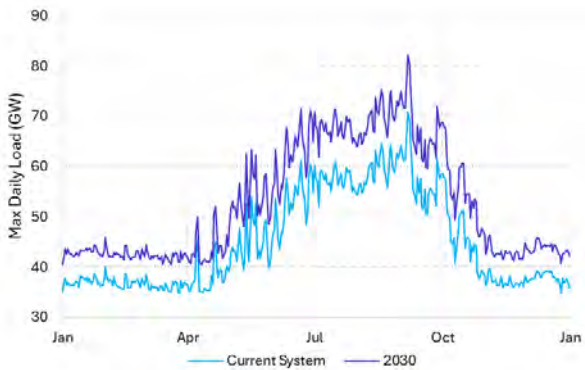


Table 14. Summary of CAISO+ Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	6.8	-	-
Normalized Unserved Energy (%)	-	0.0062	-	-
Unserved Load (MWh)	-	23,488	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	21	-	-
Normalized Unserved Load (%)	-	0.0195	-	-
Unserved Load (MWh)	-	73,462	-	-
Max Unserved Load (MW)	-	12,391	-	-

Load Assumptions

CAISO+’s peak load was roughly 79 GW in the current system model and projected to increase to roughly 82 GW by 2030. Approximately 2 GW of this relates to new AI/DCs being installed (4% of U.S. total).



Subregion	2024	2030
CALI-N	29,366	34,066
CALI-S	41,986	48,666
Total	70,815	82,146

Figure 22. CAISO+ Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 117 GW. In 2030, 14 GW of new capacity was added leading to 131 GW of capacity in the No Plant Closures case. In the Plant Closures case, 8 GW of capacity was retired such that net closures in the Plant Closures case were +6 GW, or 123 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
CALI-N	47,059	48,897	52,501
CALI-S	69,866	74,041	78,308
Total	116,925	122,938	130,809

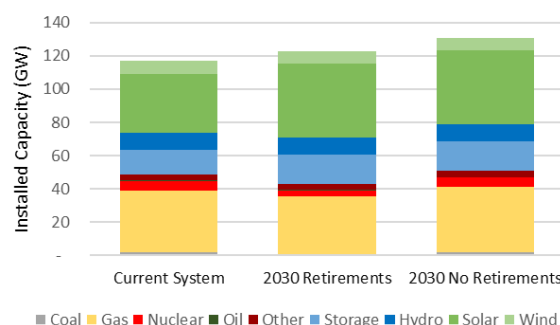


Figure 23. CAISO+ Generation Capacity by Technology and Scenario

CAISO+'s generation mix was comprised primarily of natural gas, solar, storage, and hydro. In 2024, natural gas comprised 32% of nameplate, solar comprised 31%, storage 13%, and hydro 9%. In 2030, most retirements come from coal, natural gas, and nuclear while additions occur for solar and storage. The model assumed 10 GW of rooftop solar and less than 1 GW of demand response.

Table 15. Nameplate Capacity by CAISO+ Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	1,816	37,434	5,582	185	3,594	14,670	10,211	35,661	7,773	116,925
CALI-N	0	12,942	5,582	165	1,872	4,639	8,727	11,759	1,373	47,059
CALI-S	1,816	24,492	0	20	1,722	10,031	1,483	23,902	6,400	69,866
Additions	0	2,126	0	0	92	3,161	0	8,507	0	13,885
CALI-N	0	735	0	0	44	757	0	3,906	0	5,442
CALI-S	0	1,391	0	0	48	2,404	0	4,600	0	8,442
Closures	(1,800)	(3,771)	(2,300)	0	0	0	0	0	0	(7,871)
CALI-N	0	(1,304)	(2,300)	0	0	0	0	0	0	(3,604)
CALI-S	(1,800)	(2,467)	0	0	0	0	0	0	0	(4,267)

2.8 West Non-CAISO

In both the current system and No Plant Closures cases, the West Non-CAISO region maintained adequacy on average. In the Plant Closures case, the region's reliability declined, with annual LOLH increasing and peak shortfalls in the worst year affecting up to 20% of hourly load in some subregions. While overall NUSE normalized unserved energy remained just above the 0.002% threshold, specific areas, especially those with limited local resources and constrained transmission, exceeded acceptable risk levels. These reliability gaps were primarily driven by increasing reliance on variable energy resources without sufficient firm generation.

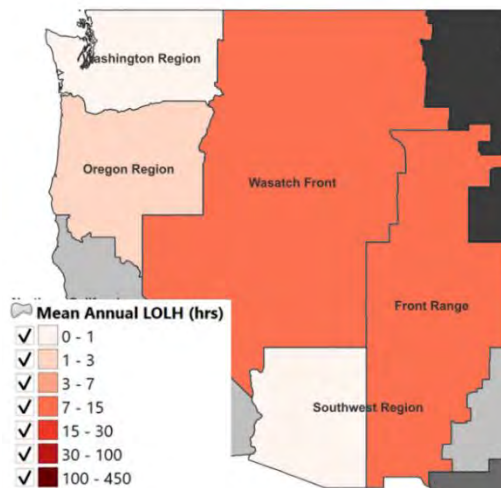
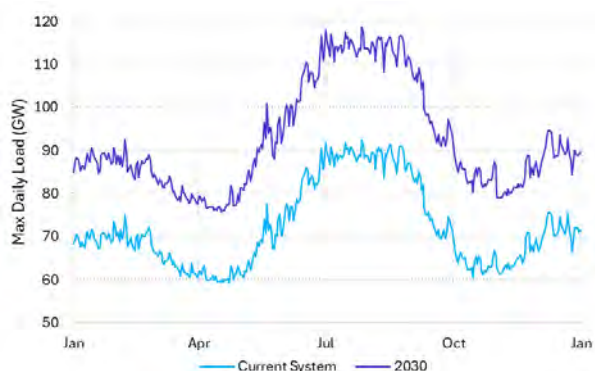


Table 16. Summary of West Non-CAISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	17.8	-	-
Normalized Unserved Energy (%)	-	0.0032	-	-
Unserved Load (MWh)	-	21,785	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	47	-	-
Normalized Unserved Load (%)	-	0.0098	-	-
Unserved Load (MWh)	-	66,248	-	-
Max Unserved Load (MW)	-	5,071	-	-

Load Assumptions

West Non-CAISO's peak load was roughly 92 GW in the current system model and projected to increase to roughly 119 GW by 2030. Approximately 12 GW of this relates to new AI/DCs being installed (24% of U.S. total).



Subregion	2024	2030
WASHINGTON	20,756	23,187
OREGON	11,337	16,080
SOUTHWEST	23,388	30,169
WASATCH	27,161	35,440
FRONT R	20,119	24,996
Total	92,448	118,657

Figure 24. West Non-CAISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 178 GW. In 2030, 29 GW of new capacity was added leading to 207 GW of capacity in the No Plant Closures case. In the Plant Closures case, 13 GW of capacity was retired such that net generation change in the Plant Closures case was 16 GW, or 193 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
WASHINGTON	35,207	36,588	37,573
OREGON	19,068	21,689	22,081
SOUTHWEST	42,335	47,022	49,158
WASATCH	42,746	45,175	50,251
FRONT R	38,572	43,011	47,844
Total	177,929	193,485	206,908

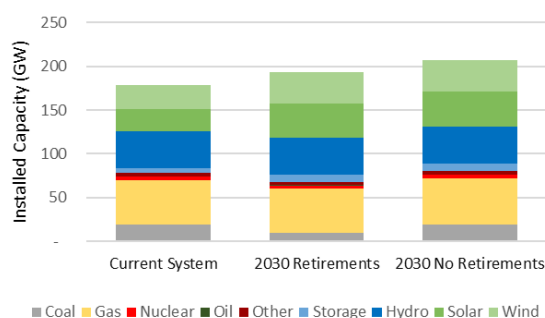


Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario

West Non-CAISO's generation mix was comprised primarily of natural gas, hydro, wind, solar, and coal. In 2024, natural gas comprised 28% of nameplate, hydro comprised 24%, wind 15%, solar 13%, and coal 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar, wind, storage, and natural gas. The model assumed 6 GW of rooftop solar and over 1 GW of demand response.

Table 17. Nameplate Capacity by West Non-CAISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	19,850	49,969	3,820	644	4,114	5,104	42,476	24,652	27,298	177,929
WASHINGTON	560	3,919	1,096	17	595	489	24,402	1,438	2,690	35,207
OREGON	0	3,915	0	6	456	482	8,253	2,517	3,440	19,068
SOUTHWEST	4,842	17,985	2,724	323	1,316	2,349	1,019	8,093	3,685	42,335
WASATCH	7,033	14,061	0	87	1,433	1,194	7,587	7,299	4,052	42,746
FRONT R	7,415	10,089	0	211	314	590	1,215	5,306	13,432	38,572
Additions	0	2,320	0	1	8	2,932	0	14,759	8,959	28,979
WASHINGTON	0	246	0	0	0	109	0	1,059	952	2,366
OREGON	0	246	0	0	0	150	0	1,399	1,218	3,013
SOUTHWEST	0	309	0	0	0	2,338	0	3,578	599	6,823
WASATCH	0	884	0	0	7	233	0	4,946	1,435	7,505
FRONT R	0	634	0	0	0	102	0	3,779	4,756	9,271
Closures	(9,673)	(2,540)	0	(6)	(311)	(170)	(627)	0	(95)	(13,422)
WASHINGTON	(317)	(195)	0	(0)	(66)	(28)	(369)	0	(11)	(986)
OREGON	0	(195)	0	(0)	(58)	0	(125)	0	(14)	(392)
SOUTHWEST	(1,185)	(951)	0	0	0	0	0	0	0	(2,136)
WASATCH	(3,978)	(699)	0	(2)	(178)	(89)	(115)	0	(16)	(5,077)
FRONT R	(4,194)	(501)	0	(4)	(8)	(53)	(18)	0	(54)	(4,832)

2.9 ERCOT

In the current system model, ERCOT exceeded reliability thresholds, with 3.8 annual Loss of Load Hours and a NUSE of 0.0032%, indicating stress even before future retirements and load growth. In the No Plant Closures case, conditions worsened as average LOLH rose to 20 hours per year and the worst-case year reached 101 hours, driven by data center growth and limited dispatchable additions. The Plant Closures case intensified these risks, with average annual LOLH rising to 45 hours per year and unserved load reaching 0.066%. Peak shortfalls reached 27% of demand, with outages concentrated in winter when generation is most vulnerable. To meet reliability targets, ERCOT would require 10,500 MW of additional perfect capacity by 2030.

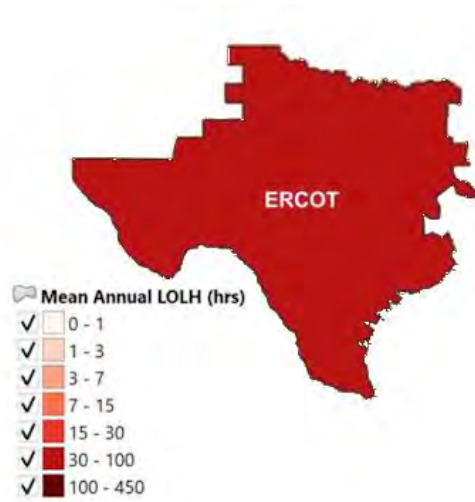
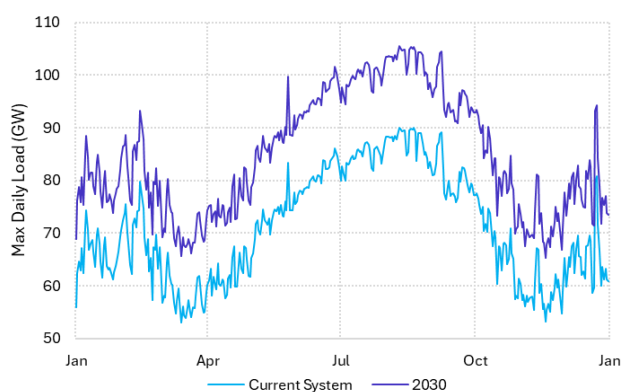


Table 18. Summary of ERCOT Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	3.8	45.0	20.3	1.0
Normalized Unserved Energy (%)	0.0032	0.0658	0.0284	0.0008
Unserved Load (MWh)	15,378	397,352	171,493	4,899
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	30	149	101	12
Normalized Unserved Load (%)	0.0286	0.02895	0.01820	0.0098
Unserved Load (MWh)	136,309	1,741,003	1,093,560	58,787
Max Unserved Load (MW)	10,115	27,156	23,105	8,202

Load Assumptions

ERCOT's peak load was roughly 90 GW in the current system model and projected to increase to roughly 105 GW by 2030. Approximately 8 GW of this relates to new data centers being installed (62% of U.S. total).



Subregion	2024	2030
ERCOT	90,075	105,485
Total	90,075	105,485

Figure 26. ERCOT Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 157 GW. In 2030, 55 GW of new capacity was added leading to 213 GW of capacity in the No Plant Closures case. In the Plant Closures case, 4 GW of capacity was retired such that net generation change in the Plant Closures case was +51 GW, or 208 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ERCOT	157,490	208,894	212,916
Total	157,490	208,894	212,916

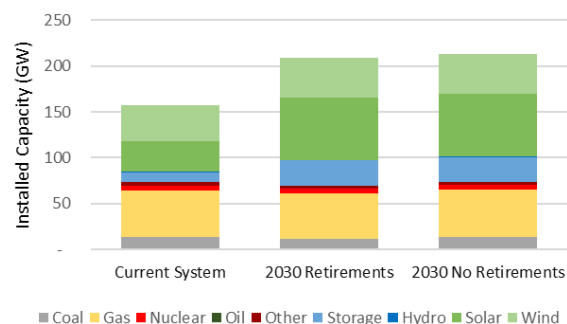


Figure 27. ERCOT Generation Capacity by Technology and Scenario

ERCOT's generation mix was comprised primarily of natural gas, wind, and solar. In 2024, natural gas comprised 32% of nameplate, wind comprised 25%, and solar 22%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed 2.5 GW of rooftop solar and 3.5 GW of demand response.

Table 19. Nameplate Capacity for ERCOT and by Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	13,568	50,889	4,973	10	3,627	10,720	583	33,589	39,532	157,490
ERCOT	13,568	50,889	4,973	10	3,627	10,720	583	33,589	39,532	157,490
Additions	0	569	0	0	0	16,538	0	34,681	3,638	55,426
ERCOT	0	569	0	0	0	16,538	0	34,681	3,638	55,426
Closures	(2,000)	(2,022)	0	0	0	0	0	0	0	(4,022)
ERCOT	(2,000)	(2,022)	0	0	0	0	0	0	0	(4,022)

Appendix A - Generation Calibration and Forecast

The study team started with the grid model from the NERC ITCS, which was published in 2024 with reference to NERC 2023 LTRA capacity.²⁷ This zonal ITCS model serves as the starting point for the network topology (covering 23 U.S. regions), transmission capacity between zones, and general modeling assumptions. The resource mix and retirements in the ITCS model were updated for this study to reflect the various 2030 scenarios discussed previously. Prior to developing the 2030 scenarios, the study team also updated the 2024 ITCS model to ensure consistency in the current model assumptions.

2024 Resource Mix

Because there were noted changes in assumed capacity additions between the 2023 and 2024 LTRAs²⁸, the ITCS model was updated with the 2024 LTRA data, provided directly by NERC to the study team. The 2024 LTRA dataset, reported at the NERC assessment area level—which is more aggregated in some areas than the ITCS regional structure (covering 13 U.S. regions; see Figure A.1)—includes both existing resource capacities²⁹ and Tier 1, 2, and 3 planned additions for each year from 2024 to 2033. As explained below, to incorporate this data into the ITCS model, a mapping process was developed to disaggregate generation capacities from the NERC assessment areas to the more granular ITCS regions by technology type. To preserve the daily or monthly adjustments to generator availability for certain categories (wind, solar, hybrid, hydropower, batteries, and other) by using the ITCS methods, the nameplate LTRA capacity was used. For all other categories (mostly thermal generators), summer and winter on-peak capacity contributions were used.

27. NERC, “Interregional Transfer Capability Study (ITCS).”
https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf.

28. NERC, “2024 Long-Term Reliability Assessment,” December, 2024, 24.
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

29. Capacities are reported for both winter and summer seasonal ratings, along with nameplate values.

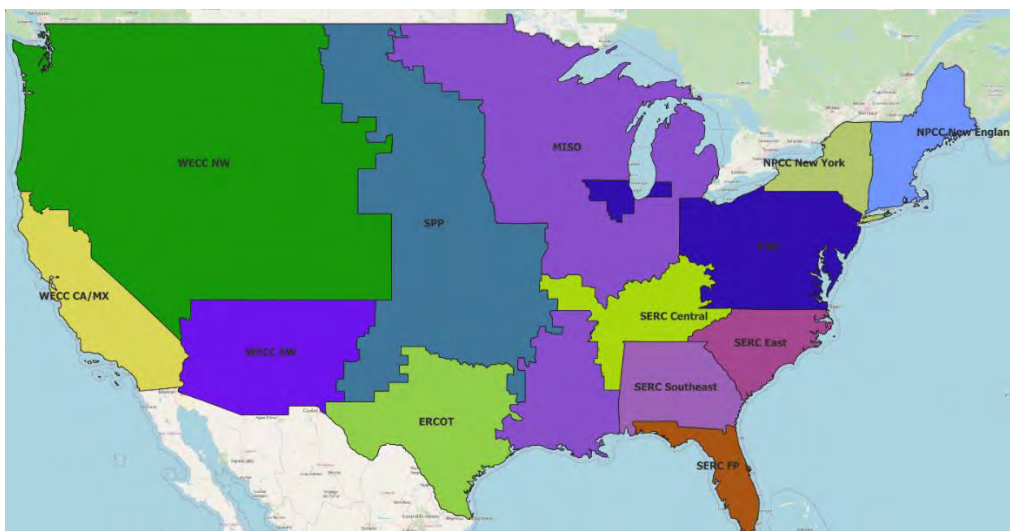


Figure A.1. NERC assessment areas.

To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant-level data were used to tabulate the generation capacity for each ITCS region and NERC assessment area. The geographical boundaries for the NERC assessment areas and the ITCS regions were constructed based on ReEDS zones.³⁰ Disaggregation fractions were then calculated by technology type using the combined existing capacity and planned additions through 2030 from EIA 860 data as of December 2024. Specifically, to compute each fraction, an ITCS region's total (existing plus planned) capacity was divided by the corresponding total capacity across all ITCS regions within the same mapped NERC assessment area and fuel type group:

$$Fraction_{rf} = \frac{Capacity_{rf}}{\sum_{r' \in ITCS(R)} Capacity_{r'f}} \quad (Equation.1)$$

Where $Capacity_{rf}$ is the capacity of fuel type f in ITCS region r and $ITCS(R)$ is the set of all ITCS regions mapped to the same NERC assessment area R . The denominator is the total capacity of that fuel type across all ITCS regions mapped to R .

Note that in cases where NERC assessment areas align one-to-one with ITCS regions, no mapping was required. Table A.1 summarizes which areas exhibited a direct one-to-one matching and which required disaggregation (1-to-many) or aggregation (many-to-one) to align with the ITCS regional structure.

An exception to this general approach is the case of the Front Range ITCS region, which geographically spans across two NERC assessment areas—WECC-NW and WECC-SW—resulting in two-to-one mapping. For this case, a separate allocation method was used: Plant-level data from EIA 860 were analyzed to determine the proportion of Front Range capacity located in each NERC area. These proportions were then used to derive custom weighting factors for allocating capacities from both WECC-NW and WECC-SW into the Front Range region.

30. NREL, “Regional Energy Development System,” <https://www.nrel.gov/analysis/reeds/>.

Table A.1. Mapping of NERC assessment areas to ITCS regions.

NERC Area	ITCS Region	Match
ERCOT	ERCOT	1 to 1
NPCC-New England	NPCC-New England	1 to 1
NPCC-New York	NPCC-New York	1 to 1
SERC-C	SERC-C	1 to 1
SERC-E	SERC-E	1 to 1
SERC-FP	SERC-FP	1 to 1
SERC-SE	SERC-SE	1 to 1
WECC-SW	Southwest Region	1 to 1
MISO	MISO Central	1 to 4
MISO	MISO East	
MISO	MISO South	
MISO	MISO West	
SPP	SPP North	1 to 2
SPP	SPP South	
WECC-CAMX	Southern California	1 to 2
WECC-CAMX	Northern California	
WECC-NW	Oregon Region	1 to 3
WECC-NW	Washington Region	
WECC-NW	Wasatch Front	
WECC-NW	Front Range	2 to 1
WECC-SW	Front Range	

Table A.2 and Figure A.2 show the same combined capacities by ITCS region and NERC planning region, respectively.

Table A.2. Existing and Tier 1 capacities by NERC assessment area (in MW) in 2024.

2024 Existing + Tier 1		Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	Total	143,035	330,342	82,793	26,771	3,624	-	991	19,607	3,298	28,980	72,757	94,364	25,753	24,367	856,682
	ISONE Total	541	15,494	3,331	5,710	818	-	233	1,571	57	1,911	3,386	2,553	661	3,713	39,979
	MISO Total	37,914	64,194	11,127	2,867	613	-	329	4,396	1,031	2,533	29,777	41,715	7,775	3,049	207,319
	MISO-W	12,651	13,608	2,753	1,491	244	-	2	-	200	777	7,368	29,411	2,367	741	71,612
	MISO-C	15,050	10,307	2,169	494	32	-	152	773	499	769	10,587	7,350	2,026	1,774	51,982
	MISO-S	5,493	31,052	5,100	589	243	-	117	49	5	845	8,024	596	2,109	291	54,511
	MISO-E	4,720	9,227	1,105	292	94	-	57	3,574	327	143	3,799	4,359	1,273	243	29,213
	NYISO Total	-	22,937	3,330	2,631	334	-	-	1,400	60	4,915	1,039	2,706	860	5,710	45,924
	PJM Total	39,915	84,381	32,535	9,875	851	-	-	5,062	338	3,071	10,892	11,718	7,397	8,603	214,638
	PJM-W	34,917	39,056	16,557	1,933	112	-	-	234	149	1,252	5,780	10,065	3,814	599	114,467
	PJM-S	2,391	15,038	5,288	3,985	479	-	-	2,958	127	1,070	3,932	360	1,824	2,498	39,951
	PJM-E	2,608	30,287	10,690	3,956	260	-	-	1,870	62	749	1,180	1,294	1,759	5,506	60,221
	SERC Total	45,747	113,334	31,702	4,063	989	-	83	6,701	768	11,425	26,959	982	7,707	3,221	253,680
	SERC-C	13,348	20,127	8,280	148	36	-	-	1,784	100	4,995	2,308	982	1,851	20	53,978
	SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	115	3,260	7,267	-	2,069	317	67,073
	SERC-FL	4,346	47,002	3,502	1,957	310	-	83	-	538	-	10,121	-	2,804	2,051	72,714
	SERC-E	14,777	16,340	11,902	1,044	219	-	-	3,369	15	3,170	7,263	-	983	833	59,914
	SPP Total	18,919	30,003	769	1,626	20	-	345	477	1,044	5,123	703	34,689	1,353	71	95,142
	SPP-N	5,089	3,467	304	504	1	-	185	-	8	3,041	84	7,041	333	7	20,065
	SPP-S	13,829	26,536	465	1,121	19	-	160	477	1,037	2,082	619	27,649	1,020	64	75,078
ERCOT	Total	13,568	50,889	4,973	10	163	-	-	-	10,720	583	31,058	39,532	3,464	2,531	157,490
	ERCOT Total	13,568	50,889	4,973	10	163	-	-	-	10,720	583	31,058	39,532	3,464	2,531	157,490
WEST	Total	21,666	87,403	9,403	829	1,565	4,093	106	4,536	15,238	52,687	44,042	35,071	1,944	16,271	294,854
	CAISO+ Total	1,816	37,434	5,582	185	726	2,004	35	3,514	11,156	10,211	25,614	7,773	829	10,047	116,925
	CALI-N	-	12,942	5,582	165	465	1,049	9	1,967	2,672	8,727	6,723	1,373	349	5,036	47,059
	CALI-S	1,816	24,492	-	20	261	955	26	1,547	8,484	1,483	18,891	6,400	480	5,011	69,866
	Non-CA WECC Total	19,850	49,969	3,820	644	839	2,089	71	1,022	4,082	42,476	18,428	27,298	1,115	6,224	177,929
	WA	560	3,919	1,096	17	352	-	-	140	350	24,402	1,052	2,690	243	386	35,207
	OR	-	3,915	-	6	293	21	-	-	482	8,253	2,145	3,440	141	372	19,068
	SOUTHWEST	4,842	17,985	2,724	323	102	1,047	-	176	2,173	1,019	5,641	3,685	168	2,452	42,335
	WASATCH	7,033	14,061	-	87	56	1,011	61	444	750	7,587	5,625	4,052	305	1,674	42,746
	FRONT R	7,415	10,089	-	211	36	10	10	262	328	1,215	3,966	13,432	258	1,340	38,572
Total		178,268	468,635	97,169	27,610	5,353	4,093	1,096	24,144	29,256	82,249	147,856	168,966	31,161	43,169	1,309,026

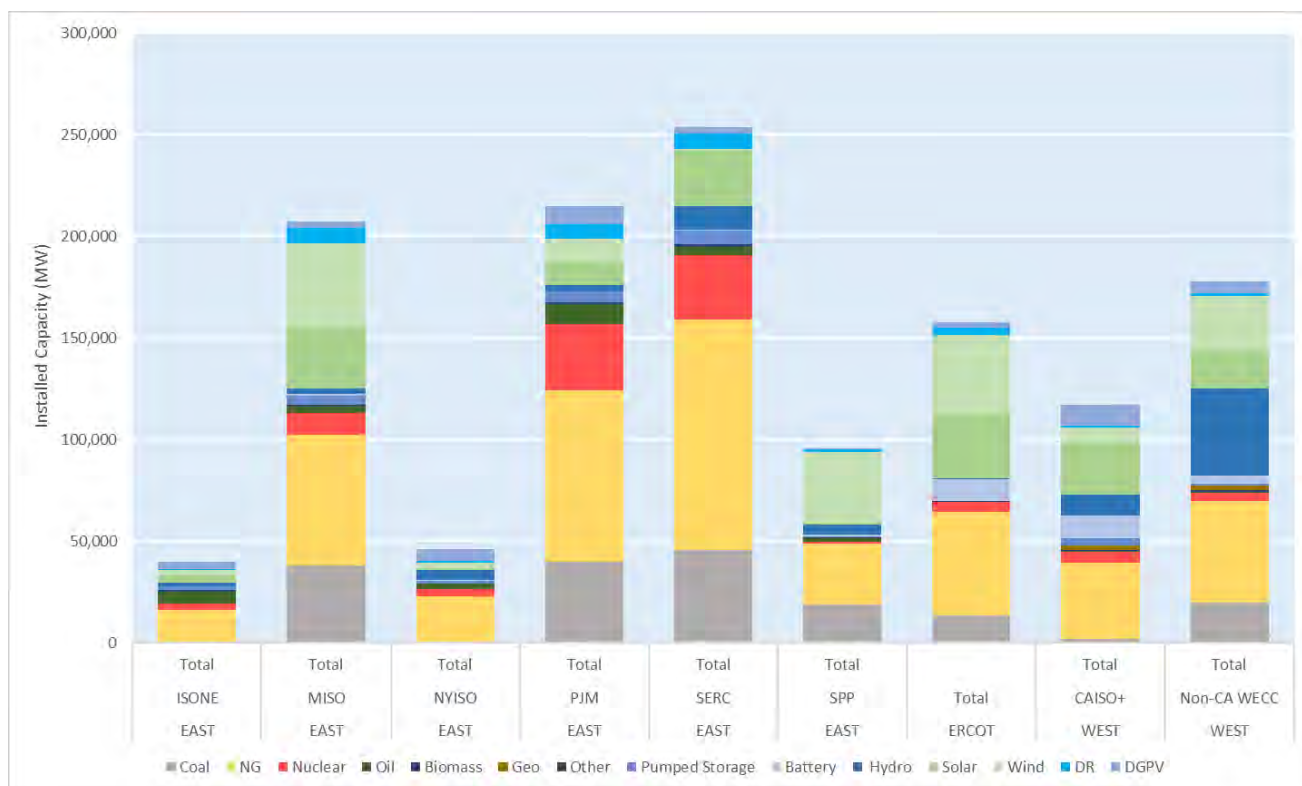


Figure A.2. Existing and Tier 1 capacities by NERC assessment area in 2024.

Forecasting 2030 Resource Mixes

To develop the 2030 ITCS generation portfolio, the study team added new capacity builds and removed planned retirements.

- (i) *Tier 1*: Assumes that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built. This results in minimal capacity additions beyond 2026. The data are based on projects designated as Tier 1 in the 2024 LTRA data for the year 2030.

Retirements

To project which units will retire by 2030, the study team primarily used the LTRA 2024 data and cross-checked it with EIA data. The assessment areas were disaggregated to ITCS zones based on the ratios of projected retirements in EIA 860 data. The three scenarios modeled are as follows:

- (i) *Announced*: Assumes that in addition to confirmed retirements, generators that have publicly announced retirement plans but have not formally notified system operators have also begun the retirement process. This is based on data from the 2024 LTRA, which were collected by the NERC team from sources like news announcements, public disclosures, etc.

- (ii) *None*: Assumes that there are no retirements between 2024 and 2030 for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirements contribute to resource adequacy challenges in regions where rapid AI and data center growth is expected.

Generation Stack for Each Scenario

Finally, when summing all potential future changes, the team arrived at a generation stack for each of the various scenarios to be studied. The first figure provides a visual comparison of all the cases, which vary from 1,309 GW to 1,519 GW total generation capacity for the entire continental United States, to enable the exploration of a range of potential generation futures. The tables below provide breakdowns by ITCS region and by resource type.

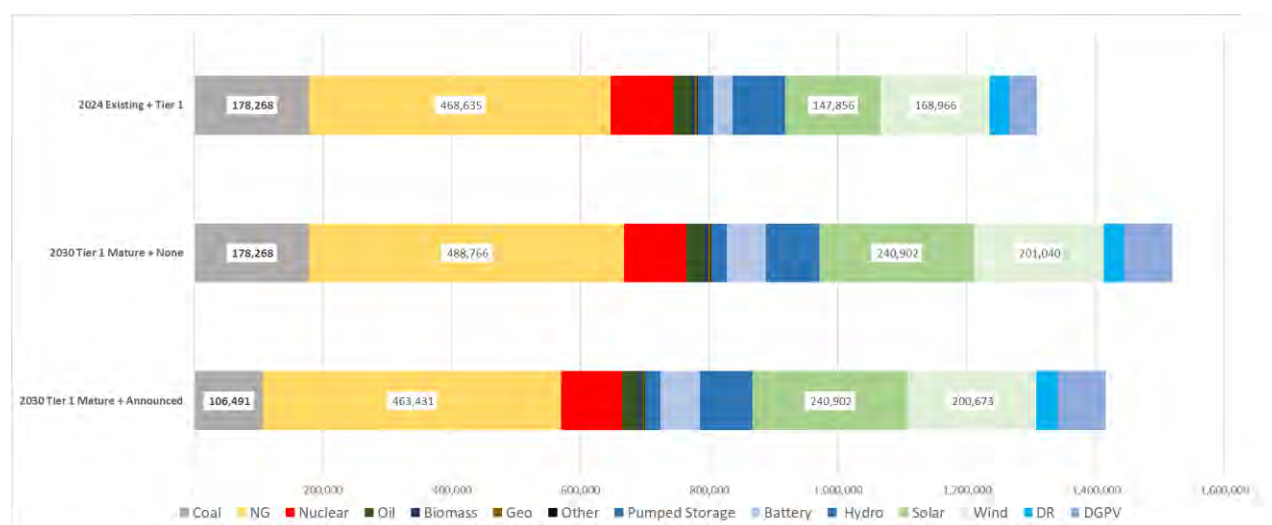


Figure A.9. Comparison of 2030 generation stacks for the various scenarios.

Table A.4. 2030 generation stack for Tier 1 mature + announced retirements.

2030 Tier 1 Mature + Announced		Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	Total	84,730	328,457	82,793	24,272	3,473	-	991	19,591	12,415	28,897	126,849	113,568	26,837	36,768	889,641
	ISONE Total	7	13,708	3,331	5,687	741	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	42,845
	MISO Total	13,001	60,132	11,127	2,873	473	-	329	4,380	2,960	2,450	44,132	43,369	7,775	3,049	196,049
	MISO-W	4,338	12,747	2,753	1,494	188	-	2	-	574	751	10,920	30,577	2,367	741	67,453
	MISO-C	5,161	9,655	2,169	495	25	-	152	770	1,433	743	15,690	7,642	2,026	1,774	47,735
	MISO-S	1,883	29,087	5,100	591	187	-	117	49	14	817	11,892	619	2,109	291	52,756
	MISO-E	1,619	8,643	1,105	293	72	-	57	3,561	938	138	5,630	4,531	1,273	243	28,105
	NYISO Total	-	21,907	3,330	2,628	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	50,396
	PJM Total	26,662	87,228	32,535	8,117	917	-	-	5,062	2,276	3,071	33,530	18,807	7,638	10,955	236,798
	PJM-W	23,323	40,373	16,557	1,589	120	-	-	234	1,004	1,252	17,793	16,153	3,939	762	123,100
	PJM-S	1,597	15,546	5,288	3,276	516	-	-	2,958	853	1,070	12,105	577	1,883	3,181	48,850
	PJM-E	1,742	31,309	10,690	3,252	280	-	-	1,870	419	749	3,632	2,076	1,816	7,012	64,848
	SERC Total	31,672	116,117	31,702	3,391	989	-	83	6,701	3,021	11,425	38,360	982	8,088	7,893	260,423
	SERC-C	8,883	23,777	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	54,014
	SERC-SE	10,321	28,127	8,018	899	424	-	-	1,548	618	3,260	9,024	-	2,213	317	64,768
	SERC-FL	2,851	47,092	3,502	1,477	310	-	83	-	2,208	-	16,717	-	3,022	5,865	83,127
	SERC-E	9,617	17,122	11,902	868	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	58,513
	SPP Total	13,389	29,365	769	1,576	20	-	345	477	2,434	5,123	5,991	41,755	1,815	71	103,130
	SPP-N	3,602	3,394	304	489	1	-	185	-	18	3,041	717	8,475	447	7	20,679
	SPP-S	9,787	25,971	465	1,087	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	82,451
ERCOT	Total	11,568	49,436	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	208,894
ERCOT	Total	11,568	49,436	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	208,894
WEST	Total	10,193	85,538	7,103	823	1,427	3,983	106	4,366	21,330	52,060	51,648	43,935	1,981	31,931	316,424
	CAISO+ Total	16	35,789	3,282	185	726	2,059	35	3,514	14,316	10,211	27,112	7,773	866	17,055	122,938
	CALI-N	-	12,373	3,282	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	48,897
	CALI-S	16	23,416	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	74,041
	Non-CA WECC Total	10,177	49,749	3,820	639	701	1,924	71	852	7,014	41,849	24,536	36,162	1,115	14,876	193,485
	WA	243	3,971	1,096	16	286	-	-	111	459	24,033	1,404	3,631	243	1,092	36,588
	OR	-	3,967	-	6	238	18	-	-	632	8,128	2,865	4,644	141	1,051	21,689
	SOUTHWEST	3,657	17,343	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	47,022
	WASATCH	3,055	14,247	-	86	45	850	61	355	983	7,472	7,512	5,470	305	4,733	45,175
	FRONT R	3,221	10,222	-	208	30	8	10	209	430	1,197	5,296	18,133	258	3,789	43,011
Total		106,491	463,431	94,869	25,106	5,063	3,983	1,096	23,958	61,003	81,539	240,902	200,673	32,282	74,563	1,414,959

Table A.5. 2030 generation stack for Tier 1 mature + no retirements.

2030 Tier 1 Mature + No Retirements			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	Total		143,035	345,459	82,793	27,336	3,701	-	991	19,607	12,415	28,980	126,849	113,840	26,837	36,768	968,610
	ISONE	Total	541	15,584	3,331	5,891	818	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	45,534
	MISO	Total	37,914	66,729	11,127	3,197	613	-	329	4,396	2,960	2,533	44,132	43,641	7,775	3,049	228,393
		MISO-W	12,651	14,145	2,753	1,662	244	-	2	-	574	777	10,920	30,768	2,367	741	77,605
		MISO-C	15,050	10,714	2,169	551	32	-	152	773	1,433	769	15,690	7,690	2,026	1,774	58,823
		MISO-S	5,493	32,278	5,100	657	243	-	117	49	14	845	11,892	623	2,109	291	59,710
		MISO-E	4,720	9,592	1,105	326	94	-	57	3,574	938	143	5,630	4,560	1,273	243	32,255
	NYISO	Total	-	22,937	3,330	2,646	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	51,444
	PJM	Total	39,915	88,880	32,535	9,907	928	-	-	5,062	2,276	3,071	33,530	18,807	7,638	10,955	253,504
		PJM-W	34,917	41,138	16,557	1,939	122	-	-	234	1,004	1,252	17,793	16,153	3,939	762	135,810
		PJM-S	2,391	15,840	5,288	3,998	522	-	-	2,958	853	1,070	12,105	577	1,883	3,181	50,667
		PJM-E	2,608	31,902	10,690	3,969	284	-	-	1,870	419	749	3,632	2,076	1,816	7,012	67,027
	SERC	Total	45,747	120,232	31,702	4,063	989	-	83	6,701	3,021	11,425	38,360	982	8,088	7,893	279,285
		SERC-C	13,348	24,958	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	59,660
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	618	3,260	9,024	-	2,213	317	69,478
		SERC-FL	4,346	48,163	3,502	1,957	310	-	83	-	2,208	-	16,717	-	3,022	5,865	86,173
		SERC-E	14,777	17,246	11,902	1,044	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	63,973
	SPP	Total	18,919	31,098	769	1,632	20	-	345	477	2,434	5,123	5,991	41,755	1,815	71	110,449
		SPP-N	5,089	3,594	304	506	1	-	185	-	18	3,041	717	8,475	447	7	22,385
		SPP-S	13,829	27,504	465	1,126	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	88,064
ERCOT	Total		13,568	51,458	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	212,916
	ERCOT	Total	13,568	51,458	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	212,916
WEST	Total		21,666	91,849	9,403	829	1,565	4,156	106	4,536	21,330	52,687	51,648	44,030	1,981	31,931	337,717
	CAISO+	Total	1,816	39,560	5,582	185	726	2,059	35	3,514	14,316	10,211	27,112	7,773	866	17,055	130,809
		CALI-N	-	13,677	5,582	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	52,501
		CALI-S	1,816	25,883	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	78,308
	Non-CA WECC	Total	19,850	52,289	3,820	645	839	2,097	71	1,022	7,014	42,476	24,536	36,257	1,115	14,876	206,908
		WA	560	4,166	1,096	17	352	-	-	140	459	24,402	1,404	3,642	243	1,092	37,573
		OR	-	4,161	-	6	293	22	-	-	632	8,253	2,865	4,658	141	1,051	22,081
		SOUTHWEST	4,842	18,294	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	49,158
		WASATCH	7,033	14,945	-	88	56	1,018	61	444	983	7,587	7,512	5,486	305	4,733	50,251
		FRONT R	7,415	10,723	-	212	36	10	10	262	430	1,215	5,296	18,187	258	3,789	47,844
Total			178,268	488,766	97,169	28,175	5,429	4,156	1,096	24,144	61,003	82,249	240,902	201,040	32,282	74,563	1,519,243

Appendix B - Representing Canadian Transfer Limits

Introduction

The reliability and stability of cross-border electricity interconnections between the United States and Canada are critical to ensuring continuous power delivery amid evolving demands and variable supply conditions. In recent years, increased integration of wind and solar generation, coupled with extreme weather events, has introduced significant uncertainties in regional power flows.

This report describes the development and implementation of a machine learning (ML)-based model designed to project the maximum daily energy transfer (MaxFlow) across major United States–Canada interfaces, such as BPA–BC Hydro and NYISO–Ontario. Leveraging 15 years of high-resolution load and generation data, summarizing it into key daily statistics, and training a robust eXtreme Gradient Boosting (XGBoost) regressor can allow data-driven predictions to be captured with quantified uncertainty.

The project team provided percentile-based forecasts—25, 50, and 75 percent—to support both conservative and strategic planning. The conservative methodology (25 percent) was used for this report to ensure availability when needed.

The subsequent sections detail the methodology used for data processing and feature engineering, the architecture and training of the predictive model, and the validation metrics and feature importance analyses used. Future enhancements could include incorporating weather patterns, neighboring-region dynamics, and fuel-specific generation profiles to further strengthen predictive performance and support grid resilience.

Methodology

This section describes the ML approach used to build the MaxFlow prediction model.

Dataset Collection and Preparation

Data were collected for hourly and derived daily load and generation over a 15-year period (2010–2024), comprising 8,760 hourly observations annually. Hourly interconnection flow rates were collected for the same years across all major United States–Canada interfaces.^{1–17}

Underlying Hypothesis

The team hypothesized that the MaxFlow between interconnected regions is critically influenced by regional load and generation extrema (maximum and minimum) and their variability. These statistics reflect grid stress conditions, influencing interregional energy flow. Additionally, nonlinear interactions due to imbalances in adjacent regions further affect energy transfer dynamics.

Regression Model

The XGBoost regression model was chosen because of its ability to capture complex, nonlinear relationships, regularization capability to prevent overfitting, high speed and performance, fast convergence, built-in handling of missing data, and ease of confidence interval approximation.

XGBoost builds many small decision trees, one after another. Each new tree learns to correct the mistakes of the previous ensemble by focusing on which predictions had the greatest error. Instead of creating one large, complex tree, it combines many simpler trees—each making a modest adjustment—so that, together, they capture nonlinear patterns and interactions. Regularization (penalties for tree size and leaf adjustments) prevents overfitting, and a “learning rate” scales each tree’s contribution so that improvements are made gradually. The final prediction is simply the sum of all those small corrections.

Model Training, Validation, and Assessment

Figure B.1 shows the data analysis and prediction process, which ties together seven stages—from raw CSV loading through outlier filtering, feature engineering, projecting to 2030, rebuilding 2030 features, training an XGBoost model, and finally making and evaluating the 2030 flow forecasts with quantiles. Each stage feeds into the next, ensuring that the features used for training mirror exactly those that will be available for future (2030) predictions.

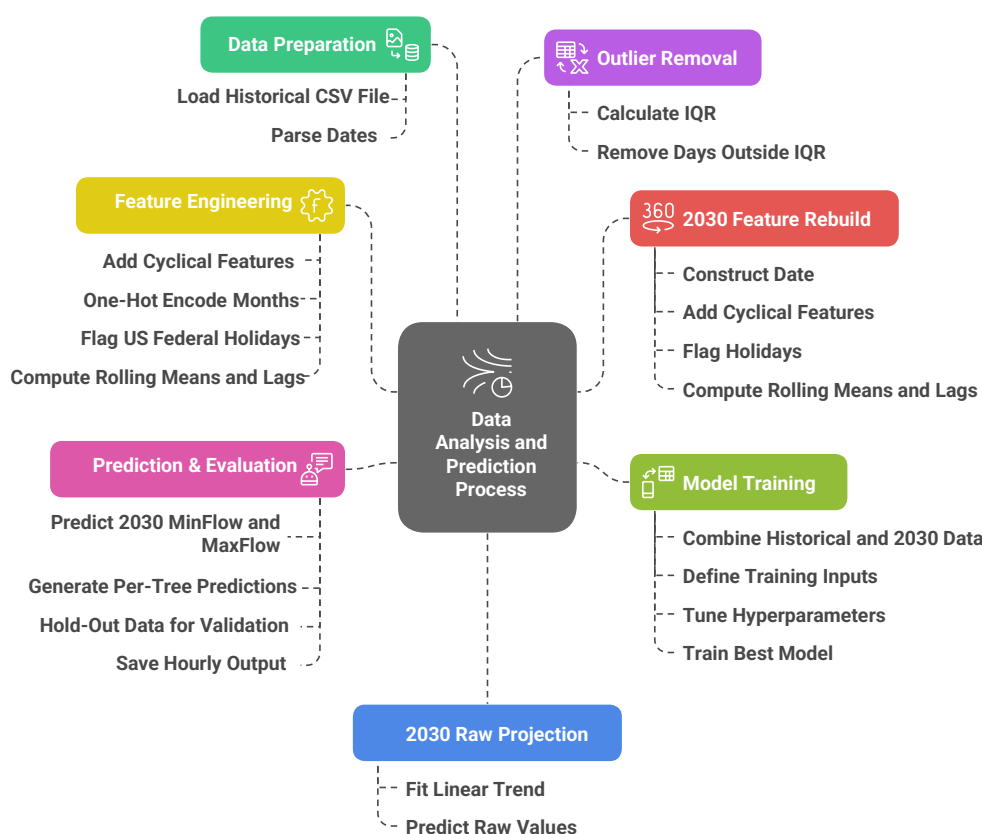


Figure B.1. Data analysis and prediction process.

Example Feature Importance for Predicting MaxFlow from Ontario to NYISO

The trained ML/XGBoost model can be used for predicting the desired year’s MaxFlow. In addition, feature importance analysis can be added to assess the contribution of each variable.

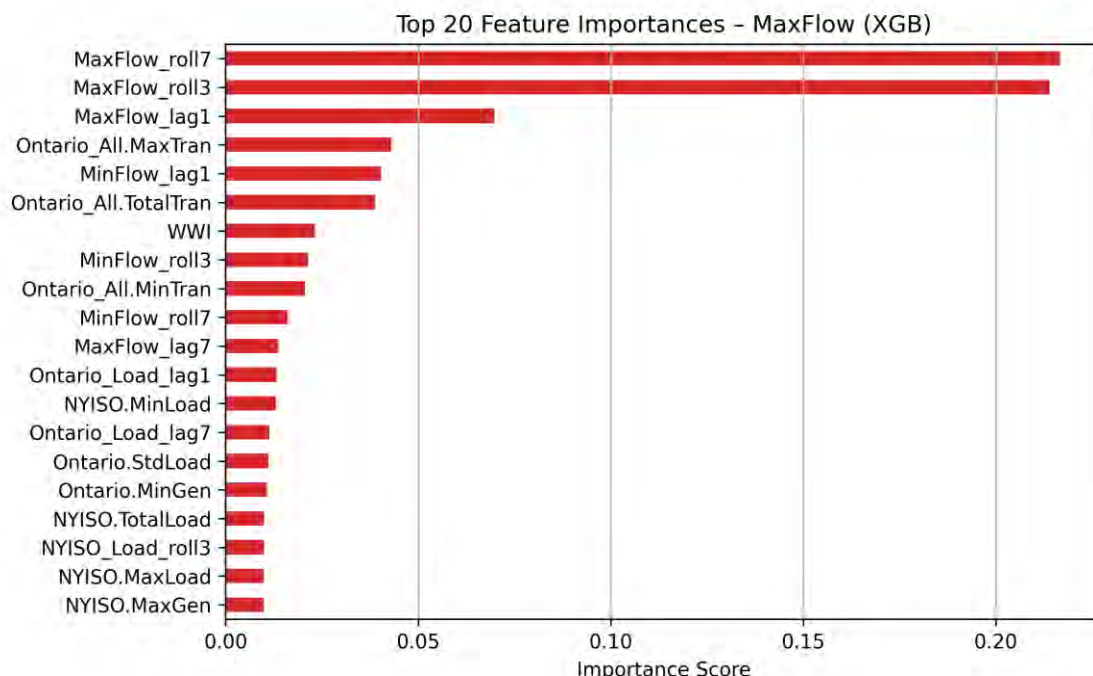


Figure B.2. Feature importance for predicting the hourly maximum energy transfer (MaxFlow) between NYISO and Ontario. XGB = eXtreme Gradient Boosting.

The feature importance plot shows that MaxFlow rolling/lagging features and Ontario_All.MaxTran are the dominant predictors of MaxFlow, meaning temporal patterns and Ontario's peak transfer capacity strongly influence interregional flow limits. Weather-related variables (WWI, e.g., temperature, humidity, etc.) and Ontario_All.TotalTran also rank highly. The 2030 MaxFlow prediction plot shows seasonal fluctuations, with higher values early and late in the year. The red shaded area represents a 95 percent confidence interval for the predictions.

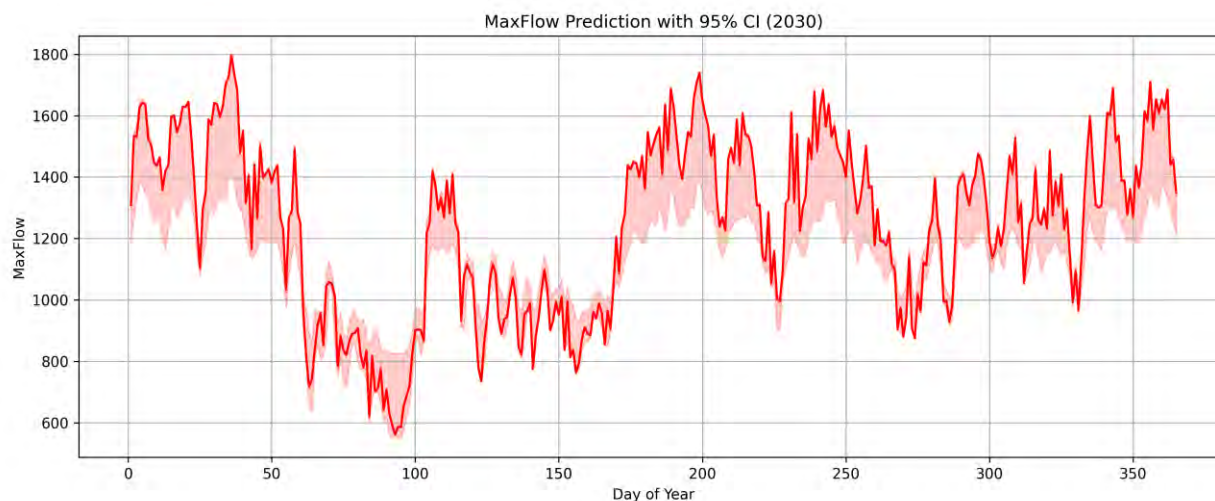


Figure B.3. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI).

Model Performance

Validating model performance on unseen data is essential to ensure the model’s reliability and generalizability. The following evaluation examines how well the XGBoost model predicts minimum energy transfer (MinFlow) and MaxFlow on the validation split, highlighting strengths and areas for improvement.

Rigorous performance evaluation is a fundamental step in any ML workflow. From quantifying error metrics (root mean square error and mean absolute error) and goodness-of-fit (R^2) on both training and validation splits, it is possible to identify overfitting, assess generalization, and guide model refinement. Table B.1 shows XGBoost model performance for the Ontario–NYISO transfer limit.

Table B.1. eXtreme Gradient Boosting model performance for the Ontario–NYISO transfer limit.

Metric	Value	Explanation
MinFlow RMSE (Train)	69.2528	Root mean square error (RMSE) on training data for minimum energy transfer (MinFlow)
MinFlow R^2 (Train)	0.9651	R^2 on training data for MinFlow (higher → better fit)
MinFlow RMSE (Validation)	163.6642	RMSE on held-out data for MinFlow
MinFlow R^2 (Validation)	0.8073	R^2 on held-out data for MinFlow (higher → better generalization)
MaxFlow RMSE (Train)	114.4234	RMSE on training data for maximum energy transfer (MaxFlow)
MaxFlow R^2 (Train)	0.8838	R^2 on training data for MaxFlow (higher → better fit)
MaxFlow RMSE (Validation)	144.9614	RMSE on held-out data for MaxFlow
MaxFlow R^2 (Validation)	0.8178	R^2 on held-out data for MaxFlow (higher → better generalization)

Overall, the XGBoost model delivers excellent in-sample as well as out-of-sample accuracy. Similar outputs are available for each transfer limit.

Maximum flow predictions: Ontario to New York

Ontario and NYISO are connected through multiple high-voltage interconnections, which collectively provide a total transfer capability of up to 2,500 MW, subject to individual tie-line limits. Table B.2 outlines the data sources, preparation process, and assumptions used in creating datasets for the prediction models.

Table B.2. Ontario to New York transmission flow data and assumptions overview.

	Description
Data source	https://www.ieso.ca/power-data/data-directory
Data preparation	IESO public hourly inter-tie schedule flow data can be accessed for the years spanning from 2002 to 2023.
Assumptions	Positive flow indicates that Ontario is exporting to NY, and negative flow indicates that Ontario is importing from NY.

Figure B.4 illustrates the historical monthly MaxFlow for Ontario from 2007 through 2024, alongside 2030 projected quartile scenarios (Q1, Q2, and Q3). Analyzing these trends helps assess future reliability and facilitates capacity planning under varying conditions.

Historical monthly peaks (2007–2023) reveal a clear seasonal cycle for ONT–NYISO transfers: flows typically increase in late winter/early spring (February–April) and again in late fall/early winter (November–December). Over 16 years, the average spring peaks hovered around 1,700–1,900 MW, with occasional spikes above 2,200 MW. The 2030 forecast for Q1, Q2, and Q3 aligns with this pattern, predicting a springtime peak near 1,800 MW, a summer trough around 1,400 MW, and a modest late-summer uptick near 1,500 MW.

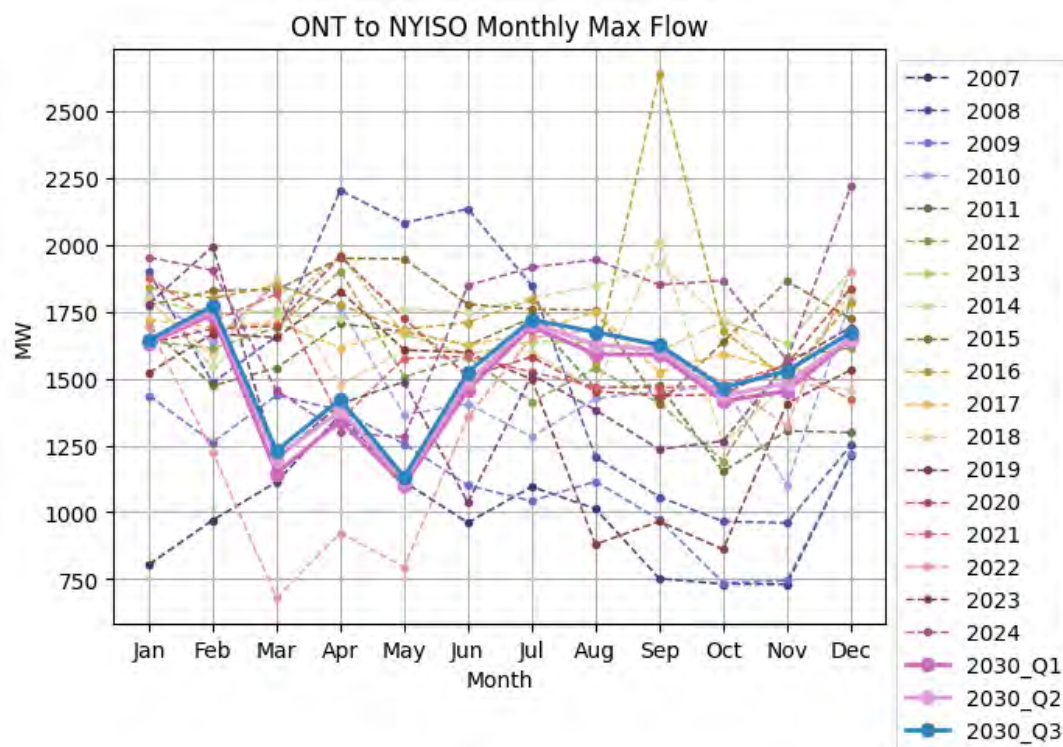


Figure B.4. Monthly maximum energy transfer between Ontario (ONT) and New York (NYISO).

The team used robust validation metrics to justify these results. When trained on daily data from the 2010–2024 period—including projected 2030 loads, seasonal flags, and holiday effects—the XGBoost model achieved $R^2 > 0.80$ and a root mean square error below 150 MW on an unseen 20 percent hold-out dataset. Moreover, the 95 percent confidence intervals for monthly maxima were narrow (approximately ± 150 MW), demonstrating low predictive uncertainty. A comparison of predicted maxima with historical extremes revealed that 2030 forecasts consistently fell within (or slightly above) the previous window of variability, implying realistic demand-driven behavior. In summary, the close alignment with historical peaks, strong cross-validated performance, and tight confidence bands collectively validate the results.

Discussion

The reason that the team used ML/XGBoost to approximate the 2030 transfer profiles was to ensure that there would be no violations or inconsistencies between transfer limits, load, and generation. The 15 years of data used were sufficient for having the models learn historical relationships and project them forward to 2030 to capture the underlying trends in load,

generation, and their interactions. The use of such an extensive dataset justifies using ML to establish consistent transfer profiles.

However, in some regions, like Ontario to NYISO, the available data encompassed a shorter time period, and the relationships were only partially captured because of a lack of neighboring-region data. In such cases, it was necessary to incorporate additional predictors, such as rolling and lag features from the transfer limits. Although the direct use of transfer limit data to project future transfer limits would typically be avoided, these engineered features help improve predictions when data coverage is sparse and the model's goodness-of-fit is low.

In all cases, the ML models ensured that these historical relationships were not violated, maintaining internal consistency among load, generation, and transfer limits. Overall, the team relied on ML when long-term data were available for training and projecting load and generation profiles. Rolling and lag features were used to reinforce the model when data availability was limited, but always with the goal of upholding consistent physical relationships in the 2030 projections.

Supplementary Plots for Additional Transfers

This section presents figures and tables showing results and source data information for each transfer listed below:

- (iii) Pacific Northwest to British Columbia
- (iv) Alberta to Montana
- (v) Manitoba to MISO West
- (vi) Ontario to MISO West
- (vii) Ontario to MISO East
- (viii) Ontario to New York
- (ix) Hydro-Quebec to New York
- (x) Hydro-Quebec to New England
- (xi) New Brunswick to New England

The figures show the daily MaxFlow for each transfer that was considered in this analysis.

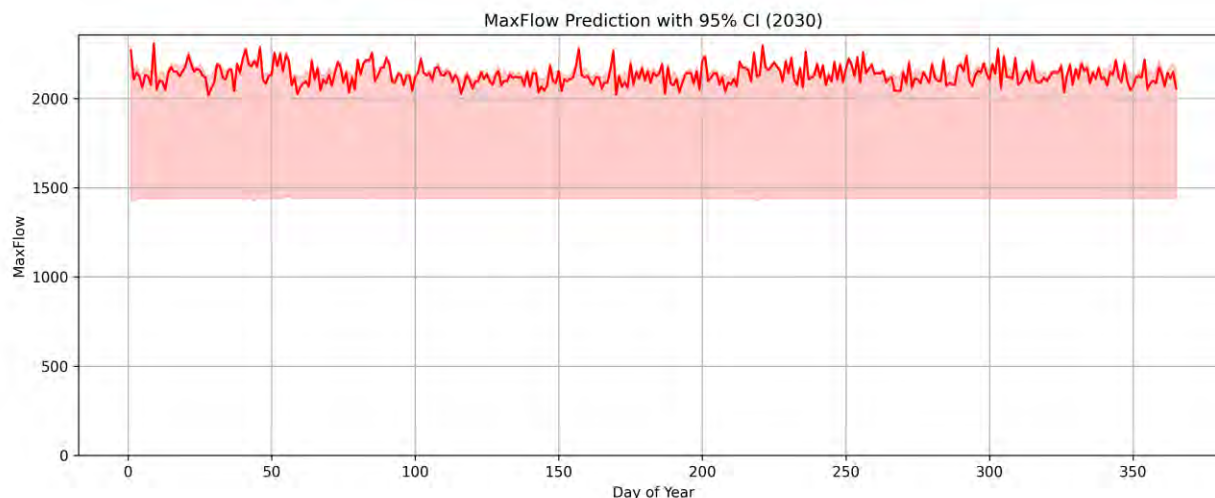


Figure B.5. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between British Columbia and the Pacific Northwest.

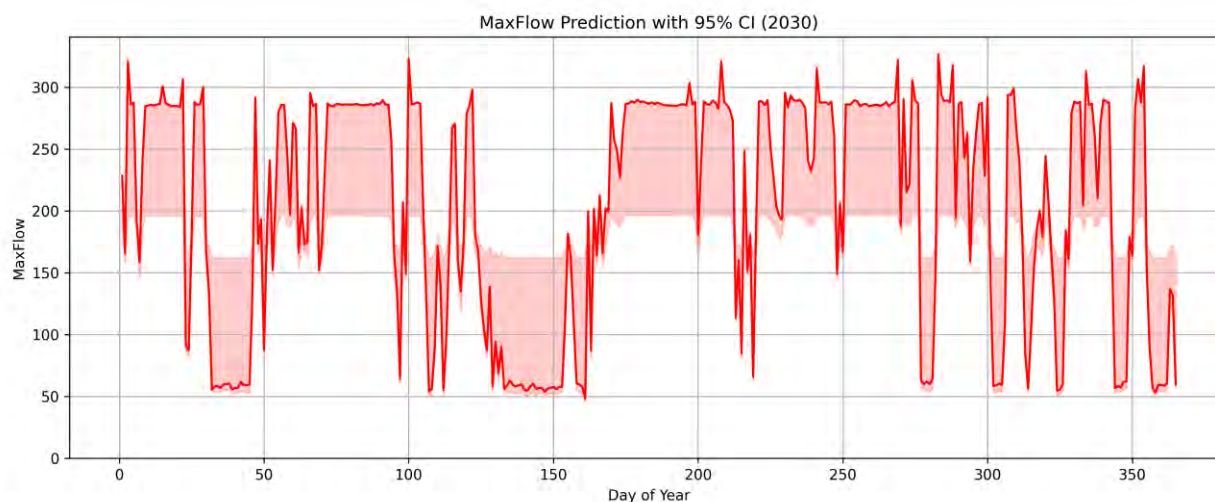


Figure B.6. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between AESO and Montana.

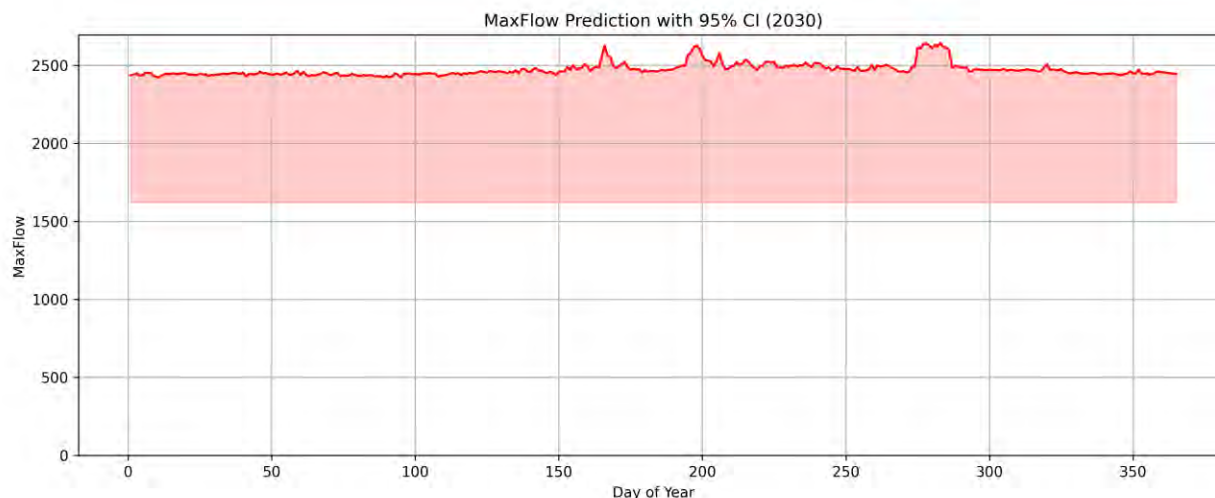


Figure B.7. Projected 2030 maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Manitoba and MISO.

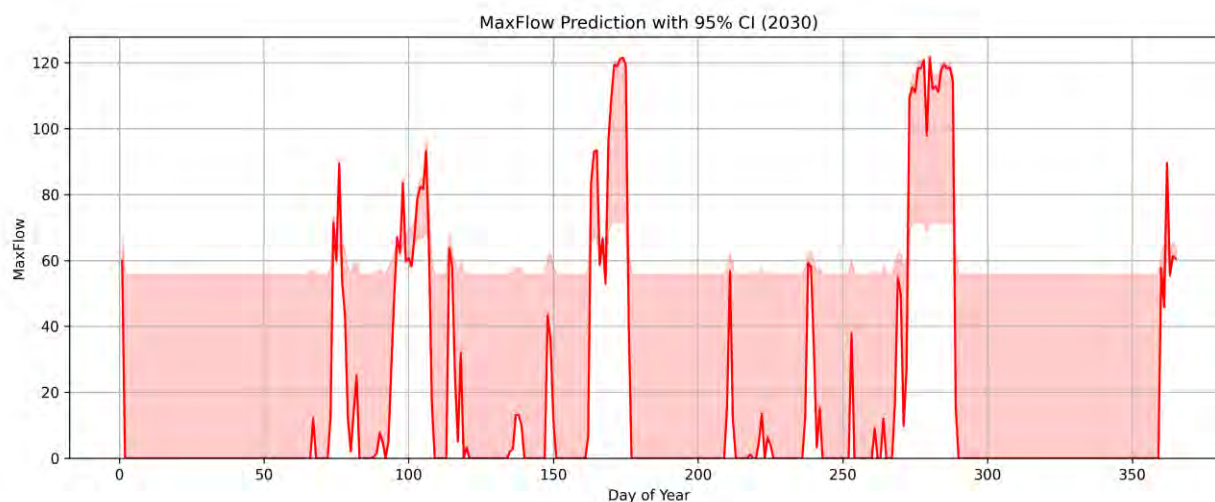


Figure B.8. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO West.

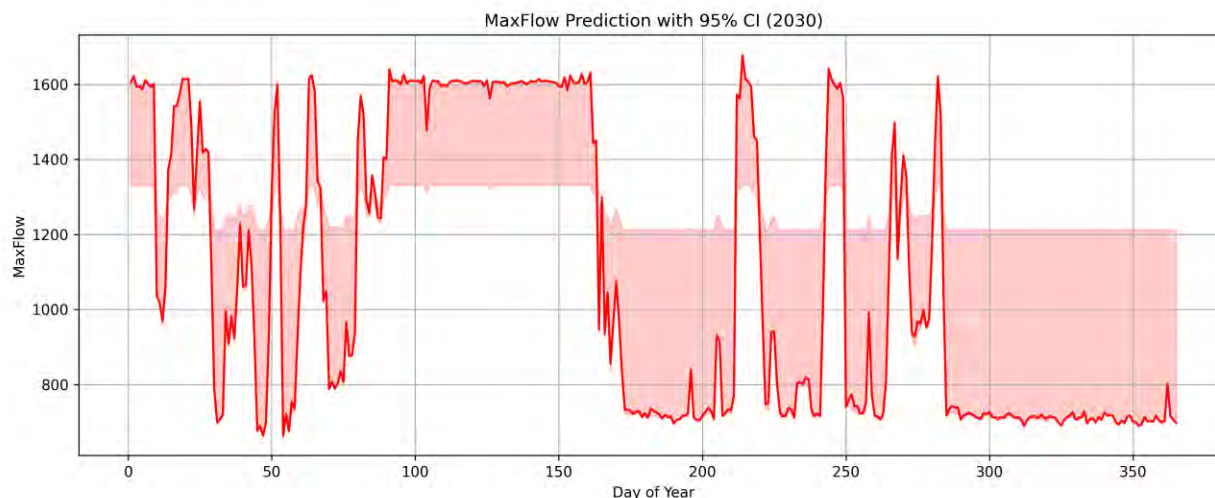


Figure B.9. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO East.

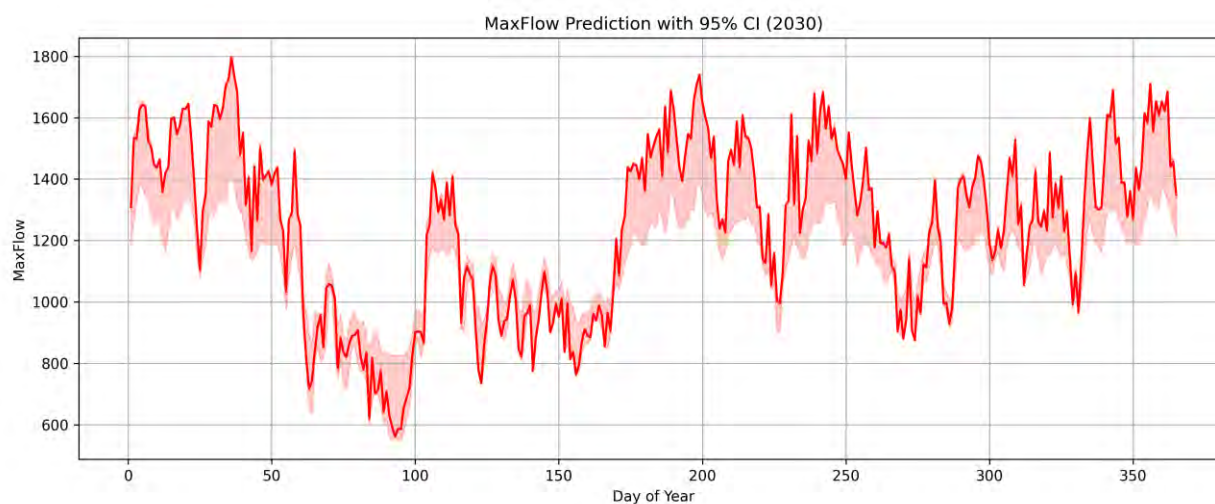


Figure B.10. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and New York.

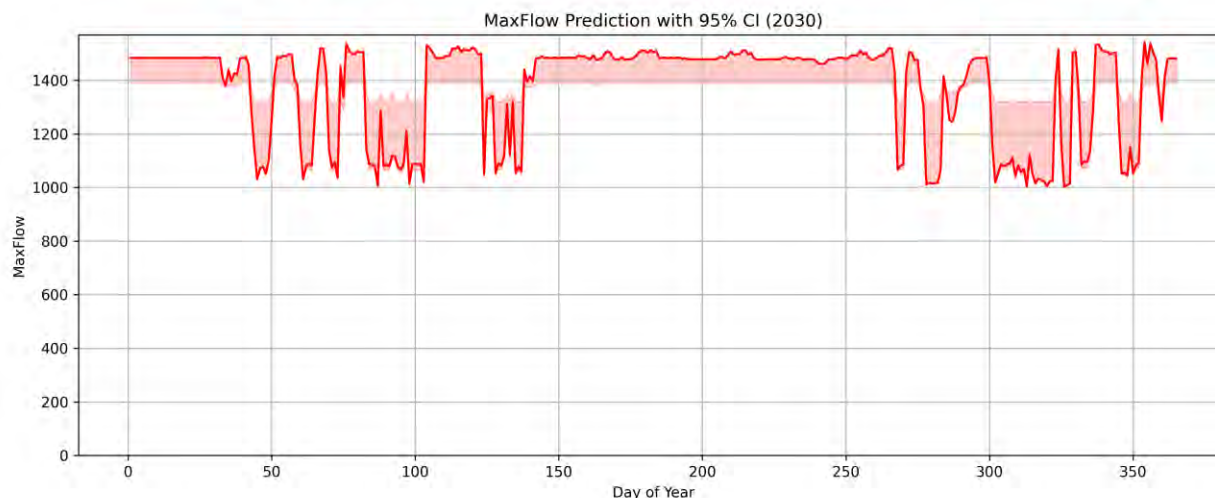


Figure B.11. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New York.

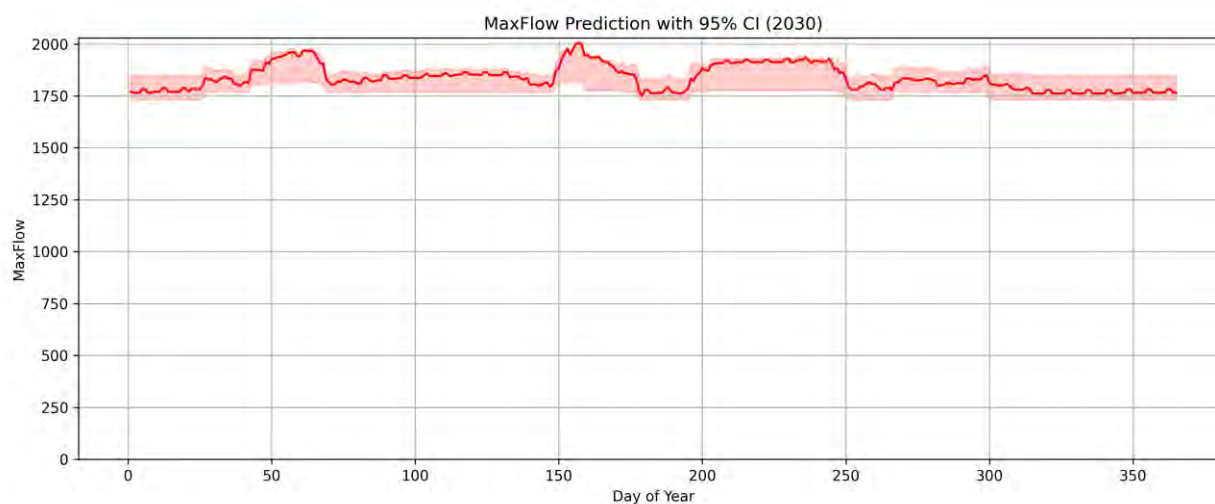


Figure B.12. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New England.

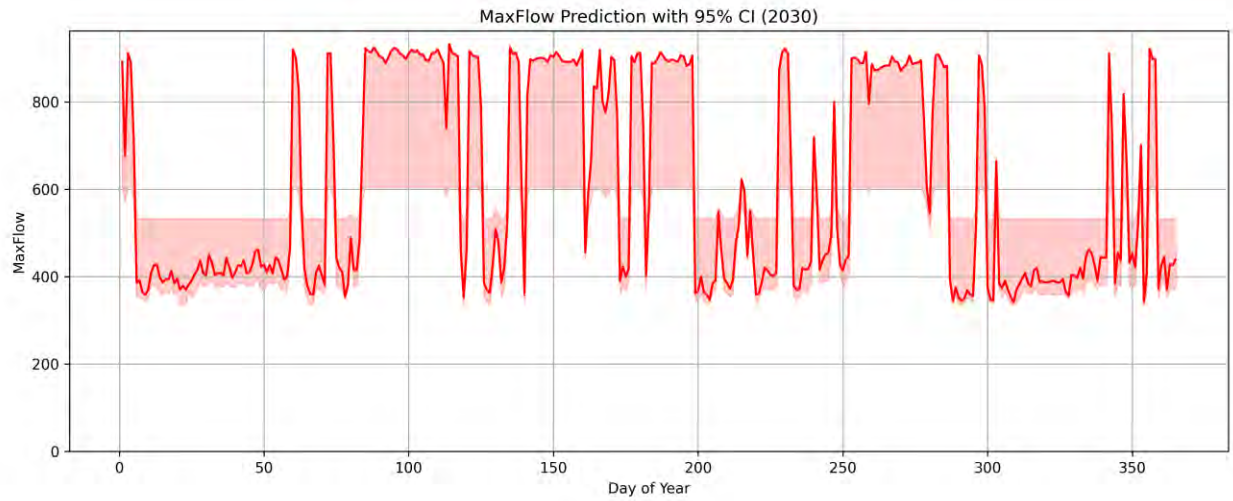


Figure B.13. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between New Brunswick and New England.

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EO 14262



Federal Register / Vol. 90, No. 70 / Monday, April 14, 2025 / Presidential Documents

15521

Presidential Documents

Executive Order 14262 of April 8, 2025

Strengthening the Reliability and Security of the United States Electric Grid

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered:

Section 1. Purpose. The United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and an increase in domestic manufacturing. This increase in demand, coupled with existing capacity challenges, places a significant strain on our Nation's electric grid. Lack of reliability in the electric grid puts the national and economic security of the American people at risk. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy from all available electric generation sources and the integrity of our Nation's electric grid.

Sec. 2. Policy. It is the policy of the United States to ensure the reliability, resilience, and security of the electric power grid. It is further the policy of the United States that in order to ensure adequate and reliable electric generation in America, to meet growing electricity demand, and to address the national emergency declared pursuant to Executive Order 14156 of January 20, 2025 (Declaring a National Energy Emergency), our electric grid must utilize all available power generation resources, particularly those secure, redundant fuel supplies that are capable of extended operations.

Sec. 3. Addressing Energy Reliability and Security with Emergency Authority.

(a) To safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure, the Secretary of Energy, in consultation with such executive department and agency heads as the Secretary of Energy deems appropriate, shall, to the maximum extent permitted by law, streamline, systemize, and expedite the Department of Energy's processes for issuing orders under section 202(c) of the Federal Power Act during the periods of grid operations described above, including the review and approval of applications by electric generation resources seeking to operate at maximum capacity.

(b) Within 30 days of the date of this order, the Secretary of Energy shall develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy. This methodology shall:

- (i) analyze sufficiently varied grid conditions and operating scenarios based on historic events to adequately inform the methodology;
- (ii) accredit generation resources in such conditions and scenarios based on historical performance of each specific generation resource type in the real time conditions and operating scenarios of each grid scenario; and
- (iii) be published, along with any analysis it produces, on the Department of Energy's website within 90 days of the date of this order.

(c) The Secretary of Energy shall establish a process by which the methodology described in subsection (b) of this section, and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability. This protocol shall additionally:

(i) include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region; and

(ii) prevent, as the Secretary of Energy deems appropriate and consistent with applicable law, including section 202 of the Federal Power Act, an identified generation resource in excess of 50 megawatts of nameplate capacity from leaving the bulk-power system or converting the source of fuel of such generation resource if such conversion would result in a net reduction in accredited generating capacity, as determined by the reserve margin methodology developed under subsection (b) of this section.

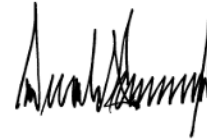
Sec. 4. General Provisions. (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.



THE WHITE HOUSE,
April 8, 2025.

[FR Doc. 2025-06381
Filed 4-11-25; 8:45 am]
Billing code 3395-F4-P

Available at (accessed on 5/27/2025):

<https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid>



U.S. DEPARTMENT
of **ENERGY**

For more information, visit:
energy.gov/topics/reliability

DOE/Publication Number • July, 7 2025

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-25-14
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit MM: Tri-State, *General APEN- Form APCD-200* (Apr. 21, 2025)



General APEN – Form APCD-200

Air Pollutant Emission Notice (APEN) and
Application for Construction Permit

All sections of this APEN form must be completed for both new and existing sources, including APEN updates. The Permit Application/Registration Checklist (Form APCD-100) must also be completed and submitted with this APEN form, unless specifically exempted. Incomplete applications will be rejected and will require re-submittal. *Your application will be rejected if it is filled out incorrectly, is missing information, or lacks payment for applicable fees. The re-submittal will require new payment for applicable fees.*

There may be a more specific APEN for your source (e.g. boiler, mining operations, engines, etc.). A list of all available APEN forms can be found on the Air Pollution Control Division (APCD) website.

This emission notice is valid for five (5) years. Submission of a revised APEN is required 30 days prior to expiration of the five-year term, or when a reportable change is made (significant emissions increase, increase production, new equipment, change in fuel type, etc.). See Regulation No. 3, Part A, II.C. for revised APEN requirements.

Permit Number: 96OPMF155

AIRS ID Number: 081 / 0018 / 001

(Leave blank unless APCD has already assigned a permit # and AIRS ID)

Section 1 - Administrative Information

Company Name¹: Tri-State Generation and Transmission Association, Inc.

Site Name: Craig Station

Site Location: 2101 S. Ranney
Craig CO 81626

Site Location
County: Moffat

NAICS or SIC Code: 4911

Mailing Address:
(Include Zip Code) 1100 W. 116th Avenue
Westminster, CO

Contact Person: Brian Massengale

Phone Number: 303-254-3785

Portable Source
Home Base: NA

E-Mail Address²: brian.massengale@tristategt.org

¹ Use the full, legal company name registered with the Colorado Secretary of State. This is the company name that will appear on all documents issued by the APCD. Any changes will require additional paperwork.

² Permits, exemption letters, and any processing invoices will be issued by the APCD via e-mail to the address provided.

517882

Permit Number: 96OPMF155

AIRS ID Number: 081 / 0018 / 001

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 2 - Requested Action

☐ NEW permit OR newly-reported emission source (check one below)

☐ STATIONARY source

☐ PORTABLE source

- OR -

☐ MODIFICATION to existing permit (check each box below that applies)

☐ Change fuel or equipment

☐ Change company name³

☐ Add point to existing permit

☐ Change permit limit

☐ Transfer of ownership⁴

☐ Other (describe below)

- OR -

☒ APEN submittal for update only (Note blank APENs will not be accepted)

- ADDITIONAL PERMIT ACTIONS -

☐ Limit Hazardous Air Pollutants (HAPs) with a federally-enforceable limit on Potential To Emit (PTE)

☐ APEN submittal for permit exempt/grandfathered source

Additional Info & Notes: Craig Station Unit 1 Boiler

³ For company name change, a completed Company Name Change Certification Form (Form APCD-106) must be submitted.

⁴ For transfer of ownership, a completed Transfer of Ownership Certification Form (Form APCD-104) must be submitted.

Section 3 - General Information

General description of equipment and purpose: Electric Generation

Manufacturer: Babcock & Wilcox

Model No.: NB24157

Serial No.: NA

Company equipment Identification No.
(optional):

B001

For existing sources, operation began on:

1980

For new or reconstructed sources, the projected start-up date is:

NA

☒ Check this box if operating hours are 8,760 hours per year; if fewer, fill out the fields below:

Normal Hours of Source Operation: _____ hours/day _____ days/week _____ weeks/year

Seasonal use percentage: Dec-Feb: _____ Mar-May: _____ Jun-Aug: _____ Sep-Nov: _____

Permit Number: **96OPMF155**

AIRS ID Number: **081 / 0018 / 001**

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 4 - Processing/Manufacturing Information & Material Use

☒ Check box if this information is not applicable to source or process

From what year is the actual annual amount? _____

	Description	Design Process Rate (Specify Units)	Actual Annual Amount (Specify Units)	Requested Annual Permit Limit ⁵ (Specify Units)
Material Consumption:				
Finished Product(s):				

⁵ Requested values will become permit limitations or will be evaluated for exempt status, as applicable, and should consider future process growth. Requested values are required on all APENs, including APEN updates.

Section 5 - Geographical/Stack Information

Geographical Coordinates (Latitude/Longitude or UTM)
13T 280,410 m E 4,482,335 m N

☐ Check box if the following information is not applicable to the source because emissions will not be emitted from a stack. If this is the case, the rest of this section may remain blank.

Operator Stack ID No.	Discharge Height Above Ground Level (Feet)	Temp. (°F)	Flow Rate (ACFM)	Velocity (ft/sec)
S001	600	117	1,838,406	62

Indicate the direction of the stack outlet: (check one)

- ☒ Upward
 ☐ Downward
 ☐ Upward with obstructing raincap
 ☐ Horizontal
 ☐ Other (describe): _____

Indicate the stack opening and size: (check one)

- ☒ Circular Interior stack diameter (inches): **300**

☐ Square/rectangle Interior stack width (inches): _____ Interior stack depth (inches): _____

☐ Other (describe): _____

Permit Number: **96OPMF155**AIRS ID Number: **081 / 0018 / 001**

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 6 - Combustion Equipment & Fuel Consumption Information

☐ Check box if this information is not applicable to the source (e.g. there is no fuel-burning equipment associated with this emission source)

Design Input Rate (MMBTU/hr)	Actual Annual Fuel Use (Specify Units)	Requested Annual Permit Limit ⁵ (Specify Units)
4,318	956,258 tpy	3,900,000 tpy

From what year is the actual annual fuel use data? 2024

Indicate the type of fuel used⁶:

- ☐ Pipeline Natural Gas (assumed fuel heating value of 1,020 BTU/SCF)
- ☐ Field Natural Gas Heating value: _____ BTU/SCF
- ☐ Ultra Low Sulfur Diesel (assumed fuel heating value of 138,000 BTU/gallon)
- ☐ Propane (assumed fuel heating value of 2,300 BTU/SCF)
- ☒ Coal Heating value: 9,763 BTU/lb Ash content: 9.3% Sulfur content: 0.4%
- ☐ Other (describe): _____ Heating value (give units): _____

⁵ Requested values will become permit limitations or will be evaluated for exempt status, as applicable, and should consider future process growth. Requested values are required on all APENs, including APEN updates.

⁶ If fuel heating value is different than the listed assumed value, provide this information in the "Other" field.

Section 7 - Criteria Pollutant Emissions Information

Attach all emission calculations and emission factor documentation to this APEN form.

Is any emission control equipment or practice used to reduce emissions? ☒ Yes ☐ No

If yes, describe the control equipment AND state the collection and control efficiencies:

Pollutant	Control Equipment Description	Collection Efficiency (% of total emissions captured by control equipment)	Control Efficiency (% reduction of captured emissions)
TSP (PM)	Baghouse		99.9
PM ₁₀	Baghouse		99.9
PM _{2.5}	Baghouse		99.9
SO _x	Wet Scrubber		93.7
NO _x	Low NOx Burner/Overfire Air		45-60
CO	None		
VOC	None		
Other:			

Permit Number: **96OPMF155**AIRS ID Number: **081 / 0018 / 001**

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

2024From what year is the following reported *actual annual emissions* data?

Use the following table to report the criteria pollutant emissions from source:
(Use the data reported in Sections 4 and 6 to calculate these emissions.)

Pollutant	Uncontrolled Emission Factor (Specify Units)	Emission Factor Source (AP-42, Mfg., etc.)	Actual Annual Emissions		Requested Annual Permit Emission Limit(s) ⁵	
			Uncontrolled (tons/year)	Controlled ⁷ (tons/year)	Uncontrolled (tons/year)	Controlled (tons/year)
TSP (PM)	0.0100 lb/MMBtu	2024 Stack Test, AP-42		93		NA
PM ₁₀	0.0092 lb/MMBtu	2024 Stack Test, AP-42		86		NA
PM _{2.5}	0.0053 lb/MMBtu	2024 Stack Test, AP-42		49		NA
SO _x	Measured	CEMS		335		NA
NO _x	Measured	CEMS		2,176.6		NA
CO	0.5 lb/ton	AP-42	239			NA
VOC	0.0002 lb/MMBtu	1999 Stack Test, AP-42	2			NA
Other:						

⁵ Requested values will become permit limitations or will be evaluated for exempt status, as applicable, and should consider future process growth. Requested values are required on all APENs, including APEN updates.

⁷ Annual emission fees will be based on actual controlled emissions reported. If source has not yet started operating, provide projected emissions.

Section 8 - Non-Criteria Pollutant Emissions Information

Does the emissions source have any uncontrolled actual emissions of non-criteria pollutants (e.g. HAP - hazardous air pollutant) equal to or greater than 250 lbs/year?

☒ Yes☐ No

If yes, use the following table to report the non-criteria pollutant (HAP) emissions from source:
(Use the data reported in Sections 4 and 6 to calculate these emissions.)

CAS Number	Chemical Name	Overall Control Efficiency	Uncontrolled Emission Factor (Specify Units)	Emission Factor Source (AP-42, Mfg., etc.)	Uncontrolled Actual Emissions (lbs/year)	Controlled Actual Emissions ⁷ (lbs/year)
7782505 / 7440-02-0	Chlorine / Nickel		518 lb/TBtu / 1.4E-4 lb/MMBtu	2000 Stack Test / 2010 Test	10,168 / 2,748	
7440-47-3 / 75-09-2	Chromium / Methylene Chloride		2.08 E-4 lb/MMBtu / 18.9E-6 lb/TBtu	2010 Stack Test / EPRI	4,083 / 371	
57-12-5 / 7664-93-9	Cyanide / Sulfuric Acid		2.5 E-3 lb/ton / 7E-4 lb/MMBtu	AP-42 / 2009 Stack Test	2,391 / 13,070	
7647-01-0	Hydrogen Chloride		5.5 E-5 lb/MMBtu	2009 Stack Test	1,080	
7664-39-3	Hydrogen Fluoride		2.07 E-4 lb/MMBtu	2009 Stack Test	4,063	
7439-96-5	Manganese		3.67E-4 lb/MMBtu	2010 Stack Test	7,204	

⁷ Annual emission fees will be based on actual controlled emissions reported. If source has not yet started operating, provide projected emissions.

Permit Number: **96OPMF155**

AIRS ID Number: **081 / 0018 / 001**

[Leave blank unless APCD has already assigned a permit # and AIRS ID]

Section 9 - Applicant Certification

I hereby certify that all information contained herein and information submitted with this application is complete, true, and correct.

DocuSigned by:

Jerome Sturhahn

4/21/2025

AFBDE2F9ADE741B...

Signature of Legally Authorized Person (not a vendor or consultant)

Date

Jerome H. Sturhahn

Senior Vice President, General Counsel

Name (print)

Title

Check the appropriate box to request a copy of the:

- ☐ Draft permit prior to issuance
☐ Draft permit prior to public notice

(Checking any of these boxes may result in an increased fee and/or processing time)

This emission notice is valid for five (5) years. Submission of a revised APEN is required 30 days prior to expiration of the five-year term, or when a reportable change is made (significant emissions increase, increase production, new equipment, change in fuel type, etc.). See Regulation No. 3, Part A, II.C. for revised APEN requirements.

Send this form along with \$242.00 to:

Colorado Department of Public Health and Environment
Air Pollution Control Division
APCD-SS-B1
4300 Cherry Creek Drive South
Denver, CO 80246-1530

For more information or assistance, contact:

Small Business Assistance Program
cdphe_apcd_sbap@state.co.us

APCD Main Phone Number
(303) 692-3100

Make check payable to: **Colorado Department of Public Health and Environment**

Alternatively, payment can be provided online, by credit card or electronic check, via the [APCD Payment Portal](#).

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-25-14
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit N: Motion to Intervene and Protective Request for Rehearing by the Attorneys
General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado,
Connecticut, and New York, filed on August 6, 2025 with the Department

BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

In re: Resource Adequacy Report: Evaluating
the Reliability and Security of the United
States Electric Grid, July 2025

Submitted via e-mail to:
AskCR@hq.doe.gov
August 6, 2025

**Motion to Intervene and Protective Request for Rehearing by the Attorneys General of
Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut,
and New York**

The Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York (“the States”) make this filing to raise our concerns with the Department of Energy’s (“Department” or “DOE”) report titled *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, published July 7, 2025 (“Report”),¹ and request rehearing of the same.

Given that DOE has not yet applied the report to issue future emergency orders, the States do not concede that the Federal Power Act requires the States to request rehearing at this time.² Still, the States acknowledge that President Trump instructed DOE to use the methodology in this report as part of a “protocol” to issue orders pursuant to Section 202(c) of the Federal Power Act preventing the retirement of power plants identified as critical to reliability in DOE’s report.³ DOE has indicated that it intends to comply with that mandate and use this Report to “guide reliability interventions” and issue Section 202(c) emergency orders.⁴ The States reserve all rights to present these objections, or any other objection or legal challenge to the Report or DOE’s reliance on this report going forward. However, out of an abundance of caution and to preserve their arguments, the States also formally request rehearing of the methodology,

¹ Available at https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29_0.pdf [https://perma.cc/J2XU-2RRJ].

² See 16 U.S.C. § 825l.

³ See Exec. Order No. 14,262, 90 Fed. Reg. 15,521 (Apr. 14, 2025).

⁴ See U.S. DEP’T OF ENERGY, *Fact Sheet: The Department of Energy’s Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025), https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf [https://perma.cc/YLX7-8G7T] (explaining that DOE’s methodology will be used, pursuant to the executive order, “prevent [] generation resources from leaving the bulk-power system”); Press Release, U.S. Dep’t of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security (July 7, 2025), <https://www.energy.gov/articles/departments-energy-releases-report-evaluating-us-grid-reliability-and-security> [https://perma.cc/8TEJ-AGH6]. (stating that its “methodology also informs the potential use of DOE’s emergency authority under Section 202(c) of the Federal Power Act”); Report at vi (explaining that DOE’s standard will be used to “guide reliability interventions”), 1 (emphasizing the need for DOE’s “decisive intervention” in energy markets), 10 (analyzing ERCOT because “FPA Section 202(c) allows DOE to issue emergency orders to ERCOT”).

standards, and protocol identified in this Report under Section 313l of the Federal Power Act, 16 U.S.C. § 825l.

This filing details the ways in which the Report is arbitrary and why it would be unlawful to rely on it to justify future Section 202(c) orders. The States also request DOE review the Report independently before it is used in any capacity in order to address the serious errors in the analysis highlighted here.

I. Motion to Intervene

The Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York move to intervene in this proceeding pursuant to Section 313l of the Federal Power Act, 16 U.S.C. § 825l, and request that the Department of Energy grant rehearing of its July 7, 2025 report titled *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*.

Executive Order 14262 and DOE's own statements alongside the Report's publication indicate that it will be used to "guide reliability interventions" and justify issuance of emergency orders under Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c). The Report is deeply flawed and, if DOE is taken at its word, it will inflict significant harm on our states.

Many of the retiring resources targeted by this report are located in our states. In Washington, for example, the Transalta Centralia coal-fired power plant is scheduled to retire in December 2025. In Colorado, the Craig and Comanche coal-fired power plants are scheduled to retire by the end of the year as well and the state's remaining coal fired power plants are scheduled to retire by 2031. These retirements have been thoroughly vetted by state and regional authorities and approved only following an extensive examination of cost considerations and reliability impacts.

And even when a source is not located directly in one of our states, the ratepayer impacts of overriding a planned retirement based on the DOE Report will often be felt by our residents. That is because many of these resources operate within regional transmission systems that spread costs across all, or a portion of, their footprint. In MISO, for example, ratepayers across the ISO's north and central regions are being asked to foot the bill for the continued operation of the J.H. Campbell coal-fired power plant in Michigan pursuant to a Section 202(c) order issued by DOE in May. In just five weeks, complying with that Order has cost the plant's owner \$29 million.⁵ The order is expected to cost consumers close to \$100 million if it expires on August 21 and is not renewed.⁶

⁵ See CMS Energy Corp., Quarterly Report (Form 10-Q) (Jul. 31, 2025), <https://www.sec.gov/ix?doc=/Archives/edgar/data/0000201533/000081115625000071/cms-20250630.htm>.

⁶ Brian Dabbs, *Coal Plant Ordered to Stay Open Cost \$29M to Run in 5 Weeks*, POLITICO ENERGYWIRE (Aug. 1, 2025), <https://subscriber.politicopro.com/article/eenews/2025/08/01/coal-plant-ordered-to-stay-open-cost-29m-to-run-in-5-weeks-00487542>.

Our states are also harmed when Section 202(c) is used to keep polluting facilities from retiring in upwind locations. Fossil-fuel power plants are large sources of ozone-forming pollution and toxic emissions that contribute to nonattainment of air quality standards in downwind states like Connecticut, New York, and Maryland. Planned retirements have the benefit of reducing this pollution and overriding those state and regional determinations based on the DOE Report will further the harm that downwind states face from upwind sources.

Moreover, the report unlawfully intrudes on the states' authority to regulate generation resources within their borders. Section 201 of the Federal Power Act clearly reserves to the states their traditional authority "over facilities used for the generation of electric energy."⁷ That authority "is a matter that has traditionally rested with the states, and it should continue to rest there."⁸

Both EO 14262 and subsequent statements by DOE make clear that the report will be used to justify Section 202(c) orders going forward.⁹ The States are aggrieved by the report which paints an unrealistic picture of resource adequacy to justify use of DOE emergency authority. Exercising that authority in non-emergency situations will harm ratepayers and the environment and unlawfully infringe on an area of state sovereign authority. Moreover, our states are also purchasers of retail electricity and are directly harmed by the rate impacts from these decisions.

II. Background

a. Resource adequacy is highly regulated at the state and regional levels.

Existing regulatory mechanisms govern both federal requirements for reserve margins and state resource adequacy determinations. Resource adequacy is an integral part of prudent, least-cost, utility planning in every state and region of the country.¹⁰ DOE plays no role in the complex proceedings to determine either reserve margins or specific resource adequacy conclusions. The Report fails to grapple with the complicated task of resource adequacy planning undertaken by state utility offices and regional grid planners across the country, yet these existing procedures are a key part of the alleged resource adequacy conundrum which the DOE Report claims to address.

⁷ 16 U.S.C. § 824(b)(1).

⁸ *Devon Power LLC et al.*, 109 FERC ¶ 61,154, para. 47 (Nov. 8, 2004).

⁹ See U.S. Dep't of Energy, Order No. 202-25-4 (May 30, 2025) [<https://perma.cc/PS3M-6CJA>] [*hereinafter* "Eddystone Order"] (The methodology "will be used to establish a protocol to identify which generation resources within a region are critical to system reliability and prevent identified generation resources from leaving the bulk power system. . . . DOE plans to use [the July 7] methodology to further evaluate Eddystone Units 3 and 4.").

¹⁰ See SYNAPSE ENERGY ECONOMICS & LAWRENCE BERKELEY NATIONAL LABORATORY, BEST PRACTICES IN INTEGRATED RESOURCE PLANNING 1-2 (Nov. 2024), https://www.synapse-energy.com/sites/default/files/IRP_Best_Practices_2024_Synapse_LBNL_24-061_1.pdf [<https://perma.cc/D68F-WHWQ>].

i. States directly regulate resources to ensure an adequate supply of electricity.

Most states rely on resource planning processes to ensure that adequate generation is available to meet projected demand. While some states have largely delegated this authority to the regional grid operators and rely on market-based mechanisms to ensure future demand is met, it is ultimately the state that retains regulatory authority over generation resources.¹¹ These state processes are transparent and iterative, relying on technical and expert analysis to ensure that adequate resources are procured in a prudent manner. The States describe just a few of the mechanisms at play in our jurisdictions as relevant examples below.

1. Arizona

Arizona, like other states, regulates the power generation, transmission, and distribution needs of the electric grid to ensure resource adequacy and reliability. This regulatory authority is established in the State's constitution. The Arizona Constitution grants the Arizona Corporation Commission ("ACC") broad authority to regulate public service corporations, including electric utilities.¹² The Arizona Constitution also empowers the ACC to set just and reasonable classifications, rates, and charges, as well as to make and enforce rules, regulations, and orders for the governance of utilities. This constitutional authority underpins the ACC's ability to establish requirements for resource planning and grid reliability.¹³

The ACC has reliability requirements in its Resource Planning and Procurement ("RPP") rules.¹⁴ The ACC's RPP rules require load-serving entities to file and seek acknowledgement of their prospective, 15-year resource plans every three years, which include projected data for generating units and power supply systems, capital costs, environmental impacts, and cost analyses.

The most recent version of Integrated Resource Plans was authorized by the ACC on October 21, 2024,¹⁵ which approved the power generation, transmission, and distribution acquisition plans that were submitted by Arizona Public Service,¹⁶ Tucson Electric Power,¹⁷ and UNS Electric.¹⁸ The ACC requires similar data from its electric cooperatives in order to improve

¹¹ 16 U.S.C. § 824(b)(1).

¹² ARIZ. CONST. art. 15, § 3.

¹³ *Id.*

¹⁴ A.A.C. R14-2-701.

¹⁵ ACC Decision No. 79589, <https://docket.images.azcc.gov/0000212120.pdf?i=1754080707112>.

¹⁶ ARIZONA PUBLIC SERVICE, *2023 Integrated Resource Plan* (Nov. 1, 2023), <https://docket.images.azcc.gov/E000031965.pdf?i=1754080707112>.

¹⁷ TUCSON ELECTRIC POWER, *Tucson Electric Power 2024 Integrated Resource Plan* (Nov. 1, 2023), <https://docket.images.azcc.gov/E000031960.pdf?i=1754080707112>.

¹⁸ UNS ELECTRIC, *UNS Electric 2023 Integrated Resource Plan* (Nov. 1, 2023), <https://docket.images.azcc.gov/E000031961.pdf?i=1754080707112>.

grid performance and reliability in rural areas of the state.¹⁹ The decision requires technology-neutral portfolio methodologies, annual load forecast accuracy reports, and analysis of coal-fired power plant retirement timelines to enhance reliability, building on existing triannual utility analyses. It also requires sharing modeling data with stakeholders.

While one major utility in Arizona, the Salt River Project, is not subject to the ACC’s jurisdiction, it has adopted its own planning and goal-setting requirements, referred to as the Integrated System Plan.²⁰

2. New York

The New York Independent System Operator (“NYISO”) plays a significant role in safeguarding electric grid reliability while supporting the clean energy transition.²¹ As part of its biennial reliability planning process, NYISO first conducts a Reliability Needs Assessment, which examines whether New York’s power grid will have enough generation, storage, and transmission capacity to meet demand over the next ten years.²² Specifically, the Assessment uses probabilistic simulations to evaluate whether New York meets the Loss of Load Expectation (LOLE) criterion of not more than 0.1 event-days/year (equivalent to one day in ten years), which is the standard reliability criterion used by the New York State Reliability Council and the Northeast Power Coordinating Council.²³ The Assessment also evaluates how New York’s environmental and energy laws—such as the Climate Leadership and Community Protection Act, which requires 100% zero-emission electricity by 2040—will affect grid reliability, especially as fossil fuel-fired power plants retire, and electricity demand increases due to building electrification and the continued growth of the electric vehicle market.²⁴

Following the Reliability Needs Assessment, NYISO completes the biennial planning process by issuing a Comprehensive Reliability Plan that documents the plans for a reliable electric grid over the same ten years.²⁵ The Comprehensive Reliability Plan provides solutions to any shortfalls identified in the Reliability Needs Assessment, such as accelerating battery deployment, deferring certain retirements, upgrading transmission lines, or increasing demand-side participation.²⁶ While the 2022 Reliability Needs Assessment did not identify any actionable

¹⁹ ARIZONA ELECTRIC POWER COOPERATIVE, *Demand-and Supply-Side Data Filing* (Apr. 1, 2025), <https://docket.images.azcc.gov/E000042810.pdf?i=1753996193952>.

²⁰ SALT RIVER PROJECT, *Integrated System Plan* (Apr. 1, 2025), <https://www.srpnet.com/grid-water-management/future-planning/integrated-system-plan>.

²¹ See *About Us*, NYISO, <https://www.nyiso.com/about-us>.

²² See NYISO, 2024 RELIABILITY NEEDS ASSESSMENT (Nov. 19, 2024), <https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf>.

²³ *Id.* at 41.

²⁴ *Id.* at 23-24 fig. 13.

²⁵ See NYISO, 2023–2032 COMPREHENSIVE RELIABILITY PLAN (Nov. 28, 2023), <https://www.nyiso.com/documents/20142/2248481/2023-2032-Comprehensive-Reliability-Plan.pdf> (following the 2022 RNA and incorporating finding and solutions from the quarterly short term reliability process).

²⁶ See *id.*

reliability shortfalls, the 2023–2032 Comprehensive Reliability Plan nonetheless provided a forward-looking analysis that evaluated key risk factors related to reliability, including delays in major transmission projects, winter peaking and gas shortage risks, and extreme weather.²⁷

In parallel with the biennial reliability planning process, as of 2019, NYISO also conducts a quarterly short-term reliability (“STAR”) process to identify reliability needs that may arise over the next five years due to various changes in the grid, such as generator deactivations, revised transmission plans, or updated electricity demand.²⁸ For example, NYISO’s Quarter 2 2023 STAR report, published on July 14, 2023, identified the potential for electricity supply shortfalls in New York City beginning in the summer 2025 as a result of the New York State Department of Environmental Conservation’s “Peaker Rule,” which seeks to reduce nitrogen oxide (NO_x) emissions from simple-cycle combustion turbines that supply backup generation during peak demand.²⁹ Following this STAR report, NYISO sought proposed solutions from market participants and ultimately exercised its authority under the Peaker Rule to require specific peaker units to remain operational until long-term solutions—such as the Champlain Hudson Power Express line, scheduled to enter service in spring 2026, bringing 1,250 MW of hydropower to New York City—could come online.³⁰ NYISO incorporates any needs or shortfalls identified in the STAR process into its biennial reliability planning process.³¹

3. Connecticut

Connecticut General Statutes § 16a-3a requires that the Department of Energy and Environmental Protection (“DEEP”) prepare an Integrated Resource Plan (“IRP”). An IRP is composed of an assessment of the future electric needs and a plan to meet those future needs. It is “integrated” in that it looks at both demand side (conservation, energy efficiency, etc.) resources as well as the more traditional supply side (generation/power plants, transmission lines, etc.) resources in making its recommendations on how best to meet future electric energy needs in the state. Connecticut’s current IRP was completed in 2020 and updated in 2022. DEEP is currently developing the 2025 IRP, which involves planning for the next ten years.

²⁷ *Id.* at 48-67.

²⁸ See *Short-Term Reliability Process*, NYISO, <https://www.nyiso.com/short-term-reliability-process> (last visited July 28, 2025); *Reliability Planning Process and Declaring a Reliability Need: Next Steps*, NYISO (July 14, 2023), <https://www.nyiso.com/-/reliability-planning-process-and-declaring-a-reliability-need-next-steps>.

²⁹ NYISO, *Short-Term Assessment of Reliability: 2023 Quarter 2* (July 14, 2023), <https://www.nyiso.com/documents/20142/16004172/2023-Q2-STAR-Report-Final.pdf/5671e9f7-e996-653a-6a0e-9e12d2e41740>.

³⁰ Press Release, NYISO, *NYISO Identifies Solution to Solve New York City Reliability Need* (Nov. 20, 2023), <https://www.nyiso.com/-/press-release-%7C-nyiso-identifies-solution-to-solve-new-york-city-reliability-need>.

³¹ See NYISO, 2023–2032 COMPREHENSIVE RELIABILITY PLAN, *supra* note 25, at 30–32.

4. Colorado

Colorado regulations require every investor-owned retail electric utility and wholesale electric generation and transmission cooperative operating in the state to file an energy resource plan (“ERP”) with the Public Utilities Commission (“PUC”) every four years.³² ERPs must contain electric demand and energy forecasts, evaluation of existing resources, an assessment of planning reserve margins and contingency plans for the acquisition of additional resources.³³ If an ERP includes retirement of an existing coal-fired generating facility, detailed workforce transition and community assistance plans must be filed.³⁴

The planning process includes a reserve margin to meet a 0.1 days per year loss of load expectation standard.³⁵ Utilities use this reserve margin to propose additional generation for the planning period, where necessary. Those proposals are vetted through extensive stakeholder input and consideration by the Colorado PUC and the additional generation must satisfy availability and dispatchability criteria.³⁶ And where generation needs arise outside of the four-year ERP process, interim ERPs and applications for certificates of public convenience and necessity can be filed to meet those needs.³⁷ These proceedings are transparent and iterative and conducted with technical and expert analysis of grid conditions and ratepayer impacts.

5. Illinois

Illinois ratepayers are served by two Regional Transmission Organizations (“RTO”), Midcontinent Independent System Operator, Inc. (“MISO”) and PJM Interconnection, L.L.C. (“PJM”). Central and Southern Illinois are encompassed by MISO Local Resource Zone 4 and a small portion of Northwest Illinois is included in MISO Local Resource Zone 1.³⁸ The service area of Commonwealth Edison Company, the load serving entity for Illinois electricity customers in Northern Illinois, is encompassed by PJM’s ComEd Zone.³⁹ The Illinois Attorney General’s office represents Illinois ratepayers who have a significant interest in resource adequacy and maintaining reliable service at least possible cost that is materially affected by the outcome of this proceeding.

³² 4 COLO. CODE REGS. § 723-3-3603(a).

³³ 4 COLO. CODE REGS. § 723-3-3604(b-f).

³⁴ COLO. REV. STAT. § 40-2-125.5(4)(a)(VII).

³⁵ See Colo. Pub. Utils. Comm’n Proceeding No. 24A-0422E, HE 109 and HE 109 ZM-1; Colo. Pub. Utils. Comm’n Proceeding No. 21A-0141E, Hrg. Exh. 115, pp. 8-10.

³⁶ COLO. REV. STAT. § 40-2-125.5 (4)(d)(II).

³⁷ *Id.*

³⁸ See MISO Tariff, Attachment VV, Map of Local Resource Zone Boundaries, https://docs.misoenergy.org/miso12-legalcontent/Attachment_VV_-_MAP_of_Local_Resource_Zone_Boundaries.pdf.

³⁹ See MISO Tariff, Attachment VV, Map of Local Resource Zone Boundaries, https://docs.misoenergy.org/miso12-legalcontent/Attachment_VV_-_MAP_of_Local_Resource_Zone_Boundaries.pdf.

6. Washington

Washington electric utilities file clean energy implementation plans to the Washington Utilities and Transportation Commission once every four years with a biennial update filing at the midway point of every plan.⁴⁰ They also file long term integrated resource plans every four years.⁴¹ For investor-owned utilities, if an integrated resource plan identifies a resource need within the next four years, the utility must file a request for proposal with the Commission for approval.⁴²

7. Michigan

In Michigan, ratepayers are served primarily by MISO, with a smaller portion included within PJM. In MISO, the regulation of resource adequacy planning has both a state and federal aspect. MISO member states have a capacity obligation under the MISO tariff. MISO's resource adequacy requirements, however, are designed to be complementary to the primary role of the states in ensuring resource adequacy.⁴³ In Michigan, the investment decisions of utilities are regulated by the Michigan Public Service Commission ("MI PSC"). Through Michigan's state Integrated Resource Planning process, the MI PSC exercises regulatory authority over utilities in order to ensure that the utilities obtain the amounts of capacity they need to meet their obligations under the MISO tariff, and that they do so at the best value to ratepayers, and with a composition of resources that otherwise complies with state law, including environmental requirements.

Michigan's IRP statute requires electric utilities whose rates are regulated by the MI PSC to periodically file an integrated resource plan. The IRP is a projection of the utility's load obligations and a plan to meet those obligations.⁴⁴ The IRP statute directs the MI PSC to approve

⁴⁰ See WASH. REV. CODE § 19.405.060; WASH. ADMIN. CODE § 480-100-640, -645; *see also* WASH. UTILS. AND TRANSP. COMM'N, *Clean Energy Implementation Plans*, <https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act/clean-energy-implementation-plans-ceips>.

⁴¹ See WASH. REV. CODE § 19.280.040 to 050; WASH. ADMIN. CODE § 480-100-620, -625; *see also* WASH. UTILS. AND TRANSP. COMM'N, *Integrated Resource Plans*, <https://www.utc.wa.gov/integrated-resource-plans-irps>.

⁴² See WASH. ADMIN. CODE § 480-107-009(2), -017.

⁴³ *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215, 62,606 at P 13 (2020) ("approximately 90% of the load in MISO is served by vertically integrated LSEs, the vast majority of which are subject to state integrated resource planning processes. To accommodate the make-up of the MISO's footprint, MISO's proposed Tariff provisions accepted in the February 2018 Order provide that its resource adequacy requirements "are complementary to the reliability mechanisms of the states and the Regional Entities ... within the [MISO] region."); *see also id.* ("MISO's proposed Tariff language explains that the resource adequacy requirements 'are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction.' In other words, unlike the centralized capacity constructs used in the Eastern RTOs/ISOs, MISO's Auction is not—and has never been—the primary mechanism for its [Load Serving Entities] to procure capacity."); *Midwest Indep. Transmission Sys. Operator, Inc.*, 119 FERC ¶ 61,311, 62,722 at P 75 (2007) ("From the beginning . . . the Commission has recognized the role that state resource planning plays in managing the resource adequacy of [MISO]").

⁴⁴ MICH. COMP. LAWS § 460.6t(3).

a plan if the MI PSC determines that it “represents the most reasonable and prudent means of meeting the electric utility’s energy and capacity needs.”⁴⁵ To make that decision, the statute instructs the MI PSC to consider whether the IRP appropriately balances seven statutory factors: (i) resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement; (ii) compliance with applicable state and federal environmental regulations; (iii) competitive pricing; (iv) reliability; (v) commodity price risks; (vi) diversity of generation supply; and (vii) whether proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective.⁴⁶

The IRP statute also directs the MI PSC to establish – among other things – computer modeling scenarios that must be used to analyze the costs of possible plans in an IRP, including costs associated with plant retirement dates.⁴⁷ In Consumers Energy’s 2021 IRP, for example, the company conducted modeling that compared other possible retirement dates of its J.H. Campbell coal-fired power plant to a 2025 retirement and concluded that the most cost-effective retirement date was 2025.

8. Minnesota

Since 1991, Minnesota law has required each public utility to propose a set of resource options that the utility could use to meet the electricity service needs of its customers over a forecast period of 15 years.⁴⁸ The resource options include using, refurbishing and constructing utility plant and equipment, buying power generated by other entities, controlling customer loads, and implementing customer energy conservation. The Minnesota Public Utilities Commission (“Minnesota Commission”) evaluates the plan’s ability to ensure reliability of utility service, keep customer’s bills and utility rates as low as practicable, minimize adverse socioeconomic effects and adverse effects on the environment, and limit risk.⁴⁹ The Commission uses an extensive notice and comment process in which the utilities and stakeholders evaluate detailed modeling of demand and various resource costs. The Minnesota Commission may approve, reject or modify utility resource plans.⁵⁰ In the most recent resource plan for Minnesota’s largest utility, the Minnesota Commission approved including in the resource plan a new natural-gas fired 420 MW combustion turbine plant to address peak load.⁵¹

⁴⁵ MICH. COMP. LAWS § 460.6t(8)(a).

⁴⁶ *Id.*

⁴⁷ MICH. COMP. LAWS § 460.6t(1).

⁴⁸ MINN. STAT. § 216B.2422; MINN. R. ch. 7843; *see also Electric Integrated Resource Planning (IRP)*, MINN. PUB. UTILS. COMM’N, <https://mn.gov/puc/activities/economic-analysis/planning/irp/> (last accessed Aug. 6, 2025).

⁴⁹ MINN. R. 7843.0600, subp. 3.

⁵⁰ MINN. STAT. § 216B.2422.

⁵¹ MINN. PUB. UTILS. COMM’N, Dkt. No. E-002/RP-24-67; E-002/CN-23-212, Order Approving Settlement Agreement With Modifications (Apr. 21, 2025), <https://www.edockets.state.mn.us/documents/%7B30F45996-0000-CF1F-80E3-5E41B2F16918%7D/download?contentSequence=0&rowIndex=3>.

ii. Regional operators establish mechanisms to ensure resource adequacy and grid stability.

State primacy over resource adequacy is further complemented by the regional transmission operators. For example, MISO and PJM both have extensive processes for obtaining resource adequacy and reliability. MISO works collaboratively with its member states to ensure resource adequacy throughout its service area.⁵² MISO ensures there is sufficient generation capacity through forecasting demand growth, assessing existing generation assets, and planning for new generation resources.⁵³ MISO accounts for state Integrated Resource Planning and also operates a capacity auction where utilities and other load-serving entities can procure the necessary generation capacity to meet projected demand. MISO's capacity market is intended to incentivize the development and maintenance of adequate generation resources.⁵⁴ MISO's annual Planning Resource Auction ("PRA") procures sufficient resources and allows market participants to buy and sell capacity via the auction.⁵⁵

Resource adequacy within the PJM footprint is subject to an established, extensive, layered, framework of oversight and regulation. The resource adequacy contribution of each PJM electric generating plant operating is subject to ongoing, technical reviews by PJM, pursuant to its tariff, and in conformity with rules promulgated and periodic grid reliability reviews conducted by Reliability First Corporation and NERC, respectively.⁵⁶ PJM also conducts an auction, its base residual auction ("BRA"), for the procurement of capacity from generating resources.

b. Historic use of 202(c) is limited.

Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c), grants the Secretary of Energy the authority to issue orders that require the "temporary connection[]" of power plants and the "generation, delivery, interchange, or transmission of electric energy" in order to address certain emergencies "and serve the public interest."⁵⁷ The law also effectively waives compliance with "any Federal, State, or local environmental law or regulation" that would conflict with any

⁵² *System Planning*, MISO, https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/grid_planning_basics/ (last visited July 30, 2025).

⁵³ *Id.*

⁵⁴ *Id.*

⁵⁵ *Resource Adequacy*, MISO, <https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc> (last visited July 30, 2025).

⁵⁶ *See, e.g., North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009); Order No. 748, Final Rule, 134 FERC ¶ 61,213 (2011). FERC approved regional reliability standards applicable to PJM, developed by RFC and submitted to FERC by NERC. *Notice of Proposed Rulemaking on Plan. Res. Adequacy Assessment Reliability Standard*, 133 FERC ¶ 61,066 (2010) (proposed rule for RFC); *Plan. Res. Adequacy Assessment Reliability Standard*, Order No. 747, 134 FERC ¶ 61,212 (2011) (final approval of RFC's Resource Adequacy Reliability Standard).

⁵⁷ 16 U.S.C. § 824a(c)(1).

party's obligations under such an order, but limits the length of any order that conflicts with a pollution control requirement to 90-days, with extension possible.⁵⁸

That authority originated principally as a wartime power of what was then the Federal Power Commission. Section 202(c) was enacted in 1935, in the leadup to World War II, with the same “emergency” language that exists in the statute today, specifically to guard against energy related shortages that were viewed as hampering national security during World War I.⁵⁹ It was initially used largely to issue “interconnection” orders specifically between utilities at a time when America’s electric grid was more fragmented, monopolized, and less diversified than it is today.⁶⁰ Interconnection was seen as a powerful means to increase grid reliability, but the federal government largely lacked regulatory power over the electric sector at the time.⁶¹ The then-Federal Power Commission did not invoke its emergency authority until the United States entered World War II.⁶² Section 202(c) orders were issued repeatedly during the war, primarily to order interconnection between utilities, but the provision was rarely invoked once the war ended. A number of organizational changes ensued in the decades following the War and the provision’s authority eventually came to rest with the Secretary of Energy.⁶³

From 2000, when the authority of Section 202(c) was “rediscovered” in response to the California Energy Crisis, through 2024, the provision was sparingly invoked to respond to true emergencies to avoid imminent widespread blackouts.⁶⁴ Most 202(c) orders issued during this period involved natural disasters or other acute power outages.⁶⁵ These emergencies included one high-profile incident near the nation’s capital that led to the statute’s 2015 amendment, adding the provisions explicitly waiving environmental liability due to compliance with a Section 202(c) order, leading the statute to read as it does today.⁶⁶ Orders issued during this period were typically of limited duration, lasting for a period of days to weeks.⁶⁷

The typical process for issuing a Section 202(c) order is outlined by DOE implementing regulations at 10 C.F.R. §§ 205.370-379. In the normal course, requests for Section 202(c) orders originate with a grid operator or utility facing an acute and unforeseen emergency that normal processes and demand response mechanisms are incapable of addressing, though they may be issued by the Department unprompted as well.⁶⁸ Applications for Section 202(c) orders made by

⁵⁸ *Id.* at § 824a(c)(3)-(4).

⁵⁹ For a deeper discussion of the history of Section 202(c), see Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789 (2025). *See also id.* at 798-802.

⁶⁰ *Id.* at 802-804.

⁶¹ *Id.* at 801-802.

⁶² *See id.* at 803 n.82 and accompanying text.

⁶³ *Id.* at 803-04; 42 U.S.C. § 7151(b).

⁶⁴ *Id.* at 805-509.

⁶⁵ Rolsma, *supra* note 59, at 805-09, 839-42 tbl.1.

⁶⁶ *Id.* at 806-08 (citing DEP’T OF ENERGY, ORDER NO. 202-05-3 (Dec. 20, 2005)); 16 U.S.C. § 824a(c)(3)-(5).

⁶⁷ *See* Rolsma, *supra* note [x], at 839-42 tbl.1 (chronicling all Section 202(c) orders issued “after dissolution of the Federal Power Commission”).

⁶⁸ *See* 10 C.F.R. § 205.370.

outside entities are to include specific details to “be considered by the DOE in determining that an emergency exists” and the appropriate intervention.⁶⁹ This information is supposed to include “[d]aily peak load and energy requirements for each of the past 30 days and projections for each day of the expected duration of the emergency,” “[a] description of the situation and a discussion of why this is an emergency, ... includ[ing] any contingency plan of the applicant and the current level of implementation,” and “[a] description of efforts made to obtain additional power through voluntary means and the results of such efforts.”⁷⁰ Section 202(c) orders bypass environmental review under NEPA and can waive pollution control requirements that would otherwise apply to the facilities.⁷¹

c. President Trump Declares a National Energy Emergency on his first day in office and subsequently issues EO 14262.

On January 20, 2025, his first day in office, President Trump issued Executive Order 14156 titled “Declaring a National Energy Emergency”.⁷² That unilateral declaration did not provide any factual support for its assertion that emergency conditions had overtaken the electricity grid.⁷³

On April 8, 2025, President Trump issued Executive Order 14262, “Strengthening the Reliability and Security of the United States Electric Grid.”⁷⁴ Section 3(b) of the executive order directs the Secretary of Energy (Secretary) to:

develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy.⁷⁵

It further requires that the methodology in the Report (Methodology) “be published, along with any analysis it produces, on the Department of Energy’s website within 90 days of the date of this order,” or July 7, 2025.⁷⁶

The Executive Order describes the featured role that the Report will play in future DOE actions. EO 14262 § 3 is titled “Addressing Energy Reliability and Security with Emergency Authority” and § 3(c) directs the Secretary to “establish a process by which the [Methodology],

⁶⁹ 10 C.F.R. § 205.373.

⁷⁰ 10 C.F.R. §§ 205.373(a)-(o).

⁷¹ *See, e.g., Environmental Integrity Project v. DOE*, 471 F. Supp. 3d 132 (D.D.C. 2023).

⁷² 90 Fed. Reg. 8433.

⁷³ *See Id.* (providing no factual support for claimed emergency). Many of the States have since joined litigation challenging that declaration. *See Complaint, Washington v. Trump*, NO. 2:25-cv-00869 (W.D. Wa. May 9, 2025).

⁷⁴ The EO was signed alongside Exec. Order No. 14261, Reinvigorating America’s Beautiful Clean Coal Industry and Amending Executive Order 14241, 90 Fed. Reg. 15517 (Apr. 8, 2025), at a White House event with members of the coal industry.

⁷⁵ Exec. Order No. 14262, 90 Fed. Reg. 15521, 15521 (Apr. 8, 2025).

⁷⁶ Exec. Order No. 14262, 90 Fed. Reg. 15521, 15521 (Apr. 8, 2025) (referring to § 3(b)(iii)).

and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability.”⁷⁷ It indicates the protocol shall “include all mechanisms available under applicable law, including Section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region.”⁷⁸ In short, Executive Order 14262 instructs DOE to publish a methodology by July 7, 2025 that will form the basis for future exercises of its Section 202(c) authority.

d. DOE’s 2025 Emergency Orders Preventing the Retirement of Fossil Fuel Power Plants.

Since January 20, 2025, the U.S. Department of Energy (DOE) has issued five emergency orders under Section 202(c) of the Federal Power Act (FPA), a sharp uptick from the less than one order per year issued on average from 2017-2024.⁷⁹ Three of these orders were largely in line with DOE’s historic Section 202(c) practice – allowing units to modify their operations in response to acute risks to the grid.⁸⁰ However, in late May 2025 DOE issued a pair of Section 202(c) orders requiring facilities that were slated to retire the very next business day to remain on-line. These orders represent a marked shift in how Section 202(c) has historically been used.⁸¹

For example, the orders for the J.H. Campbell Generating Station in Michigan and the Eddystone Plant in Pennsylvania, both previously slated for retirement, cited general concerns about resource adequacy and not any acute emergency. In Michigan, regulators warned that the Campbell order would place upward pressure on ratepayers, particularly in Consumers Energy’s service territory, where decommissioning costs were already being recovered through base rates. One Michigan regulator estimated that the costs of complying with DOE’s order for 90 days would approach \$100 million.⁸² Consumers Energy has since disclosed that continued operation

⁷⁷ Exec. Order No. 14262, 90 Fed. Reg. 15521, 15522 (Apr. 8, 2025) (referring to § 3).

⁷⁸ Exec. Order No. 14262, 90 Fed. Reg. 15521, 15522 (Apr. 8, 2025) (referring to § 3) (emphasis added).

⁷⁹ U.S. DEP’T OF ENERGY, *DOE Issues 202(c) Orders to PREPA for Grid Stability*, <https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority>.

⁸⁰ See Duke Energy Carolinas (Order No. 202-25-5) (allowing increased operations to support grid stability); H.A. Wagner (Order No. 202-25-6) (allowing exceedance of operational limit – but maintained compliance with pollution control requirements – to allow units to respond to demand); PREPA (Order No. 202-25-1) (requiring measures to mitigate outage risks during high load conditions)

⁸¹ U.S. Dep’t of Energy, Order No. 202-25-3 (May 23, 2025), https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf [<https://perma.cc/Q7P7-TDTX>] [hereinafter “Campbell Order”]; Eddystone Order, *supra* note 9.

⁸² See, e.g., Ella Nilsen, *The Trump Admin Ordered a Coal Power Plant to Stay On Past Retirement. Customers in 15 States Will Foot the Bill*, CNN (June 6, 2025), <https://www.cnn.com/2025/06/06/climate/michigan-coal-plant-energy-cost-wright>.

of the plant in the first five weeks since the Order was issued has resulted in a net financial impact of \$29 million.⁸³

e. DOE Publishes its Methodology and Reliability Standard to Guide Future Section 202(c) “Reliability Interventions.”

On July 7, 2025, DOE published a “Report on Evaluating U.S. Grid Reliability and Security,” which set forth the methodology and reliability standard that the Executive Order had mandated. *See* Report at *vi* (hereinafter, “the Report”). DOE stated the methodology “will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States.” *Id.* Despite this statement, DOE has not explained how or when it will re-assess the methodology and, to date, has not involved the public in the creation of the methodology or offered an opportunity for public comment on the methodology.

i. DOE did not provide public notice or an opportunity for comment on the Report.

Before publishing the Report, DOE provided no public notice or request for comment on methods or reliability standards that DOE was considering. DOE did not consult with the undersigned States or, to the States’ knowledge and belief, consult with any grid operator or other State on appropriate mechanisms to ensure grid reliability and grid reliability issues around the country.⁸⁴ Other than the statements in the Report, DOE has not made the underlying data or models available to allow the public to reproduce or test DOE’s analysis. DOE has not requested public comment on the Report, opened any administrative proceeding to otherwise involve the public in DOE’s methodology, or published the Report in the Federal Register.

DOE has confirmed, consistent with the Executive Order’s mandate, that it will rely on the Report to justify future Section 202(c) orders.⁸⁵ DOE explained in the June 2025 Eddystone Order that it would use the forthcoming Report “to establish a protocol to identify which generation resources within a region are critical to system reliability and prevent identified generation resources from leaving the bulk power system[,]” including potential Section 202(c) orders extending DOE’s Eddystone Order.⁸⁶ DOE also issued the Report with a “Fact Sheet,”

⁸³ *See supra* notes 5-6 and accompanying text; NRDC, *Trump Administration’s DOE Is Forcing Coal Plants to Stay Open. Michigan Is the First Target* (June 16, 2025), <https://www.nrdc.org/bio/derrell-e-slaughter/trump-administrations-doe-forcing-coal-plants-stay-open-michigan-first>.

⁸⁴ *See* Report at *i* (acknowledging lack of data from regional and utility levels).

⁸⁵ *See* Report at *vi* (explaining that DOE’s standard will be used to “guide reliability interventions”), 1 (emphasizing the need for DOE’s “decisive intervention” in energy markets), 10 (analyzing ERCOT because “FPA Section 202(c) allows DOE to issue emergency orders to ERCOT”).

⁸⁶ Eddystone Order, *supra* note 9.

wherein DOE explained that the methodology will be used to “prevent [] generation resources from leaving the bulk-power system.”⁸⁷

ii. DOE’s analysis rests on key assumptions about load growth, retirements, and capacity additions.

The Report’s analysis rests on assumptions about future electricity demand (referred to as “load growth”), anticipated retirements of existing facilities (“retirements”), and future electricity generation sources (referred to as “capacity additions”). DOE made additional assumptions, some explicit and others implicit, which the States have not yet been able to fully analyze or comment on here.⁸⁸

Regarding load growth, DOE assumes 101 Gigawatts (“GW”) of new load will be added to the grid by 2030.⁸⁹ DOE projects that data centers, especially for developing Artificial Intelligence (“AI”), will add 50 GW of that new load, and other demand growth will add 51 GW. DOE appears to assume that data-center load will be “firm,” meaning electricity to meet that demand must be guaranteed at all times.⁹⁰ That is in contrast to “interruptible” load for which supply can be reduced during peak periods.⁹¹ DOE also appears to assume that all the new data centers will connect to the grid, rather than rely on “behind-the-meter” generation and that regulators and grid operators will allow every MW of new load to connect to the grid on a firm basis, even if doing so threatens the grid’s reliability.⁹² Based on these assumptions, DOE projects a 15% increase in load by 2030.⁹³

The Report assumes 51 GW of non-data-center load, purportedly based on the NERC’s 2024 ITCS projections.⁹⁴ DOE does not explain why using projections from a NERC report on inter-regional transmission is reasonable or why those projections are reliable for DOE’s purposes. Additionally, NERC’s 2024 projections likely already include some data center load expectations, as well as policies to encourage the electrification of transportation, heating and cooling, and other energy uses that the Trump Administration has rescinded or is planning to

⁸⁷ U.S. DEP’T OF ENERGY, *Fact Sheet: The Department of Energy’s Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025), https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf [<https://perma.cc/YLX7-8G7T>]; *see also* Press Release, U.S. Dep’t of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security (July 7, 2025), <https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security> [<https://perma.cc/8TEJ-AGH6>] (stating that its “methodology also informs the potential use of DOE’s emergency authority under Section 202(c) of the Federal Power Act”).

⁸⁸ *See generally* Report at 10-19.

⁸⁹ Report at 2-3.

⁹⁰ Report at 18.

⁹¹ *Id.*

⁹² *See id.* at 2-3, 15-18.

⁹³ *See* Ric O’Connell, *GridLab Analysis: Department of Energy Resource Adequacy Report* (July 11, 2025), <https://gridlab.org/gridlab-analysis-department-of-energy-resource-adequacy-report/> [<https://perma.cc/GN56-VLNA>].

⁹⁴ *See* Report at 11.

rescind.⁹⁵ DOE apparently did not account for shifting electrification policies in its load projections.

Regarding retirements, DOE assumed 104 GW of “firm capacity” retirements by 2030, roughly three-quarters from coal-fired power plants and one-quarter gas plants.⁹⁶ *Id.* at 5; see also Report at 3, 12-13, A1-A8. DOE included approximately 50 GW of “confirmed retirements,” retirements that have been formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date.⁹⁷ DOE also included approximately 50 GW of “announced retirements,” which are generators that have publicly stated retirement plans but not formally notified system operators or initiated the retirement process.⁹⁸

Regarding capacity additions, DOE took a more conservative approach. Rather than including all announced projects, DOE assumed “that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built.” Report at A-5. These projects, known as Tier 1 resources, are by their very nature likely to be built in the short term. As a result, DOE assumed “minimal capacity additions beyond 2026.” *Id.* In addition, DOE does not appear to have modeled new transmission projects, despite their grid reliability benefits.

The Report’s assumptions about load growth and electricity supply differ significantly from other forecasts.⁹⁹ As one grid reliability expert commented, DOE’s report “used aggressive assumptions regarding load growth and retirements, but conservative assumptions about how much new generation capacity will be added, even assuming no new resources after 2026.”¹⁰⁰ For example, DOE assumed 15% load growth by 2030, but the U.S. Energy Information Agency recently assumed just 6% in their “high” growth” case.¹⁰¹ Other differences with the Energy

⁹⁵ See NERC, 2024 Long Term Reliability Assessment Report 8 (July 15, 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf [https://perma.cc/NMP4-KRN5] (discussing how “the continued adoption of electric vehicles and heat pumps is a substantial driver for demand around North America”).

⁹⁶ Report at 5.

⁹⁷ *Id.* at 12; see also O’Connell, *supra* note 93.

⁹⁸ Report at 12.

⁹⁹ Report at 2 (noting that demand forecasts vary widely).

¹⁰⁰ O’Connell, *supra* note 93.

¹⁰¹ U.S. Energy Information Administration, Form EIA-860 (June 11, 2025) <https://www.eia.gov/electricity/data/eia860/>.

Information Agency forecasts are described in the chart below:¹⁰²

DOE Report Assumptions vs. U.S. Energy Information Administration Data:

	DOE Report	EIA 860
Load growth:	101 GW	N/A
Capacity Additions	209 GW	200 GW
Gas Capacity Additions	22 GW	35 GW
Battery Capacity Additions	31 GW	53 GW
Retirements	104 GW	52 GW

The Report also does not address actions already being taken by states, utilities, and regional grid operators to meet increased load growth or how markets are already responding to increasing demand. As GridLab explained in its analysis:

Markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that could add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.¹⁰³

iii. Based on these assumptions and DOE's resource adequacy standard, DOE concluded intervention in electricity markets is needed to prevent outages.

DOE then adopted a novel "resource adequacy standard," using a combination of non-traditional and non-standardized metrics ("Loss of Load Hours" and "Normalized Unserved Energy").¹⁰⁴ DOE selected the target to be achieved with each metric.¹⁰⁵

DOE did not define what energy sources it considered "firm" capacity or why only those sources provide the necessary attributes for grid reliability. DOE's usage of the term in the report suggests that only coal or gas power plants count as "firm" capacity and excluded other sources that could provide similar, greater, or different levels of reliability (like batteries or transmission) from its analysis.¹⁰⁶

¹⁰² O'Connell, *supra* note 93.

¹⁰³ *Id.*

¹⁰⁴ Report at 3-4.

¹⁰⁵ *Id.*

¹⁰⁶ *See, e.g., id.* at 1, 32, 37.

DOE portrayed three scenarios in an attempt to assess the impact of planned retirements on resource adequacy in 2030.¹⁰⁷ The first scenario is “Plant Closures,” which assumes that announced retirements and capacity additions “in the final stages for connection” that are “either under construction or ha[ve] received approved planning requirements” will occur.¹⁰⁸ The second scenario is “No Plant Closures,” which has the same assumption about additions as the “Plant Closures” scenario but assumes no retirements.¹⁰⁹ The third scenario is “Required Build” which uses the “Plant Closures” scenario’s assumptions about retirements and then artificially adds enough hypothetical perfect capacity to the system to meet DOE’s new reliability standard.¹¹⁰ Perfect capacity is hypothetical capacity that experiences no outages and is used in the modeling “to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations.”¹¹¹

DOE then concluded, based on the above assumptions, the risk of power outages in 2030 would be 100 times higher in 2030 than it is today.¹¹² DOE concluded that “decisive intervention” and “robust and rapid reforms” are necessary to avoid this result and to accommodate “projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”¹¹³ Numerous grid experts have commented on the shortcomings of this approach.¹¹⁴

III. Statement of Issues and Specification of Errors.

1. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure Act and Federal Power Act because it suffers from numerous analytical, mathematical, and empirical flaws, including but not limited to the following:
 - a. DOE relies on key assumptions about load growth, retirements, and capacity additions that are unreasonable and unsupported by evidence or logic.

¹⁰⁷ *Id.* at 3, 5.

¹⁰⁸ *Id.* at 4-5.

¹⁰⁹ *Id.*

¹¹⁰ *Id.*

¹¹¹ *Id.* at 5.

¹¹² *Id.* at 1.

¹¹³ *Id.*

¹¹⁴ See, e.g., Jeff St. John, *Critics Fear Trump Will Use Flawed DOE Report to Push Pro-Coal Agenda*, CANARY MEDIA (July 14, 2025), <https://www.canarymedia.com/articles/fossil-fuels/trump-doe-report-open-coal-plants> [https://perma.cc/2T7L-3FWX]; Matthias Fripp & Brendan Pierpont, *Energy Department’s Flawed Grid Study Props Up Expensive, Zombie Power Plants*, UTILITYDIVE (July 24, 2025), <https://www.utilitydive.com/news/doe-grid-reliability-study-zombie-power-plants/753596/> [https://perma.cc/QH3V-KM5R]; INST. FOR POL’Y INTEGRITY, *ENOUGH ENERGY: A REVIEW OF DOE’S RESOURCE ADEQUACY METHODOLOGY* (July 2025), https://policyintegrity.org/files/publications/IPI_EnoughEnergy_FinalReport.pdf [https://perma.cc/WN39-K9LE].

- b. DOE assumes the transmission grid will remain static over the next five years and fails to consider how new transmission projects in development will impact reliability.
- c. DOE fails to define “firm power capacity” or reasonably explain why DOE apparently considers only coal and gas to be “firm power capacity” when other generation sources, energy storage, or transmission could provide similar or greater reliability attributes.
- d. DOE’s assumptions unreasonably presume that the market, grid operators, and state regulators will take no action in the next five years to address load growth or reliability issues, and that no alternative other than preserving aging coal and gas power plants will ensure grid reliability.
- e. DOE’s analysis suffers from mathematical errors, analytical flaws, and lacks sufficient data or regional input. Those flaws are amply described in the attached analysis by the Institute for Policy Integrity and are incorporated and adopted here. *See* IPI Report (attached as Ex. XX).
- f. Although DOE acknowledged that data and input from states and regional entities could improve the analysis, DOE chose not to consult with those entities or seek to obtain that data.
- g. DOE selected non-traditional and non-standardized resource adequacy metrics and targets to be achieved without providing a reasoned explanation for its choices, including why it selected Normalized Unserved Energy (“NUSE”) and Loss of Load Hours (“LOLH”) instead of other possible metrics that would provide different data, an explanation of the costs and benefits of its choices and the target to be achieved, and why a nationwide target is appropriate despite regional differences in the costs and benefits with regard to resource adequacy.
- h. DOE offers no reasonable explanation how the Report could be used to identify “at-risk region[s] and guide reliability interventions” when it arbitrarily relies on geographic groupings that do not match boundaries used by utilities, balancing authority areas, transmission planning regions, regional wholesale markets, NERC regional entities, or NERC reliability coordinators to reliably operate the nation’s electric grid.

These assumptions and omissions work together to arbitrarily tip the scales in favor of finding a resource adequacy risk. *See Motor Vehicles Mfrs. Ass’n v. State Farm*, 463 U.S. 29, 43 (1983); *WildEarth Guardians v. U.S. Bureau of Land Mgmt.*, 870 F.3d 1222, 1237 (10th Cir. 2017); *Nat. Res. Def. Council, Inc. v. Herrington*, 768 F.2d 1355, 1391 (D.C. Cir. 1985); *see also infra* Section 4.a.

- 2. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure and Federal Power Acts because it pursues an extra-statutory motive of preserving aging and uneconomic fossil fuel

power plants at consumer expense, which contradicts the Federal Power Act’s express goal of preserving just and reasonable rates and preventing undue discrimination or preference. The Administration’s energy actions, when viewed collectively, also demonstrate that DOE has prejudged the outcome of this proceeding and intended its analysis to reach only one result: preventing the retirement of fossil-fueled power plants. *See Dep’t of Com. v. New York*, 588 U.S. 752, 785 (2019); *Gresham v. Azar*, 950 F.3d 93, 104 (D.C. Cir. 2020), *vacated as moot*, *Becerra v. Gresham*, 142 S. Ct. 1665 (2022). *See also infra* Section 4.a.iii-iv.

3. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure and Federal Power Acts because it purports to guide emergency action under Section 202(c) of the Federal Power Act but does not describe an “emergency” within the meaning of the Federal Power Act or DOE’s implementing regulations. *See* 16 U.S.C. § 824a(c)(1); 10 C.F.R. § 205.371; *Otter Tail Power Co. v. Federal Power Com.*, 429 F.2d 232, 234 (8th Cir. 1970). *See also infra* Section 4.b.
4. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure and Federal Power Acts because it “fails to consider an important aspect of the problem” and fails to consider reasonable alternatives. Specifically, the Report ignores alternatives, or in some cases actively prevents viable alternatives with no explanation, such as expanding interregional transmission, batteries, renewable energy, incorporating data centers flexibly into load, and the existing resource adequacy mechanisms that are used by states and regional grid operators to assess reliability and respond to resource adequacy needs. *See State Farm*, 463 U.S. at 43. *See also infra* Section 4.a. (arbitrary and capricious) and section 4.c. (existing resource adequacy mechanisms)].
5. The Report is *ultra vires* and contrary to law in violation of the Administrative Procedure and Federal Power Acts because it intrudes upon matters reserved for the States and the Federal Energy Regulatory Commission. DOE does not possess authority to set nationwide resource adequacy standards or regulate sources of electricity generation. *See* 16 U.S.C. § 824b(1); *Whitman v. Am. Trucking Ass’n, Inc.*, 531 U.S. 457, 468 (2001). *See also infra* Section 4.d.
6. The Report violates the Administrative Procedure Act, 5 U.S.C. 553, because it establishes a legislative rule without first providing public notice and comment. *See Shalala v. Guernsey Mem’l Hosp.*, 514 U.S. 87, 99–100 (1995); *Nat’l Min. Ass’n v. McCarthy*, 758 F.3d 243 (D.C. Cir. 2014); *Children’s Health Care v. Centers for Medicare & Medicaid Servs.*, 900 F.3d 1022 (8th Cir. 2018). *See infra* Section 4.e.

7. The Report is arbitrary, capricious, and contrary to law in violation of the Administrative Procedure Act because it allegedly supports issuing Section 202(c) emergency orders based on factors and procedures that conflict and are inconsistent with DOE's existing regulations. *See Emergency Interconnection of Electric Facilities*, 46 Fed. Reg. 39,984 – 39,989 (Aug. 6, 1981); 10 C.F.R. §§ 205.371 *et seq.* *See infra* Section 4.e.ii.
8. The Report is arbitrary and capricious in violation of the Administrative Procedure Act because DOE failed to acknowledge that its methodology and protocol for issuing Section 202(c) orders is inconsistent with the factors for determining when an emergency exists that DOE's regulations already set out. *See Emergency Interconnection of Electric Facilities*, 46 Fed. Reg. at 39,985; 10 C.F.R. §§ 205.371, 205.373. It is also inconsistent with DOE's previous position that emergency orders are inappropriate for long-term reliability issues and a "utility must solve long-term problems itself." 46 Fed. Reg. at 39,985; *see also* 10 C.F.R. § 205.371. Agencies act arbitrarily when they fail to display awareness that they are changing position and offer good reasons for the change in policy. *See Food & Drug Administration v. Wages & White Lion Invs.*, 604 U.S. ---, 145 S. Ct. 898, 918 (2025); *see also infra* Section 4.e.

IV. Request for Rehearing

a. DOE's Report is Based on Flawed and Arbitrary Assumptions and is Unsupported by Substantial Evidence.

The Report's conclusions rest on critical assumptions about load growth, retirements, and capacity additions, but DOE did not reasonably explain how it arrived at those assumptions or support its choices with substantial evidence. At times, DOE's assumptions are internally inconsistent and arbitrarily tip the scales in favor of finding a need to prevent scheduled retirements. The Report also seems to adopt a definition of "firm capacity" that includes only fossil-fuel power plants, but does not explain why other generation sources or batteries are not also "firm capacity." DOE has also failed to make the data it relied on publicly available – rendering it impossible to fully test DOE's analysis.¹¹⁵

¹¹⁵ Due to the lack of public notice or any consultation or opportunity for involvement in the DOE's development of this report, the States have not had an opportunity to fully analyze DOE's methodology. DOE also has not made the data or models it used publicly available, which would allow the States to critically assess or replicate DOE's analysis and uncover additional flaws in DOE's approach. As such, the States reserve the right to raise additional flaws with DOE's analysis and conclusions at a later date, as they continue to analyze the Report.

Agencies act arbitrarily when they base decisions on key assumptions that are irrational or unsupported.¹¹⁶ Moreover, when agencies use complex models, they must publicly reveal the assumptions and data incorporated into their models and “provide a full analytical defense” of their model.¹¹⁷

i. DOE fails to reasonably explain or support its load growth assumptions

DOE assumes 15% load growth by 2030, half of which DOE assumes will serve new data centers.¹¹⁸ In doing so, DOE presumes – without evidence or a rational explanation – that data center load is firm (i.e., it cannot be interrupted at peak times). That assumption is arbitrary and directly undermined by recent advances in both policy and technology.

Some policymakers are already requiring data centers to be flexible, interruptible load.¹¹⁹ In Texas, for example, a new law grants ERCOT more flexibility to curtail certain data center loads in the event of a grid emergency.¹²⁰ DOE did not grapple with the impact of this law on its underlying assumptions despite the fact that curtailing such load during peak hours “could go a long way towards avoiding the DOE-identified resource adequacy problem” in ERCOT.¹²¹

DOE also ignores the possibility of industry reducing its demand for electricity either as a matter of policy or innovation in this rapidly developing field. NVIDIA, the foremost supplier of hardware for AI data centers, recently announced a new power supply unit that can reduce peak grid demand by up to 30%.¹²² In another recent example, Google agreed to a demand response framework with two utilities that would reduce how much electricity is used by its data centers during peak hours.¹²³

DOE’s reliance on an inflexible assumption for data center load reflects a failure to consider how this rapidly developing industry may adapt to address its significant energy

¹¹⁶ *WildEarth Guardians v. U.S. Bureau of Land Mgmt.*, 870 F.3d 1222, 1237 (10th Cir. 2017); *Hisp. Affs. Project v. Acosta*, 901 F.3d 378, 389 (D.C. Cir. 2018) (noting agencies’ affirmative duty to examine key assumptions underlying their policies).

¹¹⁷ *Nat. Res. Def. Council, Inc. v. Herrington*, 768 F.2d 1355, 1385 (D.C. Cir. 1985); *see also Columbia Falls Aluminum Co. v. EPA*, 139 F.3d 914, 923 (D.C. Cir. 1998).

¹¹⁸ Report at 18.

¹¹⁹ *See* Ex. D, Nicholas Institute Report at 25; *see also* Ex. C, IPI Report at 24

¹²⁰ S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170); *See also* Ex. C, IPI Report at 26.

¹²¹ Ex. C., IPI Report at 26.

¹²² Meris Lutz, *NVIDIA addresses AI peak power demand, spikes in new rack-scale systems*, UtilityDive (July 30, 2025), <https://www.utilitydive.com/news/nvidia-rack-scale-system-smooth-ai-power/756279/>.

¹²³ Laila Kearney, *Google agrees to curb power use for AI data centers to ease strain on US grid when demand surges*, Reuters (Aug. 4, 2025), <https://www.reuters.com/sustainability/boards-policy-regulation/google-agrees-curb-power-use-ai-data-centers-ease-strain-us-grid-when-demand-2025-08-04/>.

demand. This renders DOE's blunt conclusions regarding resource adequacy arbitrary and capricious.¹²⁴

The Report also adopts an unreasonably high estimate of future data center load, arbitrarily claiming it is simply adopting a "midpoint assumption." Report at 15. DOE admits that there are "wide variations" in estimates of future data center load growth, yet the agency does not appear to have conducted any actual evaluation of those estimates to determine their respective accuracy. DOE must explain why its adoption of an estimated 50 GW load growth is more reliable or likely than other projections. It cannot just pick what it calls a "midpoint" from available studies and move forward. A rational approach would involve projecting future growth under a number of scenarios. Indeed, DOE did not account for a number of factors that temper against aggressive assumptions for future data center load growth. Those factors include the fact that data center developers often make duplicative requests for service; that data center deployment is limited by the availability of chips and processing systems; that data center efficiency may increase in the future as technology develops; and that utilities are incentivized to adopt aggressive load forecasts.¹²⁵

The Report also assumes an additional 51 GW of non-data center load growth. DOE states that it adopted this assumption from NERC's 2024 ITCS Report. But NERC's 2024 ITCS Final Report does not contain its own load growth projections.¹²⁶ DOE has not cited which NERC projections it is relying on, what data underlie those projections, or why DOE considers it reliable for purposes of setting a uniform resource adequacy standard and guiding reliability interventions. Moreover, NERC's forecasts already contain data center load expectations meaning the Report may be double counting projected future demand from data centers.¹²⁷ NERC's forecasts may also contain other assumptions that are no longer appropriate, such as demand forecasts based on federal incentives to electrify transportation that no longer exist. Additionally, as the Institute for Policy Integrity explains in its report, DOE's method for distributing load growth across the country is questionable and does not necessarily reflect actual market decisions.¹²⁸

ii. DOE arbitrarily assumes 104 GW of retiring capacity by 2030 but only 22 GW of additions in the same time period.

The Report also assumes the retirement of 104 GW of generating capacity by 2030, an extremely aggressive estimate that cannot withstand any level of scrutiny.¹²⁹ That assumption is inconsistent with the U.S. Energy Information Administration's data from June 2025 showing

¹²⁴ See Report at 17, 40; *see also* Ex. C, IPI Report at 26 ("DOE should have considered the possibility that some of the projected data center load would be flexible, especially in ERCOT").

¹²⁵ See *generally* Ex. E, London Economics International Report.

¹²⁶ Ex. A, NERC ITCS Report.

¹²⁷ Report at 17.

¹²⁸ See Ex. C, IPI report at 24; *see also* Ex. E, LEI Report at 10-14 (noting that data centers have many choices where to locate).

¹²⁹ See Report at 5, A-5.

only half of that capacity is actually set for retirement.¹³⁰ This projection is also flawed because it arbitrarily includes announced retirements even though those generators have not formally provided notice of their retirement or initiated the retirement process.¹³¹ Many of these resources have, however, pushed back their actual retirement dates due to changing market conditions and the policies of the current administration.¹³²

At the same time that the Report overestimates the amount of load growth and retirements by 2030, it underestimates capacity additions that can be reasonably expected to come online in that same timeframe. DOE assumes only Tier 1 projects will be built by 2030. Because Tier 1 additions are projects that are either under construction or received approved planning requirements, nearly all will be in service by 2026.¹³³ DOE acknowledged that the Tier 1 assumption “results in minimal capacity additions beyond 2026,” Report at A-5, yet DOE did not explain why that assumption was nonetheless reasonable when forecasting conditions to 2030.

By focusing solely on Tier 1 projects, DOE excludes announced capacity additions or even capacity additions that are seeking approval to interconnect to the grid (NERC “Tier 2” projects).¹³⁴ Excluding capacity that has been requested but has not yet received approval for planning requirements does not make sense for predictions stretching out five years from now. Both common sense and history suggest that at least some of these additions will receive approval in that time.¹³⁵ DOE has thus adopted a view of generator additions that is completely at odds with its projection of generator retirements and together the approach arbitrarily tips the scales in favor of finding a resource adequacy risk.

These assumptions seem to ignore a fundamental property of market dynamics: that supply will respond to rising demand. DOE assumes that generators who have not initiated the retirement process will retire even if remaining in the market would still be economic for them. And DOE assumes that developers will refrain from building any new energy projects from 2027-2030 despite market signals that additional capacity is needed. Those assumptions are unreasonable and render the Report arbitrary and capricious.¹³⁶

¹³⁰ U.S. Energy Information Administration, Form EIA-860 (June 11, 2025)

<https://www.eia.gov/electricity/data/eia860/>.

¹³¹ See Report at 5, A-5.

¹³² Kevin Clark, *Where coal plant retirements are happening – And what could delay them*, Power Engineering (July 14, 2025), <https://www.power-eng.com/coal/plant-decommissioning/where-coal-plants-are-closing-and-what-could-delay-them/>. See also, Joe Schulz, *We Energies will delay Oak Creek coal plant retirement by one year to 2026*, Wisconsin Public Radio (June 26, 2025), <https://www.wpr.org/news/we-energies-delay-oak-creek-coal-plant-retirement-2026>. See also Ex. C, IPI Report at 23-24 (explaining why DOE’s retirement figure likely overstates retirements).

¹³³ NERC, *2024 Long-Term Reliability Assessment* at 22, 136-37 (2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

¹³⁴ *Id.*

¹³⁵ See also Ex. C, IPI Report at 21-22 (applying historical statistics and data to demonstrate why DOE’s exclusion of Tier 2 additions is unreasonable).

¹³⁶ See Report at 1 (concluding that, based on its model, intervention is needed to ensure a reliable power grid and meet the AI growth requirements).

DOE also arbitrarily excludes new transmission projects from its analysis altogether. Interregional transmission improvements are known to be one of the most cost-effective ways of improving grid reliability.¹³⁷ DOE apparently assumes that the nation's transmission will remain static over the next five years, despite ongoing planning processes and reforms to increase transmission projects and the well-documented reliability benefits that more transmission can provide.¹³⁸ DOE also appears to undercount the reliability benefit of existing transmission systems in its analysis.¹³⁹ It is nonsensical to ignore the benefits of new transmission when DOE is purportedly seeking to improve the reliability of the electric grid and keep costs affordable for consumers.

iii. DOE's analysis lacks sufficient regional granularity and suffers from other analytical flaws.

DOE's analysis also suffers from mathematical errors, analytical flaws, and lacks sufficient data or regional input further highlighting the importance of leaving resource adequacy to the states. DOE itself recognized that the Report's lack of regional data was a shortcoming that undercut its conclusions. As DOE acknowledges, "[e]ntities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience."¹⁴⁰ Despite this admission, DOE made no attempt to consult with States or grid operators on reliability issues or to obtain this data. An agency "may not tolerate needless uncertainties in its central assumptions when the evidence fairly allows investigation and solution of those uncertainties."¹⁴¹

This lack of state and regional granularity contributes to the report's unreasonable assumptions and overstated conclusions. Rather than focus on a region-specific analysis, DOE engaged in broad approximations to allocate nationwide projections to the various regions. For example, DOE started with a nationwide estimate of 50 GW of incremental data center load, allocated it across regions using state-level growth ratios from S&P's forecast, then mapped these state-level projections to the regions used for its analysis, the NERC Transmission Planning Regions (TPRs).⁵⁴ It is also unclear how DOE accomplished this mapping, given that the referenced NERC TPRs do not perfectly map to states.⁵⁶

Further, the Report's conclusions regarding resource adequacy are contradictory at times, even within a single region, rendering DOE's characterization of certain regions' resource adequacy arbitrary and capricious. To guide its assessments, DOE set reliability standards of "[n]o more than 2.4 hours of lost load in an individual year" and "[n]o more than an NUSE [Normalized Unserved Energy] of 0.002%."¹⁴² In its analysis of the PJM region, the Report highlights PJM's average loss of load figure of 2.4 hours under the current system analysis, apparently to indicate resource inadequacy despite clearly not *exceeding* the threshold DOE set,

¹³⁷ See generally Ex. A, NERC ITCS Report; see also Ex. F, GridStrategies Report at 1.

¹³⁸ See generally Ex. A, NERC ITCS 2024 Report (identifying areas where new transmission can significantly improve reliability); Ex. F, GridStrategies, Resource Adequacy Value of Interregional Transmission (June 2025)

¹³⁹ See Ex. C, IPI Report at 25.

¹⁴⁰ Report at i.

¹⁴¹ *Nat. Res. Def. Council, Inc. v. Herrington*, 768 F.2d 1355, 1391 (D.C. Cir. 1985).

¹⁴² Report at 4.

while also describing the region’s current system as “experienc[ing] shortfalls, but ... below the required threshold.”¹⁴³ At the same time, the Report notes that “[f]or the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM,” despite the Report’s summary of the PJM’s modeled NUSE metric in the current system clocking in at 0.0008%, again clearly meeting the reliability threshold that DOE itself selected.¹⁴⁴

The Report also fails to explain how it could be used to identify “at-risk region(s) and guide reliability interventions”¹⁴⁵ while relying on many geographic groupings that do not match the boundaries used by utilities, balancing authority areas, transmission planning regions, regional wholesale markets, NERC regional entities, or NERC reliability coordinators to reliably operate the nation’s electric grid.

For example, the “Front Range” region in the Report includes Colorado and portions of New Mexico and Wyoming but those boundaries are geographically different from regions analyzed in NERC’s reliability assessments. NERC’s 2025 Summer Reliability Assessment includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota in the “WECC-Rocky Mountain” region, and includes Arizona and New Mexico, most of Nevada, and small parts of California and Texas in the “WECC-Southwest” region.¹⁴⁶ The regional grouping used in the Report is arbitrary and inconsistent with these existing groupings.

The Report states its model is derived from NERC’s Interregional Transfer Capability Study (“ITCS”)¹⁴⁷ and asserts the subregions used in the Report, called Transmission Planning Regions (“TPRs”), “match the regional subdivisions in the NERC ITCS study, itself based on FERC’s transmission planning regions.”¹⁴⁸ However, the ITCS makes clear that FERC’s transmission planning regions were altered to create the TPRs for the ITCS,¹⁴⁹ which was focused on transfer capability between neighboring regions and not resource adequacy.¹⁵⁰ The ITCS Final Report does not explain how specific footprints were determined in any detail.¹⁵¹ In January 2025 comments filed with FERC in response to the ITCS report, DOE commented “[t]he subregion boundaries used in the ITCS are useful for evaluating interregional transfer capability given the chosen methodology, *but not for evaluating resource adequacy of those subregions.*”¹⁵² DOE explained the ITCS subregions do not reflect actual monitored transmission constraints, nor

¹⁴³ Report at 27 & Tbl. 8.

¹⁴⁴ Report at 9, 27 Tbl. 8. *See also* Ex. C, IPI Report at 20.

¹⁴⁵ Report at vi.

¹⁴⁶ NERC, *2025 Summer Reliability Assessment* at 36, 38 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

¹⁴⁷ Report at 2.

¹⁴⁸ Report at 10 n.14.

¹⁴⁹ Ex. A, NERC ITCS Report at 7.

¹⁵⁰ Fiscal Responsibility Act of 2023, H.R. 3746, 118th Congress (2023–2024) (directing NERC to study the total transfer capability between transmission planning regions).

¹⁵¹ *See* Ex. A, NERC ITCS Report at 7.

¹⁵² Comments of the U.S. Dep’t of Energy, FERC Docket No. AD25-4-000, at 6 (Jan. 17, 2025) (emphasis added).

do they accurately capture the service territories or balancing authority areas that are the footprints on which resource adequacy decisions are made.¹⁵³

Despite DOE's earlier comments, the DOE Report fails to explain why the TPR subregions, many of which have no similarities to the regions actually used by NERC to assess reliability nor the planning regions used by entities with resource adequacy obligations, are now appropriate geographic boundaries for running resource adequacy scenarios and guiding reliability interventions. Returning to the example of the Front Range region, neither the ITCS Final Report nor the DOE Report explain why resource adequacy analysis should be done collectively for Colorado and portions of New Mexico and Wyoming, in which the load serving entities and balancing authorities plan their systems, acquire generating resources, and decide to interconnect to neighboring systems under completely separate processes. Because many of the Report's subregions are divorced from how the grid is actually planned and operated, they risk inaccurate groupings of load and available generating resources and incomplete understandings of how transmission capacity may be used in times of peak demand.

The Report suffers from other analytical shortcomings, which are amply described in the Institute for Policy Integrity's report and are expressly incorporated and adopted here.¹⁵⁴ As the Institute for Policy Integrity explained, DOE fails to offer a reasonable explanation for its choice of resource adequacy metrics and targets, outage thresholds, or the use of a deterministic model instead of a more accurate probabilistic model. By relying solely on weather data from recent years in a deterministic model, rather than a more statistically accurate probabilistic model, the Report "does not sufficiently account for uncertainty," weakening the strength of its modeled findings for 2030.¹⁵⁵

Given the abundant shortcomings in DOE's methodology, it is unreasonable to rely on the data and analysis contained in the Report to draw any firm conclusions about the resource adequacy of any region of the United States electrical grid now or in 2030, and DOE's various findings of resource inadequacy despite these flaws is arbitrary and capricious.

iv. DOE's flawed analysis establishes an arbitrary and unlawful preference for fossil fuel plants over other methods to preserve grid reliability, contrary to the Federal Power Act.

The flawed assumptions discussed above lead to an obvious conclusion: that DOE designed the Report to satisfy the White House's goal of bailing out uneconomic and environmentally harmful power plants. DOE's report is not addressing an emergency, but seeking to prop up a coal industry that is unable to compete with cheaper and cleaner modern energy sources like wind, solar, and batteries.

¹⁵³ See *id.* at 6-7.

¹⁵⁴ See Ex. C, IPI Report at 18-26

¹⁵⁵ *Id.* at 21.

Executive Order 14262 was signed alongside EO 14261 *Reinvigorating America's Beautiful Clean Coal Industry and Amending Executive Order 14241*. EO 14261 claims to “encourage and support our Nation’s coal industry to increase our energy supply, lower electricity costs, stabilize our grid, create high-paying jobs, support burgeoning industries, and assist our allies.” And President Trump’s statements at the signing ceremony make clear that the two orders are intended to serve a complementary purpose. As the President said, with coal workers lining the stage behind him for a photo-op, “we’re bringing back an industry that was abandoned” and “all those plants that have been closed are going to be opened.”¹⁵⁶

The President’s Grid Reliability Order references his earlier Declaration of an Energy Emergency, *see* EO 14156 “Declaring a National Energy Emergency,” which created an energy emergency based on an alleged shortage of affordable and domestic energy sources. In all orders, the President narrowly focuses on fossil fuels and specifically excludes wind, solar, or batteries from the definition of “energy.” And the Administration has simultaneously taken steps to derail the wind and solar industries, revoking previously issued permits for offshore wind projects, pausing the issuance of approvals, permits, and loans for wind projects nationwide, and adding bureaucratic hurdles to the permitting process for wind and solar.¹⁵⁷

To the extent that the Report advances the Administration’s policy of discriminating against renewable energy, batteries, and transmission to advance the extra-statutory motive of preserving aging fossil fuel power plants at consumer expense, it is contrary to express goals of the Federal Power Act.¹⁵⁸ Sections 205 and 206 of the Federal Power Act require rates to be just and reasonable and not unduly discriminatory or preferential.¹⁵⁹ Purporting to justify Section 202(c) orders for fossil fuel plants that are not needed and ignoring other viable methods to preserve grid reliability at a lower cost for consumers is likely to result in unjust and unreasonable rates. While 202(c) permits deferral of this issue to FERC in a rate proceeding, DOE must – at minimum – consider how a streamlined and uniform methodology may impact rates and cost recovery.

Significantly, when DOE proposed in 2017 that FERC adjust its rates to compensate generation that could store 90 days of fuel on-site (i.e., coal and nuclear generation), FERC unanimously rejected that proposal.¹⁶⁰ FERC concluded that DOE failed to demonstrate that allowing all eligible resources to receive a special rate regardless of the specific reliability needs of that region would be a just and reasonable outcome.¹⁶¹ DOE also failed to show that such a remedy “would not be unduly discriminatory or preferential” since only “certain resources [could] be eligible for the rate, thereby excluding other resources that may have resilience

¹⁵⁶ Adam Burke, *Trump orders coal revival, but market favors natural gas*, NPR (April 17, 2025)

<https://www.npr.org/2025/04/16/nx-s1-5359013/trump-orders-coal-revival-market-favors-natural-gas>.

¹⁵⁷ *See generally*, Complaint, New York, et al. v. Trump, et al., No. 25-cv-11221 (D. Mass., filed May 5, 2025) (describing Administration’s assault on wind energy). *See also e.g.*, Department of the Interior, Secretarial Order 3437, <https://www.doi.gov/document-library/secretary-order/so-3437-ending-preferential-treatment-unreliable-foreign>; Department of the Interior, Secretarial Order 3438, <https://www.doi.gov/document-library/secretary-order/so-3438-managing-federal-energy-resources-and-protecting>.

¹⁵⁸ *See* FPA Sections 205 and 206; 16 U.S.C. §§ 824d, 824e.

¹⁵⁹ *Id.*

¹⁶⁰ *See* Order Terminating Rulemaking, 162 FERC ¶ 61,012, ¶ 16 (Jan. 8, 2018).

¹⁶¹ *Id.*

attributes.”¹⁶² DOE’s second attempt to manipulate the energy markets in favor of its preferred energy sources suffers from the same fatal flaws and its motives are contrary to the goals of the Federal Power Act.

b. The Report does not describe an “emergency” and cannot be used to justify future grid reliability interventions by DOE.

i. Common usage and regulation define “emergency” narrowly.

Section 202(c) is limited, by its own terms, to either “the continuance of any war in which the United States is engaged,” or “whenever the Commission determines that an emergency exists *by reason of*” certain enumerated causes.¹⁶³ Those causes include: (1) “a *sudden* increase in the demand for electric energy,” (2) “a shortage of electric energy or of facilities for the generation or transmission of electric energy,” (3) a shortage of “fuel or water for generating facilities,” and (4) “other causes.”¹⁶⁴

The relevant focus is therefore on the definition of “emergency.” In 1930, just a few years before the Act’s passage, Webster’s New International Dictionary of the English Language defined “emergency” as a “sudden or unexpected appearance or occurrence... an unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency.” The year before the statute was last amended, Merriam-Webster’s Dictionary and Thesaurus (2014) defined “emergency” as “an *unforeseen* event or condition requiring prompt action.” Thus, at all relevant times “emergency” was defined as being unexpected or unforeseen and requiring some form of exigent response.

That limited reading of Section 202(c) is bolstered by the emergency provision’s immediate statutory context. Section 202(c) is preceded by Section 202(b), which grants what is now the Federal Energy Regulatory Commission the authority to issue similar interconnection orders “*after* opportunity for hearing,” indicating that Congress intended to place a temporal constraint upon the emergency authority in Section 202(c), limiting it to situations not amenable to public notice and hearing.¹⁶⁵

DOE’s regulations implementing Section 202(c) also suggest the provision’s narrow applicability to only true emergencies.¹⁶⁶ DOE has provided that “actions under this authority are envisioned as meeting a specific inadequate power supply situation.”¹⁶⁷ The regulations

¹⁶² *Id.*

¹⁶³ 16 U.S.C. § 824a(c)(1) (emphasis added).

¹⁶⁴ *Id.* (emphasis added). The catchall “other causes” must still be the “reason” that an emergency exists. *Id.* See also Rolsma, *The New Reliability Override*, 57 U. Conn. L. Rev. at 810-13.

¹⁶⁵ 16 U.S.C. § 824a(b); 42 U.S.C. § 7172(a)(1)(B).

¹⁶⁶ See also 46 Fed. Reg. 39987 (Aug. 6, 1981).

¹⁶⁷ 10 C.F.R. § 205.371.

further define applicable emergencies to include “an *unexpected* inadequate supply of electric energy,” “*unforeseen* occurrences,” or “a *sudden* increase in customer demand,” echoing the.¹⁶⁸

In guidelines for defining “inadequate utility system fuel inventory or energy supply,” the regulations further specify that the threshold for such an emergency may be met “when, combined with other conditions, the projected energy deficiency upon the applicant’s system *without emergency action by the DOE*, will equal or exceed 10 percent of the applicant’s then normal daily net energy for load, or will cause the applicant to be unable to meet its normal peak load requirements *based upon use of all of its otherwise available resources* so that it is unable to supply adequate electric service to its ultimate customers.”¹⁶⁹ This definition again narrows the circumstances in which DOE may exercise its 202(c) authority to those not redressable by other means, implicating only acute or imminent power shortages where no other recourse is available.¹⁷⁰

ii. The report does not point to any sudden or unforeseen circumstances.

. DOE’s report does not identify any region, except ERCOT, that currently fails to meet DOE’s reliability targets.¹⁷¹ DOE’s flawed analysis points to a failure to meet reliability targets only in 2030. An expected increase in demand that can be projected over the next five years is not an energy emergency. Those shortfalls are not “unexpected” or “imminent” so as to justify a departure from normal planning procedures. The Report is squarely focused on 2030 and does not assess resource adequacy in any of the intervening years. According to the standard set out in *Otter Tail Power Co. v. Federal Power Com.*, 429 F.2d 232, 234 (8th Cir. 1970), the shortfalls predicted by the Report are at best policy crises “which [are] likely to develop in the foreseeable future but which [do] not necessitate immediate action.” In other words, the concerns may be addressable using FPA § 202(b), but certainly not FPA § 202(c).

Significantly, DOE has never before issued a 202(c) order based on such a broad and speculative increase in load demand. On the contrary, prior to 2025, DOE had only used 202(c) to delay the retirement of generation facilities on three narrow occasions, as requested by the system operator or government body, and only for as long as necessary to address the imminent emergency.¹⁷²

¹⁶⁸ *Id.* (emphasis added).

¹⁶⁹ 10 C.F.R. § 205.375 (emphasis added).

¹⁷⁰ While the regulations also state that “[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency ...,” the definition crucially does not allow for *projections* of such circumstances to qualify or include any qualifying terms indicating similar intent. On the face of the regulation, and consistent with reasonable interpretations of the statute, such an eligible power shortage must be sufficiently imminent to avoid reducing the inherent limitation of the word “emergency” to an absurdity. 10 C.F.R. § 205.371.

¹⁷¹ Report at 7.

¹⁷² See Benjamin Rolsma, *The New Reliability Override*, 57 U. Conn. L. Rev. 789, 843-46 (2025).

iii. Reliance on the Report to justify a Section 202(c) order would be contrary to law.

Based on EO 14262 and DOE's own statements, it is evident that the Department intends to rely upon the analysis and methodology in the Report to justify future Section 202(c) orders.¹⁷³ But the Report cannot lawfully be relied upon to justify the exercise of DOE's limited emergency authority. Doing so would be contrary to law.¹⁷⁴

As discussed above, the Secretary of Energy's authority under Section 202(c) of the Federal Power Act is statutorily limited to wartime or certain "emergency" situations; otherwise, similar proceedings fall under the jurisdiction of the Federal Energy Regulatory Commission through a process of notice and hearing.¹⁷⁵ Even taking the Report at face value, its own conclusions fail to describe anything resembling an emergency in any part of the country besides ERCOT.¹⁷⁶ Any conclusion that an emergency exists is undermined by the arbitrary nature of the Report's analysis.¹⁷⁷

Moreover, the Report's conclusions, on their face, fail to describe an "emergency". Conclusions about resource adequacy five years in the future, in 2030, fall outside of the temporal limits of an "emergency" and are exactly the type of concern that should be dealt with through usual planning processes.¹⁷⁸ Any attempt by DOE to bootstrap future Section 202(c) orders to the Report would be in direct contradiction to its statutory authority to issue such orders and its own regulations implementing that authority.¹⁷⁹

c. DOE failed to consider an important aspect of the problem: existing reliability mechanisms.

Agency action is arbitrary and capricious under the APA if it "fails to consider an important aspect of the problem." *Motor Vehicle Mfrs. Assn. of United States, Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). Here, DOE has acted as if the Report exists on a blank slate of resource adequacy and reliability planning yet that could not be farther from the

¹⁷³ See Report at vi; EO 14262 Sec. 3(c). In at least one Section 202(c) order issued after the publication of EO 14262 but before the release of the Report, the Department stated that it "plans to use this methodology to further evaluate" the generation units subject to that order. Order No. 202-25-4 ("Eddystone 202(c) Order") at 2 (May 30, 2025).

¹⁷⁴ See 16 U.S.C. § 824a(c); 10 C.F.R. §§ 205.370-371, 375.

¹⁷⁵ 16 U.S.C. §§ 824a(b)-(c); 42 U.S.C. §§ 7151(b), 7172(a)(1)(B).

¹⁷⁶ Report at 7 ("Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average load loss per year and less than 0.002% NUSE. This indicates relative reliability for most regions based on the average indicators of risk used in this study."); see also Ex. C, IPI Report at 29-31 ("Despite DOE's press statement asserting that the study's methodology can help guide [sic] 'guide Federal reliability interventions,' presumably to address the EO's [EO 14262] mandate that DOE find a way to routinize further 202(c) emergency orders, the study reports a fundamental limitation for doing so: It does not find any near-term reliability risk from current levels of resource adequacy." (footnotes omitted)).

¹⁷⁷ See *supra* Section 4.a.

¹⁷⁸ See Report at 8-9.

¹⁷⁹ 16 U.S.C. § 824a(c); 10 C.F.R. §§ 205.370-371, 375.

truth. As described above, a multilayered system of resource planning involving states and regional grid operators ensures adequate supplies and grid stability.¹⁸⁰

The Report’s conclusion that “absent intervention, it is impossible for the nation’s bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens,” is undermined by this failure.¹⁸¹ States across the nation are grappling with how to meet increased demand from AI data centers while maintaining grid reliability and distributing the costs of those changes in an equitable manner. Without an analysis of the existing framework for making such determinations, and ongoing efforts to adjust those systems to meet new challenges, there is no basis for DOE’s conclusion that “intervention” – likely through 202(c) orders – is the only way to possibly reach those goals.¹⁸²

d. As described in the EO, the report intrudes upon state authority.

EO 14262 directs the Secretary of Energy to rely upon the methodology disclosed in the Report to “identify current and anticipated regions with reserve margins below acceptable thresholds” and “identify which generation resources within a region are critical to system reliability.”¹⁸³ The Executive Order also directs DOE to further develop a “protocol” for applying this analysis to “include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource.”¹⁸⁴ The Report is therefore foundational to the “protocol” that EO 14262 intends will direct emergency orders to override planned retirements. The Report thus directly intrudes on the States’ lawful resource adequacy planning processes.

With respect to regulatory oversight for resource adequacy, section 201 of FPA, 16 U.S.C. § 824(b)(1), reserves authority over generation facilities to the states. It states in pertinent part: “The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction*, except as specifically provided in this subchapter and subchapter III of this chapter, *over facilities used for the generation of electric energy* or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.”¹⁸⁵

The Federal Power Act is likewise clear that federal regulatory jurisdiction over the power sector “extend[s] only to those matters which are not subject to regulation by the States.”¹⁸⁶ With the few and specific exceptions outlined elsewhere in the statute, this jurisdiction

¹⁸⁰ See *Supra*, Section 2.a.

¹⁸¹ Report at 1.

¹⁸² *Id.*

¹⁸³ Executive Order 14262, §§ 3(b)-(c).

¹⁸⁴ *Id.* at § 3(c).

¹⁸⁵ *Id.* (emphasis added).

¹⁸⁶ 16 U.S.C. § 824(a).

does *not* extend to “facilities used for the generation of electric energy”¹⁸⁷ This statutory language places the regulation of generation resource adequacy squarely in the ambit of the states, not the federal government.¹⁸⁸

States have typically exercised this authority through a combination of individual state legislative and regulatory functions as well as engaging in multistate RTOs and ISOs. Some states have retained this authority over resource adequacy in its entirety,¹⁸⁹ while others have directed their utilities to join RTOs/ISOs that, through their tariffs, impose resource adequacy requirements. Those RTO/ISOs also generally establish markets that allow market participants to buy and sell capacity and thereby to facilitate market entry and exit decisions based on price signals. Resource adequacy requirements in RTO/ISO tariffs have been held to be practices affecting wholesale rates subject to the jurisdiction of FERC under sections 205 and 206 of the Federal Power Act, 16 U.S.C. §§ 824d & 824e.¹⁹⁰

Through these channels, states conduct the careful, calculated, long-term capacity planning that goes ignored in DOE’s Report.¹⁹¹ The Report utterly fails to recognize or properly account for the states’ traditional and statutory role in resource adequacy planning, and as forecasted by EO 14262, the Report constitutes a central component of the federal government’s proposed protocol to usurp the states’ authority over this issue.

The use of emergency orders to illegally override state resource adequacy planning has been challenged on the same grounds by the Organization of MISO States, Inc. (OMS), in its Petition for Rehearing of DOE Order No. 202-25-3 (ordering continued operation of the J.H. Campbell coal-fired power plant). In its Petition, OMS noted among other points that “[t]his is the first time the DOE has invoked Section 202(c) outside a severe weather event or emergency, and for the first time, uses the power to suspend a retirement and interfere with established and vetted state and regional planning processes.”¹⁹² OMS’ petition continues, “[t]his expansive use of emergency powers sets a troubling precedent, enabling interventions in routine, state-approved planning decisions without an actual crisis and risks establishing its use to circumvent normal utility, RTO, and states processes, and likely exposes ratepayers to costs that should not be borne.”¹⁹³ In DOE’s issuance of the Report pursuant to EO 14262, the federal government is

¹⁸⁷ *Id.* § 824(b)(1).

¹⁸⁸ See, e.g., Ashley J. Lawson, CONG. RESEARCH SERV., R47521, *Electricity: Overview and Issues for Congress*, at 7 (Feb. 14, 2025).

¹⁸⁹ See *Devon Power LLC et al.*, 109 FERC ¶61,154, P 47 (2004) (“Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.”).

¹⁹⁰ See *Conn. Dep’t of Pub. Util. Control v. FERC*, 569 F.3d 477, 483 (D.C. Cir. 2009).

¹⁹¹ E.g., Report at 2-3, 5, 12-13 (relying solely on federal, EIA, and NERC estimates and failing to mention nuanced state, RTO, or ISO figures and actions).

¹⁹² See Petition to Intervene and Request for Rehearing of the Organization of MISO States, Inc., Order No. 202-25-3 (filed June 23, 2025), <https://www.energy.gov/sites/default/files/2025-07/Petition%20to%20Intervene%20and%20Request%20for%20Rehearing%20of%20the%20Organization%20of%20MISO%20States.pdf>.

¹⁹³ See *id.* at 5; see also *id.* at 4 (challenging “Violation of the Federal Power Act and State Jurisdiction.”).

attempting to establish its own rule for resource adequacy planning from which it can routinely issue illegal orders under the same flawed premise that OMS challenges in its Petition.

Lastly, Section 202(c) does not serve as a widespread grant of DOE jurisdiction over resource adequacy and capacity planning. “Congress ... does not ... hide elephants in mouseholes.”¹⁹⁴ First, as described above in Part [3b], Congress assigned non-emergent questions of interconnection and transmission necessity amenable to public notice and hearing to FERC, not DOE.¹⁹⁵ Moreover, even this authority should not be seen as a substitute for the overarching reservation of regulatory jurisdiction over resource adequacy planning to the states.¹⁹⁶ No reasonable reading of the relevant statutory authorities could construe DOE’s authority in 16 U.S.C. § 824a(c) as intruding on the explicit and traditional role of the states in regulating electricity generation and resource adequacy. However, all available indicators in the Report and EO 14262 evince a flawed understanding contrary to DOE’s appropriate and limited role in this space, thus the Department should reconsider its findings and position on this authority.

e. DOE’s Failure to Provide Public Notice and Comment on its New Standard and Methodology Violated the Administrative Procedure Act, 5 U.S.C. § 553.

Before adopting a final rule, the Administrative Procedure Act requires agencies to publish in the Federal Register a notice of proposed rulemaking and accept public comment.¹⁹⁷ An agency action that imposes legally binding obligations or prohibitions on regulated parties, substantially removes the agency’s discretion, or would be the basis for an enforcement action for violations of those requirements, is a legislative rule that requires notice and comment.¹⁹⁸ Notice and comment is also required when agencies establish new standards that are not derived from an existing statute or regulation or when an agency relies on its statutorily delegated authority to establish policy.¹⁹⁹ Additionally, agency documents that adopt a “new position inconsistent with any of the [agency’s] existing regulations” are subject to notice and comment.²⁰⁰

DOE’s report creates a brand-new national standard and methodology for evaluating resource adequacy. This standard has concrete legal effects because DOE plans to enforce it via Section 202(c) emergency orders. It also is inconsistent with DOE’s existing regulations, which direct DOE to issue emergency orders in very different circumstances based on different criteria than what DOE now proposes. Significantly, DOE acknowledges that its conclusions lack sufficient input from the entities responsible for operating the grid, but DOE nonetheless refused to submit the Report to notice and comment where the public could have tested DOE’s assumptions and conclusions. Assuming DOE continues to comply with the Executive Order’s

¹⁹⁴ *Whitman v. Am. Trucking Ass’n, Inc.*, 531 U.S. 457, 468 (2001).

¹⁹⁵ 16 U.S.C. § 824a(b); 42 U.S.C. § 7172(a)(1)(B).

¹⁹⁶ 16 U.S.C. §§ 824(a)-(b).

¹⁹⁷ 5 U.S.C. § 553(b)-(c).

¹⁹⁸ See *Nat’l Min. Ass’n v. McCarthy*, 758 F.3d 243, 251–52 (D.C. Cir. 2014).

¹⁹⁹ See *Children’s Hosp. of the King’s Daughters, Inc. v. Azar*, 896 F.3d 615, 622 (4th Cir. 2018).

²⁰⁰ *Shalala v. Guernsey Mem’l Hosp.*, 514 U.S. 87, 99–100 (1995).

unlawful command to use this Report to support future Section 202(c) orders, the Report and any action relying on it must be set aside for failure to provide notice and comment.

i. DOE’s standard is an exercise of assumed legislative authority, and it has concrete legal effects.

Pursuant to the Executive Order, DOE established a “uniform methodology” for assessing resource adequacy across the country.²⁰¹ That methodology adopts a new “resource adequacy standard” to measure the desired level of adequacy needed for the bulk power system.²⁰² DOE acknowledges that it is not using the “traditional . . . criterion” for measuring resource adequacy and is relying on metrics that are “not standardized in the U.S. today.”²⁰³ Instead, DOE unilaterally adopts new metrics to evaluate resource adequacy and establishes the reliability targets that should be obtained.²⁰⁴ DOE’s choice of metrics and the targets to be achieved are value judgments and should be informed by economic tradeoffs and other policy considerations about what level of system reliability should be achieved and at what cost to consumers, areas where public input is essential to sound decision making.²⁰⁵

DOE also fills its methodology with value-laden policy choices around the data inputs and assumptions that determine when DOE’s reliability standard is achieved. As just one example, DOE includes projected future demand from potential new AI data centers as part of its calculation of future load.²⁰⁶ Those data centers have not yet been built and some may never be.²⁰⁷ And, as DOE recognized, grid operators are not likely to allow those large loads to connect if doing so threatens reliability.²⁰⁸ Including those potential loads in DOE’s determinations of system reliability thus inherently represents a policy choice: Should present-day consumers pay to keep retiring power plants online to ensure that potential data centers can be reliably served in the future?²⁰⁹

Even assuming *arguendo* that DOE has the statutory authority to set a uniform reliability standard, place risks of future large load growth on current consumers, or engage in long-term resource adequacy planning for the entire nation, it still must involve stakeholders through notice and comment in those legislative choices. “When an agency relies on expressly delegated authority to establish policy . . . courts generally treat the agency action as legislative [] rulemaking” and require notice and comment.²¹⁰ In other words, “when Congress leaves [] a policy choice to the agency, [courts] should lean toward finding that the agency’s making of that

²⁰¹ See Report at vi (explaining that the report is “delivering the required uniform methodology to identify at-risk region(s)”; Executive Order 14262 § 3(b)).

²⁰² Report at 3.

²⁰³ *Id.* 3-4.

²⁰⁴ See *id.*

²⁰⁵ See Ex. C, IPI Report at ii (criticizing DOE’s choice of targets as not “appropriately justified based on a cost-benefit framework, and the use of a one-size-fits-all target for the entire country ignores regional differences”).

²⁰⁶ See Report at 1-3.

²⁰⁷ See, e.g., Ex. E, London Economics International Report; Laila Kearney and Liz Hampton, *U.S. Power Stocks Plummet as DeepSeek Raises Data Center Demand Doubts*, Reuters (Jan. 27, 2025) <https://www.reuters.com/business/energy/us-power-stocks-plummet-deepseek-raises-data-center-demand-doubts-2025-01-27/>.

²⁰⁸ See Report at 14.

²⁰⁹ See also *supra* Section 4.a. (discussing other arbitrary assumptions in DOE’s analysis).

²¹⁰ *Children’s Hosp. of the King’s Daughters, Inc.*, 896 F.3d at 622.

choice requires notice and comment.²¹¹ “Otherwise, it would be difficult to imagine what regulations *would* require notice and comment procedures.”²¹²

DOE’s standard also has concrete legal effects because, consistent with the Executive Order, DOE will use Section 202(c) emergency orders (or the threat of Section 202(c) orders) to ensure regions meet the new standard. The Executive Order directs DOE to use this standard to “establish . . . a protocol” to identify generation resources that are critical to system reliability.²¹³ DOE’s “protocol shall additionally” use Section 202(c) of the Federal Power Act to “ensure” those resources are retained and prevent their retirement.²¹⁴ “Protocol” means “a set of rules to be followed . . .”²¹⁵ As DOE has made clear, DOE “plans to use” this new standard to evaluate retiring coal plants and potentially issue Section 202(c) emergency orders preventing their retirement.²¹⁶

DOE’s new standard, and protocol for enforcing it, removes DOE’s discretion and is intended to provide the basis for enforcement actions via Section 202(c) orders.²¹⁷ The new standard is not derived from the Federal Power Act or, as explained further below, from DOE’s existing regulations, but is an entirely new method of determining resource adequacy across the country. DOE must accordingly submit its new standard and methodology to public notice and comment.²¹⁸

ii. DOE must provide notice and comment because its standard allegedly supports issuing emergency orders based on factors that conflict with existing regulations.

DOE’s Report provides new bases for issuing emergency orders that conflict with DOE’s existing regulations, but DOE cannot amend those standards without first providing notice and comment.²¹⁹ DOE promulgated regulations detailing how and when it issues Section 202(c) emergency orders following public notice and comment in 1981.²²⁰ Under DOE’s current regulations, emergency orders “are envisioned as meeting a *specific* inadequate power supply situation,” occasioned by “acts of God[] or unforeseen occurrences not reasonably within the

²¹¹ *Id.*

²¹² *Id.* (quoting *N.H. Hosp. Ass’n v. Azar*, 887 F.3d 62, 70–71 (1st Cir. 2018)).

²¹³ Executive Order 14262 at § 3(c).

²¹⁴ *Id.*

²¹⁵ PROTOCOL, Black’s Law Dictionary (12th ed. 2024).

²¹⁶ Order No. 202-25-4 at 2 (Eddystone Order). *See also* U.S. DEP’T OF ENERGY, *Fact Sheet: The Department of Energy’s Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025), https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf [<https://perma.cc/YLX7-8G7T>] (explaining that DOE’s methodology will be used, pursuant to the executive order, “prevent [] generation resources from leaving the bulk-power system”); Press Release, U.S. Dep’t of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security (July 7, 2025), <https://www.energy.gov/articles/departments-energy-releases-report-evaluating-us-grid-reliability-and-security> [<https://perma.cc/8TEJ-AGH6>]. (stating that its “methodology also informs the potential use of DOE’s emergency authority under Section 202(c) of the Federal Power Act”); Report at *vi* (explaining that DOE’s standard will be used to “guide reliability interventions”), 1 (emphasizing the need for DOE’s “decisive intervention” in energy markets), 10 (analyzing ERCOT because “FPA Section 202(c) allows DOE to issue emergency orders to ERCOT”).

²¹⁷ *See Nat’l Min. Ass’n v. McCarthy*, 758 F.3d 243, 251–52 (D.C. Cir. 2014).

²¹⁸ *See id.*; *Children’s Hosp. of the King’s Daughters, Inc. v. Azar*, 896 F.3d 615, 622 (4th Cir. 2018).

²¹⁹ *See Shalala*, 514 U.S. at 99–100.

²²⁰ *See Emergency Interconnection of Electric Facilities*, 46 Fed. Reg. 39,984 - 39,989 (Aug. 6, 1981).

power of the affected ‘entity’ to prevent.”²²¹ DOE did not intend its emergency authority to replace long-term planning by utilities: “while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.”²²²

As DOE stated then, “[t]he factors that DOE will consider in determining whether an emergency exists are specified in § 205.373.”²²³ Section 205.373 requires applicants to submit detailed information on “daily peak load and energy requirements for each of the past 30 days and projections for each day of the expected duration of the emergency” and make a “showing that adequate electric service cannot be maintained without additional power transfers.” Applicants must also describe what “conservation or load reduction actions have been implemented” before seeking emergency relief.²²⁴ In sum, DOE’s current regulations direct a case-by-case analysis of specific, temporary shortages in particular situations, based on detailed information from an applicant.

DOE’s new standard and methodology is an unprecedented expansion of the bases upon which DOE will justify Section 202(c) emergency orders, but DOE has not offered public comment on that expansion. Rather than focusing on specific showings of an imminent threat to grid stability, the report rests on DOE’s analysis of “the U.S. electric grid’s ability to meet future demand through 2030.”²²⁵ Rather than consider the “daily peak load and energy requirements of the past 30 days and projections for each day of the [] emergency,” 10 C.F.R. § 205.373, DOE now plans to base Section 202(c) decisions on speculation over the development of artificial intelligence, re-industrialization of the U.S. economy, and other uncertain developments over the next five years.²²⁶ Rather than consider the “scheduled . . . deliveries” during the emergency period and needs of existing firm customers, § 205.373(d),(f), DOE now proposes to find an emergency based on potential load growth for customers who do not currently, and may never, exist.²²⁷

Rather than allowing utilities and grid operators to solve long-term planning issues themselves, DOE now seeks to intervene in those state- and FERC-regulated processes based on its own assumptions about future load growth and electricity supply. But unlike DOE’s Report, the long-term resource adequacy plans developed by utilities and grid operators are transparent and publicly-accountable processes that involve relevant stakeholders and the public.²²⁸ DOE, on the other hand, published its analysis without critical data or insights from the entities who actually operate and maintain the electric grid.²²⁹

²²¹ 10 C.F.R. § 205.371 (emphasis added).

²²² 46 Fed. Reg. at 39,985; *see also* 10 C.F.R. § 205.371

²²³ 46 Fed. Reg. at 39,985.

²²⁴ *Id.*; *see also* 10 C.F.R. § 205.375 (defining an inadequate energy supply as when an applicant is “unable to meet its normal peak load requirements based upon use of all its otherwise available resources.”).

²²⁵ Report at 2.

²²⁶ Report at 2; *see also supra* Section 4.a.

²²⁷ *See, e.g.,* Ex. E London Economics International Report; Laila Kearney and Liz Hampton, *U.S. Power Stocks Plummet as DeepSeek Raises Data Center Demand Doubts*, Reuters (Jan. 27, 2025)

<https://www.reuters.com/business/energy/us-power-stocks-plummet-deepseek-raises-data-center-demand-doubts-2025-01-27/>.

²²⁸ *See supra* Section 2.a.

²²⁹ Report at *i*.

Rather than considering what other “conservation or load reduction actions have been implemented” before turning to emergency relief, 10 C.F.R. § 205.373, DOE’s standard ignores those possibilities altogether. Instead, DOE adopts aggressive and likely overstated assumptions of load growth and ignores whether any of that future demand could be flexibly integrated into the grid, what measures state and local regulators are taking to mitigate the impact of new data center demand on grid reliability, or other factors influencing grid reliability over the long-term.²³⁰ DOE appears to admit that its overstated potential load growth will not *actually* lead to any grid reliability emergency, as there is no “indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system.”²³¹

DOE appropriately involved the public when it initially set out the process and factors to consider for Section 202(c) orders in its 1981 rulemaking. Yet now, DOE seeks to expand the bases for Section 202(c) orders in ways that intrude on state-regulated processes and the free market, without any input from stakeholders or the public who will ultimately pay for DOE’s actions. Because the methodology and protocol effectively “expand[s] the footprint [of DOE’s emergency authority] by imposing new requirements, rather than simply interpreting the legal norms Congress or the agency itself has previously created” and is inconsistent with DOE’s existing regulations, it is a “rule” under the APA and notice and comment is required.²³²

iii. DOE acknowledges the importance of involving the States and other actors yet fails to provide public notice and comment to test DOE’s assumptions and conclusions.

DOE’s failure to provide public notice and comment is prejudicial error. DOE admittedly lacks the “range of data and insights” to make robust reliability decisions that entities responsible for the maintenance and operation of the grid have access to.²³³ Had the States been given adequate notice and an opportunity to comment, they could have provided more information to DOE on how existing mechanisms address grid reliability, issues with DOE’s assumptions, chosen metrics, and choice of data, identified gaps in DOE’s analysis and data, and other issues. Numerous grid experts have commented on shortfalls with DOE’s report.²³⁴ Given adequate notice and an opportunity to comment, the States could have obtained their own expert analysis and potentially raised even more issues with DOE’s proposed standard and methodology than what time permitted the States to raise here.

DOE has previously acknowledged the importance of involving States and the public in these questions. When DOE initially established regulations governing how and when it would

²³⁰ See, e.g., Ex. D, Nicholas Institute Report; Jason Plautz, *State lawmakers grapple with energy demand for data centers*, E&E News (Mar. 3, 2025) <https://www.eenews.net/articles/state-lawmakers-grapple-with-energy-demand-for-data-centers/>; Washington Office of the Governor, *Gov. Bob Ferguson Signs Executive Order Establishing a Data Center Workgroup* (Feb. 4, 2025) <https://governor.wa.gov/news/2025/governor-bob-ferguson-signs-executive-order-establishing-data-center-workgroup>.

²³¹ Report at 14.

²³² *Children’s Health Care v. Centers for Medicare & Medicaid Servs.*, 900 F.3d 1022, 1025 (8th Cir. 2018); see also *Shalala*, 514 U.S. at 99–100.

²³³ Report at *i*

²³⁴ See, e.g., Jeff St. John, *Critics fear Trump will use flawed DOE report to push pro-coal agenda*, Canary Media (July 14, 2025), <https://www.canarymedia.com/articles/fossil-fuels/trump-doe-report-open-coal-plants>; Matthias Fripp and Brendan Pierpont, Opinion, *Energy Department’s flawed grid study props up expensive, zombie power plants*, UtilityDive, <https://www.utilitydive.com/news/doe-grid-reliability-study-zombie-power-plants/753596/>.

issue emergency orders, DOE consulted with the Federal Energy Regulatory Commission and state officials.²³⁵ DOE also explained that “[t]he DOE intends to utilize any available State and local expertise in resolving an emergency.”²³⁶ Indeed, DOE’s organizational statute *requires* it to consult with States “[w]henever any proposed action by the Department conflicts with the energy plan of any State.”²³⁷ And States are already taking actions to address reliability issues and load growth in their jurisdictions.²³⁸ DOE’s refusal to collaborate with States or meaningfully involve other stakeholders here is inexplicable, conflicts with DOE’s organizational statute, and the APA.

V. Conclusion

The State’s request for rehearing should be granted and DOE should withdraw or otherwise amend the subject Report following public vetting through notice and comment proceedings. In the meantime, DOE cannot rely on the challenged report to support the exercise of its 202(c) authority. Doing so would be arbitrary and capricious and otherwise contrary to law and impose significant harm on our States.

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²³⁵ 46 Fed. Reg. at 39,985.

²³⁶ *Id.*

²³⁷ 42 U.S.C. § 7113; *see also* 16 U.S. Code § 824h (encouraging federal-state collaboration).

²³⁸ Jason Plautz, *State lawmakers grapple with energy demand for data centers*, E&E News (Mar. 3, 2025) <https://www.eenews.net/articles/state-lawmakers-grapple-with-energy-demand-for-data-centers/>; Washington Office of the Governor, *Gov. Bob Ferguson Signs Executive Order Establishing a Data Center Workgroup* (Feb. 4, 2025) <https://governor.wa.gov/news/2025/governor-bob-ferguson-signs-executive-order-establishing-data-center-workgroup>.

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Craig Unit 1

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Order No. 202-25-14

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit NN: Division, *Colorado Visibility and Regional Haze SIP for the Twelve
Mandatory Class I Federal Areas in Colorado* (Dec. 15, 2016)

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

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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 NO_x 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 NO_x 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 NO_x emissions impacting Colorado Class I areas. California identified measures being taken in the State to reduce NO_x 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 program² 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/>

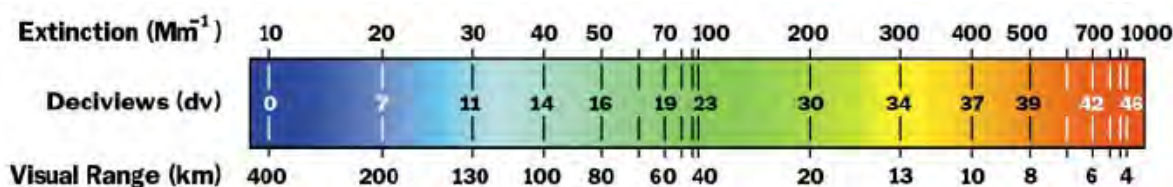
⁴ <http://pah.cert.ucr.edu/aqm/308/>

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 ($1/\text{Mm}$ 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)

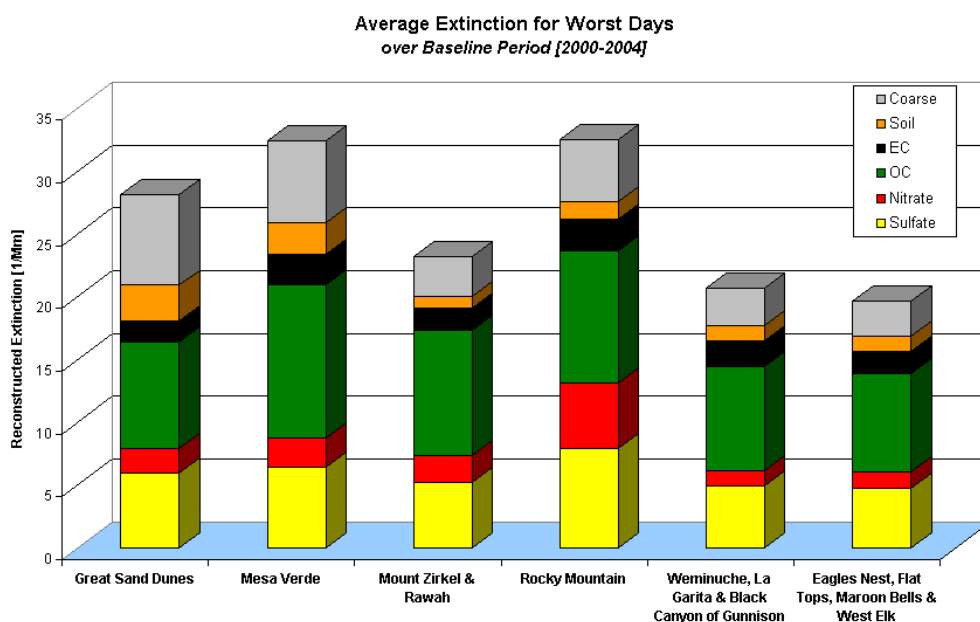
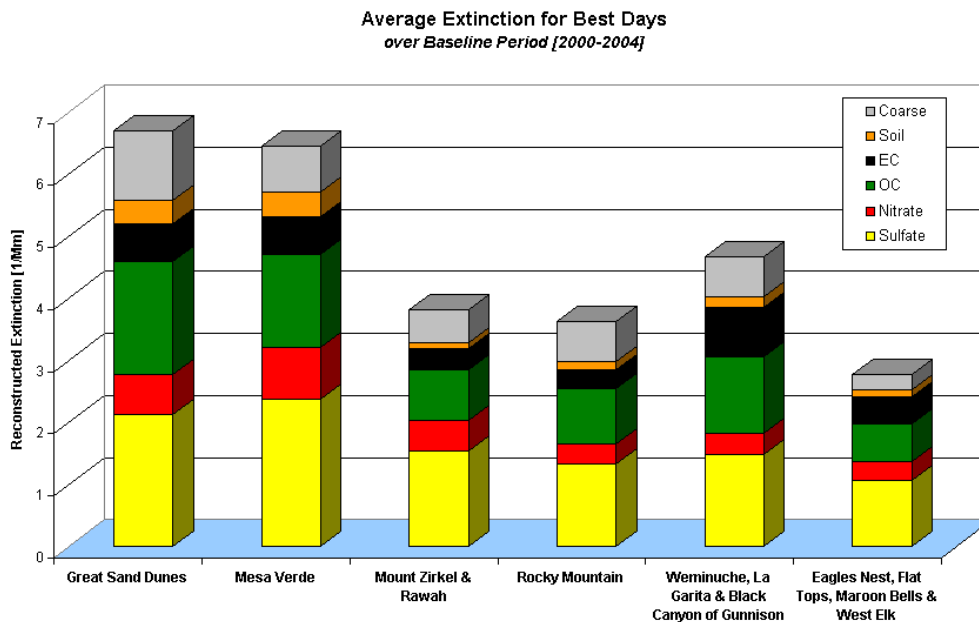


Figure 4-2 Reconstructed Aerosol Components for 20% Best Days (2000-2004)



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:

$$2018\ UPG = [URP] \times [14\ years]$$

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

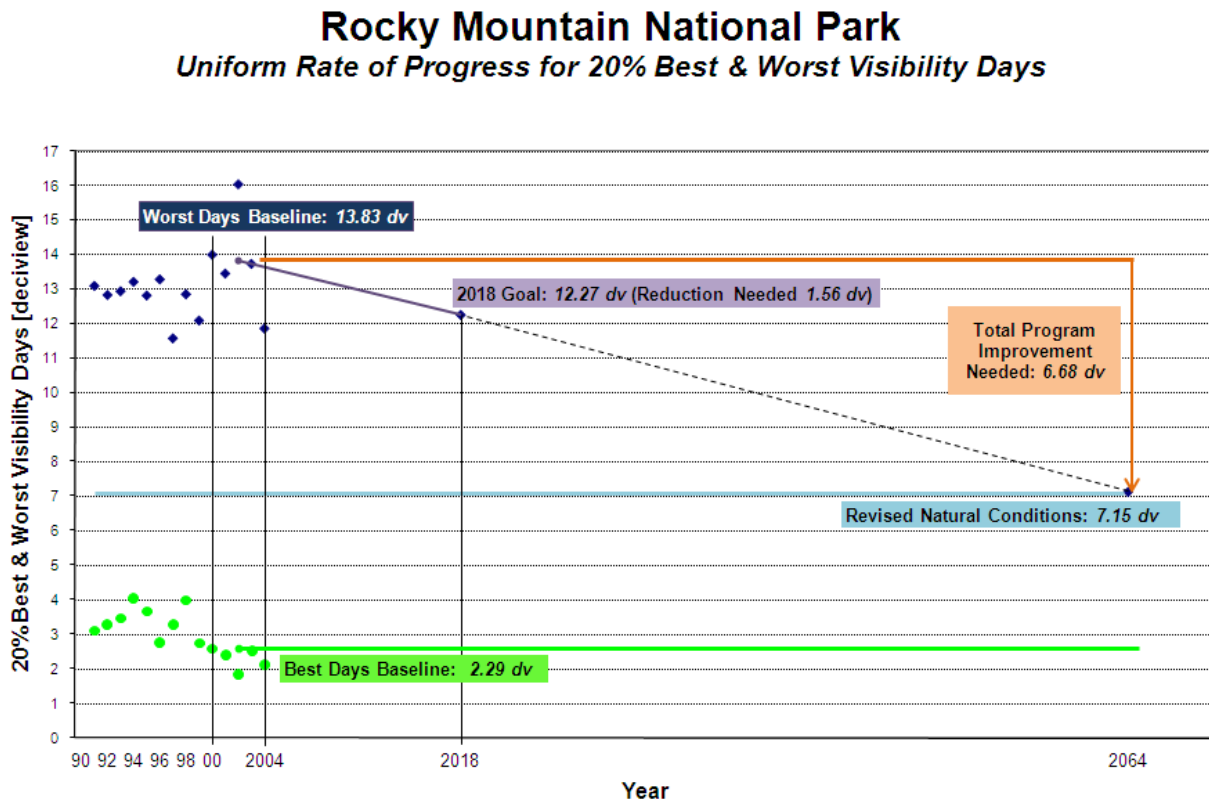
Baseline Summary of Best & Worst Days in Haze Index Metric

Baseline Period (2000-2004)

Mandatory Class I Federal Area	20% Worst Days					20% Best Days
	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 & NO_x 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 (NO_x), volatile organic compounds (VOC), primary organic aerosol (POA), elemental carbon (EC), fine particulate (Soil-PM_{2.5}), 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

<i>Colorado Planning and Projection Emission Inventories</i>			
Source Category	Statewide SO ₂ 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

<i>Colorado Planning and Projection Emission Inventories</i>			
Source Category	Statewide NO _x Emissions		
	Plan 2002(d) [tons/year]	PRP 2018(b) [tons/year]	Net Change
Point	118,667	101,818	-14%
Area	11,729	16,360	39%
On-Road Mobile	141,883	45,249	-68%
Off-Road Mobile	62,448	37,916	-39%
WRAP Area O&G	23,518	33,517	43%
Road Dust	1	1	32%
Fugitive Dust	16	14	-13%
Anthro Fire	520	408	-21%
Natural Fire	9,377	9,377	0%
Biogenic	37,349	37,349	0%
Total:	405,507	282,010	-30%

Nitrogen oxides (NO_x) 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

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

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

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

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

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

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

Colorado Planning and Projection Emission Inventories			
Source Category	Statewide EC Emissions		
	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

<i>Colorado Planning and Projection Emission Inventories</i>			
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

<i>Colorado Planning and Projection Emission Inventories</i>			
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, NO_x 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 (98 th 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 SO ₂ .				
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	SO₂ Control Type	SO₂ 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 NO_x 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 NO_x 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 NO_x 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 desulfurization (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 NO_x controls, the state has assessed pre-combustion and post-combustion controls and upgrades to existing NO_x 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.

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 NO_x 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 NO_x 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 NO_x emissions, post-combustion controls for NO_x 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 NO_x 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 NO_x 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 NO_x Limits for Electric Generating Units* and *Technical Support Document for BART NO_x 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 NO_x 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 (NO_x) from the atmosphere, or \$/ton of NO_x removed); and, (ii) visibility improvement expected from the control options analyzed (e.g., expressed as visibility improvement in delta deciview (Δ dv) from CALPUFF air quality modeling).

- Accordingly, as part of its five factor consideration the state has elected to generally employ criteria for NO_x post-combustion control options to aid in the assessment and determinations for BART - a \$/ton of NO_x removed cap, and two minimum applicable Δ dv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows. For the highest-performing NO_x 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 Δ dv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NO_x 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 Δ dv 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

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 NO_x controls, *i.e.*, SCR, has the ability to provide significant NO_x reductions, but also has initial capital dollar requirements that can approach or exceed \$100 million per unit.¹⁵ The lesser-performing post-combustion NO_x controls, *e.g.*, SNCR, reduce less NO_x 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 NO_x controls (*i.e.*, SCR), the state anticipates a direct level of visibility improvement contribution, generally 0.50 Δ_{dv} or greater of visibility improvement at the primary affected Class I Area.¹⁷ For the lesser-performing add-on NO_x controls (*e.g.*, SNCR), the state anticipates a meaningful and discernible level of visibility improvement that contributes to broader visibility improvement, generally 0.20 Δ_{dv} or greater of visibility improvement at the primary affected Class I Area. Employing the foregoing guidance criteria for post-combustion NO_x 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 Δ_{dv} 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 Δ_{dv} 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 NO_x emissions. The raw material dryer emits minor amounts of SO₂ and NO_x; in 2008 Cemex reported SO₂ and NO_x 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 1600-2000°F) for reducing NO_x 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 NO_x 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				
SO ₂ Control Technology	Estimated Control Efficiency	Annual Controlled Hourly SO ₂ Emissions (lbs/hr)	Annual Controlled SO ₂ Emissions (tpy)	Annual Controlled SO ₂ Emissions (lb/ton of Clinker)
Baseline SO ₂ 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				
SO ₂ Control Technology	SO ₂ Emission Reduction (tons/yr)	Annualized Cost (\$/yr)	Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
Baseline SO ₂ 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		
SO ₂ 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/PM₁₀. The state assumes that the BART emission limits can be achieved through the operation of the existing fabric filter baghouse.

NO_x BART Determination for Cemex Lyons - Kiln

Water injection, firing coal supplemented with tire-derived fuel (TDF), indirect firing with low NO_x burners, and selective non-catalytic reduction (SNCR) were determined to be technically feasible and appropriate for reducing NO_x 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				
NO _x Control Technology	Estimated Control Efficiency	Annual Controlled Hourly NO _x Emissions (lbs/hr)	Annual Controlled NO _x Emissions (tpy)	Annual Controlled NO _x Emissions (lb/ton of Clinker)
Baseline NO _x Emissions	-	464.3	1,747.1	7.39
Water Injection	7.0%	431.8	1,624.8	6.87
Coal w/TDF	10.0%	417.8	1,572.3	6.65
Indirect Firing with LNB	20.0%	371.4	1,397.6	5.91
SNCR (30-day rolling)	45.0%	255.3	960.9	4.06
SNCR (12-month rolling)	48.4%	239.4	901.0	3.81
SNCR w/LNB	55%	208.9	786.2	3.33

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

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

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

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

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

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

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

The Cemex - Lyons facility is a unique kiln system most accurately described as a modified long dry kiln, the characteristics of a modified long dry kiln system are not similar to either a long wet kiln or a multi stage preheater/precalciner kiln. The temperature profile in a long dry kiln system ($>1500^{\circ}\text{F}$) is significantly higher at the exit than a more typical preheater precalciner kiln (650°F). This is a significant distinction that limits the location and residence time available for an effective NO_x 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 NO_x 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 NO_x 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 NO_x 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 NO_x reduction from the kiln (846.1 tpy) and contributes significant visibility improvement (0.38 Δ dv). 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.

NO_x 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 NO_x 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, SO₂, PM₁₀), 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 “NO_x 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 SO₂ 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 reduce 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 - SO ₂ 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/PM₁₀. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NO_x BART Determination for CENC - Boilers 4 and 5

Low NO_x 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 NO_x 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 - NO _x 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 (Δ dv)	NOx l Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ dv)
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 NO_x BART for Boiler 5 is the following NO_x 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 NO_x 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 NO_x 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, SO₂, PM₁₀), 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 SO₂ removal.
- *Use of more reactive sorbent* - PSCo is using a highly reactive lime with 92% calcium oxide content reagent that maximizes SO₂ 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 NO₂. Since NO₂ is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO₂ removal rates, such as those experienced at Comanche. There are no known acceptable reagents without this side effect that would allow additional SO₂ 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 SO₂ 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:

SO ₂ Control Method	Comanche - Unit 1		Comanche - Unit 2	
	SO ₂ Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO ₂ 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/PM₁₀) represents the most stringent level of available control for PM/PM₁₀. The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for PM/PM₁₀ as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NO_x BART Determination for Comanche - Units 1 and 2

SNCR and SCR were determined to be technically feasible for reducing NO_x 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:

NO _x Control Method	Comanche - Unit 1		Comanche - Unit 2	
	NO _x Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NO _x 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 NO_x BART is the 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 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, SO₂, PM₁₀), 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 SO₂ concentrations seen at Craig Units 1 and 2.
 2. DBA could cause changes in sulfite oxidation with impacts on SO₂ removal and solids settling and dewatering characteristics.
 3. Installation of the perforated plate tray accomplished the same objective of increased SO₂ 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 SO₂ 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 SO₂ removal rates.
 2. Forced oxidation within the SO₂ 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 SO₂ 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 SO₂ 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:

SO ₂ Control Method	Craig - Unit 1		Craig - Unit 2	
	SO ₂ Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO ₂ 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/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/PM₁₀. The state assumes that the BART emission limit can be achieved through the operation of the existing pulse jet fabric filter baghouses.

NO_x 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 NO_x 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 - NO _x 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 (Δ dv)	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ dv)
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 NO_x 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 operation¹⁸ 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 selected¹⁹.

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 NO_x 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 NO_x 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 NO_x 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 NO_x 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 NO_x 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 NO_x 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 NO_x emission limit of 0.28 lb/MMBtu 30-day rolling average until closure or conversion to natural gas. Additionally, an annual NO_x 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 NO_x 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, SO₂, PM₁₀), 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 SO₂ removal.
- *Use of more reactive sorbent* - PSCo is using a highly reactive lime with 92% calcium oxide content reagent that maximizes SO₂ 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 NO₂. Since NO₂ is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO₂ 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 SO₂ 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 SO₂ 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:

SO ₂ Control Method	Hayden - Unit 1		Hayden - Unit 2	
	SO ₂ Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO ₂ 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/PM₁₀) represents the most stringent level of available control for PM/PM₁₀. The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for PM/PM₁₀ as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

NO_x BART Determination for Hayden - Units 1 and 2

LNB upgrades, SNCR and SCR were determined to be technically feasible for reducing NO_x 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:

NO _x Control Method	Hayden - Unit 1		Hayden - Unit 2	
	NO _x Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	NO _x 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 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.

- 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.

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, SO₂, PM₁₀), and having commenced operation in the 15-year period prior to August 7, 1977. The combined emissions of these boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, all three boilers are subject-to-BART. Initial air dispersion modeling performed by the Division demonstrated that the Martin Drake Plant contributes to visibility impairment (a 98th percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Colorado Springs Utilities (CSU) submitted a BART Analysis to the Division on August 1, 2006 with updated cost information submitted on March 29, 2007. CSU also provided information in its "NO_x 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 - SO ₂ 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:

SO ₂ Control Method	Drake - Unit 5		Drake - Unit 6		Drake - Unit 7	
	SO ₂ Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO ₂ Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)	SO ₂ 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/PM₁₀. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses.

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

Ultra low NO_x burners (ULNB), ULNB including OFA, SNCR, SNCR plus ULNB, and SCR were determined to be technically feasible for reducing NO_x 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 NO _x 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 (Δ dv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ dv)	NOx Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ dv)
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 Δ dv). 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 NO_x 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.

Analysis under 40 CFR Part 51, § 308(e)

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

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

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

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

Table 6-6: Sources Included Within the PSCo Alternative

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

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

The PSCo BART Alternative includes the emission reductions achieved through Colorado HB 10-1365 (§ 40-3.2-201 C.R.S., *et seq.*). The PSCo BART Alternative was developed to address requirements other than BART, including to support the attainment of federal ambient air quality standards, to meet other federal requirements that can affect electric generating units, and improve air quality on the Front Range of Colorado. Since the PSCo BART Alternative was designed to address requirements other than BART, it meets the EPA SIP provision noted 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 NO_x emissions, the PSCo BART Alternative will reduce NO_x 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 NO_x, 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 NO_x 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 NO_x 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 NO_x 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 SO₂ 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 NO_x 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

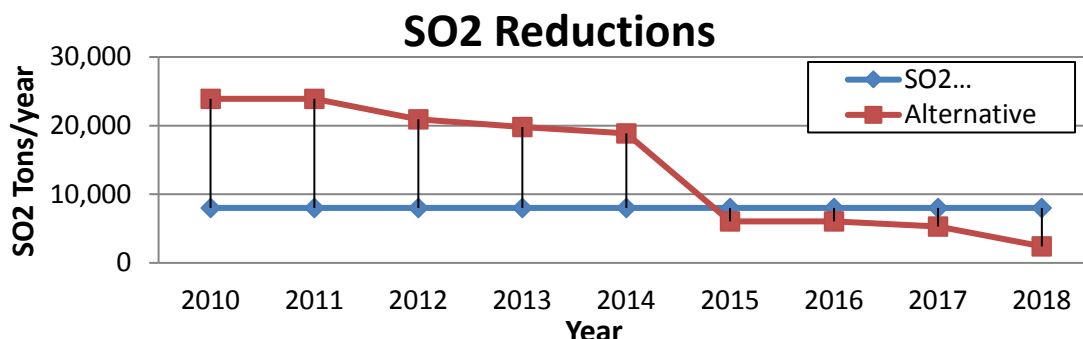
Facility	MMBtu Average 2006 to 2008	SO ₂ TPY Average 2006 to 2008	SO ₂ TPY at 0.15 lb/MMBtu Presumptive	SO ₂ TPY under PSCo Alternative in 2018	% Reduction Beyond Presumptive BART
Arapahoe					
Unit 3	4,380,121	924.97	328.51	0.00	100.00%
Unit 4	8,545,791	1,764.70	640.93	1.28 ²¹	99.8%
Cherokee					
Unit 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 NO_x emissions. Table 6-8 compares the PSCo BART Alternative to a standard based on NO_x limits established by EPA in 70 Fed. Reg. 39135 (7/6/2005). EPA provides a NO_x lb/MMBtu level based on the boiler type and the coal type burned. The PSCo BART Alternative reflects 600 tpy of NO_x emitted from Arapahoe 4 operating on natural gas as a “peaking” unit, 300 tpy of NO_x reserved for “netting” or “offsets” from the Arapahoe facility, and 500 tpy of NO_x reserved for “netting” or “offsets” from the Cherokee facility.

Table 6-8: NO_x Reductions beyond Presumptive BART for PSCo Alternative

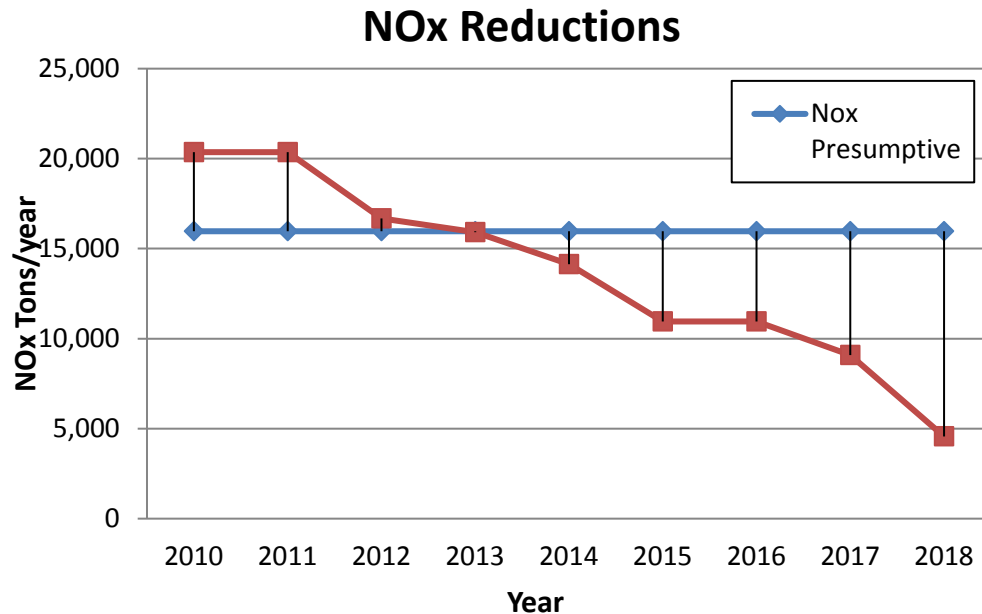
Facility	MMBtu Average 2006 to 2008	NO _x TPY Average 2006 to 2008	NO _x lb/MMBtu Standard	TPY NO _x at Standard	TPY NO _x Under PSCo Alternative in 2018	% Reduction Beyond Presumptive BART
Arapahoe						
Unit 3	4,380,121	1,770.47	0.23	503.71	0.00	100.00%
Unit 4	8,545,791	1,147.67	0.23	982.77	900.00 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 NO_x from operation of Arapahoe 4 on natural gas as a “peaking” unit and 300 tpy NO_x reserved for “netting” and “offsets” for additional natural gas generation. The 300 tpy NO_x 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 NO_x/mmBTU and 500tpy NO_x reserved for “netting” or “offsets”. The 500 tpy NO_x 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 NO_x reductions of the alternative program based on the criteria established by the state for BART and reasonable progress for NO_x reductions. As part of its five factor consideration the state has elected to generally employ criteria for NO_x post-combustion control options to aid in the assessment and determinations for BART - a \$/ton of NO_x removed cap, and two minimum applicable Δ dv improvement figures relating to CALPUFF modeling for certain emissions control types, as follows.

- For the highest-performing NO_x 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 Δ dv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NO_x 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 Δ dv 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 NO_x removed or the visibility improvement from SCR is less than 0.50 Δ dv. 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 NO_x 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 NO_x 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 NO_x reduction, of 50%, to assess performance of presumed SNCR on these units as against the PSCo BART Alternative for NO_x.²⁵

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

²⁵ This level of NO_x 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 NO_x 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

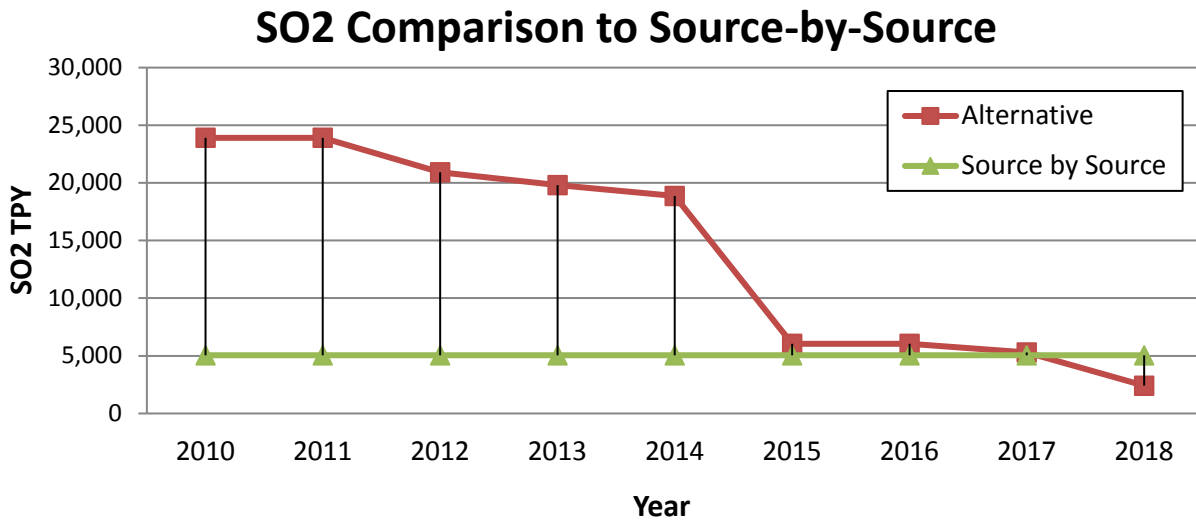
Facility	SO ₂ TPY from AP-42	Source-by-Source	SO ₂ TPY from PSCo Alternative	% Reduction Beyond Source-by-Source
Arapahoe				
Unit 3	1,076.53	53.82	0.00	100.00%
Unit 4	2,322.21	1.28	1.28	0.00%
Cherokee				
Unit 1	2,803.67	140.18	0.00	100.00%
Unit 2	2,662.17	133.10	0.00	100.00%
Unit 3	3,438.79	171.93	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



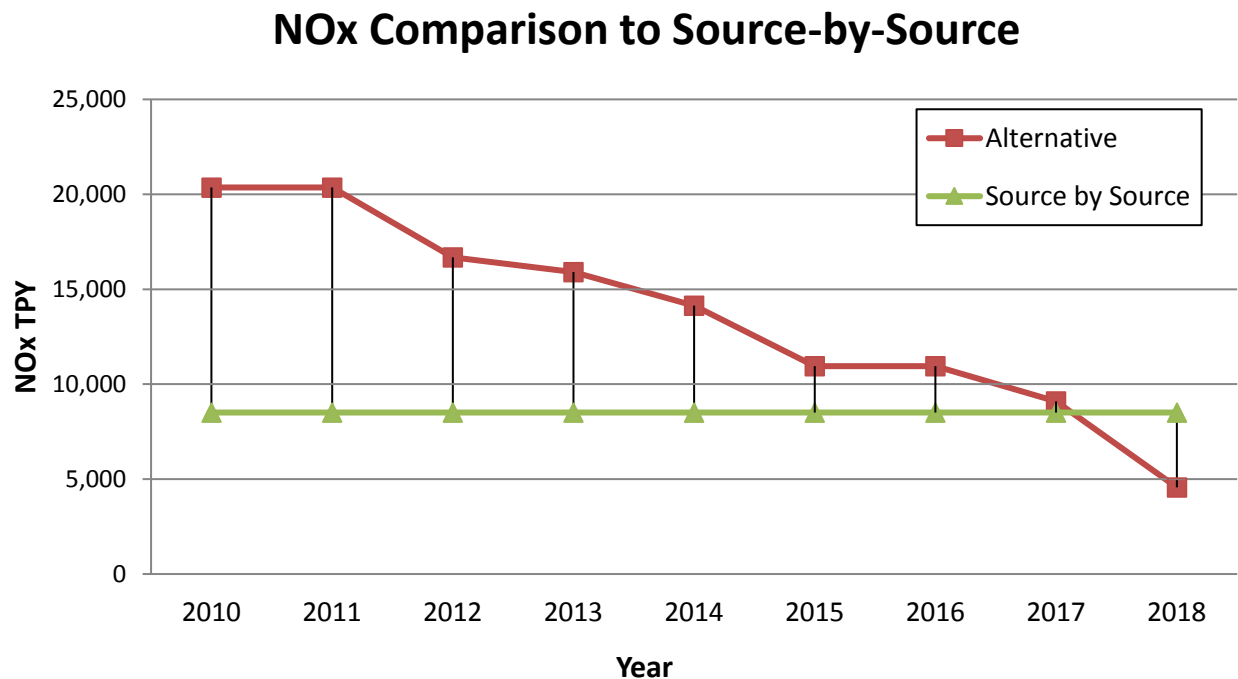
For NO_x the state looked at a source by source analysis for Arapahoe Unit 4, Cherokee Unit 4 and Pawnee. For the remainder of the sources, for demonstration purposes, the state applied an aggressive 90% control level assumption to the sources. The 90% was taken from emissions calculated using AP-42.³² The source by source analysis considered the operation of Arapahoe Unit 4 with natural gas as a peaking unit and retaining 300 tpy of NO_x 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 NO_x 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 NO_x 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 NO_x 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 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 <i>Based on WRAP CMAQ Modeling using the PRP 2018b</i>								
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

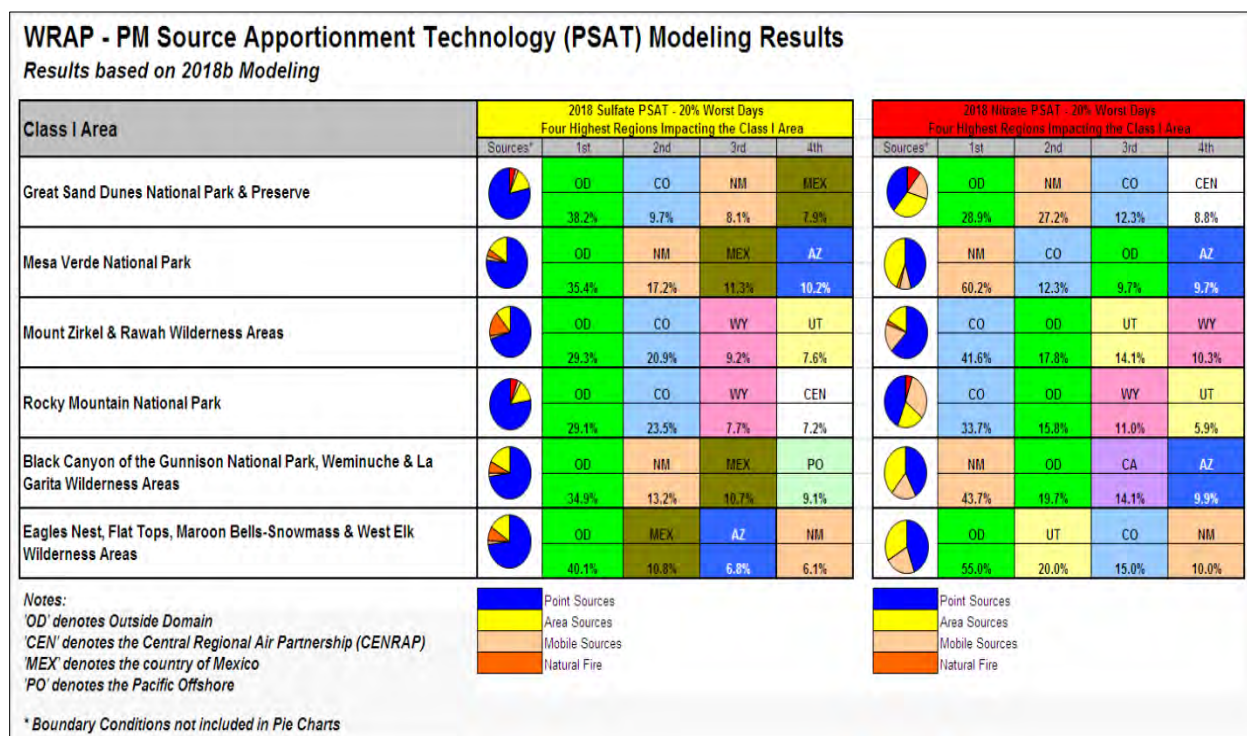


Figure 7-3 identifies the change in the Colorado portion of particulate sulfate and nitrate concentrations, from 2002 to 2018 at each Class I area. For 2018, the PSAT modeling forecasts a reduction in the Colorado portion of sulfate at all Class I areas ranging from 25% to 33%. These particulate sulfate 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 SO ₄ [ug/m ³]	Colorado SO ₄ [ug/m ³]	Colorado Share SO ₄	Colorado Sulfate Change	Total NO ₃ [ug/m ³]	Colorado NO ₃ [ug/m ³]	Colorado Share NO ₃	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 evaluation³⁹ 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), NO_x (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

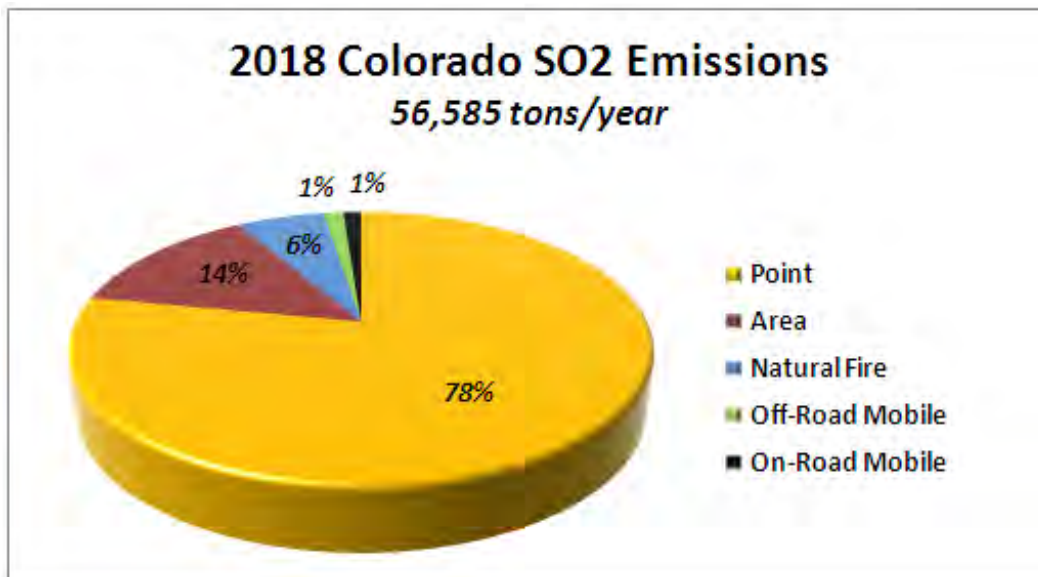
This determination is based on the well documented point source emission inventories for SO₂ and NO_x, and the Regional Model performance for sulfate and nitrate was determined to be acceptable. Significant point source PM emissions are also evaluated because of the Q/d screening methodology (Q = total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

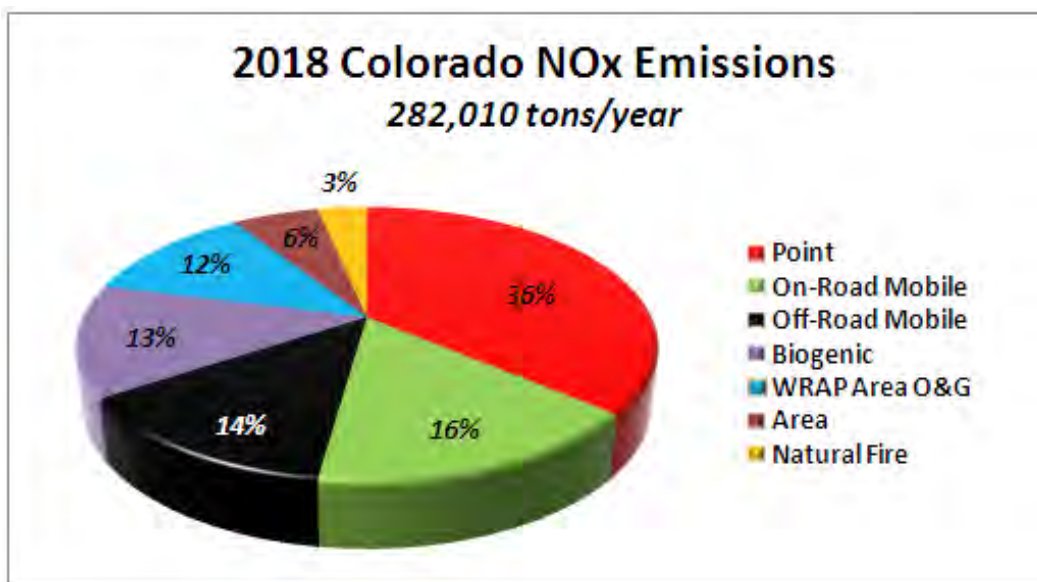


As indicated, 78% of total statewide SO₂ emissions are from point sources - largely coal-fired boilers. Area source SO₂ emissions (14%) are dominated by thousands of boilers and internal combustion engines statewide that burn distillate fuel. Depending on use and fuel grade, the maximum sulfur content 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 NO_x 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 NO_x Emissions in 2018



Point sources comprise 36% of total NO_x 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 NO_x emissions respectively. A portion of the on-road mobile source NO_x emissions reflect some level of NO_x 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 NO_x emissions by design, and lean burn engines are designed to have relatively lower NO_x emissions.

Colorado has undertaken regulatory initiatives to control NO_x 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 NO_x (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 NO_x 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 NO_x 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 NO_x 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 NO_x 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 NO_x. At an average of about 10 tons of NO_x 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 NO_x reductions will occur.

The 2018 emissions inventory assumes approximately 16,199 tons of NO_x per year from RICE of all sizes in Colorado. The NO_x 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 NO_x emissions inventory by approximately 5,800 tons/year to approximately 10,400 tons/year. For new RICE subject to the NSPS and NESHAP, NO_x emissions reductions have not been estimated. Because the 2018 estimate of 16,199 tons/year of NO_x 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 NO_x from engines is attributed to existing lean burn engines which are uncontrolled for NO_x (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 NO_x, 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
- SO₂ - 40 tons per year
- PM₁₀ - 15 tons per year

Facility - Turbine	Total 2006 - 2008 Averaged NO _x Annual Emissions (tpy)	Total 2006 - 2008 Averaged SO ₂ Annual Emissions (tpy)	Total 2006 - 2008 Averaged PM ₁₀ Annual Emissions (tpy)	Greater than <i>de minimis</i> levels?
Front Range Power Plant - Turbine #1	159.6	2.9	4.9	Yes - NO _x only
Front Range Power Plant - Turbine #2	147.9	2.8	4.9	Yes - NO _x only

The combustion turbines at the Front Range Power Plant were installed with advanced dry-low NO_x combustion systems, and based on 2006 - 2008 CEMs data and AP-42 emission factors, are achieving 89.4% and 90.1% NO_x 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 NO_x 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 NO_x reduced annually. In the state's judgment for this planning period for Reasonable Progress, the potential 275 tons per year of NO_x reductions are not cost-effective. The state has determined that NO_x 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 control⁴⁰.

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, NO_x 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 (Δ dv) impact ranging from 0.06 Δ dv to 0.56 Δ dv. The resultant average of the range is about 0.3 Δ dv, which is a more conservative RP threshold than the 0.5 Δ dv 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 (PM₁₀) emissions to the RP evaluation process.

The evaluation of potential RP sources involved all Colorado stationary sources with actual SO₂, NO_x 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

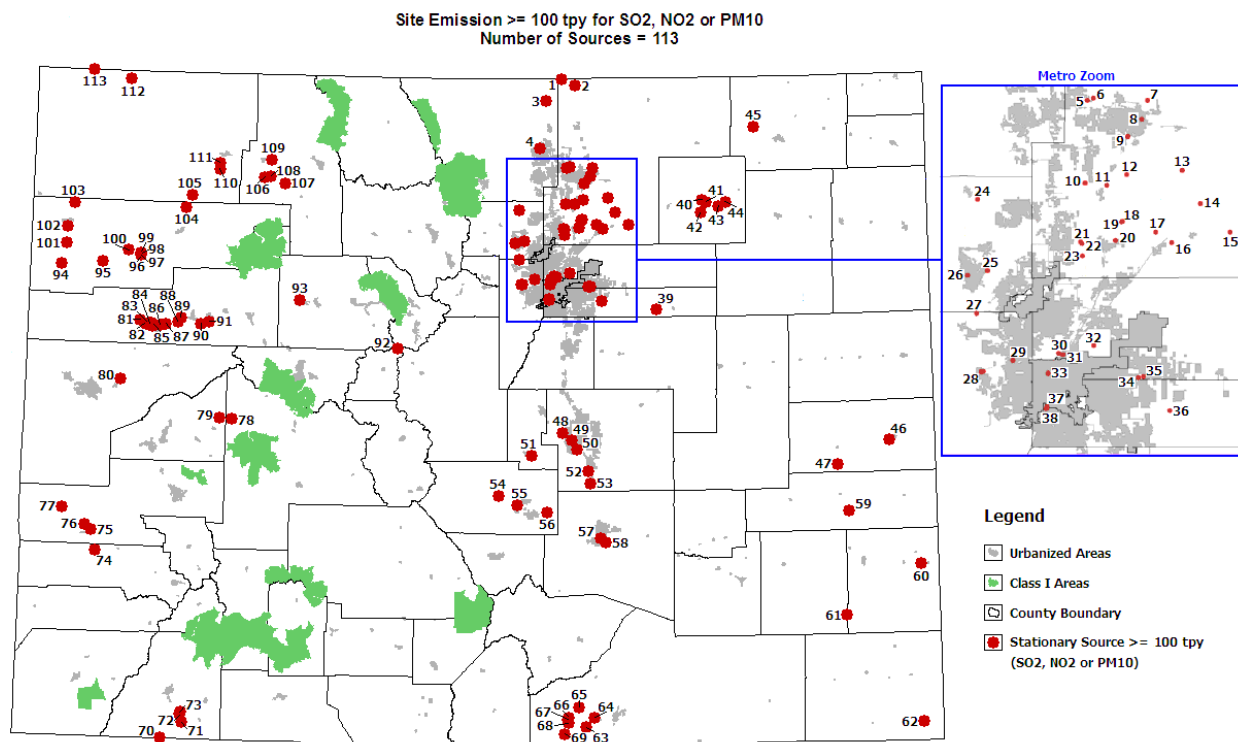


Table 8-1: Colorado Significant Point Sources with a Q/d ≥ 20

ArcGIS DATA - Statewide Sources over 100 tpy for SO ₂ , NO _x and PM ₁₀ (based on 2007 data)								
Count	FACILITY NAME	SO ₂ [tpy]	NO ₂ [tpy]	PM ₁₀ [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	2,826	1,786	42	4,453	Rocky Mnt NP	54.5	81.7
5	PUBLIC SERVICE CO - CHEROKEE	7,116	10,205	261	17,681	Rocky Mnt NP	66.3	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	3,260	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	2,686	1,051	112	3,760	Black Canyon NP	70.6	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	Fiat 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, NO_x and PM emissions. The state has determined that the CEMEX BART determinations for the kiln and the dryer (see Chapter 6) satisfy the SO₂, NO_x 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 NO_x (see Chapter 6), which satisfies the SO₂ and NO_x 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, NO_x and PM emissions. The CENC BART determination for these two boilers (see Chapter 6) satisfies the SO₂, NO_x 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 NO_x (see Chapter 6), which satisfies the SO₂ and NO_x 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 NO_x (see Chapter 6), which satisfies the SO₂ and NO_x 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 NO_x (see Chapter 6), which satisfies the SO₂ and NO_x 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, NO_x and PM emissions. The Drake BART determination (see Chapter 6) satisfies the SO₂, NO_x 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, NO_x and PM emissions. The Comanche BART determination (see Chapter 6) satisfies the SO₂, NO_x 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, NO_x, 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, NO_x and PM emissions. The Hayden BART determination (see Chapter 6) satisfies the SO₂, NO_x 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, NO_x and PM emissions. The BART determinations for units 1 and 2 (see Chapter 6) satisfy the SO₂, NO_x 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 NO_x 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 NO_x 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 NO_x controls, the state has assessed pre-combustion and post-combustion controls and upgrades to existing NO_x 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 NO_x 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 NO_x 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 NO_x emissions, post-combustion controls for NO_x 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 NO_x 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 NO_x emissions.

⁴¹ EGU's 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 NO_x 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 (NO_x) from the atmosphere, or \$/ton of NO_x removed); and, (ii) visibility improvement expected from the control options analyzed (e.g., expressed as visibility improvement in delta deciview (Δ dv) from CALPUFF air quality modeling).

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

- For the highest-performing NO_x 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 Δ dv or greater at the primary Class I Area affected, that level of control is generally viewed as reasonable.
- For lesser-performing NO_x 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 Δ dv 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 NO_x controls, *i.e.*, SCR, have the ability to provide significant NO_x reductions, but also have initial capital dollar requirements that can approach or exceed \$100 million per unit.⁴⁴ The lesser-performing post-combustion NO_x controls, *e.g.*, SNCR, reduce less NO_x 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 NO_x 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 NO_x 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 NO_x 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.

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, SO₂, PM₁₀) at a facility with a Q/d impact greater than 20. Platte River Power Authority (PRPA) submitted a "Rawhide NO_x 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 SO₂ 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 SO₂ 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 - SO ₂ 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:

SO ₂ Control Method	SO ₂ 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/PM₁₀. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouses.

NO_x 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 NO_x 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 - NO _x 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:

NO _x Control Method	NO _x Annual Emission Rate (lb/MMBtu)	98 th 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 NO_x RP for Rawhide Unit 101 is the following NO_x 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, SO₂, PM₁₀) 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 - SO ₂ 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/PM₁₀. 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 "NO_x 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 - SO ₂ 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 (Δ dv)
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% SO₂ 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 SO₂ 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/PM₁₀) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limits is RP for PM/PM₁₀. 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, 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 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/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-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 SO₂. In addition to the kiln system/main stack emissions, there are two other process points whose PM/PM₁₀ 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 SO₂ emission rate of 99.17 lbs/hour, a NO_x 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. 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 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.

SO₂ 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 SO₂ 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 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 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 SO₂ 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 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.

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 PM₁₀ emissions rates. The facility is currently permitted to emit 246.3 tpy of PM₁₀ 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 PM₁₀ per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for PM₁₀). The actual kiln system PM₁₀ 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 PM₁₀ 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 PM₁₀, 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 PM₁₀ per ton of clinker (19.83 lbs/hour) and a rate of 0.04 pound of PM₁₀ 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 (NO₃) followed by sulfates (SO₄). The contribution of PM₁₀ to the total visibility impairment was insignificant in the analysis. The level of PM₁₀ 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 PM₁₀ emissions from the kiln system on visibility impairment, the state has determined that no additional PM₁₀ 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 PM₁₀ (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 PM₁₀ 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 $[3.64/0.9*(1-0.45) = 2.23 \text{ lb/ton}]$. 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		
NO _x Control Method	98th Percentile Impact (Δdv)	98th Percentile Improvement (Δdv)
Maximum (24-hr max) (based on modeled emission rates of 1,363 lb/hr NO _x , 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, SO₂, PM₁₀) 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 - SO ₂ 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/PM₁₀. 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 NO_x 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 NO_x control scenarios for Nucla. Finally, Tri-State shall propose to the state any preferred SO₂ and NO_x 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 NO_x 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 NO_x 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 NO_x 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, SO₂, PM₁₀) 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 SO₂ 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 SO₂ 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:

SO ₂ Control Method	Craig - Unit 3	
	SO ₂ Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ _{dv})
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/PM₁₀. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

NO_x RP Determination for Craig - Unit 3

Selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NO_x emissions at Craig Unit 3. The following table lists the emission reductions, annualized costs and cost effectiveness of the control alternatives:

Craig Unit 3 - NO _x Cost Comparisons			
Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)
Baseline	0	\$0	\$0
SNCR	853	\$4,173,000	\$4,887
SCR	4,281	\$29,762,387	\$6,952

SCR was eliminated from consideration due to the excessive cost/benefit ratio.

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling. There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period. The projected visibility improvements attributed to the alternatives are as follows:

NOx Control Method	NOx Annual Emission Rate (lb/MMBtu)	98 th Percentile Impact (Δ dv)
Daily Maximum (2 nd half 2009)	0.365	
SNCR	0.240	0.32
SCR	0.070	0.79

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions. Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Craig Unit 3 is the following NOx emission rates:

Craig Unit 3: 0.28 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of SNCR. To the extent practicable, any technological application Tri-State utilizes to achieve this RP emission limit shall be installed, maintained, and operated in a manner consistent with good air pollution control practice for minimizing emissions. For SNCR-based emission rates at Unit 3, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls with guidance cost criteria discussed in Section 8.4.

- 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 its NSR and PSD programs meet the long-term strategy requirements for preventing future impairment from proposed major stationary sources or major modifications to existing facilities.

9.2.3 Smoke Management Practices

The LTS requires smoke management practices of prescribed burning be addressed. The 2004 LTS described Colorado's Regulation 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 9-1 Colorado's Nitrate and Sulfate Impacts at Bandelier and Canyonlands

Mandatory Class I Area	Modeled Visibility Improvement by 2018 [deciviews]	Colorado's Contribution to 2018 Nitrate	2018 Total Nitrate Impacts at CIA	Colorado's Nitrate Contribution to 2018 Haze at CIA	Colorado's Contribution to 2018 Sulfate	2018 Total Sulfate Impacts at CIA	Colorado's Total Sulfate Contribution to 2018 Haze at CIA	Colorado's Total Nitrate & Sulfate Contribution to 2018 Haze at CIA
Bandelier National Monument	0.3	5.1%	6.6%	0.3%	1.2%	15.5%	0.2%	0.5%
Canyonlands National Park	0.5	6.9%	9.5%	0.7%	2.3%	14.8%	0.3%	1.0%

All Colorado Impacts to nearby Class I Areas that exceed 5.0% are shaded in purple. No Colorado 2018 Sulfate Contributions exceeding 5% were identified.

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 NO_x, SO₂ and particulates throughout the state, as well as in the Denver Metro Area/Northern Front Range region for VOCs, NO_x, 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 NO_x control is in the SIP or has been submitted for approval into the SIP - these provisions relate to VOC and NO_x 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 NO_x 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 NO_x 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 NO_x 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 NO_x, 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 PM_{2.5} 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/aqcc> As recently as 1995 Colorado had 12 "non-attainment" areas within the state for carbon monoxide, ozone, and/or PM10 health standards. Generally, all of these areas now maintain good air quality. This progress reflects the effects of local, statewide, regional, and national emission control strategies. This clean-up of Colorado's non-attainment areas also benefited Class I visibility conditions to some unknown degree.

In the summer of 2003, the Denver metropolitan area violated the 8-hour ozone standard. EPA designated all or parts of 9 counties in northeastern Colorado as nonattainment for the 1997 8-hour ozone standard, though the nonattainment designation was deferred with the adoption of the Ozone Action Plan by the Colorado Air Quality Control Commission in March 2004 under EPA's Early Action Compact provisions. High concentrations of ground-level ozone during the 2005-2007 period put the nine-county Denver region in violation of the 1997 standard, and the deferred nonattainment designation became effective in November 2007. A detailed plan to reduce ozone was adopted by the Colorado Air Quality Control Commission in December 2008 and submitted to EPA for approval in 2009. This new plan contains additional VOC and NOx emission reduction measures to support achievement of compliance with the 1997 ozone standard by the end of 2010.

Table 9-1 shows the designation status for all current and former non-attainment areas.

Table 9-1 REDESIGNATION and PLAN AMENDMENT STATUS REPORT

<u>PM10</u>	<u>Redesignations</u>	<u>Plan Amendments</u>
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
<u>Carbon Monoxide</u>	<u>Redesignations</u>	<u>Plan Amendments</u>
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
<u>Ozone</u>	<u>Redesignations</u>	<u>Plan Amendments</u>
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
<u>Lead</u>	<u>Redesignations</u>	<u>Plan Amendments</u>
Denver	EPA redesignated Denver attainment in 1984	
<u>Nitrogen Dioxide</u>	<u>Redesignations</u>	<u>Plan Amendments</u>
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 coarse 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 requirement⁴⁷. 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 permittees 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 NO_x emission reduction of 123,497 tons per year by 2018. (SO₂ and NO_x 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 (enhanced 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 NO_x and SO₂

Additional NO_x and SO₂ Reductions						
<i>Difference between PRP2018b and Proposed BART/RP</i>						
PLANT	PRP 2018b NO _x [tpy]	2018 BART/RP NO _x [tpy]	Difference [tpy]	PRP 2018b SO ₂ [tpy]	2018 BART/RP SO ₂ [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 NO_x 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?
<i>Great Sand Dunes National Park & Preserve</i>	12.78	11.35	1.43	12.20	40.6%	4.50	4.16	Yes
<i>Mesa Verde National Park</i>	13.03	11.58	1.45	12.50	36.6%	4.32	4.10	Yes
<i>Mount Zirkel & Rawah Wilderness Areas</i>	10.52	9.48	1.04	9.91	58.7%	1.61	1.29	Yes
<i>Rocky Mountain National Park</i>	13.83	12.27	1.56	12.83	64.1%	2.29	2.06	Yes
<i>Black Canyon of the Gunnison National Park, Weminuche & La Garita Wilderness Areas</i>	10.33	9.37	0.96	9.83	52.1%	3.11	2.93	Yes
<i>Eagles Nest, Flat Tops, Maroon Bells - Snowmass and West Elk Wilderness Areas</i>	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, NO_x (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 <i>Based on WRAP CMAQ Modeling using the PRP 2018b</i>											
Mandatory Class I Federal Area	20% Worst Days									Number of years to NC [yrs]	New NC Goal [year]
	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]		
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

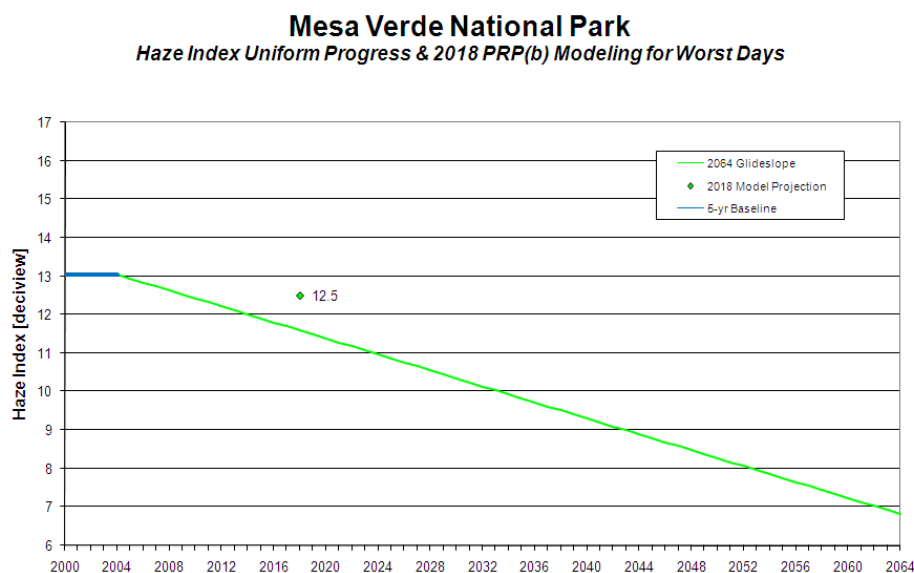
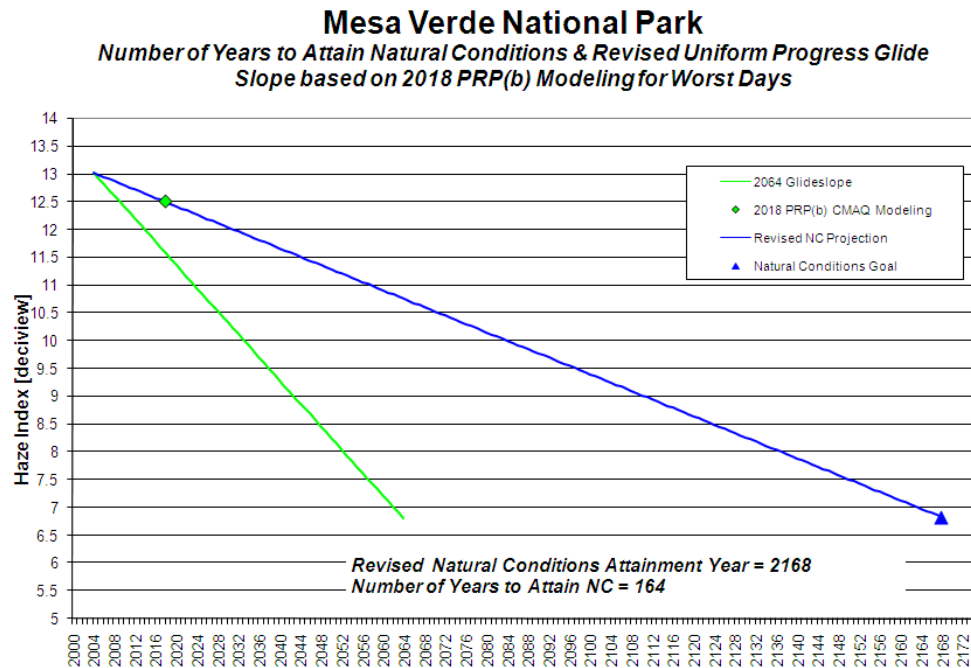


Figure 9-10 Revised Glidepath for Mesa Verde Illustrating the Number of Years to Achieve Natural Conditions



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 permittees 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 NO_x, SO₂, 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 SO₂, 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 SO₂ emission reduction options and associated cost. Craig Station Units 1 and 2 at the time achieved 65% SO₂ 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 SO₂ and NO_x 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, 2001² 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 NO_x, SO₂, 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 PM _{2.5} (chemically speciated) and PM ₁₀ (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 tying-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 SO₂ 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), SO₂ decreased in the Yampa Valley by 48% and NO_x increased 7%.
- Regional Emission Changes
 - Not only was there an emission change at Hayden, but large emission reductions of SO₂ 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 SO₂ gas to visible sulfate particles is not linear. That is, a one unit decrease in SO₂ may not lead to a one unit decrease in sulfate.

Results.

- Emissions
 - Sulfur dioxide (SO₂) removal at Hayden has always been at least 85% over 30 and 90 day rolling averages since the compliance period began. Nitrogen oxides (NO_x) have decreased approximately 50% annually. The new particulate control system has completely eliminated the occasional black smoke-plume episodes that previously occurred.
- Ambient SO₂ 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 SO₂.
- 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 SO₂ 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 (NO_x) 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	2.0	4.0	1.0
	January 1, 2011	1.0	2.0	0.7
Greater than 500 hp	July 1, 2007	2.0	4.0	1.0
	July 1, 2010	1.0	2.0	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

	<u>Redesignations</u>	<u>Plan Amendments</u>
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

	<u>Redesignations</u>	<u>Plan Amendments</u>
		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 all 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 PM₁₀ 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 permittees 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 permittees 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.”

Permittees 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 permittees 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 PM₁₀ 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 indicates¹² 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 TYPE¹
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 TYPE¹
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
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. NO_x 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.

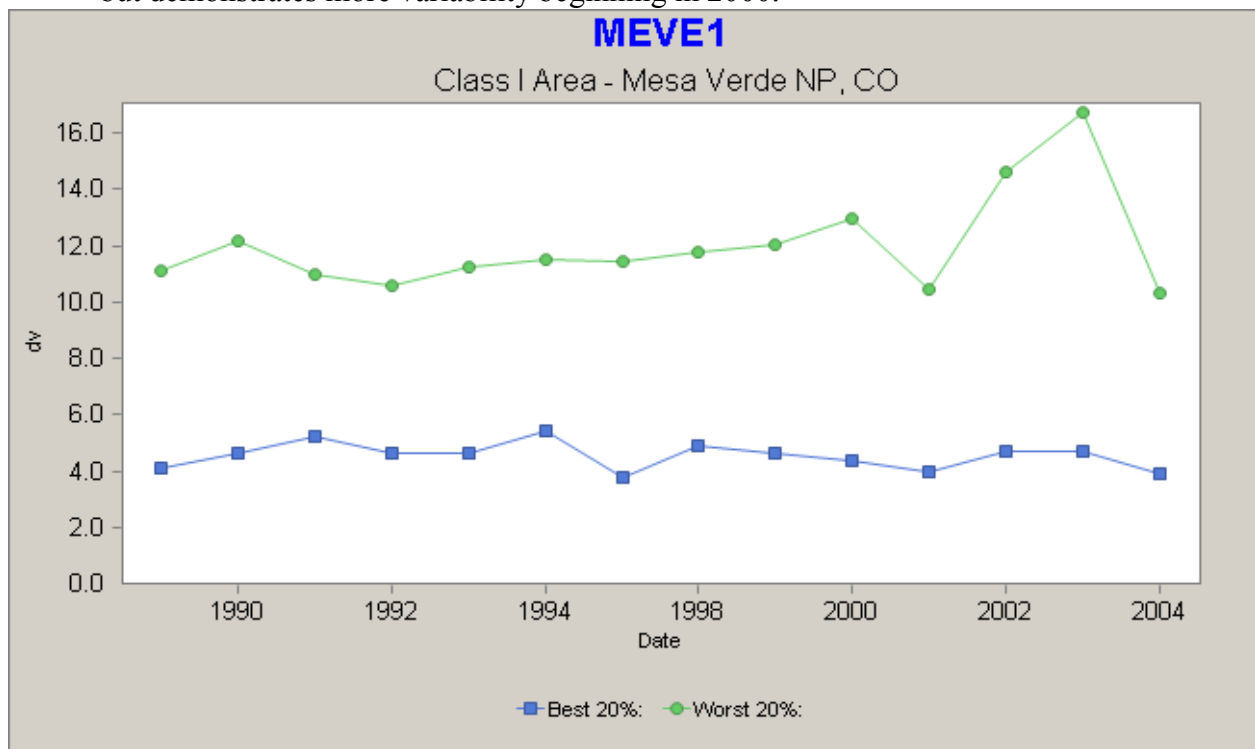


Figure 1: Mesa Verde National Park, Best and Worst Days, 1989 through 2004

- 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:

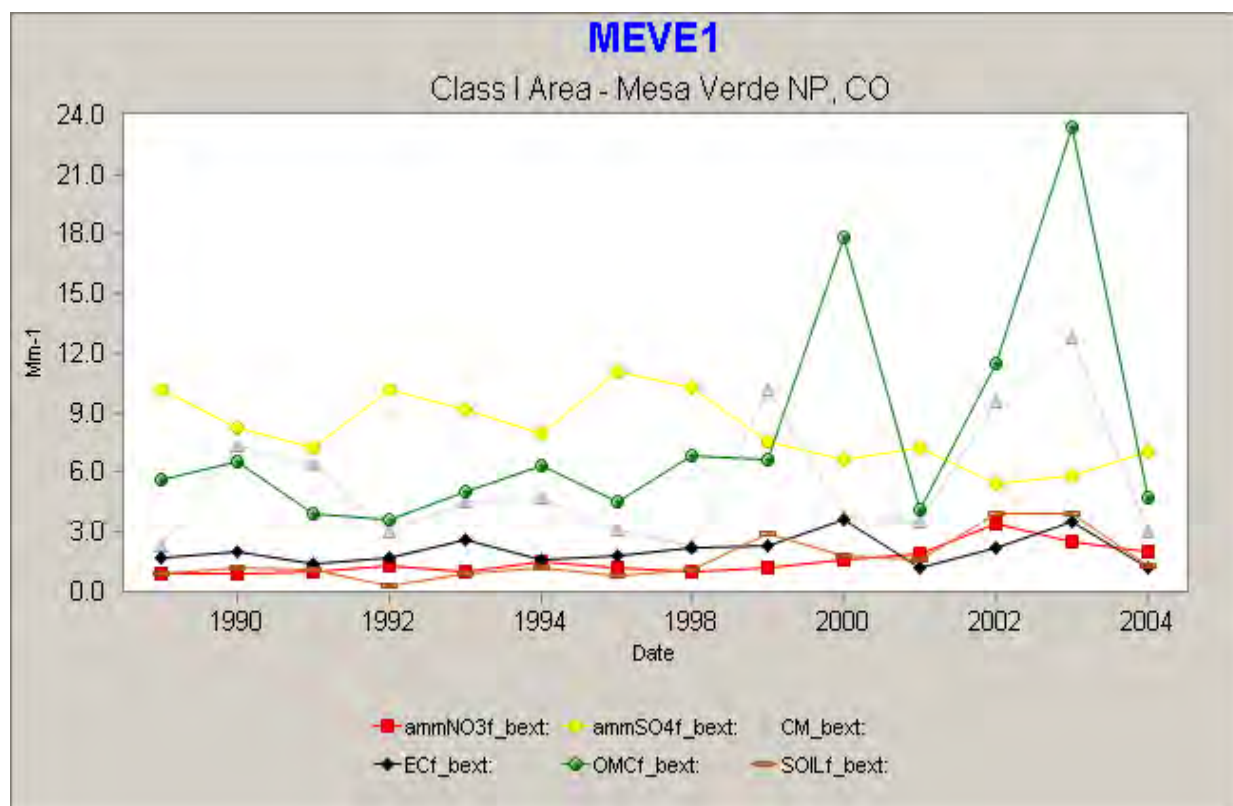


Figure 2: Mesa Verde National Park, Annual Extinction Values by Aerosol Species, Worst Days 1989 through 2004

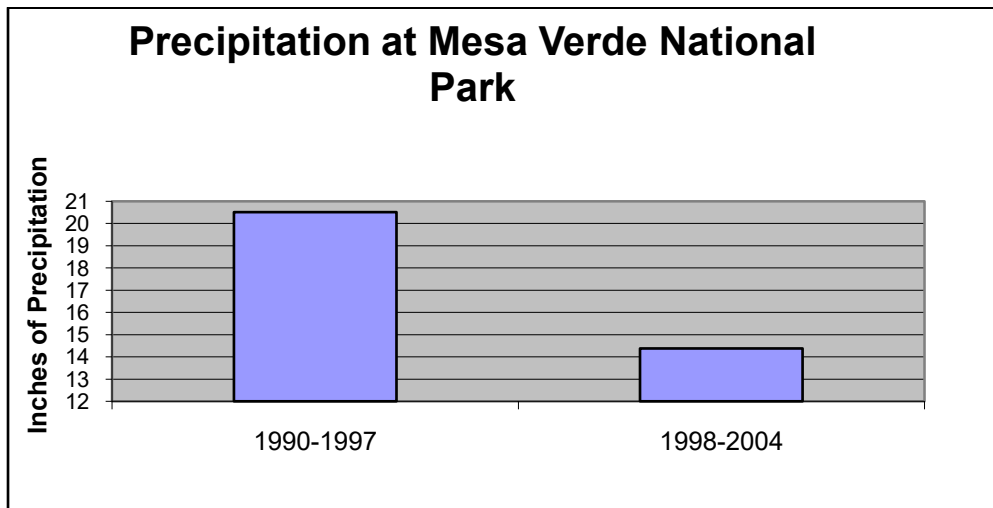


Figure 3: Precipitation At Mesa Verde National Park, 1990-1997 vs 1998-2004

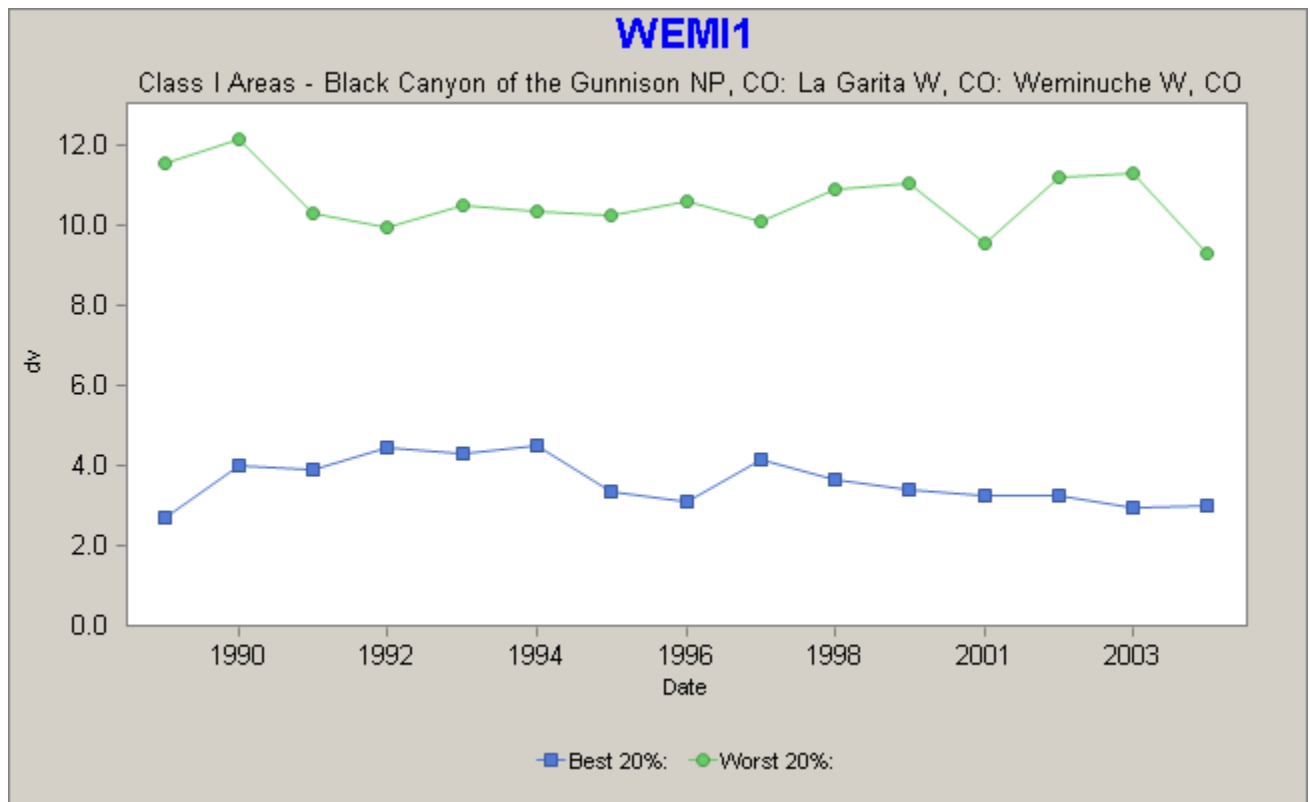


Figure 5: Weminuche Wilderness Area, Best and Worst Days 1989 through 2004

- 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.

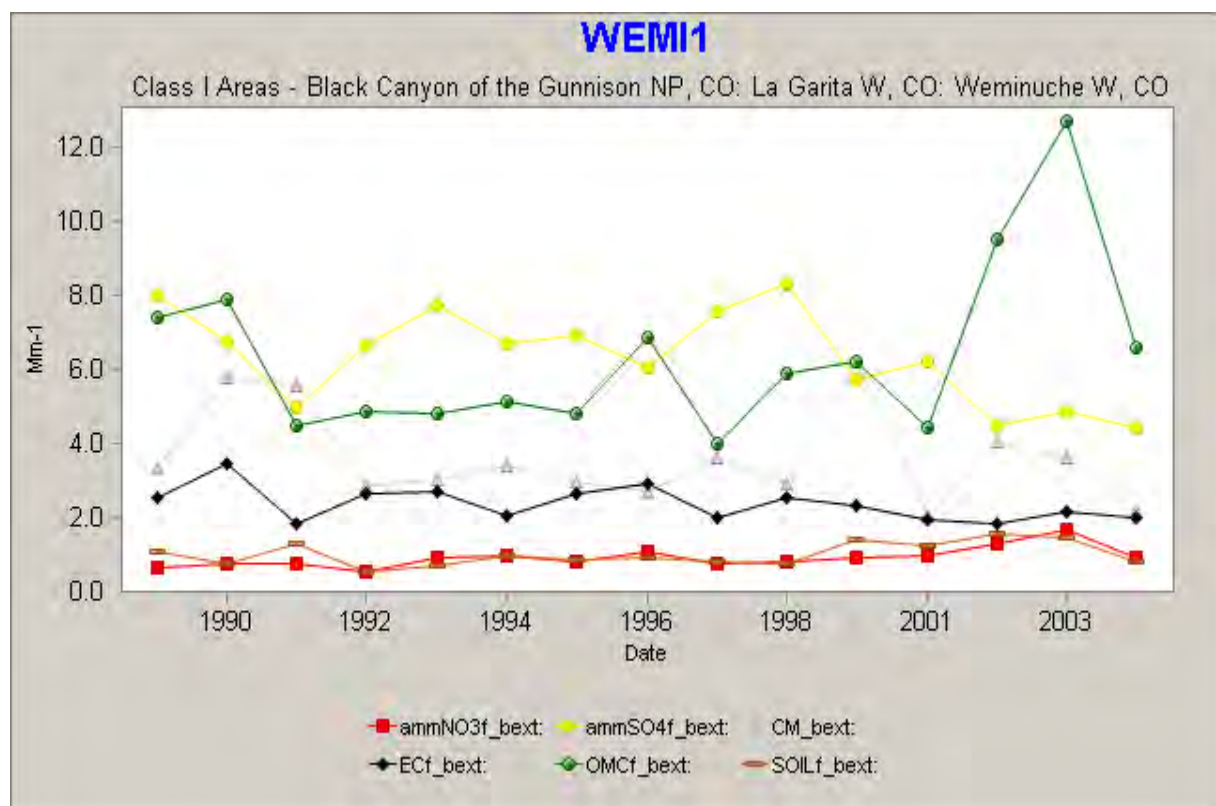


Figure 6: Weminuche Wilderness Area, Annual Extinction Values by Aerosol Species, Worst Days 1989 through 2004

(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:

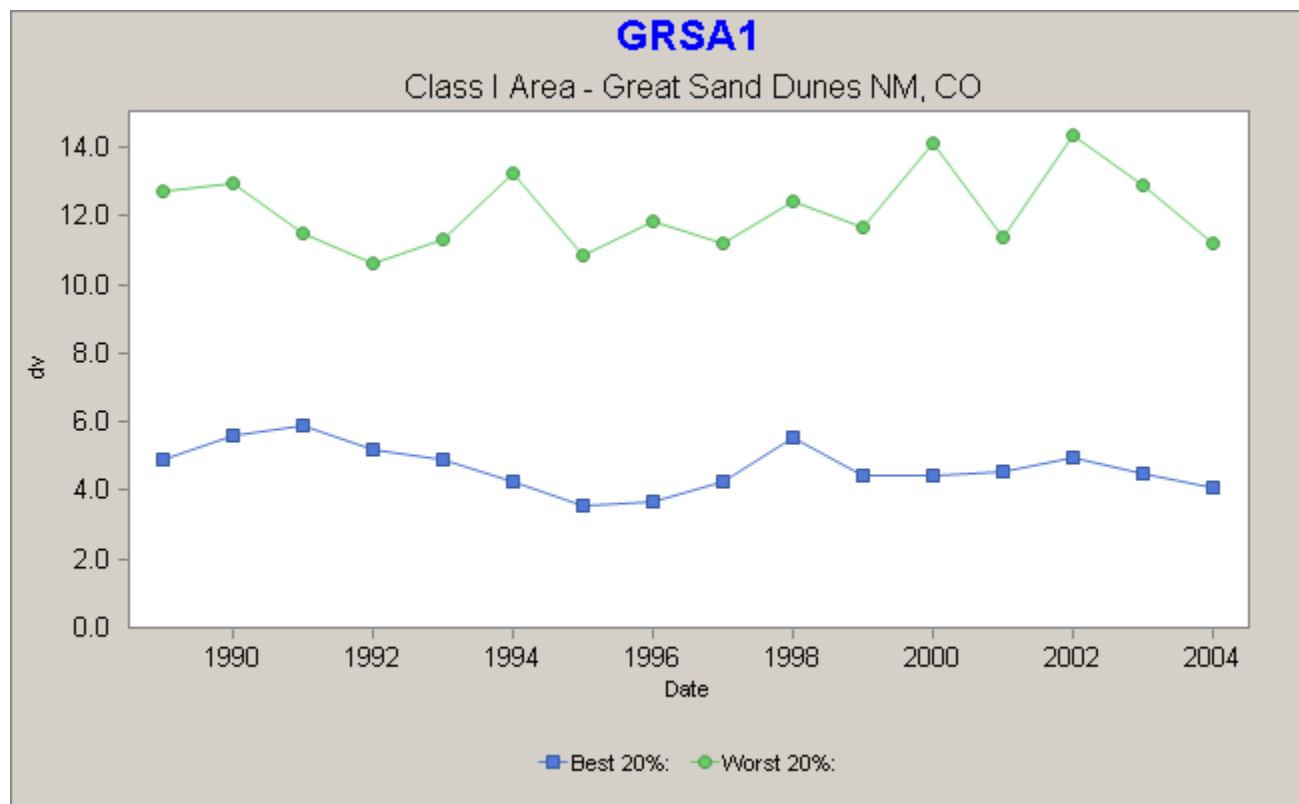


Figure 7: Great Sand Dunes National Park, Best and Worst Days 1989 through 2004

- 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.

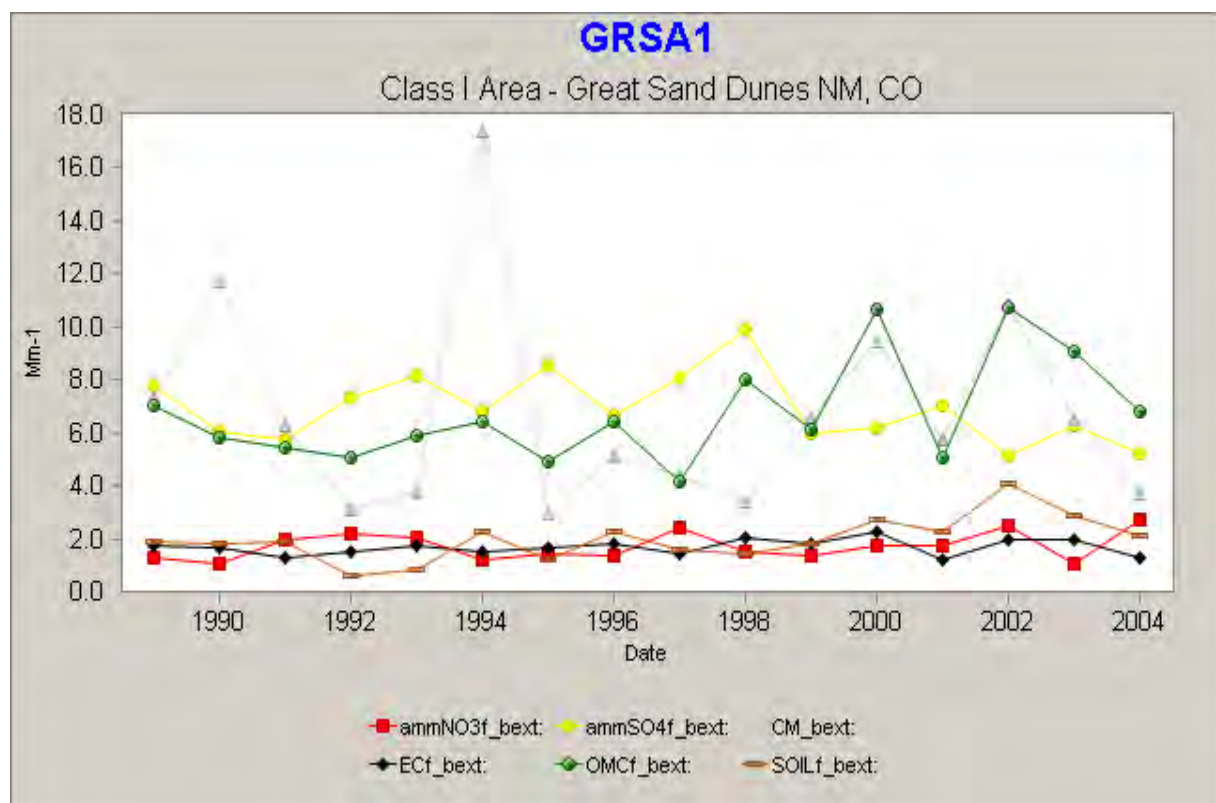


Figure 8: Great Sand Dunes National Park, Annual Extinction Values by Aerosol Species, Worst Days 1989 through 2004

(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:

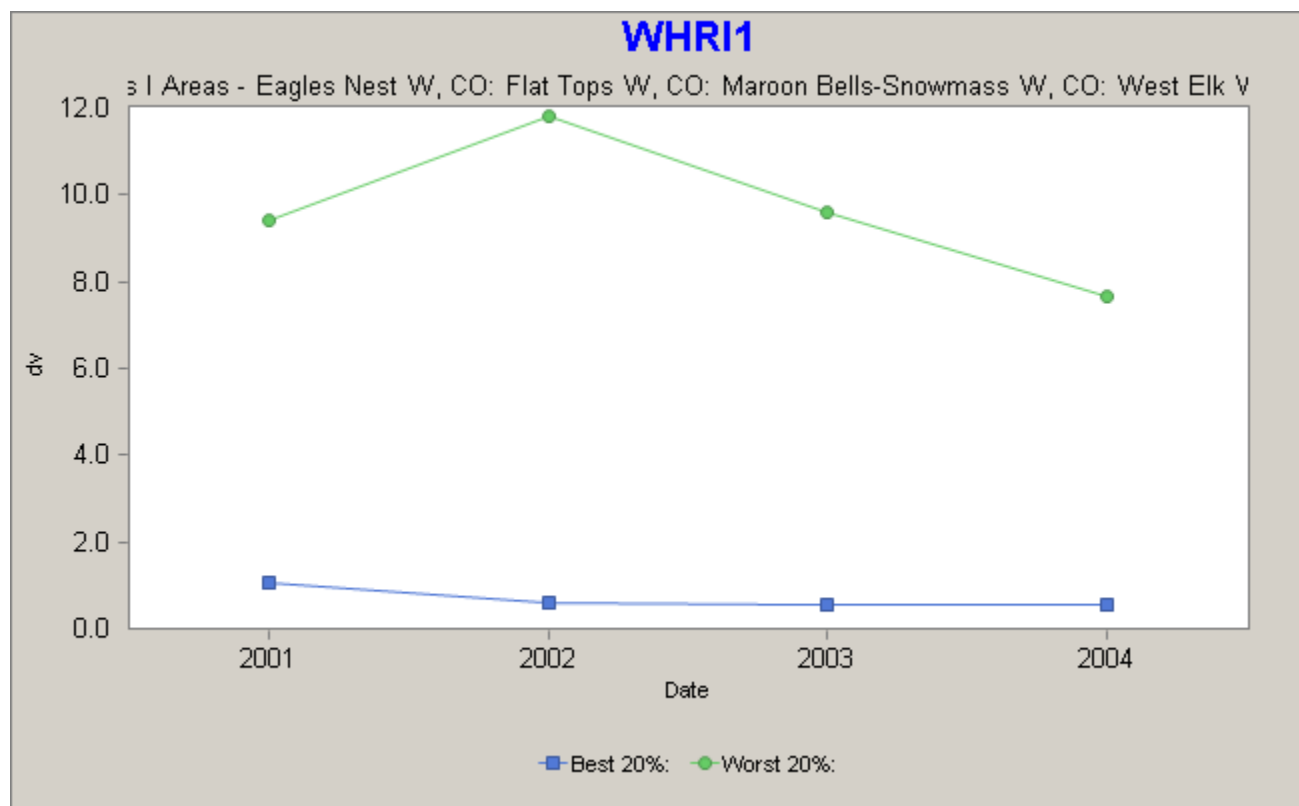


Figure 9: White River National Forest, Best and Worst Days 2001 through 2004

- 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 coarse 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).

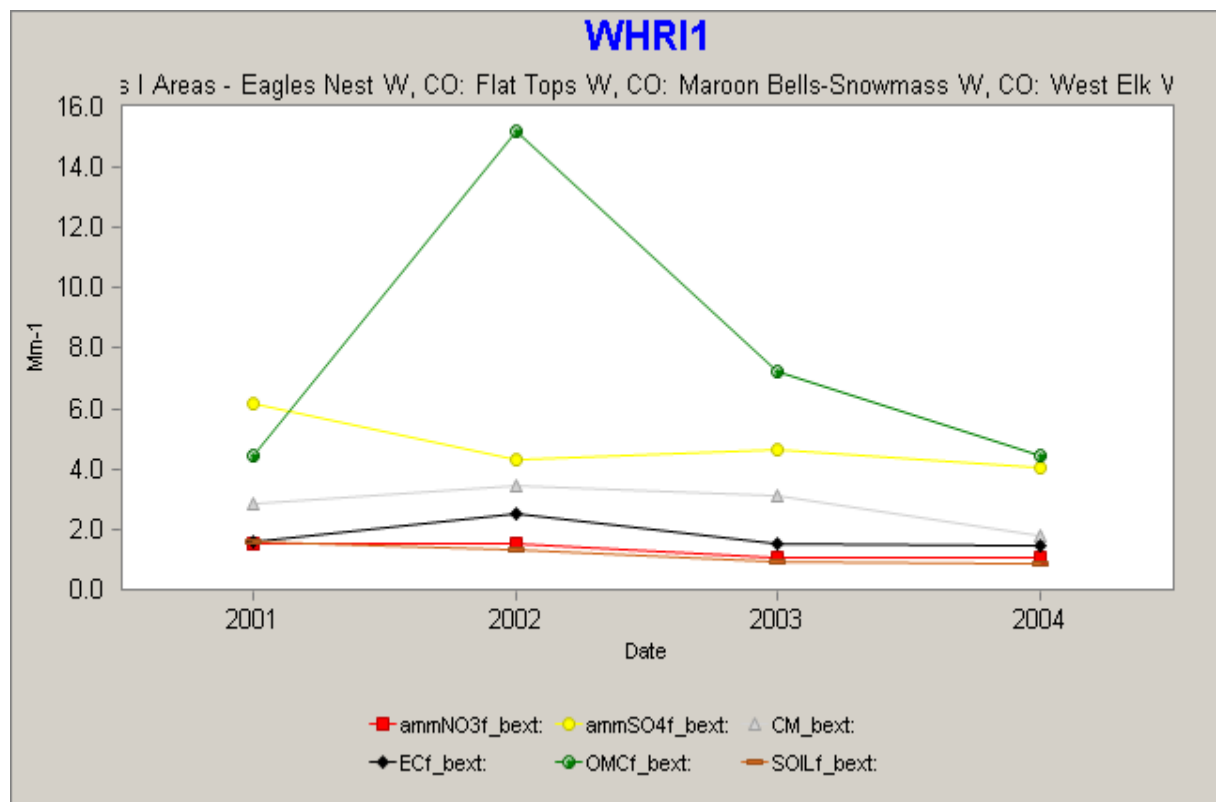


Figure 10: White River National Forest, Annual Extinction Values by Aerosol Species, Worst Days 2001 through 2004

(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.

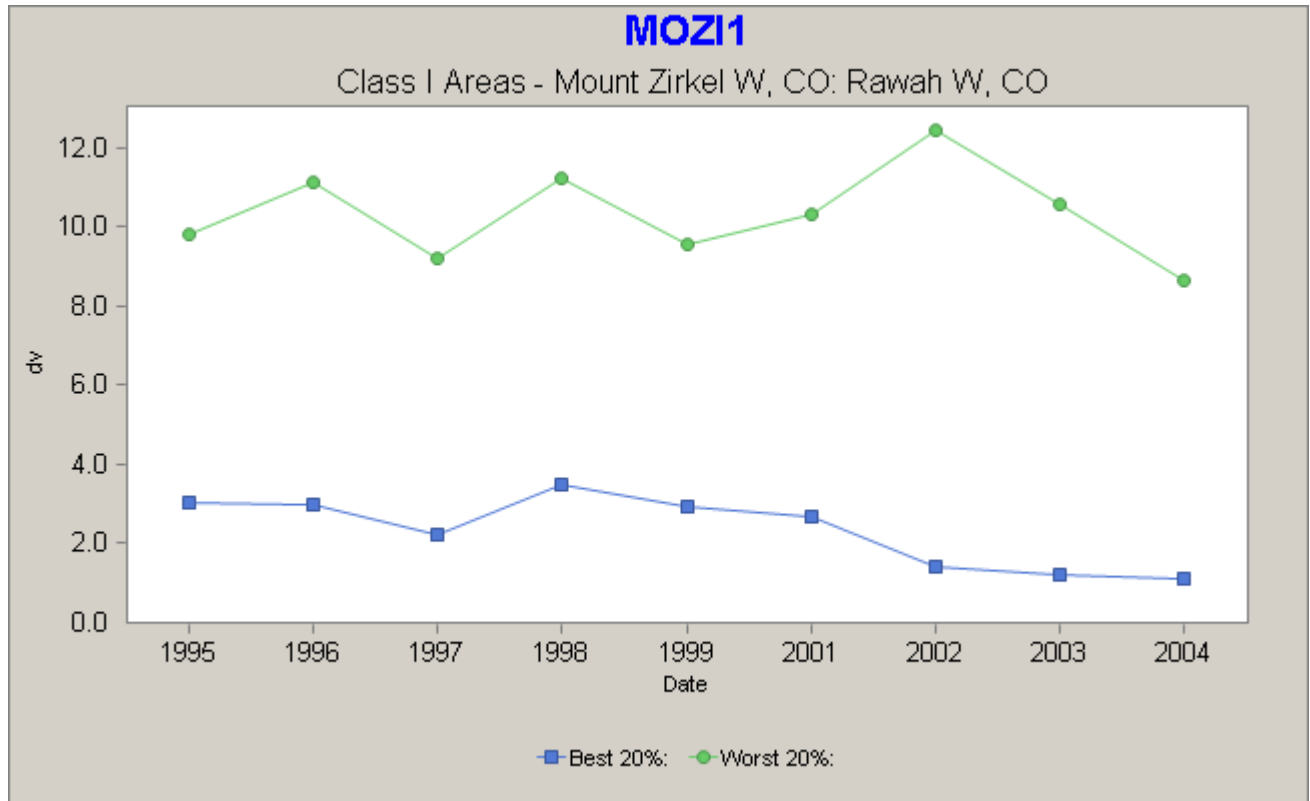


Figure 11: Mt. Zirkel Wilderness Area, Best and Worst Days 1995 through 2004

- 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

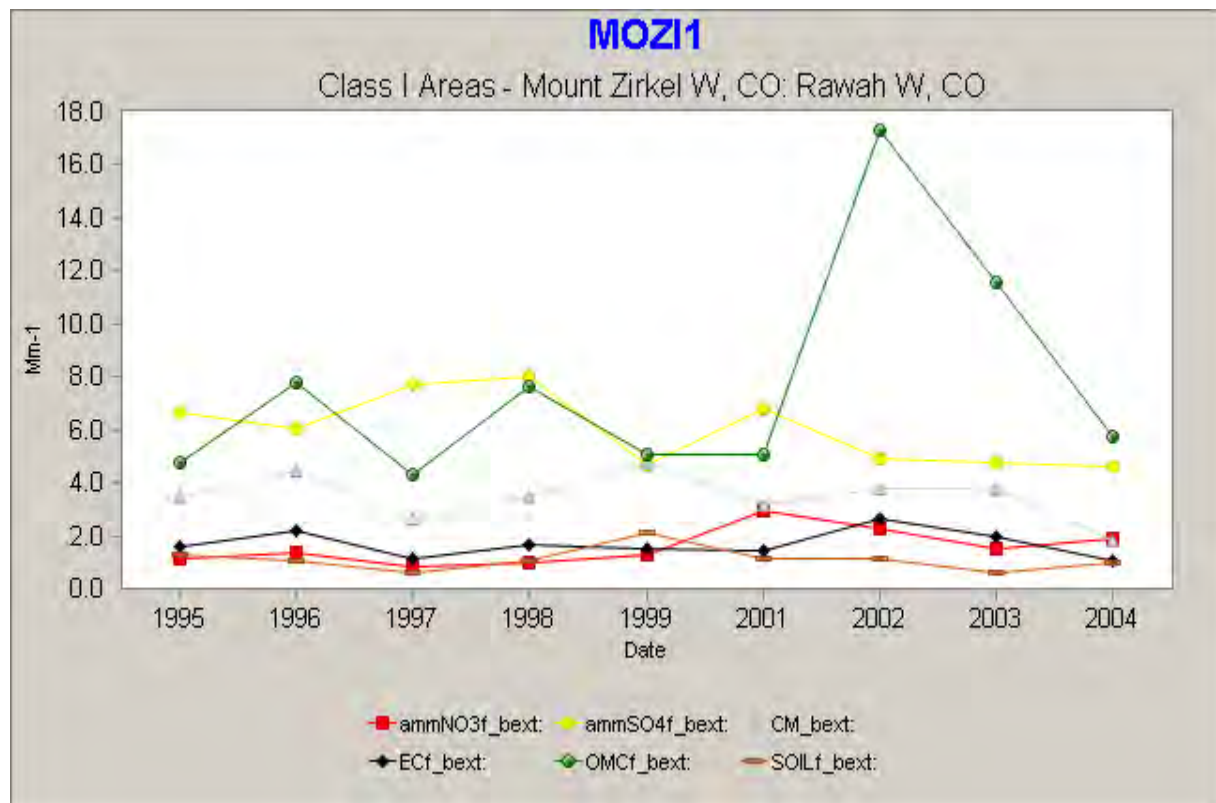


Figure 12: Mt. Zirkel Wilderness Area, Annual Extinction Values by Aerosol Species, Worst Days 1995 through 2004

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

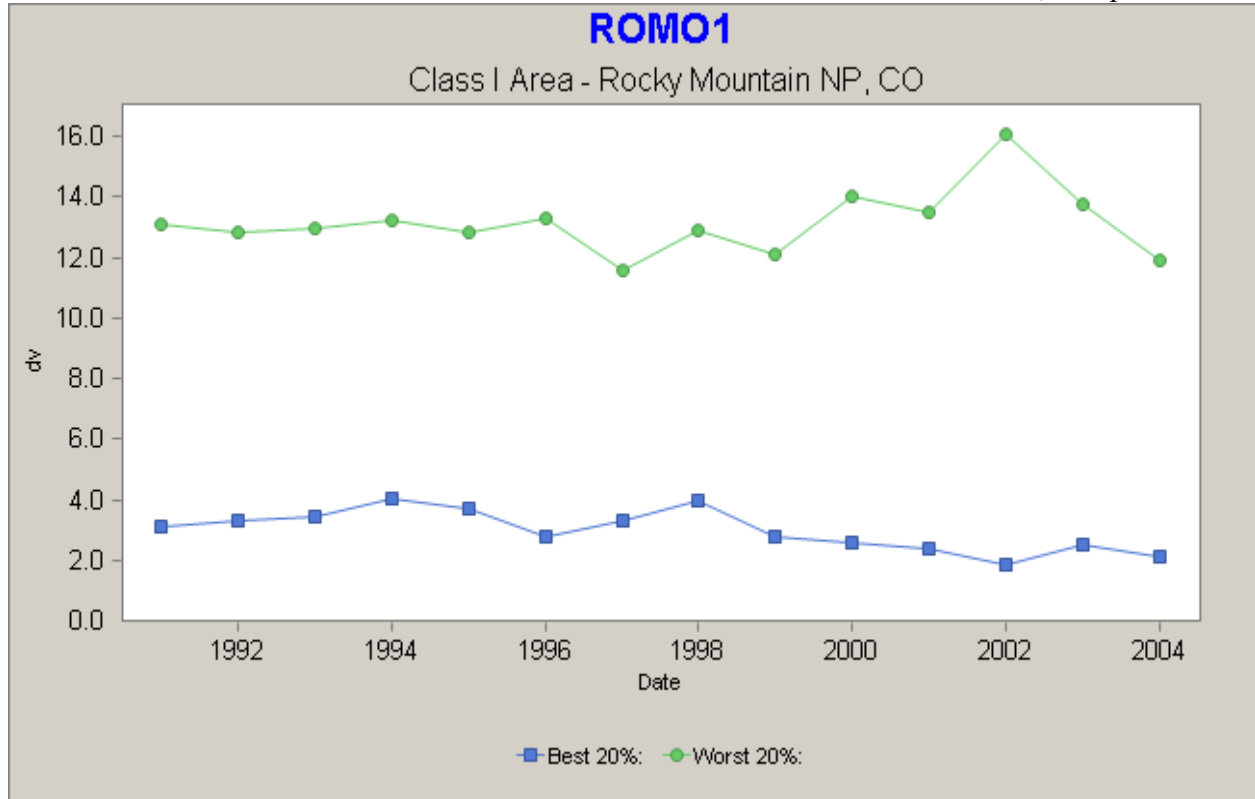


Figure 13: Rocky Mountain National Park, Best and Worst Days 1991 through 2004

many other sites in Colorado, of the drought in recent years.

- ECf_bext (elemental carbon extinction) is 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

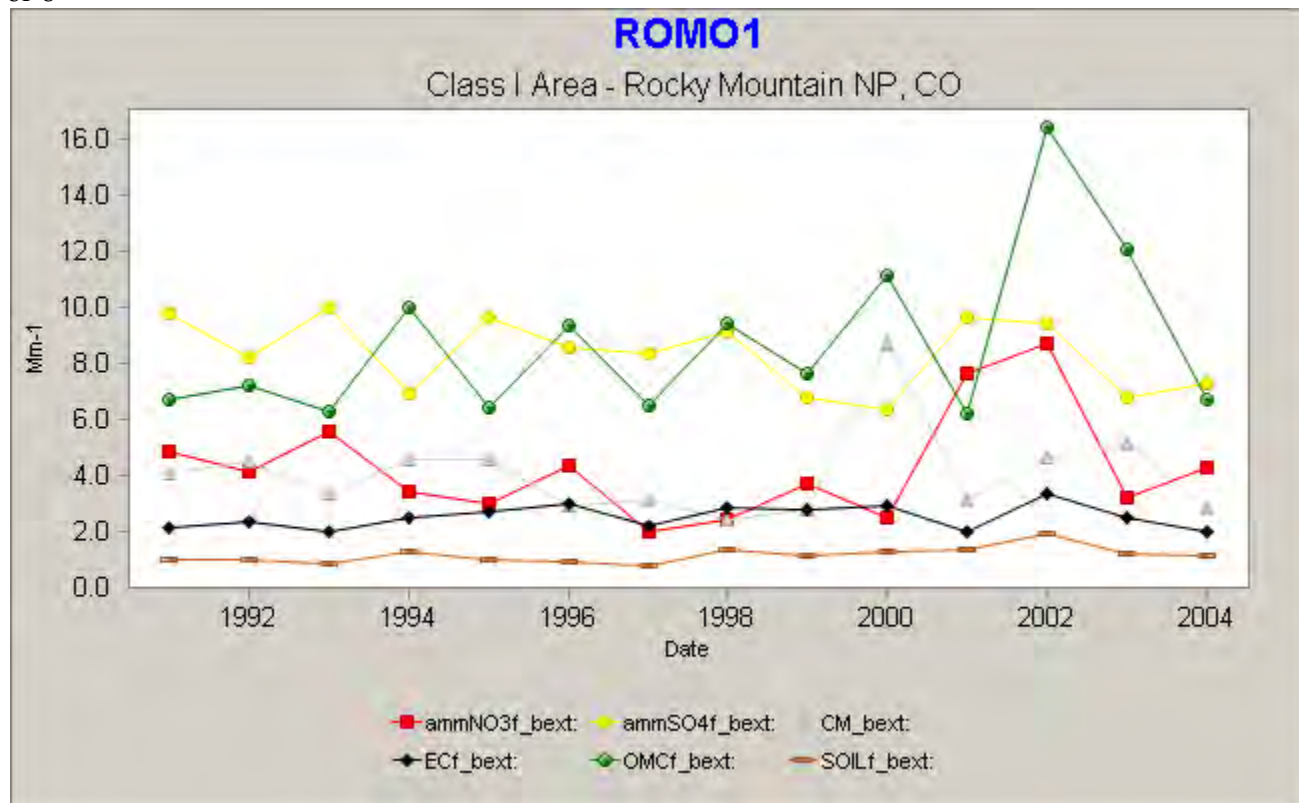


Figure 14: Rocky Mountain National Park, Annual Extinction Values by Aerosol Species, Worst Days 1991 through 2004

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>

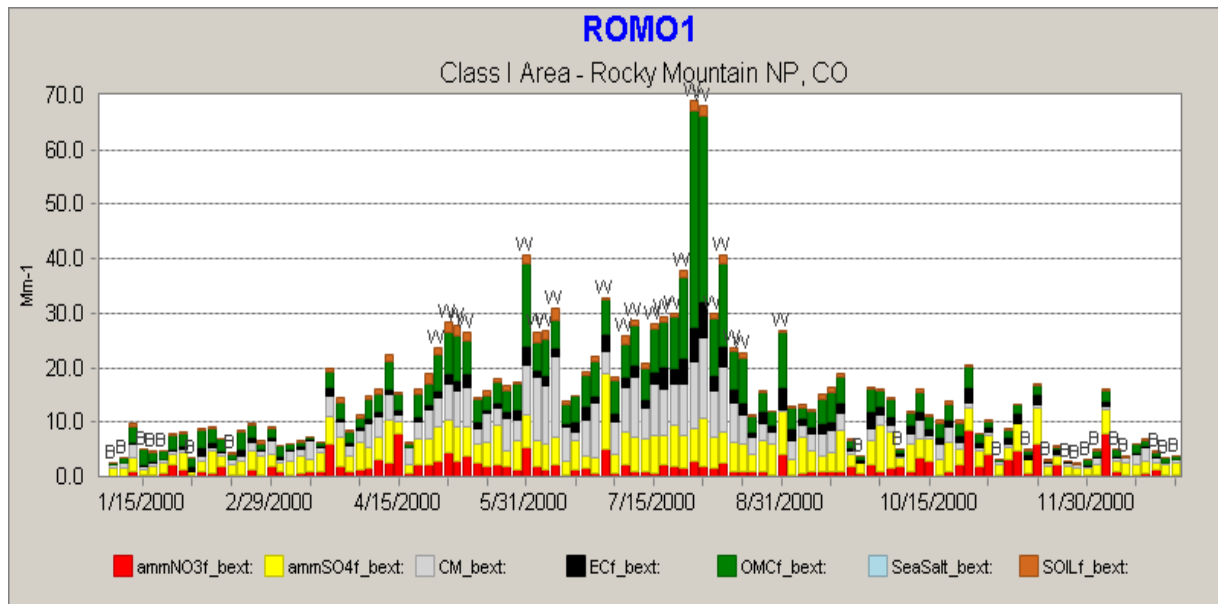


Figure 15: Rocky Mountain National Park, Composition Plot by Aerosol Species for Each Sample in 2000

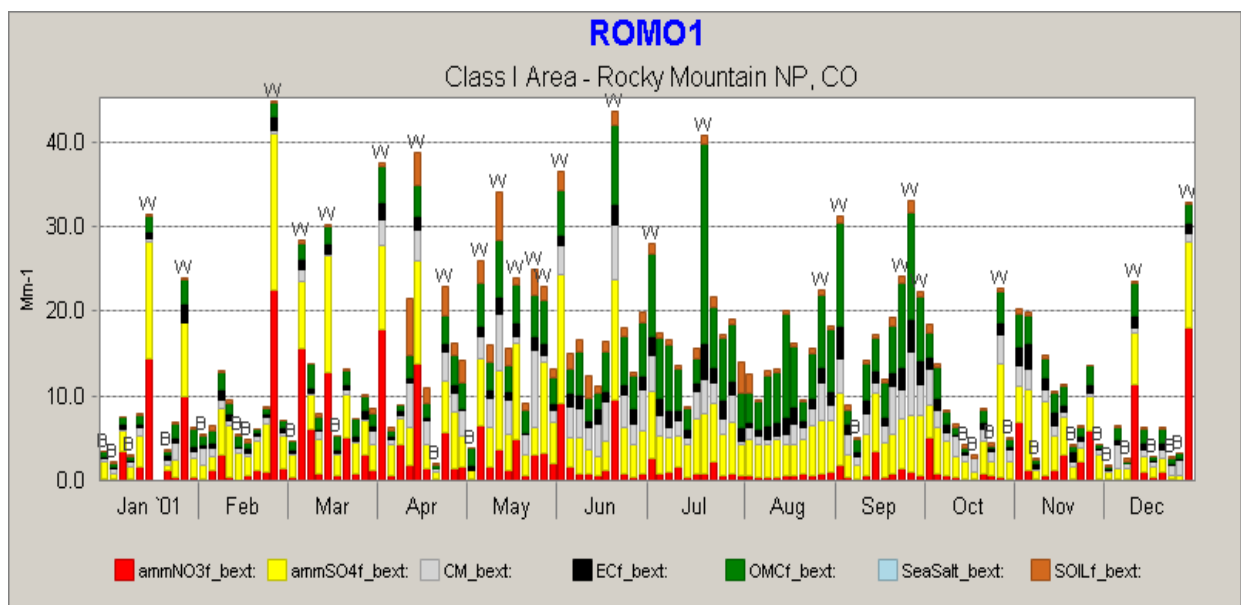


Figure 16: Rocky Mountain National Park, Composition Plot by Aerosol Species for Each Sample in 2001

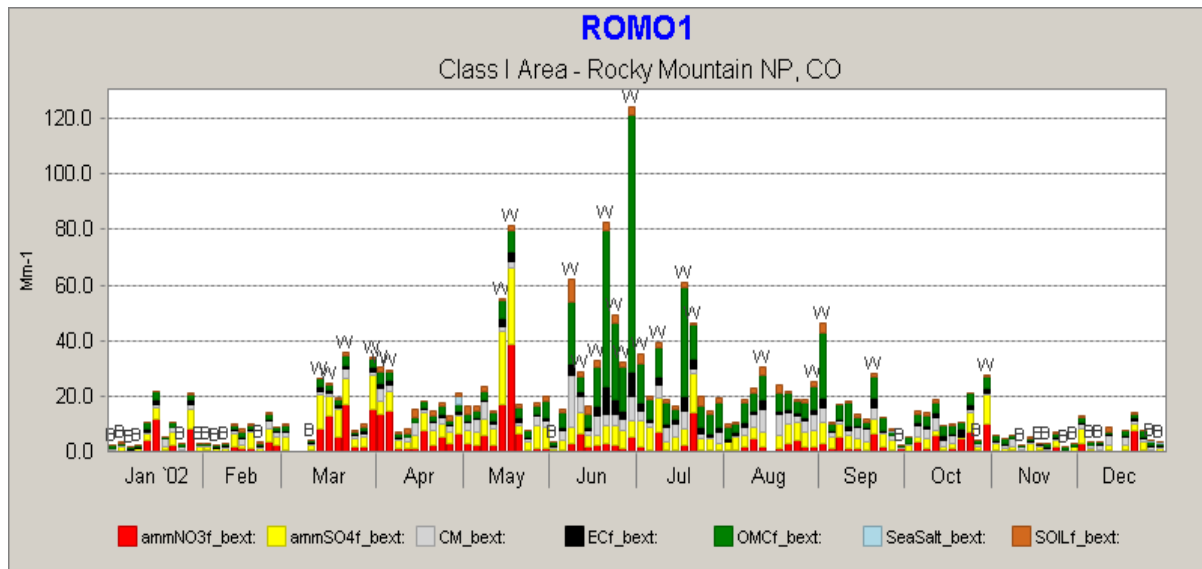


Figure 17: Rocky Mountain National Park, Composition Plot by Aerosol Species for Each Sample in 2002

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 SO₂ 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, NO_x and SO₂ upgrades were finished by December 19, 2003. Testing of the NO_x upgrades continued through the end of 4th quarter 2003. SO₂ removal has consistently been above 90% since mid-December 2003 (limit is 90%). The NO_x 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. SO₂ emissions from Unit 2 have also consistently achieved better than 90% removal and the NO_x 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.

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 NO_x, SO₂, 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 SO₂ and NO_x 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 NO_x, SO₂, 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, 2001³ 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. PM₁₀.

The State of Colorado has attained and maintained the PM₁₀ standard in its non-attainment areas throughout the State. PM₁₀ 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 PM₁₀ 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 PM₁₀ 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

* 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 NO_x 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 permittees 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

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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 NO_x emissions. The raw material dryer emits minor amounts of SO₂ and NO_x; in 2008 Cemex reported SO₂ and NO_x 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/precalcliner designs that are not directly comparable. Cemex has a unique single stage preheater/precalcliner system with different emission profiles and energy demands. New Portland cement plants have further developed the preheater/precalcliner 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/precalcliner vessels where temperatures are ideal (between 1600-2000°F) for reducing NO_x 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 than 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 NO_x = 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	SO ₂	NO _x	PM ₁₀	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, NO_x 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 NO_x 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	SO ₂	NO _x	PM ₁₀	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]	SO ₂ [tpy]	SO ₂ [lbs/ton of Clinker]	NO _x [tpy]	NO _x [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 NO_x = 10.41 tpy; SO₂ = 0.89 tpy; and PM₁₀ = 5.12 tpy; based on a recent stack test. CALPUFF modeling¹, of the dryer and kiln combined indicates a 98th percentile visibility impact (at Rocky Mountain National Park) of 0.78 delta deciview² (Δdv) and 98th percentile visibility impact at of only the kiln is 0.76 Δdv³. 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, NO_x 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 SO_x 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:

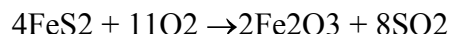
The source uses low sulfur coal and inherent removal of SO₂ emissions through contact with the clinker results in about 80% control.

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:



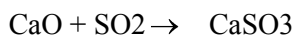
Using raw materials with lower pyritic sulfur content would reduce the potential for SO₂ emissions from the kiln system. However, while pyrites are present in the limestone and other raw materials used at the plant, concentrations of sulfide sulfur in these materials is typically low. On average, the 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:





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 \$153,271 per 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 cost⁴ 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 SO ₂ Emissions [lbs/hr]	Annual Controlled SO ₂ Emissions [tpy]	Annual Controlled SO ₂ Emissions [lb/ton of Clinker]
Baseline SO ₂ 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	SO ₂ Emission Reduction [tons/yr]	Annualized Cost [\$ /yr]	Cost Effectiveness [\$ /ton]	Incremental Cost Effectiveness [\$ /ton]
Baseline SO ₂ 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 (Δv)	98th Percentile Improvement (from 24-hr Max) (Δv)	Cost Effectiveness (\$/ Δv)
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 Δv 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 Δv at a cost of \$110.3 million dollars per Δv . 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 Δv at a cost of \$5 million dollars per Δv . Dry sorbent injection has a visibility improvement of 0.036 Δv , 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 Δv visibility improvement at a cost of \$63 million dollars per Δv . 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 Δv). Despite not having cost information on Dry Sorbent Injection, the Division has determined that the minimal visibility improvement of 0.036 Δv 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 Δv 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	SO ₂ Control Technology	SO ₂ 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	SO ₂ Control	SO ₂ 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 NO_x 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 NO_x generated from the kiln system. Cemex's current allowable NO_x emission rate is 2,649 tpy NO_x, which equates to an average allowable emission rate of 667 pounds NO_x per hour based on the permit limit of 8064 hours of operation per year. Using 2002 as the baseline, the annual average NO_x emission rate is 464.3 lbs/hr (1,747.1 tpy) or about 4.73 lbs/ton of dry kiln feed.

Variations in kiln NO_x 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 study⁵, *"The results of these changes range from zero emissions of NO_x during a complete outage of the system to significantly higher than normal NO_x 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 NO_x emissions. For a variety of factors, the operation of some pre-calciner kiln systems is more stable than others. Almost invariably, however, pre-calciner kiln systems exhibit more stable operation than the three other types of kiln systems, and experience the least variability in NO_x 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 NO_x emissions depending on cement product produced and variations in raw materials.

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

Cemex identified six available technologies for the removal of NO_x 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 NO_x Burners (LNB)
5. Selective Non Catalytic Reduction (SNCR)
6. LNB with SNCR
7. Selective Catalytic Reduction (SCR)

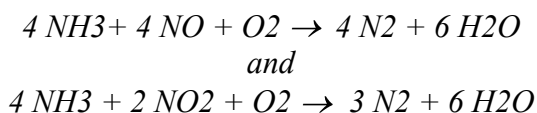
Step 2: Eliminate Technically Infeasible Options

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 NO_x controls for purposes of BART at the facility.

7. Selective Catalytic Reduction (SCR):

Selective catalytic reduction (SCR) refers to the reduction of NO_x 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 NO_x. The EPA released a NO_x control technology update for new cement kilns entitled "Alternative Control Techniques Document Update – NO_x 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:



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 NH₃: 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/m³ (~ 0.8 lb/t) of NO_x is typically achieved from an inlet of 1,050 mg/Nm³ (4.2 lb/t) or 80% control. Also, ammonia slip was less than 1 mg/m³. 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.

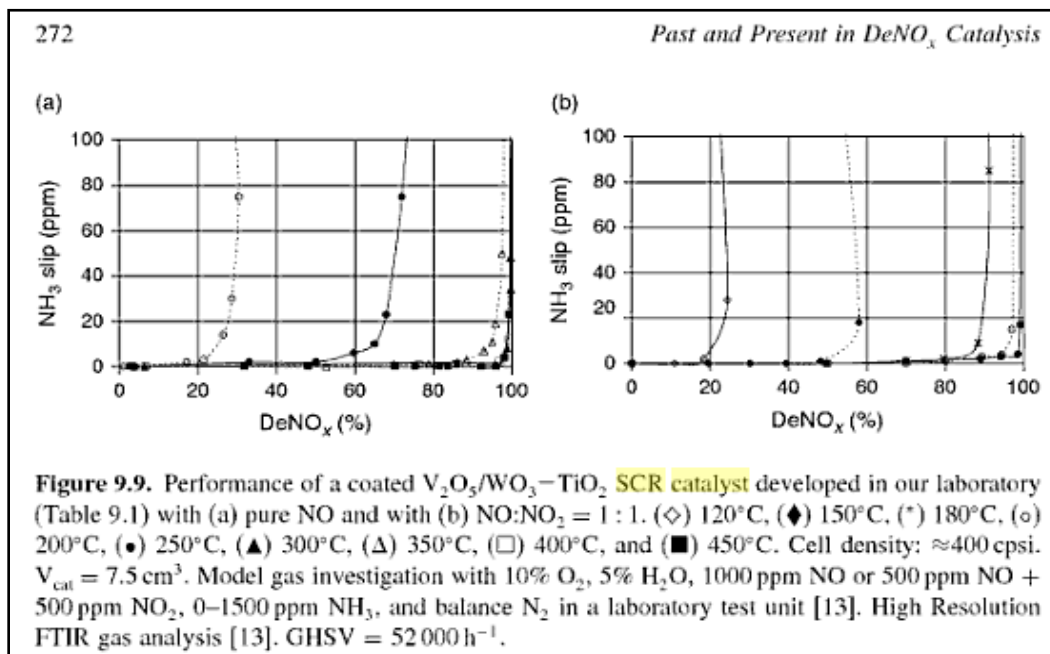
The design of a SCR system is expected to be site specific. According to Schreiber⁶, the technology transfer of SCR systems from the power plant industry to the Portland cement industry requires substantial research and pilot testing before the technology could be considered commercially available. Figure 1, from Granger⁷ shows the performance of a typical catalyst under different conditions of temperature and gas composition. The highest NO_x reduction

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 DeNO_x 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 NO_x 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 NO_x Control and Ammonia slip at Various Temperatures



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 NO_x 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 NO_x 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 NO_x control. If post NO_x control cooling is required, additional water usage would be necessary along with the challenges of the resultant high moisture (20-25%) exhaust gas stream.

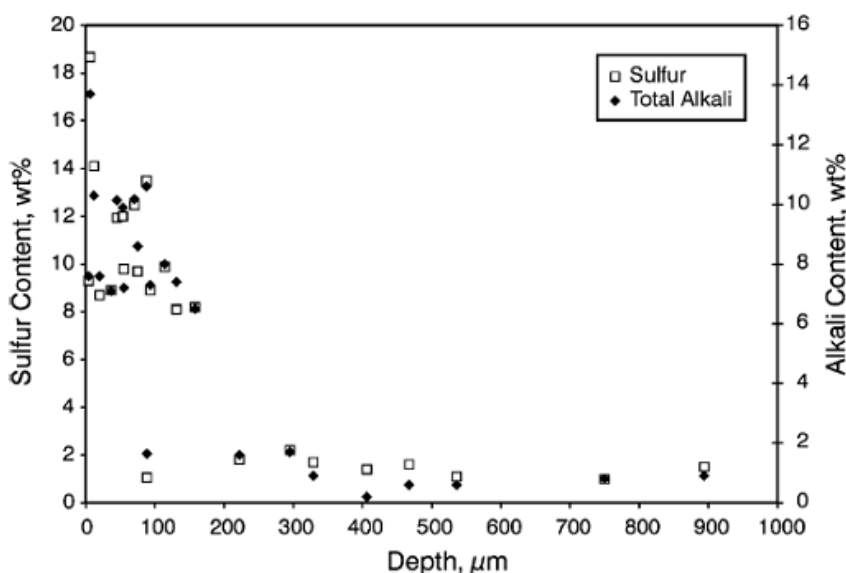
There is limited information regarding the geometry and optimal positioning of the catalyst to allow for effective NO_x reduction and low pressure loss. Further, engineering analysis on overall efficiency during the catalyst life-cycle would be required to ascertain effectiveness. According to Benson⁸, 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 alkalies⁹.

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 NO_x 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 NO_x 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.

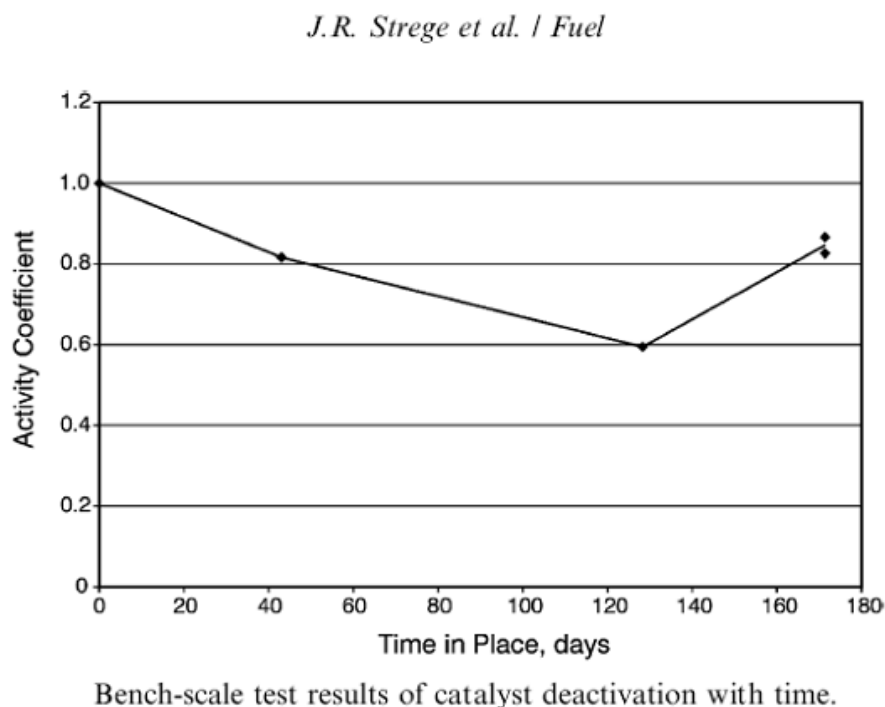
Figure 2: Sulfur and Alkali Penetration into the pores of the catalyst



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 NO_x reduction (see Strege *et al.*, 2008).

Figure 3: Bench Scale Test Results of Catalyst Deactivation over a Period of 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 NO_x 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 Barbaro¹⁰, 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.; Bianchini, 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 NO_x formation is a function of the flame temperature and residence time at that temperature, water injection reduces the generation of thermal NO_x. Cemex - Lyons has stated that its own experience indicates that water injection can reduce the thermal NO_x by approximately 7%. The Division anticipates some reduction in thermal NO_x 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% NO_x reduction, the control cost is about \$356 per ton of NO_x 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 NO_x. 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 NO_x. 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 NO_x 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 NO_x in the exhaust stream. Cemex estimates that firing TDF can reduce NO_x 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 NO_x 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 NO_x reduction objectives.

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 10% NO_x reduction, the control cost is estimated at about \$986 per ton of NO_x 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-NO_x Burners:

Low NO_x burners (LNBs) reduce the amount of NO_x 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-NO_x burner creates primary and secondary combustion zones at the end of the main burner pipe to reduce the amount of NO_x 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 NO_x formation and produces free radicals that chemically reduce some of the NO_x 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 NO_x 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 NO_x 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 NO_x by 20% at the Lyons plant.

Cost of Compliance:

Cemex also provided information from a NESCAUM report (Dec 2000) that indicates 20-30% NO_x 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 NO_x reduced.

Energy Impacts and Non Air-Quality Impacts:

None.

Existing Controls in Use at Source:

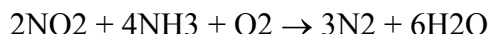
None.

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 NO_x without the need for a catalyst to form water and molecular nitrogen in accordance with the following simplified reactions.



As applied to NO_x 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 NO_x, thereby increasing NO_x 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 –PM_{2.5}.

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 – NO_x 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 NO_x 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% NO_x reduction, the control cost is about \$1,934 per ton of NO_x 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 NO_x Burners (LNB):

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

In the cement manufacturing industry, it is well known that thermal NO_x represents the majority of the NO_x formation in cement kiln systems. Thermal NO_x 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 NO_x 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 NO_x 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 NO_x 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 NO_x 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 NO_x.

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 NO_x 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 NO_x 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 NO_x emission levels, kiln type, and fuels used. According to EPA's "Alternative Control Techniques Document Update – NO_x Emissions from Cement Manufacturing," EPA-453/R-94-004, March 2004, the NO_x 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 NO_x 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 NO_x 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% NO_x reduction (long term) at the Lyons Plant. This level of NO_x 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 NO_x 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. NO_x 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. NO_x 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 NO_x Control Technologies for the Kiln

Control Technology	NO _x Emission Reduction [tons/yr]	Annualized Cost [\$/yr]	Cost Effectiveness [\$/ton]	Incremental Cost Effectiveness [\$/ton]
Baseline NO _x 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 NO_x 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 NH₃:3 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 950°C (1,740°F), while for urea, the temperature increases to about 1,000°C (1,830°F).

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 N₂O. The rate of N₂O formation is a weak function of both the reactant and the NO

concentration. However, N₂O 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% NO_x reduction (30-day rolling average) and 48.43% NO_x 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 NO_x 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°F) is significantly higher at the exit than a more typical preheater precalciner kiln (650°F). This is a significant distinction that limits the location and residence time available for

an effective NO_x 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 NO_x 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 NO_x 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 NO_x emissions from the kiln. Table 13 specifies the Division NO_x 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 NO_x 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 NO_x BART limits will be determined by a continuous emissions monitor system (CEMS).

Table 13: NO_x Emission Limits on the Kiln

Subject Unit	NO _x Control Technology	NO _x 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 NO_x 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 NO_x 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 NO_x.

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

RBLC ID	NO _x Control	NO _x 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/calcliner	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 NO_x reduction requirements established under the kiln retrofit options require

SNCR with a 12-month rolling emission limit of 4.89 lbs NO_x/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 NO_x) helps to further validate the stringency of the NO_x 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 NO_x 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 NO_x limits through SNCR technology and process controls. Improving process controls may allow Cemex - Lyons to limit formation of NO_x in the kiln and thus meet the NO_x 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 NO_x emission rate is reasonable for the older cement kiln process, and that SNCR control at 255.3 lb/hr NO_x on a 30-day rolling average (which is about 4.06 lbs of NO_x per ton of clinker) is NO_x BART for the Cemex – Lyons facility. This BART determination will remove 45% of the NO_x 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 to 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

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

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/PM₁₀ 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, SO₂, PM₁₀), 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 “NO_x 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 SO₂ emissions. Days with zero emissions/heat input were not included in these averages.

***The PM₁₀ 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)

Emission Unit	Specifications		
	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 (SO₂)**

Step 1: Identify All Available Technologies

CENC identified four SO₂ control options:

Flue gas desulfurization (FGD):

Lime spray dry absorber (SDA or dry FGD)

Dry sorbent injection – Trona (DSI)

SO₂ 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 SO₂ 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 plants¹. 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 SO₂ Emissions: A Review of Technologies² evaluates various SO₂ 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 SO₂, 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 from 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 SO₂ controls on Units 4 and 5. The Division noted:

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 SO₂ ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum SO₂ removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CENC estimated the maximum SO₂ removal rate that can be achieved while minimizing the creation of the brown plume condition to be 65% SO₂ removal. In practical application, a higher SO₂ removal rate may be possible, while it is also possible that a lower SO₂ removal rate may be necessary to limit the brown plume formation. This determination would require actual SO₂ 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.

SO₂ 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 SO₂ 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 SO₂ 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.

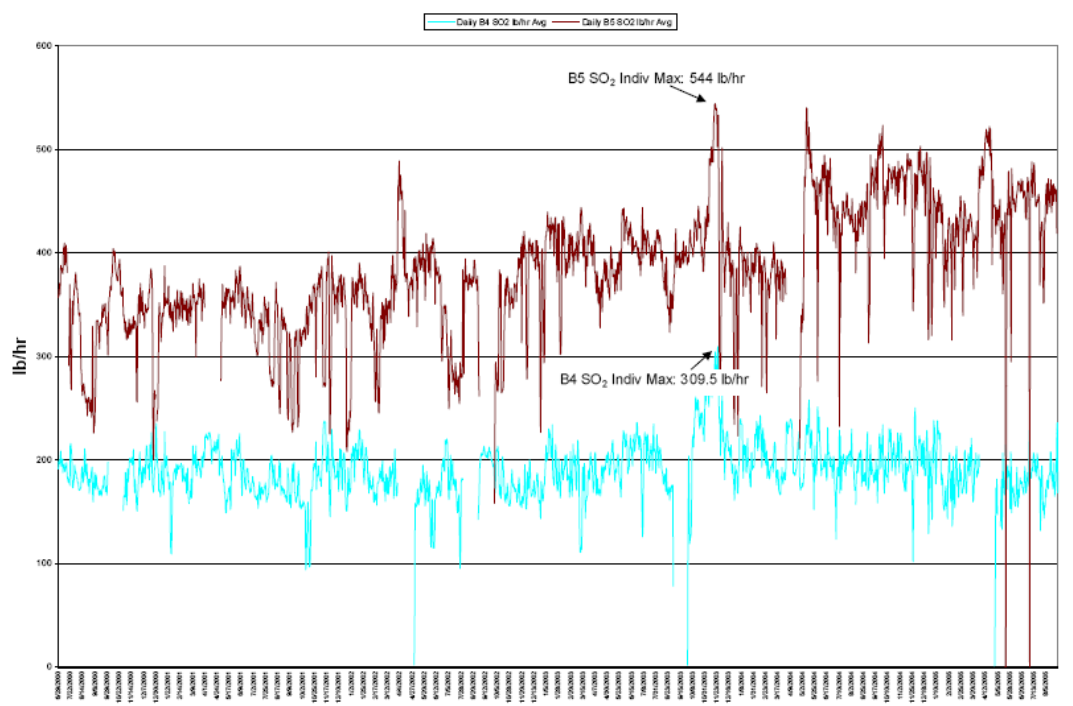


Figure 3: Boilers 4 and 5 SO₂ lb/hour daily average (2000 - 2005)

Using alternative approaches to operations management, CENC proposes a new, enforceable permit limit to reduce peak lb/hr SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ emissions management is unit-specific.

DSI: CENC asserts that the maximum SO₂ removal rate that can be achieved to be 65% SO₂ 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 submittals³ and to be conservative since this technology is relatively novel.

SO₂ 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 SO₂ Permit Limits and Emissions Reduction

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

*Refer to pages A-31, A-34, and A-35 of CENC BART Submittal (July 31, 2006) for detailed SO₂ 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) SO₂ 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 SO₂ 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 SO₂ 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 7 summarizes each available technology and technical feasibility for SO₂ control.

Table 7: CENC Boilers 4 and 5 SO₂ 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 SO₂ collected for 65 percent control. The theoretical minimum requirement is 2.4 lb Trona per lb of SO₂ 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 in Table 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 SO₂ 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 Department of Public Health and Environment - Air Pollution Control Division

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.

SO₂ Emissions Management: CENC notes that the costs for implementing a SO₂ 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 SO₂ 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 SO₂ Emission Management based on SO₂ 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 investments⁶. 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 SO₂ emissions and control cost comparisons.

Table 9: Boiler 4 Control Resultant SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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.

SO₂ Emissions Management: The Division has determined that there are not any negative energy or non-air quality related impacts related to the proposed SO₂ 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.

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 (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 protocol⁹, 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 SO₂ 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 SO₂ 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

SO ₂ Control Scenario	Unit(s)	SO ₂ Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
				Pre- Control Days >0.5 dv	Post- Control Days >0.5 dv		Pre- Control Days >1.0 dv	Post- Control Days >1.0 dv	
Max 24- hr	4	0.90	Rocky Mountain	33	---	---	10	---	---
	5	0.98							

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 – SO₂ Control Options

Scenario	Boiler(s)	SO ₂ Emission Rate (lb/MMBtu)	Output (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	(\$/dv)
Max 24-hr	4	0.90	1.07	---	---	---
	5	0.98				
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	0.361	0.28	0.79	74%	\$18,393,225
	5	0.392				

Step 6: Select BART Control

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

B. Filterable Particulate Matter (PM₁₀)

CENC Boilers 4 and 5 are each equipped with fabric filter baghouses to control PM/PM₁₀ 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/PM₁₀ 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/PM₁₀ 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/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/PM₁₀. 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/PM₁₀ 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 (NH₃) 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. SNCR 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 boiler¹² 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 boilers¹³ and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for CENC Boilers 4 and 5.

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/MMBtu¹⁴. 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

¹⁴ Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NO_x Control and Combined NO_x/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 study¹⁹ 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
ECOR®	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 investments²². 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

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/fsnscr.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 NO_x 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 NO_x 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 protocol³¹, 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 SO₂ 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 SO₂ 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		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
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.”

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Combo	4	0.07		33	3	30	10	0	10
	5	0.07							

* 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

NO _x Control Scenario	Boiler(s)	NO _x Emission Rate (lb/MMBtu)*	Output (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	(\$/dv)
Max 24-hr	4	0.67	1.07	---	---	---
	5	0.66				
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
NO _x 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		0.75	0.31	29%	\$20,669,680
Combo	4	0.07	0.28	0.79	74%	\$18,393,225
	5	0.07				

* 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 fence line, 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 NO_x BART for Boiler 4 is the following NO_x 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 NO_x 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 NO_x 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 NO_x 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 NO_x 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 SO₂ 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, SO₂, PM₁₀). 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 1 and 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 SO₂ 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/PM₁₀, 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 SO₂ 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 SO₂ emissions.

***The PM₁₀ 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 ₂ O (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 sources¹

Emission Unit	Pollutant (lb/ton)*			
	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

*SO₂ and PM/PM₁₀ 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.
 - SO₂ 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 SO₂ 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)
 - SO₂ 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 SO₂ 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 PM₁₀ 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.
- SO₂ 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 (SO₂)**

Step 1: Identify All Available Technologies

Semi-Dry FGD Upgrades – As discussed in EPA’s BART Guidelines², 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 SO₂ 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 SO₂ emission limitation with the existing controls (i.e., SO₂ 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 SO₂ 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 SO₂ 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 plants³. 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 SO₂ 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 1 indicates 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 limits⁴ depicted in Table 5. It should be noted that since July 1, 2009, when the SO₂ limits became applicable, Unit 1 is 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 SO₂ 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 SO₂. 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 NO₂. Since NO₂ is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO₂ 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 SO₂. 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% SO₂ removal. This unit was reported to have a visible plume at times likely due to the conversion from NO to NO₂ 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 SO₂ removal; there are no known acceptable reagents without side effects that would allow additional SO₂ 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 SO₂ 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 SO₂ emissions. The Division agrees that upgrades to grinding technologies are unlikely to produce additional SO₂ 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 SO₂ removal and lime use efficiency. B&W offers no upgrade in atomizer design to improve SO₂ 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 SO₂ removal. PSCo has tried some of these different nozzle designs and doesn't believe any of the designs improve the SO₂ 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 SO₂ 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 SO₂ emission limitations:

Table 6: Comanche Units 1 & 2 SO₂ Emission Limitations

	SO ₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ reduction levels will be lower during those times.

The Division reviewed available SO₂ 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 SO₂ 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 SO₂ 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 SO₂ emissions.

As explained above, the Division projects 30-day rolling SO₂ 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 SO₂ 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 SO₂ 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, SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 protocol⁵, 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 SO₂ BART control technology on a given unit, emission rates for the other pollutants (NO_x and PM/PM₁₀) 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 SO₂ 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

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		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hour	1	0.75	Great Sand Dunes National Park	60	---	---	27	---	---
	2	0.74							
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	0.12		60	4	56	27	1	26
	2								

* 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 – SO₂ Emission Rates

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Output (@ 98 th Percentile Impact)*	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum
			(dv)	(Δ dv)	(%)
Max 24-hour	1	0.75	2.05	---	---
	2	0.74			
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	0.12	0.36	1.69	82%
	2				

* 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 SO₂ BART is the following existing SO₂ 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 SO₂ limit of 0.12 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology.

B. Filterable Particulate Matter (PM₁₀)

Comanche Units 1 and 2 are each equipped with fabric filter baghouses to control PM/PM₁₀ 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 and PM₁₀. 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 PM₁₀ (assumes PM₁₀ = 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%

*PM₁₀ = 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/PM₁₀ 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/PM₁₀) represents the most stringent level of available control for PM/PM₁₀. The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for PM/PM₁₀ 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/PM₁₀ 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 °F, 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, SO₂, 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 SO₂, NO₂ 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 burners⁶. 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 – 3100°F).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 is 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 N₂. 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 1 and 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 proposals¹¹, 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 NO_x 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 boilers will 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/fsnscr.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 NO_x 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 NO_x 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 2 NO_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 protocol²², 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 (SO₂ and PM/PM₁₀) 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 SO₂ 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

NO _x Control Scenario	Boiler(s)	NO _x Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hour	1	0.40	Great Sand Dunes National	60	---	---	27	---	---
	2	0.53							
NO _x @	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

NO _x Control Scenario	Boiler(s)	NO _x Emission Rate (lb/MMBtu)*	Output (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Impact Improvement from new LNB (2009)	98 th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(Δ dv)	(%)	(\$/dv)
Max 24- hour	1	0.40	2.05	---	---	---	---
	2	0.53					
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)

Comanche Unit 2: 0.15 lb/MMBtu (combined annual average for units 1 & 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 (SO₂) 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 SO₂ 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/PM₁₀, 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, SO₂, PM₁₀), 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 SO₂ emissions.

***The PM₁₀ 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 ₂ O (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 sources¹

Emission Unit	Pollutant (lb/ton)*			
	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

*SO₂ and PM/PM₁₀ 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 (SO₂)**

Step 1: Identify All Available Technologies

Wet FGD Upgrades – As discussed in EPA’s BART Guidelines², 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 SO₂ Operating Permit Limits

	SO ₂ limits (lb/MMBtu)			Reduction (%) Required 90-day rolling
	3-hr rolling	30-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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ concentrations seen at Craig Units 1 and 2.

2. DBA could cause changes in sulfite oxidation with impacts on SO₂ removal and solids settling and dewatering characteristics.

3. Installation of the perforated plate tray accomplished the same objective of increased SO₂ 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 SO₂ 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 SO₂ removal rates.

2. Forced oxidation within the SO₂ 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 SO₂ 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 SO₂ 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 protocol³, 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 SO₂ BART control technology on a given unit, emission rates for the other pollutants (NO_x and PM/PM₁₀) 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 SO₂ 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		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
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 – SO₂ Control Options

SO ₂ Control Scenario	Boiler(s)	SO ₂ Emission Rate (lb/MMBtu)*	Output (@ 98 th Percentile Impact)*	98 th Percentile Impact Improvement	98 th 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 SO₂ 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 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.

B. Filterable Particulate Matter (PM₁₀)

Craig Units 1 and 2 are each equipped with pulse jet fabric filter (PJFF) baghouses to control PM/PM₁₀ 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/PM₁₀ 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/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/PM₁₀.

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. Mototec 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 load⁴. 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 (NH₃) 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 boiler⁵ 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 boilers⁶ 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/MMBtu⁷. 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.

⁷ Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NO_x Control and Combined NO_x/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/MMBtu⁹ 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.

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 NO_x 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 NO_x 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.

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 NO_x 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/fsnscr.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 NO_x 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/fsnscr.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 NO_x 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 NO_x 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 (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 protocol²², 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 SO₂ 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 SO₂ 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

NO _x Control Scenario	Boiler(s)	NO _x Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hour	1	0.352	Mt. Zirkel Wilderness	207	---	---	123	---	---
	2	0.345							
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	0.07							
	2	0.07		207	57	150	123	12	111

Table 17: Visibility Results – NO_x Control Options

NO _x Control Scenario	Boiler(s)	NO _x Emission Rate (lb/MMBtu)	Output (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	(\$/dv)
Max 24-hour	1	0.352	3.73	---	---	---
	2	0.345				
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	0.07		2.56	69%	
	2	0.07	1.17			\$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 operation²³ 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 selected²⁴. 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 NO_x 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 NO_x 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 NO_x 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 NO_x 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 NO_x emission limit of 0.28 lb/MMBtu 30-day rolling average until closure or conversion to natural gas. Additionally, an annual NO_x 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 PM₁₀ 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 , NO _x ,	COM CEMs for SO ₂ , NO _x ,	COM CEMs for SO ₂ , NO _x ,

	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/PM₁₀. 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, SO₂, PM₁₀), 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 “NO_x 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 Grandfathered¹.

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 SO₂ emissions.

***The PM₁₀ 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 NO_x emissions. In fact the data suggested at that time that 100% sub-bituminous coal had no effect on NO_x emissions for some of the boilers. CSU notes that this effect may be boiler specific. The difference in sulfur content and resultant SO₂ 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 ₂ O (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)

Emission Unit	Specifications		
	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 sources²

Emission Unit	Pollutant (lb/ton)*			
	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

*SO₂ and PM/PM₁₀ 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 (SO₂)

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 SO₂ 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 plants³. 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 SO₂ Emissions: A Review of Technologies⁴ evaluates various SO₂ 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 ft² and Units 6 & 7 is 8,346 ft² (or about 4,000 ft² 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.

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 SO₂ 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 SO₂ 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 SO₂ 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 NO₂ which has a reddish-brown color. This conversion of NO to NO₂ 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 SO₂ ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum SO₂ removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CSU estimated the maximum SO₂ removal rate that can be achieved while minimizing the creation of the brown plume condition to be 60% SO₂ removal. In practical application, a higher SO₂ removal rate may be possible, while it is also possible that a lower SO₂ removal rate may be necessary to limit the brown plume formation. This determination would require actual SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ Emissions: A Review of Technologies⁵ 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 SO₂ removal rate that can be achieved to be 60% SO₂ 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) SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ emissions for each technically feasible control option. Table 9, Table 10, and Table 11 show the SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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.

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 CO₂ 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 $\pm 30\%$. 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.

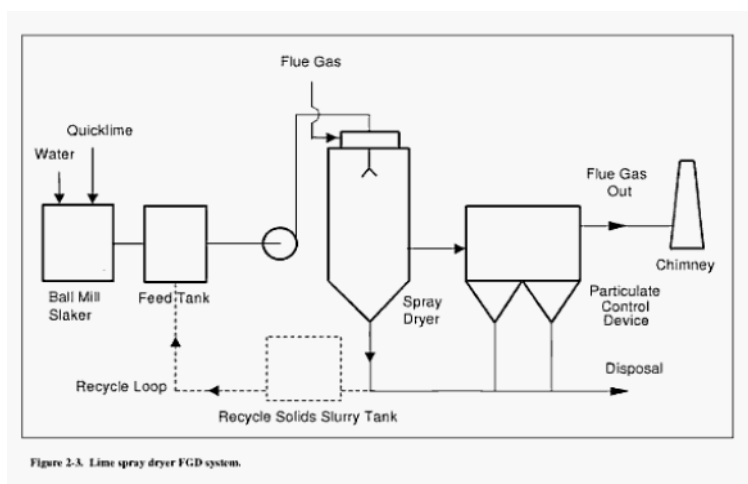


Figure 3: Lime Spray Dryer (LSD) Schematic¹⁰

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 SO₂ 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 protocol¹², 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 SO₂ BART control technology on a given unit, emission rates for the other pollutants (NO_x and PM/PM₁₀) 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 SO₂ 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)	SO ₂ 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."

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	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 – SO₂ Control Options

SO ₂ Control Scenario	Boiler(s)	SO ₂ Emission Rate (lb/MMBtu)	Output (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	(\$/dv)
Max 24-hr SO ₂ rates	5	0.943	1.84	---	---	---
	6	0.997				
	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	0.25	1.59	86%	n/a
	6	0.120				
	7	0.120				

Step 6: Select BART Control

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

Based upon its consideration of the five factors summarized herein, 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 (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% 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

B. Filterable Particulate Matter (PM₁₀)

Drake Units 5, 6, and 7 are each equipped with reverse-air fabric filter baghouses to control PM/PM₁₀ 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 PM₁₀ 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/PM₁₀ 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/PM₁₀) 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/PM₁₀. 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/PM₁₀ 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 load¹³. 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 N₂ 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 formed¹⁴. 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 (NH₃) 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

¹⁴ IEA Clean Coal Centre: Clean Coal Technologies – Air Staging 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 boiler¹⁵ 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 boilers¹⁶ 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/MMBtu¹⁷. 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 estimates for ULNBs.

¹⁷ Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NO_x Control and Combined NO_x/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 study²² 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}

²⁶ Amar, Praveen, 2000. "Status Report on NO_x 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. "NO_x 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. "NO_x 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 NO_x 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/fsnscr.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.

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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 NO _x 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 NO _x 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 NO _x 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 NO _x 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 NO _x 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 (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 protocol³⁷, 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 (SO₂ and PM/PM₁₀) 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 SO₂ 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		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hour NOx rates	5	0.619	Rocky Mountain National Park	---		34	17		---
	6	0.827							
	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.”

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	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 (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th 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

NOx Control Scenario	7	0.251*	1.58	0.26	14%	\$1,794,618
	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-NO_x burners (including over-fire air).

- Unit 5: \$1,342 per ton NO_x removed
- Unit 6: \$664 per ton NO_x removed
- Unit 7: 616 per ton NO_x 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 NO_x 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 Δ_{adv})

**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/PM₁₀. For NO_x and SO₂ 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, SO₂, PM₁₀), 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 SO₂ emissions.

***The PM₁₀ 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”) NO_x/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 ₂ O (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 sources¹

Emission Unit	Pollutant (lb/ton)*			
	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

*SO₂ and PM/PM₁₀ 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 (SO₂)**

Step 1: Identify All Available Technologies

Semi-Dry FGD Upgrades – As discussed in EPA’s BART Guidelines², 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 SO₂ 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 SO₂ 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 SO₂ 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 plants³. 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 SO₂/MMBtu (each unit) in comparison with the permit limits⁴ 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 SO₂ 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 SO₂ 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 SO₂. 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 SO₂ 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 SO₂ 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 SO₂ removal. Based on the information provided by PSCo, the Division agrees that the use performance additives are not likely to increase SO₂ 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 SO₂ 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 NO₂. Since NO₂ is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO₂ 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 SO₂. 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% SO₂ removal. This unit was reported to have a visible plume at times likely due to the conversion from NO to NO₂ 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 SO₂ removal; there are no known acceptable reagents without side effects that would allow additional SO₂ 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 SO₂ 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 SO₂ 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 SO₂ removal and lime use efficiency. B&W offers no upgrade in atomizer design to improve SO₂ 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 SO₂ removal. PSCo has tried some of these different nozzle designs and doesn't believe any of the designs improve the SO₂ 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 SO₂ 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, SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ control.

Table 6: Hayden Units 1 and 2 SO₂ 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 SO₂ 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 SO₂ control cost per unit.

Table 7: Hayden Unit 1 Control Resultant SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 protocol⁵, 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 SO₂ BART control technology on a given unit, emission rates for the other pollutants (NO_x and PM/PM₁₀) 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 SO₂ 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

SO ₂ Control Scenario	Boiler(s)	SO ₂ Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals		Δ days	3-year totals		Δ days
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
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							
	2	0.070		236	57	179	155	6	149

* 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 – SO₂ Control Options

SO ₂ Control Scenario	Boiler(s)	SO ₂ Emission Rate (lb/MMBtu)*	Output (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th 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	0.120	0.91	2.72	75%	n/a
	2	0.120				

* 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 SO₂ BART 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 (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 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.

B. Filterable Particulate Matter (PM₁₀)

Hayden Units 1 and 2 are each equipped with reverse-air fabric filter baghouses to control PM/PM₁₀ 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/PM₁₀ 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/PM₁₀) represents the most stringent level of available control for PM/PM₁₀. The units are exceeding a PM control efficiency of 95%, and the state has selected this control technology and emission limit for PM/PM₁₀ 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/PM₁₀ 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 (NH₃) 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 boiler⁶ 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 boilers⁷ 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

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 load⁸. 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/MMBtu⁹. 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 proposals¹⁰, 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 NO_x Control and Combined NO_x/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 NO_x 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/chieff/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 ($\pm 30\%$).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/fsnscr.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 NO_x 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/fsnscr.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 NO_x 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 2 NO_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 (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 protocol²⁵, 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 (SO₂ and PM/PM₁₀) 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 SO₂ 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

NO _x Control Scenario	Boiler(s)	NO _x Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hr NO _x rates	1	0.610	Mt. Zirkel Wilderness Area	236	---	---	155	---	---
	2	0.367							
NO _x Scenario	1	0.390		236	227	9	155	131	24
	2	0.280		236	230	6	155	144	11
NO _x 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

NO _x Control Scenario	Boiler(s)	NO _x Emission Rate (lb/MMBtu)*	Proposed Limit (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum	Cost Effectiveness
			(deciviews)	(deciviews)	(%)	(\$/deciview)
Max 24-hr	1	0.610	3.63	---	---	---

NO _x rates	2	0.367				
NO _x Scenario	1	0.390	3.13	0.50	14%	n/a
	2	0.280	3.42	0.20	6%	n/a
NO _x 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.

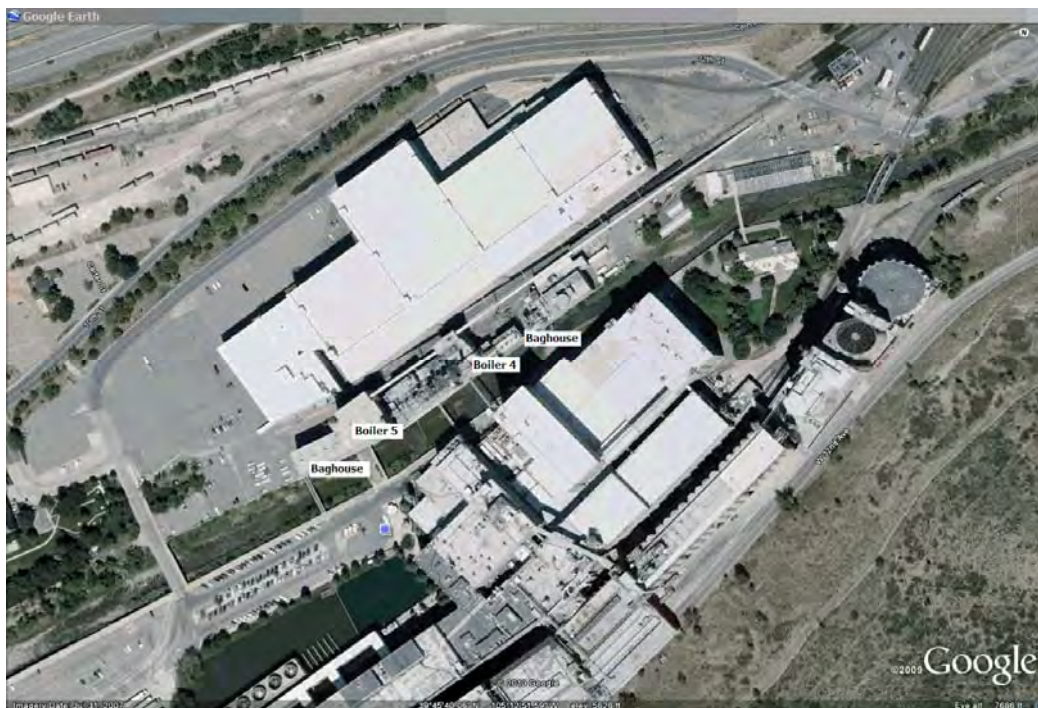


Figure 1: CENC facility Aerial Perspective

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/PM₁₀ 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, 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 be 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, SO₂, PM₁₀), 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 control¹.”

These levels are as follows:

- NO_x – 40 tons per year
- SO₂ – 40 tons per year
- PM₁₀ – 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, SO₂, PM₁₀) 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, SO₂, 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, SO₂, and PM₁₀ 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*
<i>Boiler #1 (288 MMBtu/hour – natural gas fired)</i>	<i>SO₂ (tons)</i>	<i>0.1</i>	<i>0.1</i>	<i>0.1</i>	<i>0.1</i>
	<i>SO₂ (lb/ MMBtu)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
	<i>NO_x (tons)</i>	<i>30.8</i>	<i>23.9</i>	<i>30.3</i>	<i>28.3</i>
	<i>NO_x (lb/ MMBtu)</i>	<i>0.02</i>	<i>0.02</i>	<i>0.02</i>	<i>0.02</i>
	<i>PM₁₀ (tons)</i>	<i>0.8</i>	<i>0.7</i>	<i>0.8</i>	<i>0.7</i>
	<i>PM₁₀ (lb/ MMBtu)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
<i>Boiler # 2 (288 MMBtu/hour – natural gas fired)</i>	<i>SO₂ (tons)</i>	<i>0.1</i>	<i>0.0</i>	<i>0.1</i>	<i>0.1</i>
	<i>SO₂ (lb/ MMBtu)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
	<i>NO_x (tons)</i>	<i>32.4</i>	<i>10.4</i>	<i>27.6</i>	<i>23.5</i>
	<i>NO_x (lb/ MMBtu)</i>	<i>0.03</i>	<i>0.01</i>	<i>0.02</i>	<i>0.02</i>
	<i>PM₁₀ (tons)</i>	<i>0.9</i>	<i>0.3</i>	<i>0.7</i>	<i>0.6</i>
	<i>PM₁₀ (lb/ MMBtu)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
<i>Boiler #3 (225 MMBtu/hour – coal fired)</i>	<i>SO₂ (tons)</i>	<i>264</i>	<i>205</i>	<i>267</i>	<i>245</i>
	<i>SO₂ (lb/ MMBtu)</i>	<i>0.27</i>	<i>0.21</i>	<i>0.27</i>	<i>0.25</i>
	<i>NO_x (tons)</i>	<i>185</i>	<i>150</i>	<i>170</i>	<i>168</i>
	<i>NO_x (lb/ MMBtu)</i>	<i>0.19</i>	<i>0.15</i>	<i>0.17</i>	<i>0.17</i>
	<i>PM₁₀ (tons)</i>	<i>2.3</i>	<i>1.9</i>	<i>2.1</i>	<i>2.1</i>
	<i>PM₁₀ (lb/ MMBtu)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
<i>Boiler #4 – (360 MMBtu/hour – coal fired)</i>	<i>SO₂ (tons)</i>	<i>764</i>	<i>815</i>	<i>763</i>	<i>781</i>
	<i>SO₂ (lb/ MMBtu)</i>	<i>0.48</i>	<i>0.52</i>	<i>0.48</i>	<i>0.49</i>
	<i>NO_x (tons)</i>	<i>637</i>	<i>589</i>	<i>575</i>	<i>600</i>
	<i>NO_x (lb/ MMBtu)</i>	<i>0.40</i>	<i>0.37</i>	<i>0.37</i>	<i>0.38</i>
	<i>PM₁₀ (tons)</i>	<i>10.9</i>	<i>10.0</i>	<i>10.4</i>	<i>10.4</i>
	<i>PM₁₀ (lb/ MMBtu)</i>	<i>0.01</i>	<i>0.01</i>	<i>0.01</i>	<i>0.01</i>
<i>Boiler #5 – (650 MMBtu/hour – coal fired)</i>	<i>SO₂ (tons)</i>	<i>1,598</i>	<i>1,333</i>	<i>1,289</i>	<i>1,407</i>
	<i>SO₂ (lb/ MMBtu)</i>	<i>0.56</i>	<i>0.47</i>	<i>0.45</i>	<i>0.49</i>
	<i>NO_x (tons)</i>	<i>900</i>	<i>614</i>	<i>559</i>	<i>691</i>
	<i>NO_x (lb/ MMBtu)</i>	<i>0.32</i>	<i>0.22</i>	<i>0.20</i>	<i>0.25</i>
	<i>PM₁₀ (tons)</i>	<i>21</i>	<i>17</i>	<i>16</i>	<i>18</i>
	<i>PM₁₀ (lb/ MMBtu)</i>	<i>0.01</i>	<i>0.01</i>	<i>0.01</i>	<i>0.01</i>
<i>P005 – Coal Unloading and Conveying</i>	<i>PM₁₀ (tons)</i>	<i>0.03</i>	<i>0.03</i>	<i>0.03</i>	<i>0.03</i>
<i>P007 – Boiler #5 Silos – coal conveyor to Unit 5 silos</i>	<i>PM₁₀ (tons)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
<i>P008 – Ash Handling – 11, 12, 13 – general ash silo</i>	<i>PM₁₀ (tons)</i>	<i>5.57</i>	<i>5.57</i>	<i>5.38</i>	<i>5.51</i>
<i>P009 – Boiler #3 Silos – coal conveyor to Unit 5 silos</i>	<i>PM₁₀ (tons)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
<i>P010 – Ash Handling – Boiler #4 & #5 fly ash</i>	<i>PM₁₀ (tons)</i>	<i>0.02</i>	<i>0.02</i>	<i>0.02</i>	<i>0.02</i>

<i>collection</i>					
<i>P011 – Ash Handling – Fly ash silo loadout</i>	<i>PM₁₀ (tons)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
<i>P012 – Ash Handling – Fly ash silo bin vent</i>	<i>PM₁₀ (tons)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
<i>P013 – Diesel Air Compressors – GM diesel engine for backup operation of air compressor</i>	<i>SO₂ (tons)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
	<i>NO_x (tons)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>
	<i>PM₁₀ (tons)</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>	<i>0.00</i>

*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 SO₂. 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 NO_x 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 PM₁₀ 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)

Emission Unit	Specifications		
	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 SO₂ 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 SO₂ 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 plants³. 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 SO₂ Emissions: A Review of Technologies⁴ evaluates various SO₂ 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 SO₂, 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 from 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 SO₂ 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 SO₂ ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum SO₂ removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CENC estimated the maximum SO₂ removal rate that can be achieved while minimizing the creation of the brown plume condition to be 65% SO₂ removal. In practical application, a higher SO₂ removal rate may be possible, while it is also possible that a lower SO₂ removal rate may be necessary to limit the brown plume formation. This determination would require actual SO₂ 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 SO₂ 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 SO₂ 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 SO₂ removal rate that can be achieved to be 65% SO₂ 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 submittals⁵ and to be conservative since this technology is relatively novel.

Fuel Switching – Natural Gas: Conversion from coal to natural gas would reduce SO₂ emissions by almost 100% from each unit using EPA’s AP-42 emission factors⁶ and concurs with CENC’s submittal.

Table 8 summarizes each available technology options and technical feasibility for SO₂ 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/chieff/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 SO₂ collected for 65 percent control. The theoretical minimum requirement is 2.4 lb Trona per lb of SO₂ 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 Manual⁹ to estimate annual operating costs, of approximately \$25,000 per ton of SO₂

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 Administration¹¹ 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_dc_u_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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ emission reduction benefits (tons of SO₂ 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 Δ dv for DSI applied to Boiler 4 (360 MMBtu/hr). DSI controls for Boiler 4 would reduce SO₂ emissions by approximately 268 tons per year. DSI controls for Boiler 3 would reduce SO₂ emissions by about 147 tons per year. Fuel switching to natural gas would reduce SO₂ 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 Δ dv.

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/cetc/resources/pdfs/lifac/LIFAC_PPA.pdf

Table 12: CENC Boiler 4 SO₂ Modeling Results

SO ₂ Control Method	CENC - Boiler 4		
	Emission Reduction (tpy)	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
<i>Theoretical lb/MMBtu...</i>			
Maximum B3 Conversion Sulfur to SO ₂ (using fuel analysis)	0.99	0.98	0.99

Based upon its consideration of the five factors summarized herein, the state has determined that SO₂ 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 PM₁₀)

CENC Boiler 3 is equipped with fabric filter baghouses to control PM/PM₁₀ 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/PM₁₀ 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/PM₁₀ 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/PM₁₀. 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 analysis¹⁵, 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. SNCR 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 (NH₃) 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 boiler¹⁶ 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 boilers¹⁷ 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/MMBtu¹⁸. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

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 NO_x Control and Combined NO_x/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/ttn/cat1/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

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 NO_x 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 NO_x 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 Δv 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 Δ dv.

Table 18: CENC Boiler 4 NO_x Modeling Results

NO _x Control Method	Emission Reduction (tpy)	CENC - Boiler 4	
		NO _x Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δ dv)
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 NO_x 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 SO₂) 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 NO_x RP for Boiler 3 is following NO_x 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 ($\ll$ 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, SO₂, and PM/PM₁₀ control technologies and represents reasonable progress. Therefore, a full 4-factor analysis is not needed to evaluate reasonable progress for NO_x, SO₂, or PM/PM₁₀ 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 NO_x, 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:

NO_x – Steam or water injection, advanced dry low NO_x 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 SO₂, NO_x and PM₁₀ 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
- SO₂ – 40 tons per year
- PM₁₀ – 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 <i>de minimis</i> 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.

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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 NO_x 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 NO_x 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 NO_x 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 NO_x emissions associated with the high temperature pilot flame are insignificant. Low NO_x 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 NO_x 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. NO_x 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 NO_x (DLN), Dry-Low Emissions (DLE), or SoLoNO_x."

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-NO_x 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 NO_x 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% NO_x 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 NO_x 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 NO_x reductions, if any. Regardless, the Division analyzed additional achievable NO_x reductions if SCR was installed at these two turbines. Applying SCR at 90% to both turbines would result in about 275 additional tons of NO_x 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 NO_x 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-NO_x 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 SO₂ and PM₁₀. For NO_x, the majority of combustion turbines already apply advanced dry-low NO_x combustion systems, especially the larger turbines.

Based on its consideration of the four factors summarized herein, the state has determined that NO_x 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 (SO₂) 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 SO₂ 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, 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 be 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, SO₂, PM₁₀), 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 control¹.”

These levels are as follows:

- NO_x – 40 tons per year
- SO₂ – 40 tons per year
- PM₁₀ – 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, SO₂, PM₁₀) 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/PM₁₀, 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, SO₂, and PM₁₀ 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, SO₂, and PM₁₀ 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

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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 crushers) – 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

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Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
<i>F102g – Coal Storage Pile – Unit 3</i>	<i>PM (tons)</i>	<i>0.24</i>	<i>0.24</i>	<i>0.24</i>	<i>0.24</i>
<i>S102h – Coal Reclaim System – Unit 3</i>	<i>PM (tons)</i>	<i>0.003</i>	<i>0.003</i>	<i>0.0034</i>	<i>0.0031</i>
<i>S102k – Common Coal Transfer Building Extension</i>	<i>PM (tons)</i>	<i>0.003</i>	<i>0.003</i>	<i>0.0034</i>	<i>0.0031</i>
<i>S102n – Common Coal Drive House</i>	<i>PM (tons)</i>	<i>0.003</i>	<i>0.003</i>	<i>0.0034</i>	<i>0.0031</i>
<i>S102i – Coal Tripper Deck and Silos – Unit 3</i>	<i>PM (tons)</i>	<i>0.0018</i>	<i>0.0018</i>	<i>0.0018</i>	<i>0.0018</i>
<i>S102j – Loadout Coal to Railcars – Unit 3</i>	<i>PM (tons)</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>0</i>
<i>F205a – Ash Hauling to “Landfill” (Outage Waste to Trapper)</i>	<i>PM (tons)</i>	<i>0.114</i>	<i>0.114</i>	<i>0.114</i>	<i>0.114</i>
<i>F205b – Ash and Wet Waste Hauling to/from Decant Basin</i>	<i>PM (tons)</i>	<i>0.676</i>	<i>0.676</i>	<i>0.676</i>	<i>0.676</i>
<i>F205c – Ash Unloading at “Landfill” (Outage Waste) & Ash Unloading at Decant Basin</i>	<i>PM (tons)</i>	<i>0.0024</i>	<i>0.0024</i>	<i>0.0024</i>	<i>0.0024</i>
<i>F205d – Wet Waste Unloading at Decant Basin</i>	<i>PM (tons)</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>0</i>
<i>F202a – Lime Hauling (trucks)</i>	<i>PM (tons)</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>0</i>
<i>S202b – Lime Unloading – Unit 3</i>	<i>PM (tons)</i>	<i>0.0011</i>	<i>0.0011</i>	<i>0.0012</i>	<i>0.0011</i>
<i>S202c – Lime Conveying & Silo – Unit 3</i>	<i>PM (tons)</i>	<i>0.0011</i>	<i>0.0011</i>	<i>0.0012</i>	<i>0.0011</i>
<i>S202d – Lime Day Bin</i>	<i>PM (tons)</i>	<i>0.0011</i>	<i>0.0011</i>	<i>0.0012</i>	<i>0.0011</i>
<i>S401/2 – Cooling Towers – Units 1 & 2</i>	<i>PM (tons)</i>	<i>10.3</i>	<i>10.3</i>	<i>10.3</i>	<i>10.3</i>
<i>Auxiliary Boiler</i>	<i>PM (tons)</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>0</i>
<i>S403 - Cooling Tower – Unit 3</i>	<i>PM (tons)</i>	<i>5.8</i>	<i>5.2</i>	<i>5.2</i>	<i>5.4</i>

*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 SO₂ 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 SO₂. 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 SO₂ emissions using 2006 – 2008 capacity factor and current PSD permit limits.

**The PM₁₀ emissions and emissions factor are from August 2009 stack test data; PM₁₀ 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)

Emission Unit	Specifications		
	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 ₂ O (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 sources²

Emission Unit	Pollutant (lb/ton)*			
	NO _x	SO ₂	PM (filterable)	PM ₁₀ (filterable)
Unit 3	12	14.7	64.7	14.9

*SO₂ and PM/PM₁₀ 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 (SO₂)**

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 Guidelines³, 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 SO₂ limits are depicted in Table 8.

Table 8: Craig Unit 3 SO₂ PSD Permit Limits

	SO ₂ limits (lb/MMBtu)	Reduction (%) Required	Annual Emission Limit (tons/year)
	Calendar day average	30-day rolling	
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 plants⁴. 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 SO₂ 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 SO₂ 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% SO₂ 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/MMBtu⁵. 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 SO₂ emissions found that lime spray drying processes have a median design efficiency of 90%⁶.

The BART Guidelines note potential upgrades for dry scrubbing systems⁷. 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 SO₂ scrubber performance additives applicable or commercially available for the Unit 3 SDA system.

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 – SO₂ 30-day rolling average limit is 0.13 lb/MMBtu.

⁶ EPA, 2000. “Controlling SO₂ 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 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, 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 SO₂ 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 SO₂ emission limit in this reasonable progress.

Table 11 summarizes each available technology options and technical feasibility for SO₂ 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 SO ₂ control
Fuel switching – different coal type	None	Y – will not provide further SO ₂ 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		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
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 – SO₂ Control Options

SO ₂ Control Scenario	Boiler(s)	SO ₂ Emission Rate (lb/MMBtu)	Output (@ 98 th Percentile Impact)*	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum
			(dv)	(Δ dv)	(%)
Max 24-hour SO ₂ 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 SO₂ 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 (PM₁₀)

Craig Unit 3 is equipped with pulse jet fabric filter (PJFF) baghouses to control PM/PM₁₀ 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 PM₁₀ emissions and also limits total PM and PM₁₀ (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/PM₁₀ 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/PM₁₀.

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 load⁹. 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 (NH₃) 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 boiler¹⁰ 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 boilers¹¹ 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/MMBtu¹². However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

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 NO_x Control and Combined NO_x/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/MMBtu¹⁴ 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 NO_x 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

¹⁶ Bryk and Kleisley, 2000. "First Commercial Application of DRB-4Z™ Ultra-Low NO_x 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 NO_x 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/fsnscr.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 NO_x 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/fsnscr.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 NO_x 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 NO_x 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 (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th 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, SO₂, and PM/PM₁₀ control technologies and represents reasonable progress. Therefore, a full 4-factor analysis is not needed to evaluate reasonable progress for NO_x, SO₂, or PM/PM₁₀ 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-NO_x 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-NO_x 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 NO_x 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.

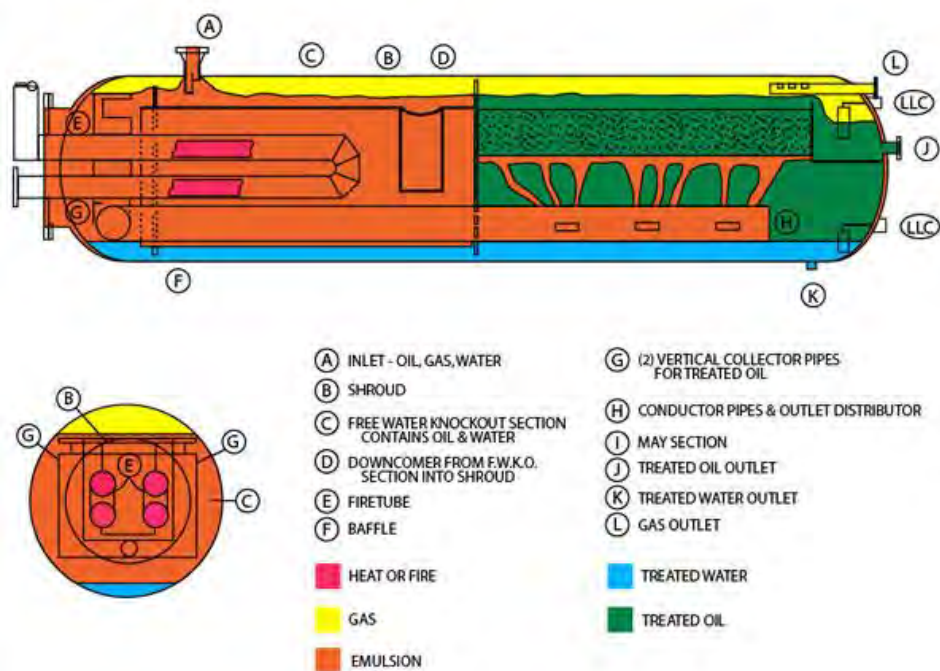
Step 5: Select Reasonable Progress Control

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.

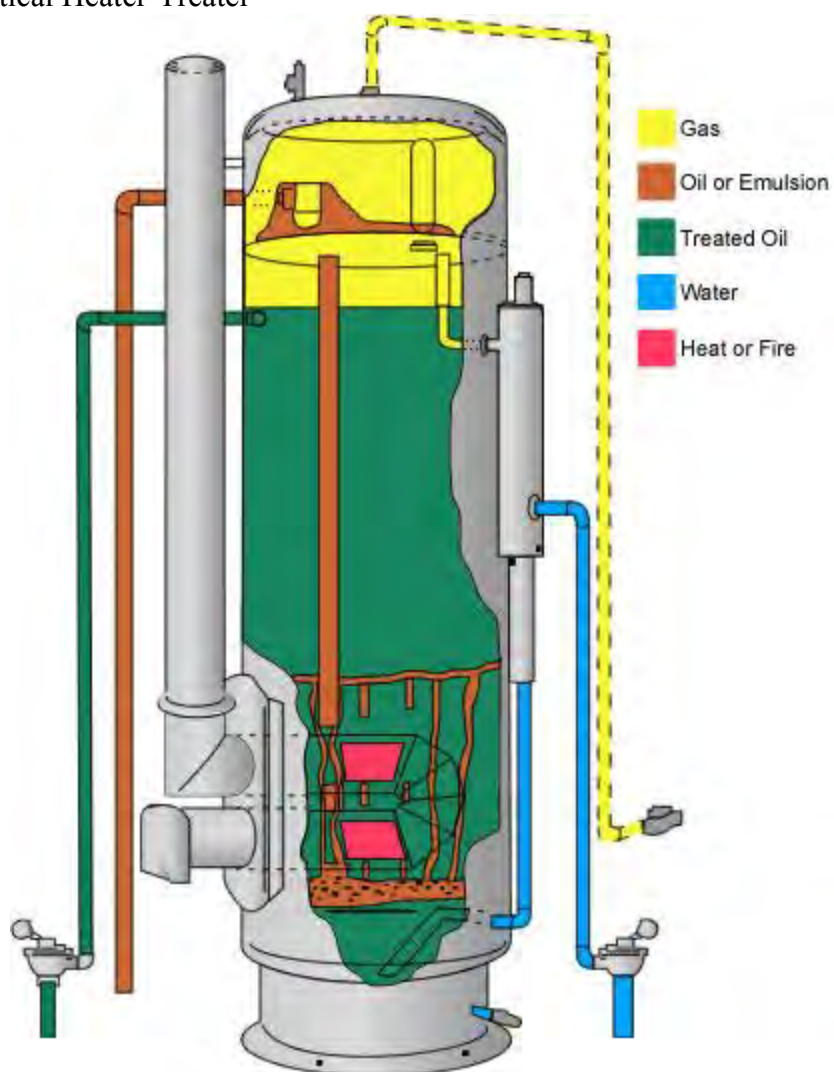
The below diagrams provide basic information on the typical heater-treater designs.

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 NO_x, 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-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 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 NO_x, 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 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 (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
- SO₂ – 40 tons per year
- PM₁₀ – 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	68.17	47.23	13.9	43.1
		NOx	2,439.7	2,287.04	1,246.55	1,931.1
		SO2	188.9	305.76	296.55	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 debader	PM10	----	0.01	0	0.005
		NOx	----	0.09	0.02	0.055
		SO2	----	0.	0	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 (SO₂)

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 SO₂ reacts with the scrubbing reagent to form CaSO₄ 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 SO₂ 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 NO_x 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 SO₂ RP Determination for Kiln System

1.30 pounds of SO₂ 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 PM₁₀)

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. Baggouses, 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 NO_x 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 PM₁₀ per ton of clinker (19.83 lbs/hour) and a rate of 0.04 pound of PM₁₀ 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 (NO₃) followed by sulfates (SO₄). The contribution of PM₁₀ to the total visibility impairment was insignificant in the analysis. The level of PM₁₀ 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 PM₁₀ emissions rates. The facility is currently permitted to emit 246.3 tpy of PM₁₀ 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 PM₁₀ per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for PM₁₀). The actual kiln system PM₁₀ 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 PM₁₀ 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 PM₁₀ emissions from the kiln system on visibility impairment, the state has determined that no additional PM₁₀ 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 PM₁₀ (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 PM₁₀ emissions.

Summary of PM/PM10 RP Determination for Kiln System

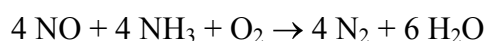
246.3 tons of PM10 per year (12-month rolling total)

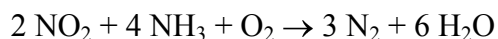
C. Nitrogen Oxides (NOx)

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:





Above this temperature range, the NH_3 is oxidized to NO_x , thereby increasing NO_x emissions. Below this temperature range, the reaction rate is too slow for completion and unreacted NH_3 may be emitted from the pyroprocess. This temperature window generally is available at some location within rotary kiln systems. The NH_3 could be delivered to the kiln system through the use of anhydrous NH_3 , or an aqueous solution of NH_3 (ammonium hydroxide) or urea $[(\text{NH}_2)_2\text{CO}]$. A concern about application of SNCR technology is the breakthrough of unreacted NH_3 as “ammonia slip” and its subsequent reaction in the atmosphere with SO_2 , sulfur trioxide (SO_3), hydrogen chloride (HCl) and/or chlorine (Cl_2) to form a detached plume of PM_{10} – $\text{PM}_{2.5}$.

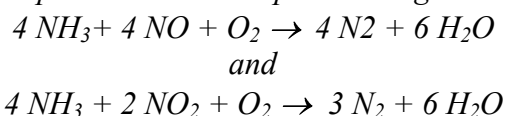
As part of this analysis, the state also considered the use selective catalytic reduction (SCR) as a NO_x control technology. The state has determined that SCR is not commercially available for the cement kiln system at the Holcim Portland Plant. Presently, SCR has not been applied to a cement plant 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 NO_x 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 NO_x . The EPA released a NO_x control technology update for new cement kilns entitled “Alternative Control Techniques Document Update – NO_x 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:



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 NH₃: 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/m³ (~ 0.8 lb/t) of NO_x is typically achieved from an inlet of 1,050 mg/Nm³ (4.2 lb/t) or 80% control. Also, ammonia slip was less than 1 mg/m³. 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 Schreiber², 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 Granger³ shows the performance of a typical catalyst under different conditions of temperature and gas composition. The highest NO_x reduction 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 NO_x 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 NO_x Control and Ammonia slip at Various Temperatures

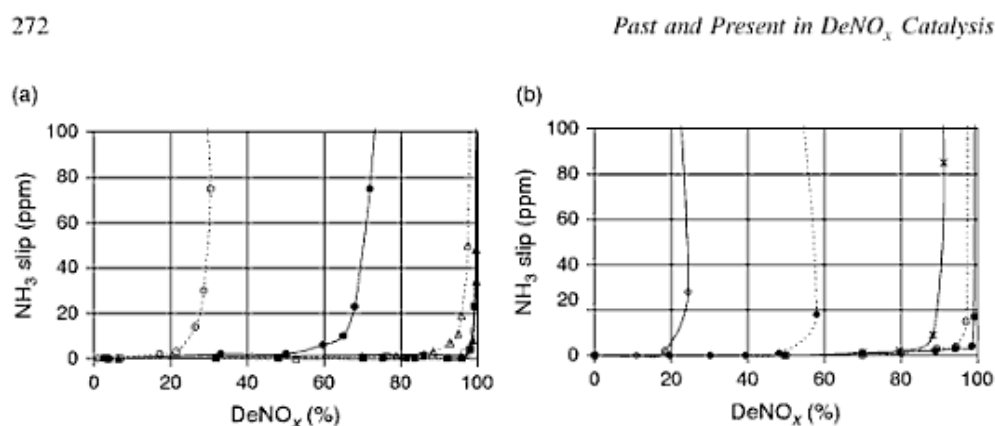


Figure 9.9. Performance of a coated V_2O_5/WO_3-TiO_2 SCR catalyst developed in our laboratory (Table 9.1) with (a) pure NO and with (b) $NO:NO_2 = 1:1$. ($\diamond$) 120°C, ($\blacklozenge$) 150°C, ($*$) 180°C, ($\circ$) 200°C, ($\bullet$) 250°C, ($\blacktriangle$) 300°C, ($\triangle$) 350°C, ($\square$) 400°C, and ($\blacksquare$) 450°C. Cell density: ≈ 400 cpsi. $V_{cat} = 7.5$ cm³. Model gas investigation with 10% O₂, 5% H₂O, 1000 ppm NO or 500 ppm NO + 500 ppm NO₂, 0–1500 ppm NH₃, and balance N₂ in a laboratory test unit [13]. High Resolution FTIR gas analysis [13]. GHSV = 52 000 h⁻¹.

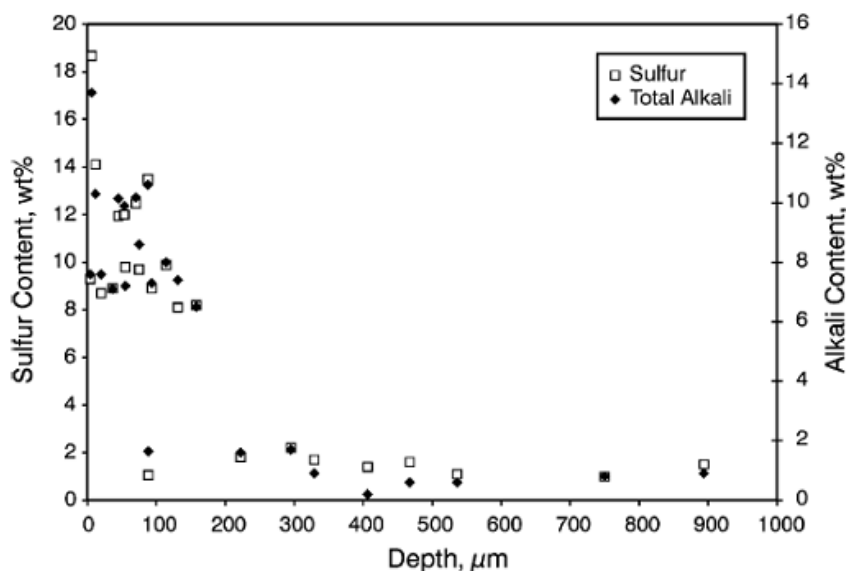
Additionally, multiple challenges exist to achieve SCR effectiveness: selection of catalyst type, positioning of the catalyst, management of catalyst life, catalyst poisoning and ammonia slip. A good catalyst must ensure high activity and selectivity for NO_x reduction and low activity in the oxidation of SO₂ to SO₄. Because of the high selectivity, the catalyst will have a specific temperature window at which the NO_x 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 DeNO_x 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 NO_x reduction and low pressure loss. Further, engineering analysis on overall efficiency during the catalyst life-cycle would be required to ascertain effectiveness. According to Benson⁴, 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 alkalis⁵. 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 NO_x 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 NO_x 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 NO_x reduction (see Strege *et al.*, 2008).

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)

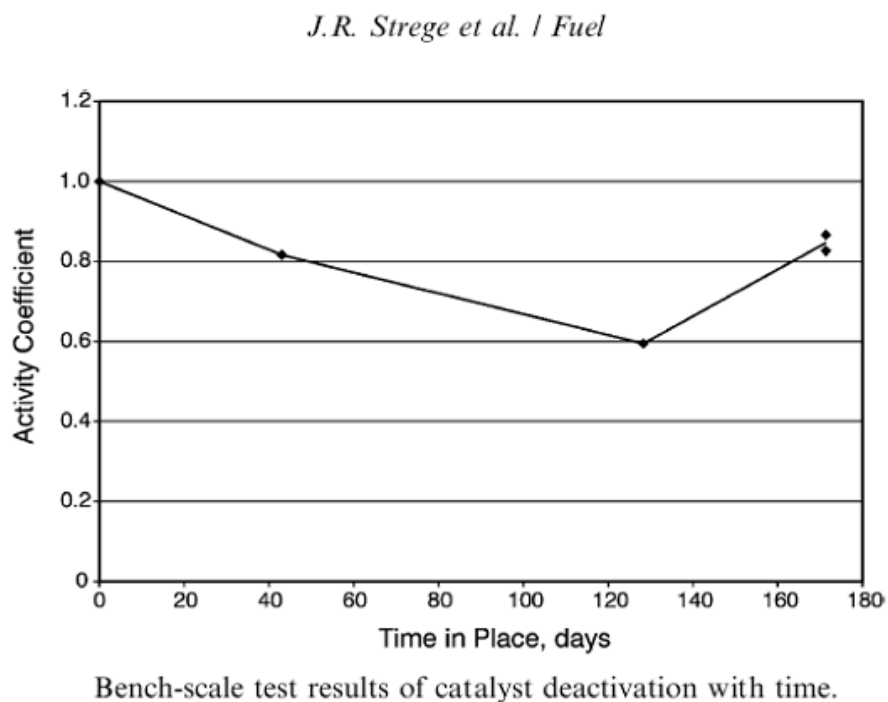
Figure 4: Bench Scale Test Results of Catalyst Deactivation over a Period of Time

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 NO_x 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 Barbaro⁶, 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.; Bianchini, 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 1600-2000°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.

The facility is currently permitted to emit 3,185.7 tpy of NO_x 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 NO_x per ton of clinker (the current permit does not contain an annual pound per ton of clinker or a short-term emission limit for NO_x). The actual kiln NO_x 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 NO_x 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 NO_x. 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 NO_x 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 NO_x control strategy has been well documented and recognized by EPA. A reduction in NO_x 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 NO_x 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 NO_x 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 [$4.47/0.9 \times (1-0.45) = 2.73$]. 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 [$3.64/0.9 \times (1-0.45) = 2.23$ 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):

NO _x Control Technology	Estimated Control Efficiency	30-day Rolling Average Emissions (lb/ton of Clinker)	Annual Controlled NO _x Emissions (tpy)
Baseline NO _x 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 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. 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 SO₂ emission rate of 99.17 lbs/hour, a NO_x 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 (Δ dv) at Great Sand Dunes National Park.

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 these NO_x controls, as identified by Holcim:

Holcim Portland Plant – Kiln System		
NO _x Control Method	98th Percentile Impact (Δ dv)	98th Percentile Improvement (Δ dv)
Maximum (24-hr max) (based on modeled emission rates of 1,363 lb/hr NO _x , 586 lb/hr SO ₂ , 86.4 lb/hr PM ₁₀)	0.814	N/A
SNCR 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

Determination

For the kiln system, the state has determined that SNCR 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.

Summary of NO_x RP Determination for Kiln System

2.73 pounds of NO_x per ton of clinker (30-day rolling average)

2,086.8 tons of NO_x 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, 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 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 control¹."

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.

- SO₂ – 40 tons per year
- PM₁₀ – 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, SO₂, and/or PM₁₀ 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, SO₂, PM₁₀) at a facility with a Q/d impact greater than 20. CSU provided information in “NO_x 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 NO _x 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 SO₂ emissions to 1.2 lb/MMBtu.

II. Source Emissions

Table 3 summarizes each unit at the facility and applicable NO_x, SO₂, 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, SO₂, 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

Colorado Department of Public Health and Environment - Air Pollution Control Division

	PM ₁₀ (tons)	89.24	82.29	88.78	86.8
	PM ₁₀ (lb/MMBtu)	0.011	0.011	0.011	0.011
<i>Auxiliary Boiler</i>	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
<i>Nixon Combustion Turbine 1</i>	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
<i>Nixon Combustion Turbine 2</i>	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 SO₂ emissions and for PM₁₀ emissions for the turbines.

***The PM₁₀ 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)

Emission Unit	Specifications		
	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 SO₂ control option:

Flue gas desulfurization (FGD):

Lime spray dry absorber (SDA or dry FGD)

The Division identified two additional SO₂ 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 SO₂ 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 plants³. 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 SO₂ Emissions: A Review of Technologies⁴ evaluates various SO₂ 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 SO₂ 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,

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 SO₂ 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 SO₂ 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 NO₂ which has a reddish-brown color. This conversion of NO to NO₂ 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 SO₂ ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum SO₂ removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CSU estimated the maximum SO₂ removal rate that can be achieved while minimizing the creation of the brown plume condition to be 60% SO₂ removal at another facility. In practical application, a higher SO₂ removal rate may be possible, while it is also possible that a lower SO₂ removal rate may be necessary to limit the brown plume formation. This determination would require actual SO₂ 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 SO₂ 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 SO₂ 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 SO₂ Emissions: A Review of Technologies⁵ 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 SO₂ removal rate that can be achieved to be 60% SO₂ 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 SO₂ control.

Table 7: Nixon Unit 1 SO₂ 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 CO₂ 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 $\pm 30\%$. 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 SO₂ 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.

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 SO₂ 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 SO₂ 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 SO₂ emissions for each technically feasible control option. Table 11 shows the SO₂ 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 SO₂ emission rate is approximately 5% higher than the annual average emission rate.

Table 10: Nixon Unit 1 Control Resultant SO₂ 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 SO₂ 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 submittals⁸, 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ emission reduction benefits (tons of SO₂ reduced annually) and visibility improvement (deciview improvement at nearest Class I

⁸Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. “Black Hills Clark Station NO_x 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

SO ₂ 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

SO ₂ 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-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% SO₂ 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 SO₂ 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 (PM₁₀)

Nixon Unit 1 is equipped with a reverse-air fabric filter baghouse to control PM/PM₁₀ 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 PM₁₀ 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/PM₁₀ 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/PM₁₀) 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/PM₁₀. 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/PM₁₀ 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 load¹¹. 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 N₂ 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 formed¹². 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 (NH₃) 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 Staging 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 boiler¹³ 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 boilers¹⁴ 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

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/MMBtu¹⁵. 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 NO_x Control and Combined NO_x/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 study²⁰ 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/chieff/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

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 NO_x 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. “NO_x 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/fsnscr.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

²⁹ CENC, 2009. "NO_x 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 NO_x 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/fsnscr.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 NO_x 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 NO_x 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 NO _x 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 NO_x Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
Ultra-low NO _x 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 submittals³⁵, 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 NO_x 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 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	Unit(s)	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
			Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
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 (SO₂). 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 SO₂. 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 control¹."

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
- SO₂ – 40 tons per year
- PM₁₀ – 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 SO₂ 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 SO₂ removal). SO₂ 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 PM₁₀ emissions, limestone injection to the combustion chamber for SO₂ 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, SO₂, PM₁₀) 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 (%)	NO _x – NA ⁴ SO ₂ – 77.4% PM/PM ₁₀ – 98% - 99.9+ ⁵

II. Source Emissions

Table 2 summarizes the NO_x and SO₂ 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, SO₂, and PM₁₀ 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
<i>Coal Handling & Processing</i>	<i>PM₁₀ (tons)</i>	<i>2.09</i>	<i>2.15</i>	<i>2.15</i>	<i>2.13</i>
<i>Ash Handling & Processing</i>	<i>PM₁₀ (tons)</i>	<i>8.91</i>	<i>10.62</i>	<i>10.62</i>	<i>10.05</i>
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.

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 Permit⁶ for the facility includes a limit of 0.55 tons PM₁₀ 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
- SO₂: 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)
- PM₁₀: 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)

Emission Unit	Specifications		
	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 sources⁷

Emission Unit	Pollutant			
	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 PM₁₀ 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 SO₂ 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 Guidelines⁸, 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 SO₂ limits are depicted in Table 6.

Table 6: Nucla Unit 4 SO₂ 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 SO₂ 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 SO₂ 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 Dakota⁹ and the waste coal-fired Bonanza Station in Utah¹⁰. 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 SO₂ emission control options at Nucla.

Limestone Injection Process Upgrades: The average reduction in SO₂ 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% SO₂ 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 4.0¹¹. 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.

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 plants¹². 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 SO₂ 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 SO₂ 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 alone¹⁶.

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% SO₂ 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 SO₂ control efficiency to 85% by increasing limestone injection is a feasible option. This correlates to an approximate 39.4% decrease in comparison to current SO₂ 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 SO₂ 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 SO₂ 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 SO₂ emissions, or 98.4% from uncontrolled SO₂ emissions.

Hydrated Ash Reinjection: EPA references vendor information showing that hydrated ash reinjection could reduce the post-combustion SO₂ emissions by about 80%.¹⁸ This results in about 95% reduction from uncontrolled SO₂ 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 SO₂ emissions or 96.9% reduction from uncontrolled SO₂ emissions.

Post-Combustion Controls – Wet Scrubbing: EPA noted a potential SO₂ removal efficiency of 94% for the post-combustion gas in the Bonanza BACT analysis¹⁹. Combined with the current limestone injection system, the overall potential control efficiency is 98.4% from uncontrolled SO₂ 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 SO₂ 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 SO ₂ 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 SO ₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 analysis²⁰, 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 SO₂ emissions for each technically feasible control option. Table 9 shows the SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ emission reduction benefits (tons of SO₂ 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/cetc/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 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.

b. Filterable Particulate Matter (PM) & Particulate Matter (PM₁₀)

Nucla Unit 4 is currently equipped with a four baghouse system to control PM/PM₁₀ 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 PM₁₀ 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/PM₁₀ emission limits in the current Title V permit revealed that these limits are for filterable PM/PM₁₀ 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/PM₁₀ 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/PM₁₀ 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/PM₁₀. 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/PM₁₀ 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 SO₂ 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 PM₁₀) 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)

Run 1: 7:28 – 8:28

Run 2: 9:14 – 10:14

Run 3: 10:44 – 11:44

High Load (109.2 MW)

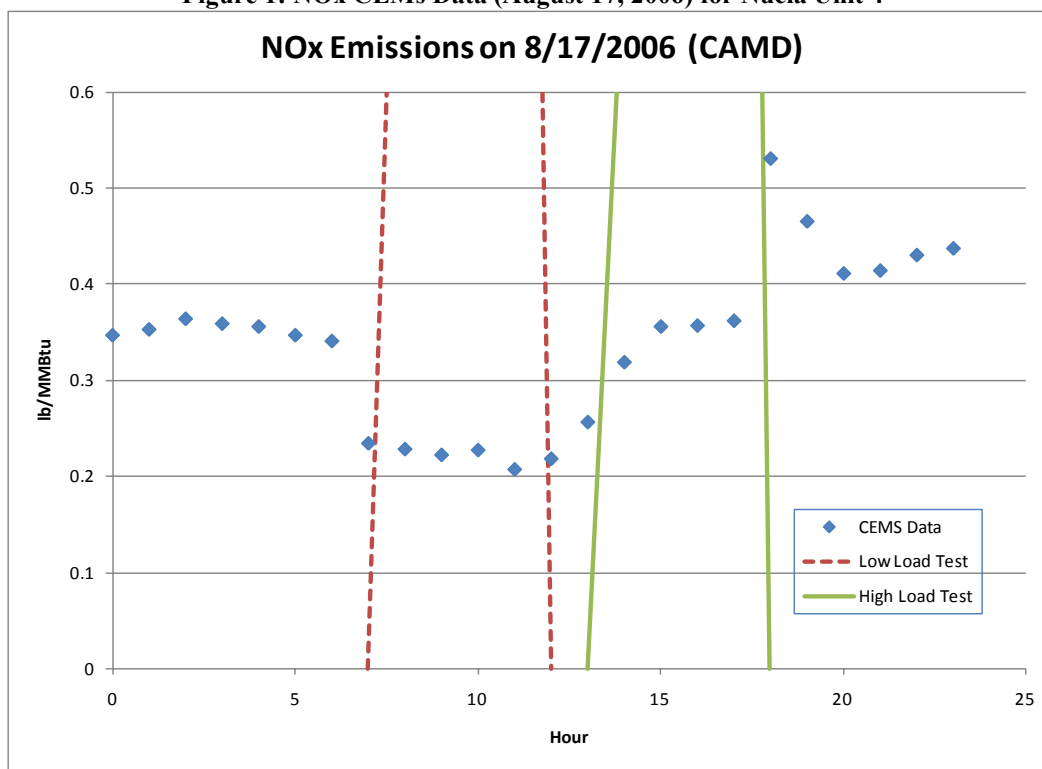
Run 1: 13:51 – 14:51

Run 2: 15:25 – 16:25

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: NO_x 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 NO _x 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 analysis²⁹, and \$40,297 per ton in the Bonanza BACT analysis³⁰. 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 that³²:

“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 project³³. 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 NO_x RP for Nucla Unit 4 is the following NO_x emission rate:

Nucla Unit 4: 0.5 lb/MMBtu (30-day rolling average)

Additional Analyses of SO₂ and NO_x 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 NO_x 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 NO_x control scenarios for Nucla.

Finally, Tri-State shall propose to the state any preferred SO₂ and NO_x 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 NO_x 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 NO_x 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 NO_x 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 (SO₂). 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 PM₁₀ and SO₂ (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 be 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 SO₂, NO_x, or PM₁₀ 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 SO₂, NO_x and PM₁₀ 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
- SO₂ – 40 tons per year
- PM₁₀ – 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, SO₂, PM₁₀) at a facility with a Q/d impact greater than 20. PRPA submitted a “Rawhide NO_x 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%

¹Emissions Reduction estimated by comparing uncontrolled AP-42 factor to actual average emission factor for PM/PM₁₀. For SO₂ 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 2002³.

Rawhide Unit 101 was initially installed in 1984 with a baghouse for particulate emission (PM/PM₁₀) 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 SO₂ 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 SO₂ 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 system⁴. This upgraded system resulted in an approximate 30% emission rate reduction of SO₂ emissions from pre-VERA emission rates.

II. Source Emissions

Table 3 summarizes the NO_x, SO₂, and PM₁₀ 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, SO₂, and PM₁₀ 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
<i>Turbine Unit A (82 MW)</i>	<i>SO₂ (tons)</i>	<i>0.10</i>	<i>0.12</i>	<i>0.12</i>	<i>0.11</i>
	<i>NO_x (tons)</i>	<i>1.17</i>	<i>5.45</i>	<i>0.75</i>	<i>2.46</i>
	<i>PM₁₀ (tons)</i>	<i>0.20</i>	<i>1.12</i>	<i>0.13</i>	<i>0.48</i>
<i>Turbine Unit B (82 MW)</i>	<i>SO₂ (tons)</i>	<i>0.09</i>	<i>0.06</i>	<i>0.11</i>	<i>0.09</i>
	<i>NO_x (tons)</i>	<i>3.87</i>	<i>3.17</i>	<i>5.07</i>	<i>4.04</i>
	<i>PM₁₀ (tons)</i>	<i>0.77</i>	<i>0.58</i>	<i>0.99</i>	<i>0.78</i>
<i>Turbine Unit C (82 MW)</i>	<i>SO₂ (tons)</i>	<i>0.04</i>	<i>0.09</i>	<i>0.03</i>	<i>0.05</i>
	<i>NO_x (tons)</i>	<i>2.03</i>	<i>4.45</i>	<i>1.65</i>	<i>2.71</i>
	<i>PM₁₀ (tons)</i>	<i>0.33</i>	<i>0.80</i>	<i>0.30</i>	<i>0.48</i>
<i>Turbine Unit D (82 MW)</i>	<i>SO₂ (tons)</i>	<i>0.05</i>	<i>0.10</i>	<i>0.03</i>	<i>0.06</i>
	<i>NO_x (tons)</i>	<i>2.53</i>	<i>4.95</i>	<i>1.50</i>	<i>2.99</i>
	<i>PM₁₀ (tons)</i>	<i>0.45</i>	<i>0.85</i>	<i>0.26</i>	<i>0.52</i>
<i>Turbine Unit F (150 MW)**</i>	<i>SO₂ (tons)</i>			<i>0.38</i>	<i>0.38</i>
	<i>NO_x (tons)</i>			<i>20.45</i>	<i>20.45</i>
	<i>PM₁₀ (tons)</i>			<i>3.75</i>	<i>3.75</i>
<i>P201 Train Unloading Facility</i>	<i>PM₁₀ (tons)</i>	<i>0.60</i>	<i>0.01</i>	<i>0.01</i>	<i>0.20</i>
<i>P201 Active Coal Pile Reclaim</i>	<i>PM₁₀ (tons)</i>	<i>0.03</i>	<i>0.02</i>	<i>0.00</i>	<i>0.02</i>
<i>P201 Coal Silo Filling and Conveyor Belt Transfer</i>	<i>PM₁₀ (tons)</i>	<i>0.30</i>	<i>0.00</i>	<i>0.00</i>	<i>0.10</i>
<i>P201 Coal Silo Discharge to Conveyor Belt</i>	<i>PM₁₀ (tons)</i>	<i>0.28</i>	<i>0.00</i>	<i>0.00</i>	<i>0.10</i>
<i>P201 Coal Crushing and</i>	<i>PM₁₀ (tons)</i>	<i>0.33</i>	<i>0.02</i>	<i>0.02</i>	<i>0.12</i>

⁴ Colorado Air Pollution Control Division, 1992. Exhibit B: Division Evaluation of Sulfur Dioxides Emission Limitation and Regulatory Assurance Periods.

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<i>Conveying</i>					
<i>P201 Coal Conveyor Belt Transfer</i>	<i>PM₁₀ (tons)</i>	<i>0.30</i>	<i>0.00</i>	<i>0.00</i>	<i>0.10</i>
<i>P201 In-Plant Silo Filling Conveyor Belt Transfer</i>	<i>PM₁₀ (tons)</i>	<i>0.30</i>	<i>0.00</i>	<i>0.00</i>	<i>0.10</i>
<i>P201 Coal Pile Stockout</i>	<i>PM₁₀ (tons)</i>	<i>1.18</i>	<i>0.01</i>	<i>0.02</i>	<i>0.40</i>
<i>P201 Active Coal Storage Area</i>	<i>PM₁₀ (tons)</i>	<i>0.93</i>	<i>1.91</i>	<i>1.96</i>	<i>1.60</i>
<i>P201 Active Coal Pile Storage Area</i>	<i>PM₁₀ (tons)</i>	<i>0.95</i>	<i>2.56</i>	<i>2.56</i>	<i>2.02</i>
<i>P201 Coal Crusher Stockout</i>	<i>PM₁₀ (tons)</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>0.00</i>
<i>P201 Coal Conveying</i>	<i>PM₁₀ (tons)</i>	<i>1.81</i>	<i>1.23</i>	<i>1.09</i>	<i>1.38</i>
<i>P301 Solid Wastes Silo Rotary Unloader Discharge</i>	<i>PM₁₀ (tons)</i>	<i>0.70</i>	<i>0.28</i>	<i>0.25</i>	<i>0.41</i>
<i>P301 Solid Wastes Hauling to Landfill</i>	<i>PM₁₀ (tons)</i>	<i>1.82</i>	<i>1.67</i>	<i>1.44</i>	<i>1.64</i>
<i>P301 Solid Wastes Haul Truck Unloading</i>	<i>PM₁₀ (tons)</i>	<i>0.04</i>	<i>0.02</i>	<i>0.01</i>	<i>0.02</i>
<i>P301 Active/Exposed Landfill Area</i>	<i>PM₁₀ (tons)</i>	<i>0.19</i>	<i>0.24</i>	<i>0.19</i>	<i>0.21</i>
<i>P301 Waste Landfilling/Reclamation</i>	<i>PM₁₀ (tons)</i>	<i>0.13</i>	<i>0.57</i>	<i>0.46</i>	<i>0.39</i>
<i>P301 Bottom Ash Excavation and Loading</i>	<i>PM₁₀ (tons)</i>	<i>0.03</i>	<i>0.02</i>	<i>0.02</i>	<i>0.02</i>
<i>P301 Solid Wastes Silo Filling</i>	<i>PM₁₀ (tons)</i>	<i>0.02</i>	<i>0.20</i>	<i>0.17</i>	<i>0.13</i>
<i>P301 Solids Vacuum Conveying System and Silo Filling</i>	<i>PM₁₀ (tons)</i>	<i>0.17</i>	<i>0.18</i>	<i>0.16</i>	<i>0.17</i>
<i>P301 Fly Ash and Solid Waste Silo Dry Unloading and Haul Truck Loading</i>	<i>PM₁₀ (tons)</i>	<i>0.02</i>	<i>0.02</i>	<i>0.01</i>	<i>0.02</i>
<i>P401 Scrubber Lime Storage Silo Filling</i>	<i>PM₁₀ (tons)</i>	<i>0</i>	<i>0.01</i>	<i>0.01</i>	<i>0.00</i>
<i>P401 Recycle Ash Storage Silo Filling</i>	<i>PM₁₀ (tons)</i>	<i>0.11</i>	<i>0.89</i>	<i>0.81</i>	<i>0.60</i>
<i>P501 Unpaved Site Roadways and Parking Lots</i>	<i>PM₁₀ (tons)</i>	<i>3.14</i>	<i>3.92</i>	<i>4.23</i>	<i>3.76</i>
<i>P501 PRS Soda Ash Storage Silo Filling</i>	<i>PM₁₀ (tons)</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>0.00</i>

*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% O₂ 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 SO₂ 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)

Emission Unit	Specifications		
	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 SO₂ 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 Guidelines⁶, 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 SO₂ emissions by about 906 tons per year, or approximately 99% (using 2006 - 2008 CAMD data average)⁷. SO₂ 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 coal⁸. 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 SO₂ 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>

plants¹⁰. 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 SO₂ by using a slaked lime containing slurry that is sprayed into the flue gas and reacts with the SO₂ 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 SO₂ removal from the gaseous emission stream of a utility boiler. PRPA has since upgraded this system (in 2002) and currently achieves greater than 80% SO₂ 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/MMBtu¹¹. 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 SO₂ 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 SO₂ 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 SO₂ limit would diminish this available capacity and likely also require an upgrade to ensure adequate margin.

PRPA notes that the SO₂ 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 – SO₂ 30-day rolling average limit is 0.13 lb/MMBtu.

¹² EPA, 2000. “Controlling SO₂ 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 SO₂ 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 SO₂ scrubber and unit availability. Achieving a lower SO₂ 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 SO₂ reductions will still present unacceptable operational challenges. SO₂ 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 SO₂ emissions below 0.09 lbs/MMBtu requires additional lime to increase feed slurry reactivity. At higher SO₂ removal rates, the lime/SO₂ 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 SO₂ scrubber reliability. Lowering the SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ reductions.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Fuel Switching – Natural Gas: Conversion from coal to natural gas would reduce SO₂ emissions by almost 100% from the boiler using EPA’s AP-42 emission factors¹³ and concurs with PRPA’s submittal.

Table 7 summarizes each available technology options and technical feasibility for SO₂ 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 SO ₂ control
Fuel switching – different coal type	None	Y – will not provide further SO ₂ 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 PRPA¹⁵. This results in an initial control cost, using EPA's Cost Control Manual¹⁶ to estimate annual operating costs, of about \$262,000 per ton of SO₂ removed annually¹⁷. 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 study¹⁸.

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 Administration¹⁹. 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 SO₂ 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 SO₂ 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 NO_x 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 NO_x 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. SO₂ 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 submittals²¹, 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.

²¹Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. "Black Hills Clark Station NO_x 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 (98th 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)	SO ₂ 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		n/a					
dry FGD	101	0.07		20	19	1	6	4	2
Fuel Switching - NG	101	0.001		n/a					

Table 12: Visibility Results - SO₂ Control Scenarios

SO ₂ Control Scenario	Unit(s)	SO ₂ 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 (PM₁₀)

PRPA Unit 101 is currently equipped with two twelve-compartment fabric filter baghouses to control PM/PM₁₀ 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/PM₁₀ emissions to 0.03 lb/MMBtu and further notes 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/PM₁₀ emission limits in the current Title V permit revealed that these limits are for filterable PM/PM₁₀ emissions only.

A Division review of EPA’s RBLC revealed recent BACT PM/PM₁₀ 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/PM₁₀. Thus, as described in EPA's BART Guidelines, a full four-factor analysis for PM/PM₁₀ 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 load²². 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/MMBtu²³. 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 (NH₃) 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.

²³ PRPA, February 18, 2010. "Re: Rawhide Unit 101 NO_x 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 boiler²⁴ 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 boilers²⁵ 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/MMBtu²⁶. 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.

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 NO_x Control and Combined NO_x/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 study²⁸ 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 NO_x 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 NO_x emissions reduction alternatives for the Rawhide Unit 101. The *Rawhide NO_x 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:

-
- 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 NO_x 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 NO_x 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/fsnscr.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 investments³⁶. 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 NO_x emissions reduction alternatives for the Rawhide Unit 101. The *Rawhide NO_x 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/fsnscr.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,
- NO_x 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 been 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 annually³⁷. 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 Administration³⁸. 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 submittals³⁹, 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		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
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 (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th 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, NO_x 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, NO_x 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 NO_x 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 NO_x emissions that represents about 16% of statewide point source NO_x emission inventory¹.

Colorado Internal Combustion Engine NO_x Emissions from the PRP 2018b Emission Inventory

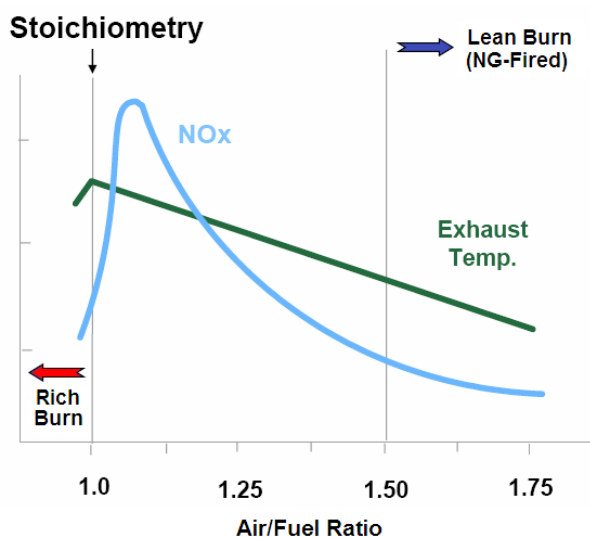
Category	Subcategory	2018 NO _x Emissions (tpy)
Industrial	Natural Gas Fired	16,199
	Large Bore Engine	256
	Distillate Oil (Diesel)	225
	Liquefied Petroleum Gas	27
	Gasoline	24
Electric Generation	All	4,323
Commercial/Institutional	All	1,152
Engine Testing	All	5
Total:		22,210

¹ Total 2018 Statewide Point Source NO_x 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 (NO_x , 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.

NO_x and Exhaust Temperature Change with Air/Fuel Ratio



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 NO_x , 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 NO_x 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 NO_x 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 NO_x

emissions is very low because LB engine exhaust temperatures are below the optimum temperature range for effective NO_x control due to reduced catalyst reactivity. The above chart provides the relative change in NO_x 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 NO_x 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	NO _x	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 NO_x 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 statewide², 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 RICE³ 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.

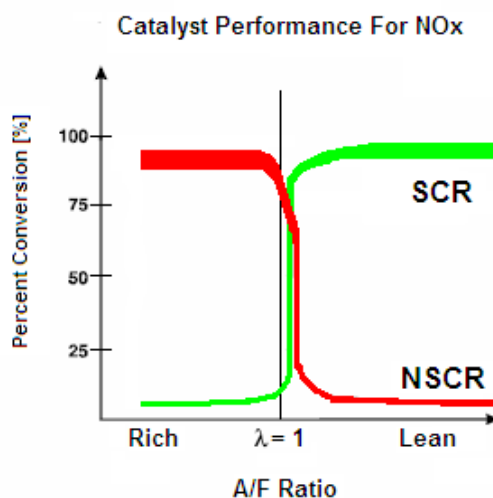
² The Statewide RICE count does not include RICE in the 9-county metro area which was subject to an earlier rulemaking, thus the actual number of total RICE in the State of Colorado is higher.

³ Reference Final Economic Impact Analysis – Revisions to Regulation No. 7, February 11, 2004.

III. NO_x Control Technology Evaluation

Step 1: Identify All Available Technologies

Generally in retrofit applications, NO_x 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 NO_x reduction. The below diagram roughly depicts the catalyst performance for conversion of NO_x emissions using a NSCR and SCR on rich and lean burn engines.



Six retrofit technologies have been identified to lower NO_x 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 statewide⁴) 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 NO_x 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 NO_x 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

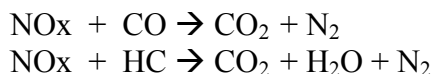
Technology #1 - Lean Burn (Air/Fuel Ratio Adjustment): In lean burn engines, increasing the air to fuel ratio decreases the NO_x emissions. Extra air dilutes the combustion gases, thus lowering peak flame temperature and reducing thermal NO_x formation. In order to avoid de-rating, combustion air to 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% reduction⁵ in NO_x emissions but is very specific to each engine and typical loading.

Technology #2 - Lean Burn (Ignition/Spark Timing Retard): This adjustment lowers NO_x 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 NO_x 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 NO_x emissions.

Technology #3 - Rich Burn NSCR: This technology uses three-way catalysts to promote the reduction of NO_x 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:



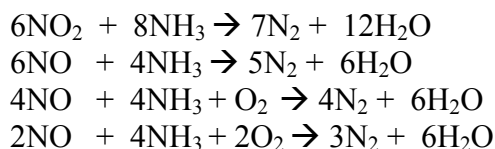
The exhaust passes over a catalyst, usually a noble metal (platinum, rhodium or palladium) which reduces the reactants to N₂, CO₂ and H₂O. Typical exhaust temperatures for effective removal of NO_x are 800-1200 degrees Fahrenheit. An oxidation catalyst using additional air can be installed downstream 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 NO_x 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 NO_x emissions.

Technology #5 – Lean Burn SCR: SCR uses catalyzed reduction of NO_x 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 NO_x 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°F and 800 °F. For higher temperatures (675 °F to 1100 °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 °F to 550 °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 NO_x over SCR catalyst:



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 NO_x by 80%. Zeolite catalysts can reduce NO_x by 90% with minimal sulfur dioxide to sulfur trioxide conversion. Exhaust gas temperatures greater than the upper limit (850 F) will pass the NO_x and ammonia unreacted through the catalyst.

Technology #6 – Replace RICE with electric motors: This control technology results in complete reduction of NO_x 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 NO_x 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 practicality of this control option in rural areas.

The below table summarizes each available technology and the technical feasibility for NO_x Control.

NG-Fired RICE – NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
<i>Lean Burn (Air/Fuel Ratio Adjustment)</i>	~5-30%	Y
<i>Lean Burn (Ignition/Spark Timing Retard)</i>	~20%	Y
<i>Rich Burn NSCR</i>	~80-90%	Y
<i>Rich/Lean Burn SNCR</i>	~50-95%	Y
<i>Lean Burn SCR</i>	~80-90%	Y
<i>Replace RICE with electric motors</i>	~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 NO_x 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 ton⁶ of NO_x 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 states⁴, the cost of this control ranges between \$310 to \$2,000 per ton of NO_x 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 (NO_x 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 NO_x 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 NO_x 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 NO_x 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 reduced⁷. 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 control⁸. 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 value⁹ of about 2.5%. This increased fuel consumption would result in increased CO₂ 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 CO₂ emissions. In addition, spent

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 disposal¹⁰. 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)		
		NO _x	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.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-25-14
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit O: Department, Order No. 202-25-3 (May 23, 2025)

Order No. 202-25-3

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

The Midcontinent Independent System Operator (MISO) faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. The North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that “[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.”¹ In particular, the retirement of thermal generation capacity creates the potential for electricity supply shortfalls. NERC anticipates that the near-term period of highest capacity shortfall for MISO will occur in August.²

Multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), “[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned.”³ Additionally EIA stated, “[t]ypically Michigan’s nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned.”⁴ The state’s Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it will not be available during the peak demand period this summer.

The 1,560 MW J.H. Campbell coal-fired power plant in West Olive, MI, is scheduled to cease operations on May 31, 2025. Its retirement would further decrease available dispatchable generation within MISO’s service territory, removing additional such generation along with the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. In 2021, Consumers announced that it planned to “speed closure” of Campbell in 2025, several years before the end of its scheduled design life.⁵ Although MISO and Consumers have

¹ 2025 summer reliability assessment. (May 14, 2025).

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf

² *Id.*

³ U.S. Energy Information Administration, Michigan State Energy Profile, Oct. 17, 2024, *available at*: <https://www.eia.gov/state/print.php?sid=mi>.

⁴ *Id.*

⁵ <https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation>

incorporated the planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates “elevated risk of operating reserve shortfalls.”

MISO’s Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources.” While the results “demonstrated sufficient capacity,” the summer months reflected the “highest risk and a tighter supply-demand balance” and the results “reinforce the need to increase capacity.”⁶

ORDER

Given the determination that an emergency exists as discussed above, the responsibility of MISO to ensure reliability of its system, and the ability of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

This Order is limited in duration to align with the emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the “hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable,” be consistent with any applicable environmental law and minimize any adverse environmental impacts.

Based on my determination of an emergency set forth above, I hereby order:

- A. From the time this Order is issued on May 23, 2025, MISO and Consumers Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

⁶ <https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf>

- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.
- C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- D. By June 15, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. The extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.
- F. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- G. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on August 21, 2025, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E.
- I. Issued in Washington, D.C. at 3:15:pm Eastern Daylight Time on this 23rd day of May 2025.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**

Chairman Mark Christie

Commissioner David Rosner

Commissioner Lindsay S. See

Commissioner Judy W. Chang

Michigan Public Service Commissioners

Chairman Dan Cripps

Commissioner Katherine Peretick

Commissioner Alessandra Carreon

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-25-14
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit OO: CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin,
Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 -
Attachment G-1 (Astrape Consulting, *Reserve Margin and Effective Load Carrying
Capability (ELCC) Study*, Public (Aug. 2, 2023)



Reserve Margin and Effective Load Carrying Capability (ELCC) Study

Final Report

8/02/2023

PREPARED FOR

Tri-State G&T

PREPARED BY

Astrapé Consulting

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ABBREVIATIONS USED IN REPORT

BAA	Balancing Authority Area
BE	Better Electrification
BESS	Battery Energy Storage System
BTMPV	Behind the meter solar
CEII	Critical Energy/Electric Infrastructure Information
CT	Combustion Turbine Generator
DR	Demand Response
EE	Energy Efficiency
EFOR	Equivalent Forced Outage Rate
EFORD	Equivalent Forced Outage Rate Demand
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
GDP	Gross Domestic Product
ICAP	Installed Capacity
ILR	Inverter Loading Ratio
IRP	Integrated Resource Plan
LFE	Economic Load Forecast Error
LOLE	Loss of Load Expectation
MW	Megawatt
NOAA	National Oceanic and Atmospheric Administration
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
ORDC	Operating Reserve Demand Curve
PCAP	Perfect Capacity
PO	Planned Maintenance Outage
PRM	Planning Reserve Margin
TTF	Time to Fail
TTR	Time to Repair
UCAP	Unforced Capacity
SAM	NREL System Advisory Model
SERVM	Astrape's Strategic Energy and Risk Evaluation Model

EXECUTIVE SUMMARY

This document provides details concerning a two-fold study performed by Astrapé Consulting for Tri-State Generation and Transmission Association (TSGT) to accomplish the following goals:

1. Determine the Planning Reserve Margin (PRM) for TSGT's 2023 Electric Resource Plan (ERP).
2. Determine the Effective Load Carrying Capability (ELCC) for a range of solar, wind, and Battery Energy Storage System (BESS) penetrations for the TSGT system.

The following summarizes the results of this study.

BASE CASE PRM RESULTS

The PRM of a system represents the amount of additional capacity in excess of forecasted peak load that a system would need in order to maintain an acceptable level of system reliability. The PRM was calculated using two different accounting methods, including:

1. ICAP – Traditional resources at Installed Capacity (ICAP) with renewable and other limited resources at their ELCC.
2. UCAP – Traditional resources at their Unforced Capacity (UCAP) with renewable and other limited resources at their ELCC.

The development of the PRM was accomplished by determining the amount of capacity that would be necessary to maintain a Loss of Load Expectation (LOLE) of 0.1 days/year. This level of reliability corresponds to an expectation of one day of loss of load every 10 years, which is consistent with industry practice. The advent of renewable and battery technologies has sparked conversation on the appropriateness of this metric since limitations on dispatchability and constraints on energy will likely affect the duration and depth of loss of load events. In prior work, Astrapé has found that renewable and storage resources generally have offsetting effects on the duration and depth of events and the 0.1 LOLE standard is expected to yield a relatively consistent relationship with most reliability metrics for a range of technology resource mixes. However, it will be important to continue to monitor these metrics and recommend changes to reliability standards if the nature of reliability events does change.

The PRM was developed using Astrapé's Strategic Energy and Risk Evaluation Model (SERVM). A detailed description of the methodology can be found in the Study Approach and Results section of this report. The PRM is the result of an evaluation of the probabilistically weighted LOLE across 42 weather year scenarios, five load forecast error scenarios, and hundreds of unit outage iterations. The PRM for the base case and most of the sensitivities were performed for the 2030 study year. The base case and its underlying assumptions are described in more detail in the Model Development section of this report.

Figure ES 1 below shows the result of the LOLE analysis for 2030. The figure shows the LOLE as a function of the ICAP reserve margin. Assuming the 1 day in 10 criteria, the figure shows 0.1 LOLE point occurs at a reserve margin of ~35.9%.

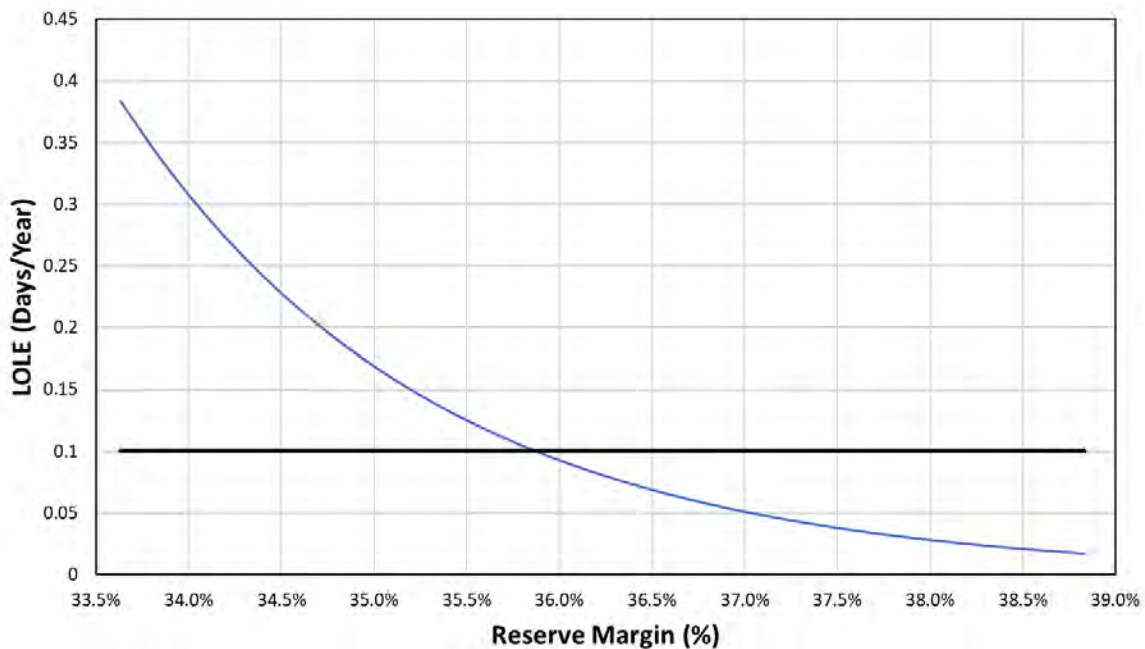


Figure ES 1. 2026 Base Case LOLE Analysis

As demonstrated in this graph, LOLE decreases with increased reserve margin. As more capacity is added to the system, reliability improves. The point at which the graph crosses 0.1 days/year LOLE marks the target PRM.

The table below shows the ICAP accounting for the base case scenario.

Table ES 1. Base Case ICAP PRM Accounting

Component	Capacity	ELCC	Equivalent Capacity
Conventional Resources	2596.3		2596.3
ELCC Resources	1934.0	18%	348.1
Adjustment Capacity			59.2
Total Capacity at Target Reliability			3003.6
Coincident Peak Load			2210.9
Reserves			792.8
ICAP PRM			35.9%

The “Adjustment Capacity” represents the amount of additional capacity above base case assumptions that was added to the system to achieve the 0.1 LOLE requirement. The ICAP PRM of 35.9% is considerably higher than TSGT’s previous requirement of 15% for several reasons. First, in the past, TSGT has variously treated the capacity brought by their member systems and their customers, sometimes giving them full or partial credit and at other times giving them no credit. However, to the extent the modeling has depended upon that capacity being available, Astrapé believes such capacity should be counted in the PRM calculation. Removing that capacity from the accounting process above may lower the apparent reserve margin, but the required capacity would stay the same. Thus, the true PRM should include all capacity relied upon to achieve the target LOLE. Second, TSGT will be losing approximately one-third of its load over the next few years as several member systems leave the system or transition to partial requirements. The result is a considerably smaller system in which shaft risk (i.e., the loss of units that are large relative to the peak load) becomes a more significant consideration than it was in the past. For example, with a prior peak of ~3000 MW the Springerville unit covered 14% of the load requirements. With a reduced peak of ~2200 MW, Springerville is now covering 19% of the load. Thus, more load is concentrated on that single unit, resulting in an increase in shaft and generation risk if that unit trips or fails. A similar issue is present for the other larger units, compounding the potential shaft risk in 2030. While there may have been shaft risk previously, that risk has been magnified by the loss in peak demand. The increased shaft risk translates directly into higher PRM requirements.

With ICAP accounting, the effects of forced outages on conventional resources are embedded in the PRM. The ELCC resources, however, are being represented by their perfect capacity equivalent. Thus, potential changes in system Equivalent Forced Outage Rate (EFOR) resulting from a change in system mix as well as changes in the penetration of renewable resources can cause changes in the PRM. An alternative accounting that attempts to stabilize the PRM by removing the effects of forced outages is called UCAP accounting. UCAP accounting discounts the capacity of conventional resources by $1 - \text{EFOR}_d$, where EFOR_d is the Equivalent Forced Outage Rate Demand for the conventional resources. The table below shows the base case assuming UCAP accounting resulting in a UCAP PRM of 30.5%.

Table ES 2. Base Case UCAP PRM Accounting

Component	Capacity	UCAP/ ELCC	Equivalent Capacity
Firm Resources			997.3
UCAP Resources	1599.0	92.6%	1480.1
ELCC Resources	1934.0	18.0%	348.1
Adjustment Capacity			59.2
Total Reliable Capacity			2884.6
Coincident Peak Load			2210.9
Reserves			673.8
ICAP PRM			30.5%

Both accounting methods are targeting identical 0.1 LOLE reliability conditions and are achieved with identical portfolios. The only difference is in the accounting treatment of various resources.

As part of the base case PRM calculation, the ELCC of the conventional resources were calculated to demonstrate the significance of the shaft risk. The table below shows the ELCC of the coal and CC units.

Table 1. Coal and CC ELCC

Resource	EFOR	ELCC
Shafer CC	7.8%	64.4%
Springerville Coal	9.2%	63.8%
Laramie River Coal	9.3%	58.8%

These ELCCs are significantly lower than expected, indicating a large impact due to shaft risk in addition to the EFOR impact. Assuming these units were small enough that shaft risk was not an issue and their EFOR were in the 5% range, the ELCC for these units would be expected to be in the 90% range. Making this assumption, it is possible to calculate what the PRM would be if these two drivers were somehow mitigated. The table below shows this calculation.

Table 2. Impact of High EFOR and Shaft Risk

Component	ELCC	MW	Impact
CC	64.4%	272	175.168
SPV	63.8%	319	203.522
LRS	58.8%	484	284.592
Weighted	61.7%	1075	663.282
Target ELCC	90.0%	1075	967.5
Impact MW			304.2
Base Case Reliable MW			3003.6
Adj for EFOR/Shaft Impact			2699.4
Coincident Peak Load			2210.9
PRM			22.1%

By capacity-weighting the existing ELCCs, it is shown that the total capacity value of these facilities is ~663 MW. If, however, their ELCC were 90%, their total capacity value would be ~968 MW. Thus, there is an ~304 MW impact associated with these two drivers. Mitigating against these drivers would thus lower the total reliable MW requirement by 304 MW, resulting in a PRM of 22.1%. This lower PRM is more consistent with other reserve margins in the region.

The lower ICAP PRM of 22.1% would represent a system in which shaft risk and high EFOR has been somewhat mitigated. Since the two drivers of this increased shaft risk are the retirement of several

coal units and the departure of approximately one-third of TSGT's peak demand, it would be reasonable to assume that a transitional PRM in this range would be appropriate to use for the transition years prior to the retirement of those units and the departure of the member load.

ELCC RESULTS

The ELCC of a renewable resource/portfolio represents the amount of dependable capacity that can be counted on by the system for resource adequacy purposes and the resource's perfect capacity equivalent. The ELCC is determined by finding the amount of perfect capacity that can replace the renewable resource/portfolio without adversely affecting system reliability. The ELCC is represented as a percent of nameplate capacity. It is calculated by dividing the amount of replacement perfect capacity by the nameplate capacity of the additional renewable resource/portfolio.

For ICAP and UCAP PRM accounting purposes, the ELCC of the base case portfolio of solar and wind resources was calculated. Those results are shown in the applicable ICAP/UCAP tables in the PRM results sections above and reflect a portfolio average ELCC of 18%.

The analysis also included the calculation of average and marginal ELCCs by technology for solar, storage, and wind up to the following maximum penetrations:

- Solar – 2,000 MW
- Battery – 1,000 MW
- Wind – 2,000 MW

The result of this analysis was a dense, three-dimensional matrix of portfolio capacity values from which average and marginal ELCCs can be determined for any desired penetration of solar, wind, and battery within the maximum penetrations evaluated. The resulting dense matrices of capacity values and ELCCs are too large to be included in this report. However, TSGT has been provided a tool that allows the average and marginal ELCC to be determined for any penetration of solar, wind, and battery.

To illustrate the representative results of the analysis, the figure below shows a surface plot of the portfolio capacity value as a function of both solar and battery penetration. The surface plot assumes zero penetration of wind.

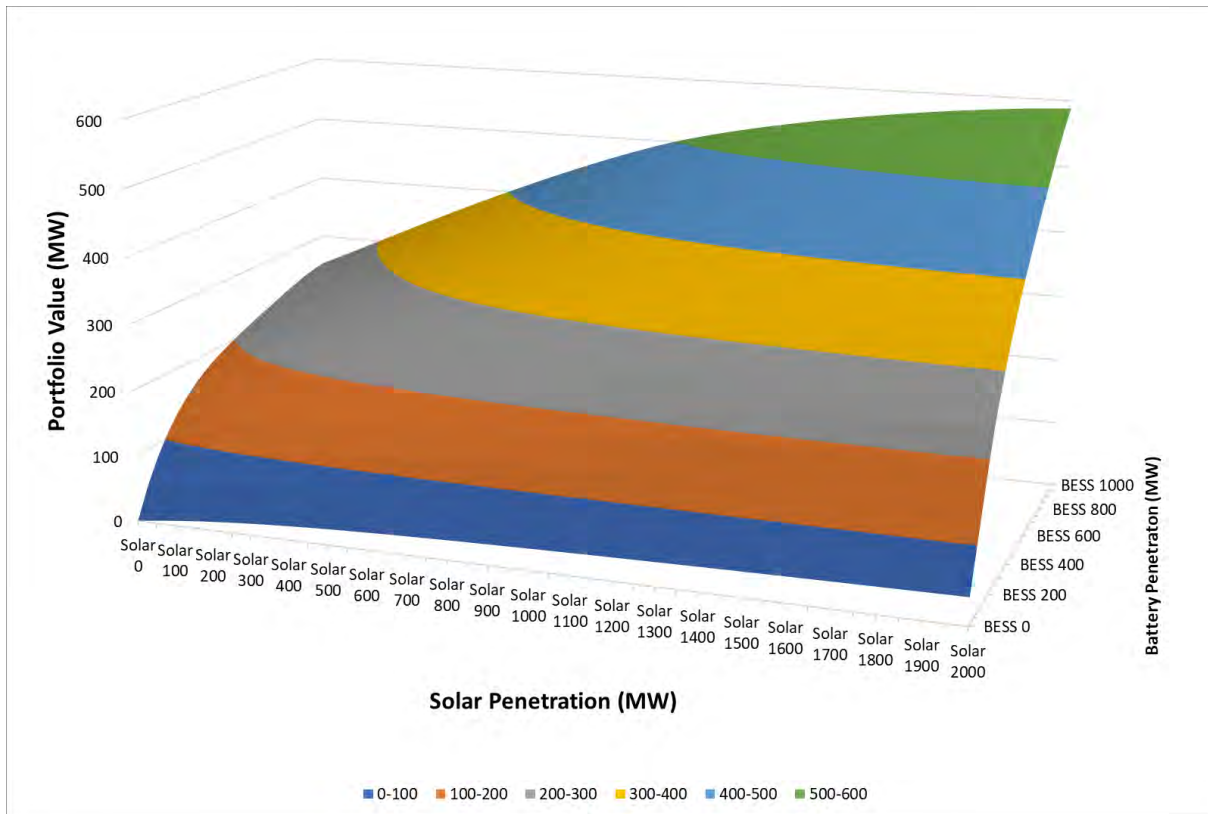


Figure 1. Portfolio Capacity Value at Zero Wind Penetration, Illustrative

To interpret this surface plot, find a desired solar penetration along the solar-axis and a desired battery penetration along the battery-axis. Then go up the vertical axis to find the total portfolio value. For example, at 2,000 MW of solar, the portfolio value is approximately 50 MW (roughly midway through the blue band). As battery penetration increases, capacity value increases to approximately 600 MW (the top of the green band). As penetrations of solar and battery increase, the total portfolio value increases. However, due to the declining improvement in capacity value, there is a flattening out of the surface along both the solar and wind axes. This will result in a declining technology specific ELCC as will be shown below.

Plots for various penetrations of wind would be similar. For example, the figure below shows the same surface plot at 2,000 MW of wind:

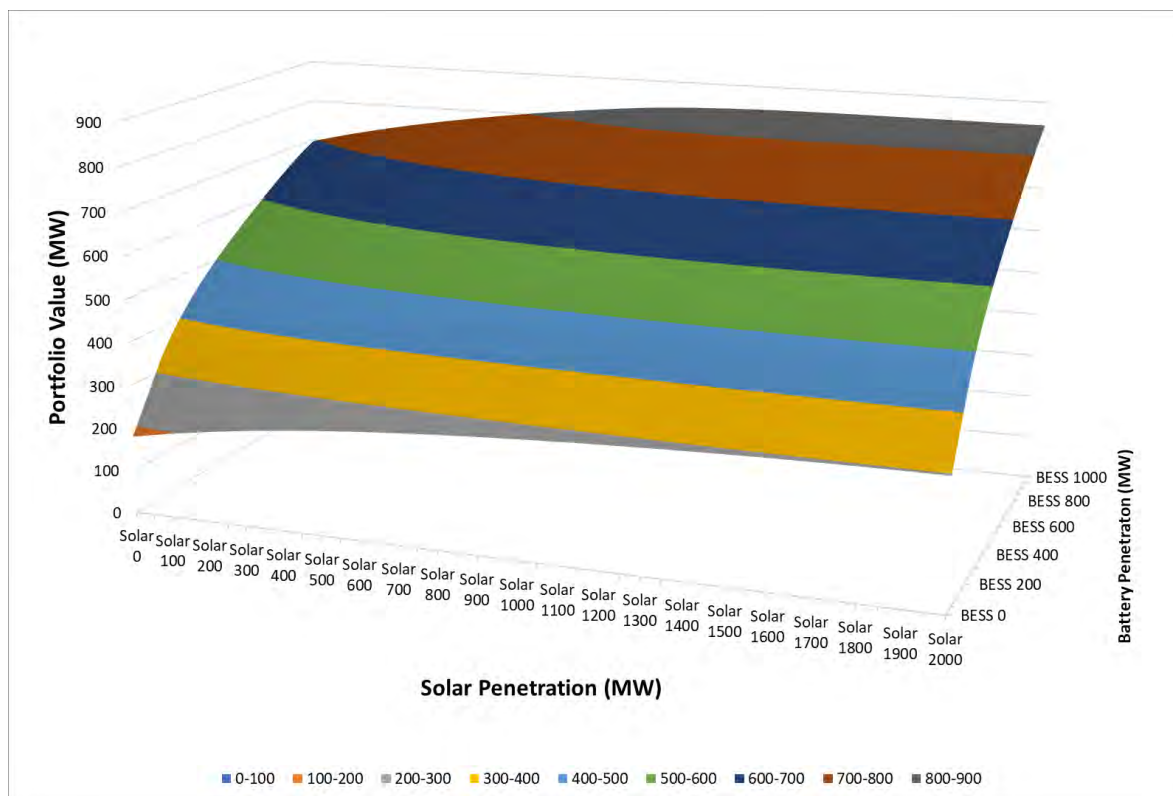


Figure 2. Portfolio Capacity Value at 2000 MW of Wind, Illustrative

From the dense matrix of portfolio capacity values, average and marginal ELCCs can be developed for any combination of solar, battery, and wind up to the maximum studied penetrations of 2,000 MW solar, 1,000 MW battery, and 2,000 MW wind. This is accomplished by finding the capacity value from the three-dimensional matrix corresponding to the desired mix of solar, wind, and battery. This is then compared to the sum of the single-technology capacity values of the desired solar, wind, and battery penetrations to establish the synergistic benefit or antagonistic harm as appropriate. That benefit/harm is then allocated among the individual technologies to get the average capacity value for the combined technologies. Marginal capacity values are calculated using the above method applied to small, incremental steps, which are then divided by the step-size to get the marginal ELCC. These marginal capacity values are then integrated to obtain the average capacity value and associated ELCC. This proprietary method is included in the ELCC tool provided to TSGT.

As an example, the following charts show the average and marginal ELCCs for solar, wind, and batteries, respectively. For illustrative purposes, the assumed penetration of the non-subject technology in each case was 1,000 MW for solar and wind and 500 MW for batteries (i.e., in the solar chart, wind is at 1,000 MW and batteries are at 500 MW, whereas in the battery chart, solar and wind are both at 1,000 MW).

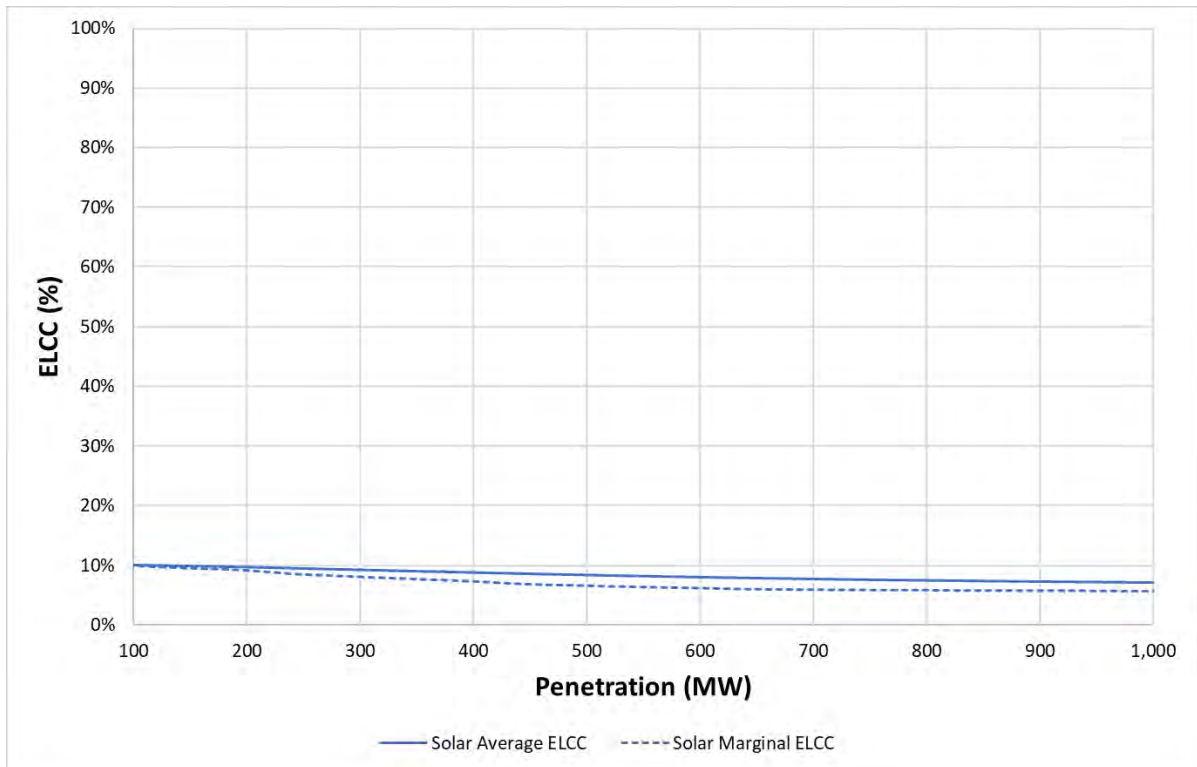


Figure 3. Solar ELCCs at 1,000 MW of Wind and 500 MW of Battery

As mentioned previously, the flattening of the surface with increased solar penetration results in a declining average and marginal ELCC. Solar ELCCs for TSGT are very low due to the significant underlying BTMPV and customer distributed solar penetrations. Although ELCC will never strictly go to zero, it will asymptotically approach zero, resulting in a flattening of the marginal ELCC curve at higher penetrations.

The wind chart is shown below.

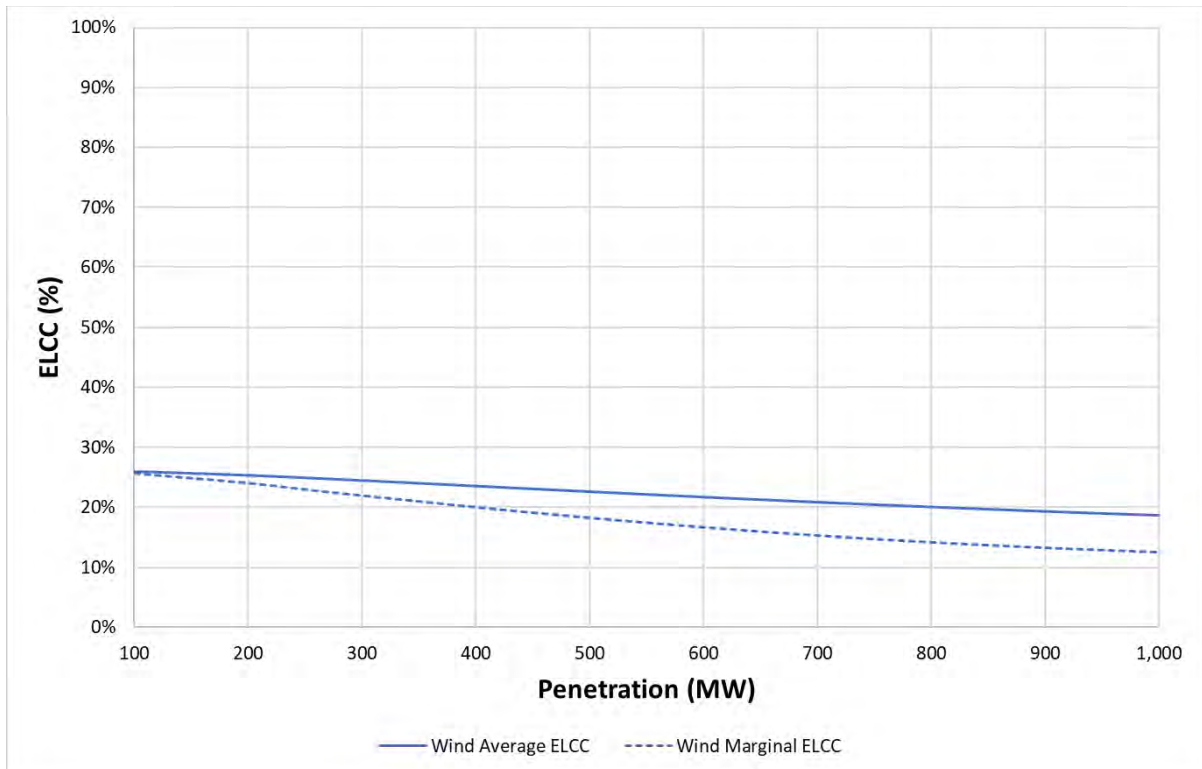


Figure 4. Wind ELCC at 1,000 MW of Solar and 500 MW of Battery

Finally, the battery chart is shown below.

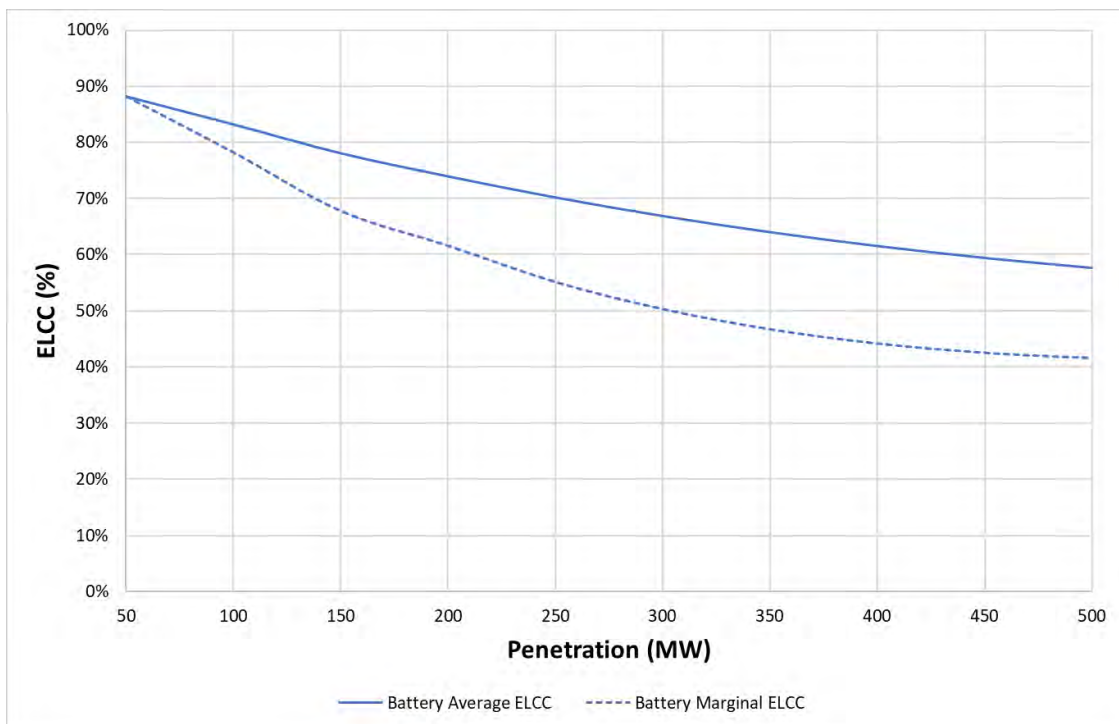


Figure 5. Battery ELCC at 1,000 MW of Solar and Wind

In addition to these scenarios, ELCC scenarios were evaluated for several other components, including member system DG (not rooftop) solar, EE, and 10-hour batteries.

To determine the ELCC of the member system DG solar, the reference case with all TSGT renewables was used as a starting point. Using that reference case, DG solar resources were removed and replaced with perfect capacity until the system returned to 0.1 days/year LOLE. This resulted in an average ELCC for the member system DG solar of 35.15%. This is considerably higher than the TSGT solar because it is presumed to be “first in the queue” relative to the TSGT solar. Since entity-specific capacity accreditation is not an issue for TSGT, the only concern is to get the appropriate total portfolio capacity credit for purposes of counting capacity towards meeting the reserve margin requirement. Therefore, it does not matter whether all renewable resources are considered to be added simultaneously or as was done in this analysis, some renewables were presumed to have a “first in the queue” status.

To determine the ELCC of the incremental EE, the existing EE was removed from the ELCC reference case to establish a reference case for the EE ELCC evaluation. Because the existing EE portfolio of approximately 13 MW is too small to accurately run an ELCC, a 100 MW block of EE was evaluated. This block of EE was added to the system and perfect capacity removed until the system returned to 0.1 days/year LOLE. This resulted in an average ELCC of 97.5% for the EE block.

Finally, three penetrations of 10-hour battery were evaluated. The three penetrations evaluated were 200 MW, 400 MW, and 600 MW. However, these ELCC values were calculated assuming an underlying penetration of 400MW of 4-hour batteries and base case solar and wind penetration assumptions of 820 MW for solar and 790 MW for wind. The result of this analysis is shown in the figure below.

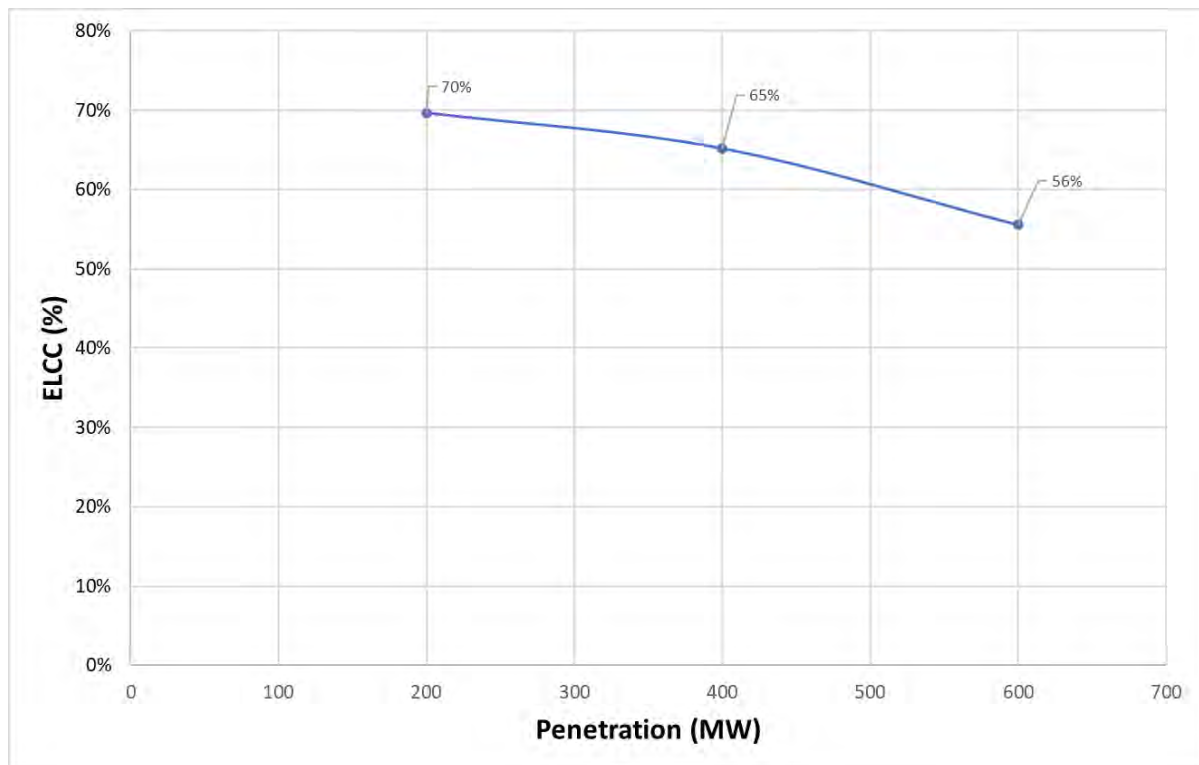


Figure 6. 10-Hour Battery Average ELCC

CONCLUSIONS

Upon examination of the study analysis, a UCAP PRM of 30.5% is warranted based on the most common industry reliability standard of 0.1 LOLE. Although this is considerably higher than the existing PRM, the differences can be attributed to accounting differences, modeling differences, and the increase in shaft risk associated with the loss of significant load responsibility. Based on an analysis of the impact of the high EFOR and shaft risk, a transitional PRM of ~22% for use prior to the retirement of certain coal facilities and the departure of certain member loads can be supported.

Regarding ELCCs, the results are as expected given the size and characteristics of the TSGT system. The very low solar ELCCs are a result of the assumed underlying rooftop and member system distributed solar receiving credit as the first tranche of solar along with the relatively small size of Tri-State's peaking load compared to online and under contract solar generation. As stated above, the order of analysis for ELCC purposes is not an issue for TSGT since the ultimate concern is the total portfolio capacity value counted towards the PRM. The lower storage ELCCs are a result of the fact that LOLE risk is driven in part by outages, resulting in longer duration EUE events.

INTRODUCTION

The purpose of this document is to describe the analysis used to determine the PRM necessary for TSGT to maintain a LOLE of 0.1 days/year or the equivalent of the common industry practice of one loss of load event in 10 years.

In addition, this document will also report on the results of a study to determine the ELCC of a series of tranches of solar, wind, and BESS resources – as well as the ELCC of several other load and resource components including customer DG solar, EE, and long duration (10-hour) batteries.

STUDY FRAMEWORK

This study was performed using the SERVVM and its associated study framework. The SERVVM framework combines an hourly (i.e., 8760-hour) production cost model coupled with Monte Carlo outage simulation and comprehensive scenario management that considers load and weather uncertainty to determine key reliability parameters such as LOLE. The following describes the key parameters and uncertainties that are considered and how they are applied within the study framework.

WEATHER UNCERTAINTY

To account for weather uncertainty, SERVVM performs hourly production cost simulations using multiple historical weather years. The uncertainties that are modeled for each modeled weather year include load shapes and renewable profiles. Load shapes for each weather year are developed to represent the expected future load response to the historical weather (temperatures). For example, a 1998 weather year represents how loads would respond if 1998 weather were to repeat during the given study year. These load shapes are then scaled so that the median of the peak demands from the various weather year load shapes equals the study year weather normal peak load forecast. In the case of TSGT, since their load forecast is based on the last 10 years of history, load shapes are scaled such that the median of the last 10 years equals the study year weather normal peak load forecast. Other load shapes were scaled such that their forecast matched the median of all available weather years. Similarly, renewable profiles are developed to represent the expected future availability associated with the historical weather profile. For purposes of this study, 42 weather year scenarios were simulated representing weather conditions for the years 1980-2021.

ECONOMIC LOAD FORECAST ERROR

Economic Load Forecast Error represents the potential error in the weather normal peak load forecast associated with uncertainty in economic forecasts. Using the Congressional Budget Office's historical forecasts for Gross Domestic Product (GDP), it is possible to predict both the magnitude and probability of error in the forecast of the GDP economic indicator three, four, or five years out into the future. This probability of error can then be converted into a Load Forecast Error (LFE). For this study, five LFE scenarios were chosen. These are described in the Model Development section of this document. Each of the 42 weather year scenarios are combined with each of the five LFE scenarios to create 210 unique load scenarios, or *cases*.

MONTE-CARLO OUTAGE ITERATIONS

SERVM uses Monte-Carlo techniques to simulate generator outages. Multiple hourly production cost simulations are run for each of the 210 load cases. With each outage iteration, random Monte-Carlo draws are made to determine thermal generation outage profiles associated with that scenario. With enough iterations, the set of random outages for each thermal unit approaches that unit's expected EFOR. For this study, convergence was achieved with 200 outage draw iterations per case. The specifics associated with how these outages were modeled are detailed in the Model Development section of this document.

As shown in the figure below, the SERVVM uncertainty framework used for this study required 42,000 hourly (8760-hour) production cost simulations for a single analytical run of the TSGT system.

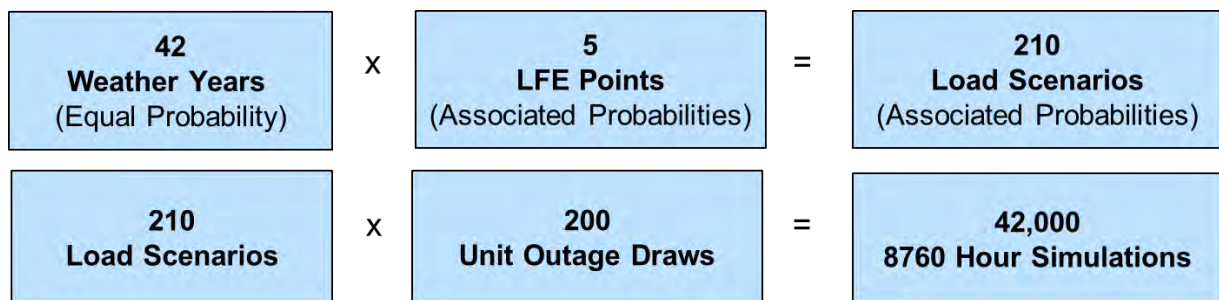


Figure 7. SERVVM Uncertainty Framework

The Study Methodology section of this document describes the numerous “analytical runs” required to perform the reserve margin analysis, its associated sensitivities, as well as the ELCC analysis.

MODEL DEVELOPMENT

The SERVIM data model utilized for this study was based upon a joint dispatch of the four Tri-State load zones in the Western Area-Colorado Missouri (WACM), Public Service Colorado (PSCO), and Public Service New Mexico (PNM) Balancing Authority Areas (BAA). Those four load zones are Tri-State New Mexico (Tri-NM), Tri-State West Colorado (Tri-WCO), Tri-State East Colorado (Tri-ECO), and Tri-State Wyoming-West Nebraska (Tri-WYNE). The system model also included representations of the immediate surrounding interconnected BAAs, including representations of the balance of each of the three before-mentioned BAAs, PacifiCorp East (PACE), Arizona (AZ),¹ and Southwest Public Service (SPS), which is in the Southwest Power Pool (SPP).² The figure below shows the configuration of the study model.

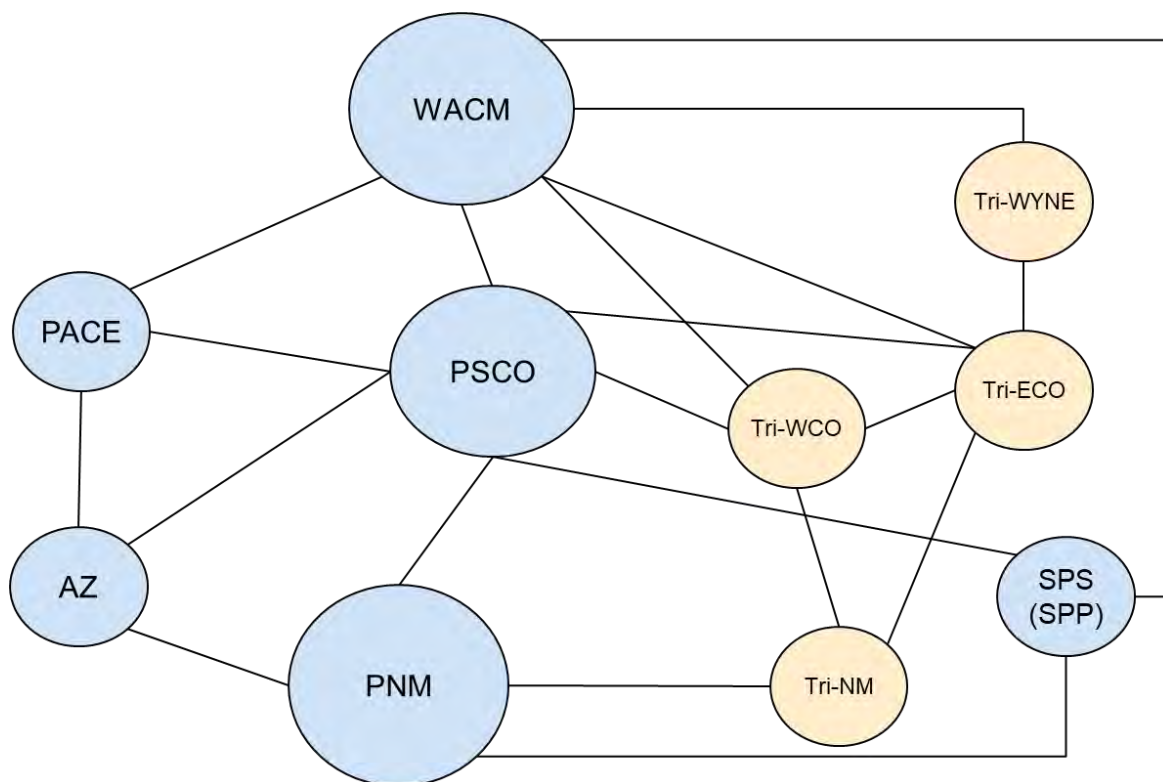


Figure 8. System Topology

BASE CASE MODEL DEVELOPMENT

For the Non-TSGT regions, the SERVIM database was developed using publicly available data from sources such as the U.S. Department of Energy's Energy Information Administration (EIA) Form 860, available documents from the North American Reliability Corporation (NERC), various publicly available Integrated Resource Plans (IRPs), and Federal Energy Regulatory Commission (FERC) Forms.

¹ This includes all of the entities in the Arizona Public Service BAA.

² SPS is across the DC ties between the Eastern Interconnect and the Western Interconnect.

The TSGT region, however, was updated using information provided by TSGT as described in the following sections.

PEAK DEMAND FORECAST

TSGT is a wholesale provider of power to members systems consisting of rural electric cooperatives and public power districts. The TSGT official load forecast is developed based on the load from these retail service providers net of adjustments for rooftop solar resources (BTMPV). For this study, these BTMPV resources were modeled as specific resources. Additionally, incremental energy efficiency (EE) was modeled as an explicit hourly load modifier. Therefore, the TSGT forecast, which was already grossed up for incremental EE, had to be further grossed up for the impacts of the BPMPV. The figure below shows the 2030 TSGT peak demand forecast as well as the grossed up peak demand forecast used for base case modeling purposes for each of the four TSGT load zones.

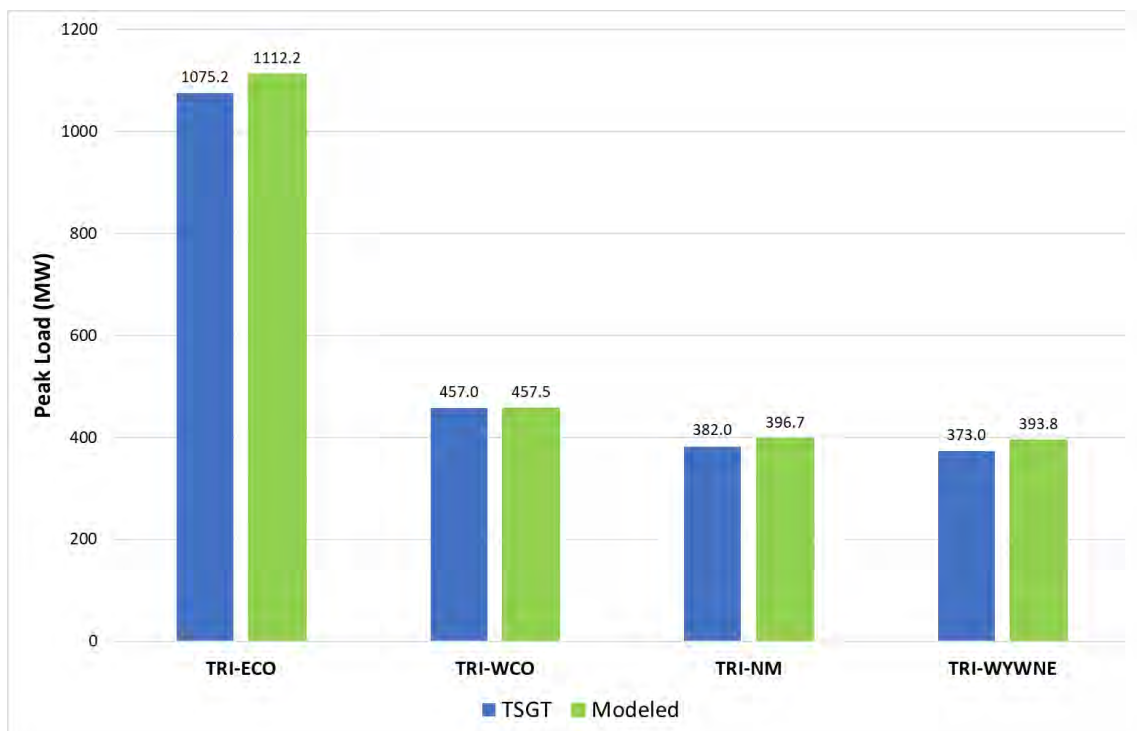


Figure 9. 2030 Peak Demand Forecast

The figure below shows the 2030 TSGT energy forecast as well as the grossed-up energy forecast used for modeling purposes.

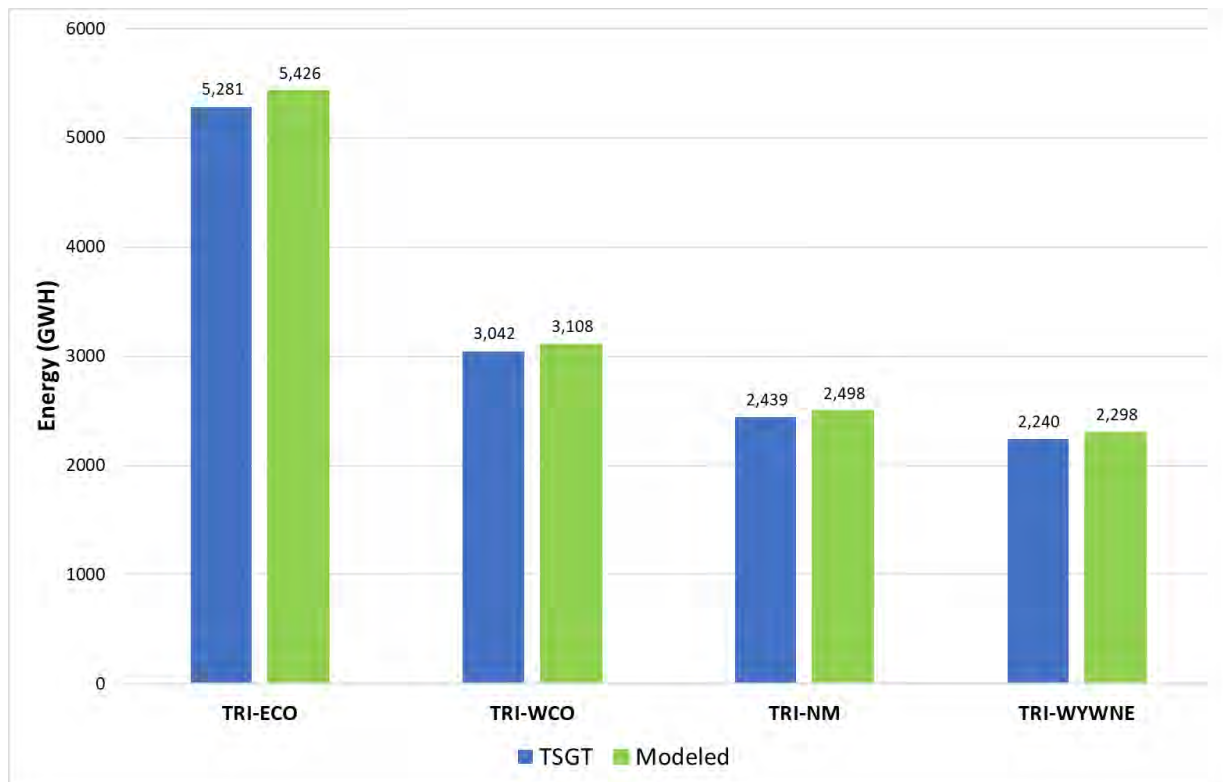


Figure 10. 2030 Energy Forecast

LOAD MODELING

As described in the Study Framework subsection above, load shapes were developed for each of the 42 study years 1980-2021. These load shapes were developed based on trends and relationships between load and weather for the five historical years 2018-2022.

To prepare the loads for trending, the historical loads were grossed up for BTMPV as indicated above. The loads were further prepared by removing economic bias as well as impacts of irrigation load uncertainty. These differences were removed from the load shapes by adjusting the loads on a seasonal basis so that the highest load hours of each season were consistent across the historical period. The figure below shows an example of the result of this process. The figure shows summer weekday loads during for the Tri-WYWNE load region for hours 13-17 when temperatures were above 85°F. Loads have been adjusted to remove economic bias.

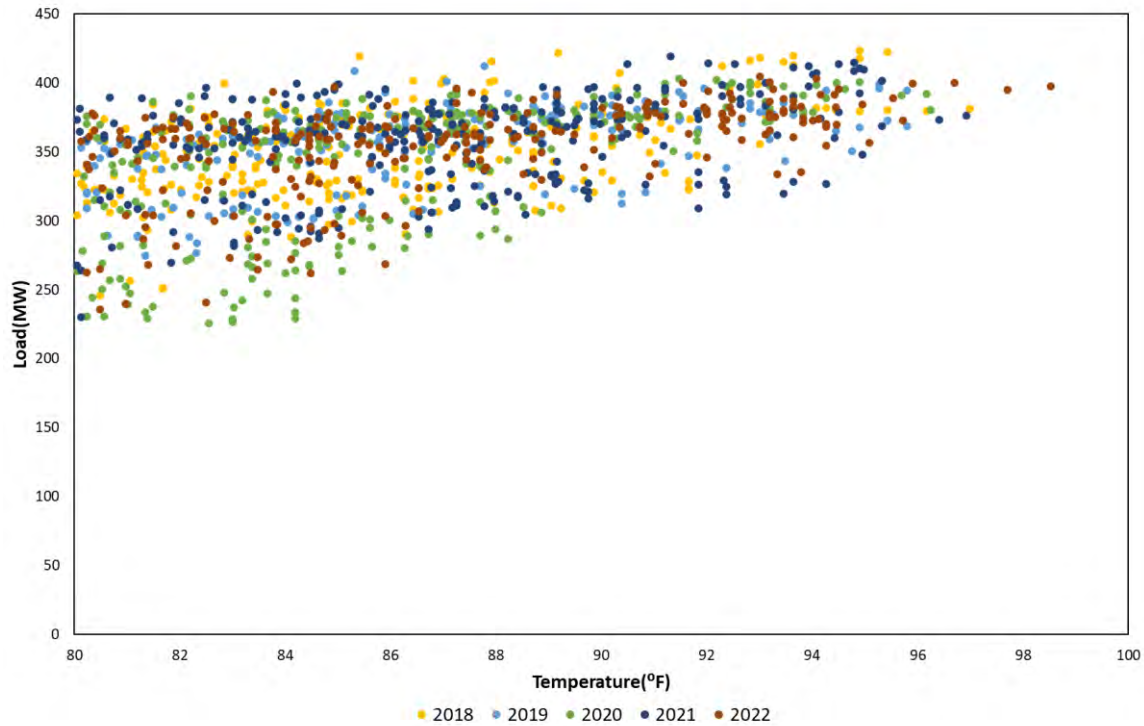


Figure 11. Summer Peak Period Temperatures

The five historical load shapes were trended using a neural network that was trained using hourly historical temperatures from the National Oceanic and Atmospheric Administration (NOAA) and other key variables. For trending purposes, temperatures from NOAA were downloaded for the period 1980-2022. However, because TSGT loads are located in more rural locations, historical temperatures were often unreliable or unavailable. Therefore, it was often necessary to use a nearby metropolitan area as a proxy for the temperatures for the TSGT loads.

Tri-ECO temperatures were based on the following locations and weightings:

- Denver – 55.4%
- Ft. Collins – 25.7%
- Colorado Springs – 7.85%
- Trinidad – 6.9%
- Pueblo – 3.9%
- Cheyenne – 0.3%

Tri-WCO temperatures were based on the following locations and weightings:

- Denver – 27.5%
- Ft. Collins – 14.5%
- Durango – 38.8%
- Grand Junction – 19.1%

Tri-NM temperatures were based on the following locations and weightings:

- Albuquerque – 41.1%
- Las Cruces – 43.9%
- Pueblo – 15%

Tri-WYWNE temperatures were based on the following locations and weightings:

- Cheyenne – 41.4%
- Casper – 58.6%

In addition to temperature, the neural net was provided with training variables that included day of week, hour of day, hour of week, 8-hour rolling average temperature, 24-hour rolling average temperature, and 48-hour rolling average temperature. “Networks” were created for Winter, Summer, and Shoulder periods. These trained networks were then applied to the NOAA weather data for the historical years 1980-2021 to develop synthetic load shapes for each of the 42 weather years.

Since the 42 years of historical weather data contains temperature data outside the range of that contained in the historical load set used to train the neural networks, those values were determined using peak load regressions developed outside the neural network. Peak load regressions were developed for summer afternoon, winter morning, and winter afternoon periods. These adjustment regressions were only applied to days in which the temperature fell outside the reasonable range of the 5-year historical data set. The figures below show the regressions performed for each of those three periods for each of the four TSGT load zones.

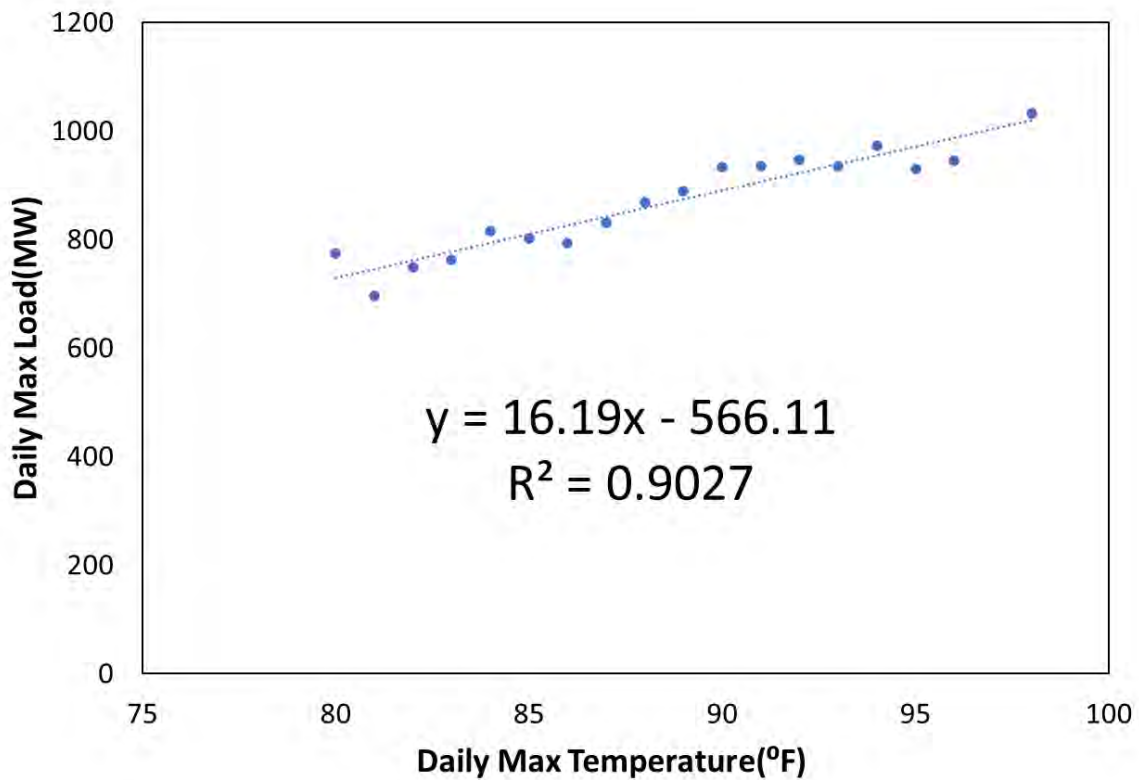


Figure 12. Tri-ECO Summer Afternoon Extreme Temperature Regression

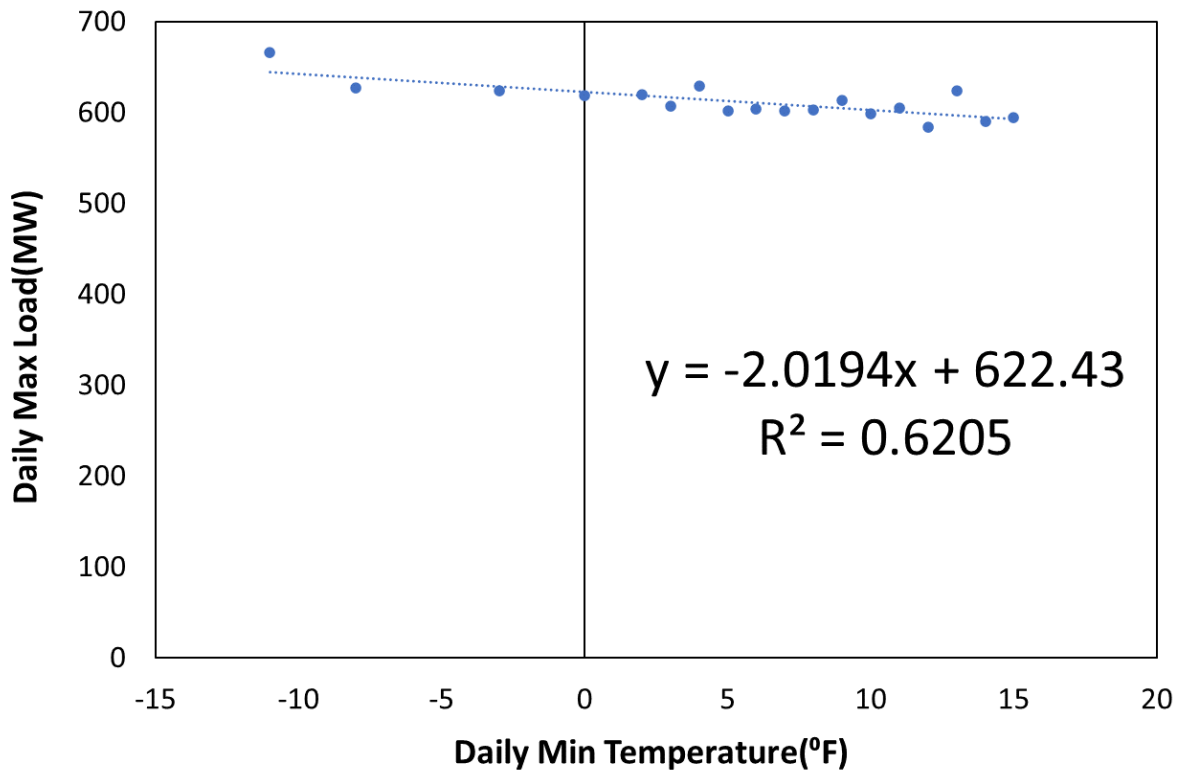


Figure 13. Tri-ECO Winter Afternoon Extreme Temperature Regression

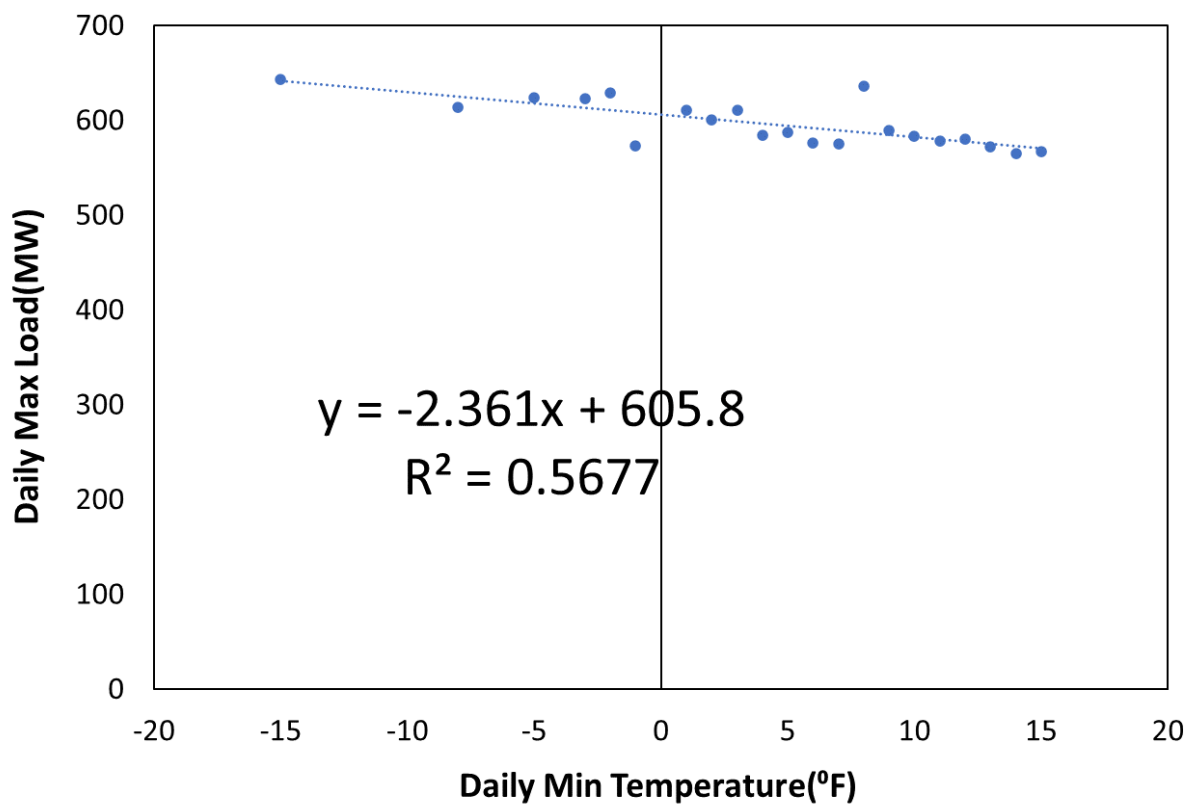


Figure 14. Tri-ECO Winter Morning Extreme Temperature Regression

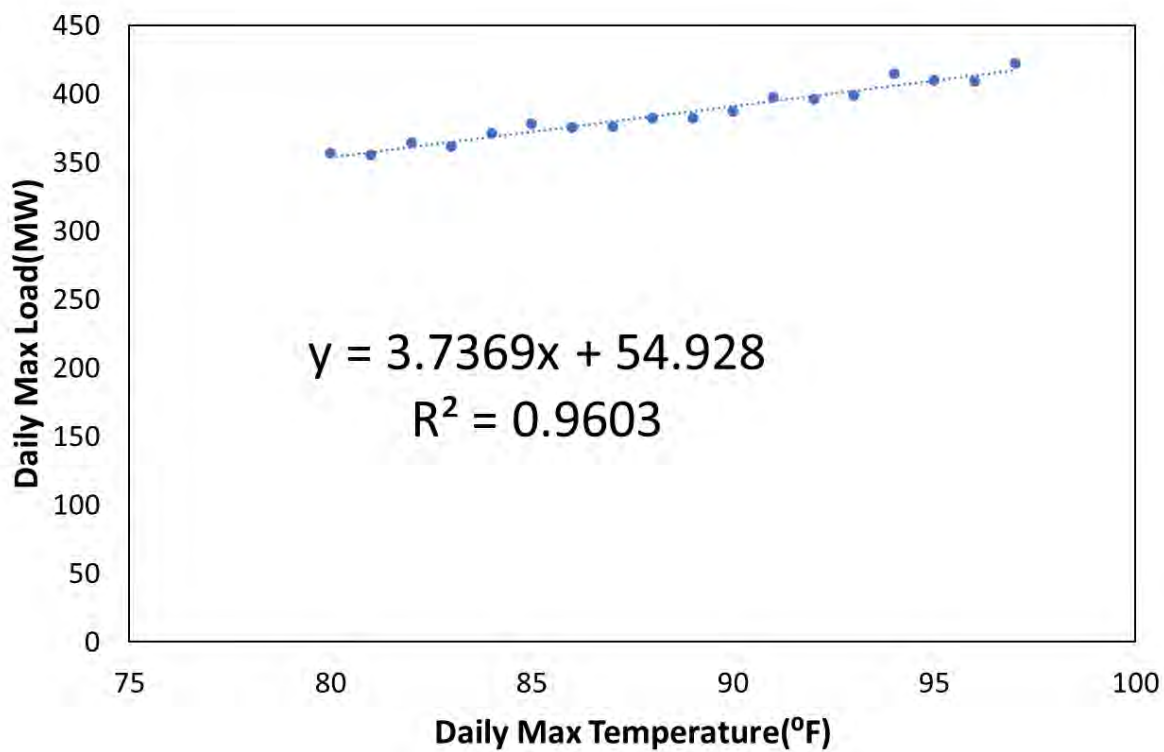


Figure 15. Tri-WCO Summer Afternoon Extreme Temperature Regression

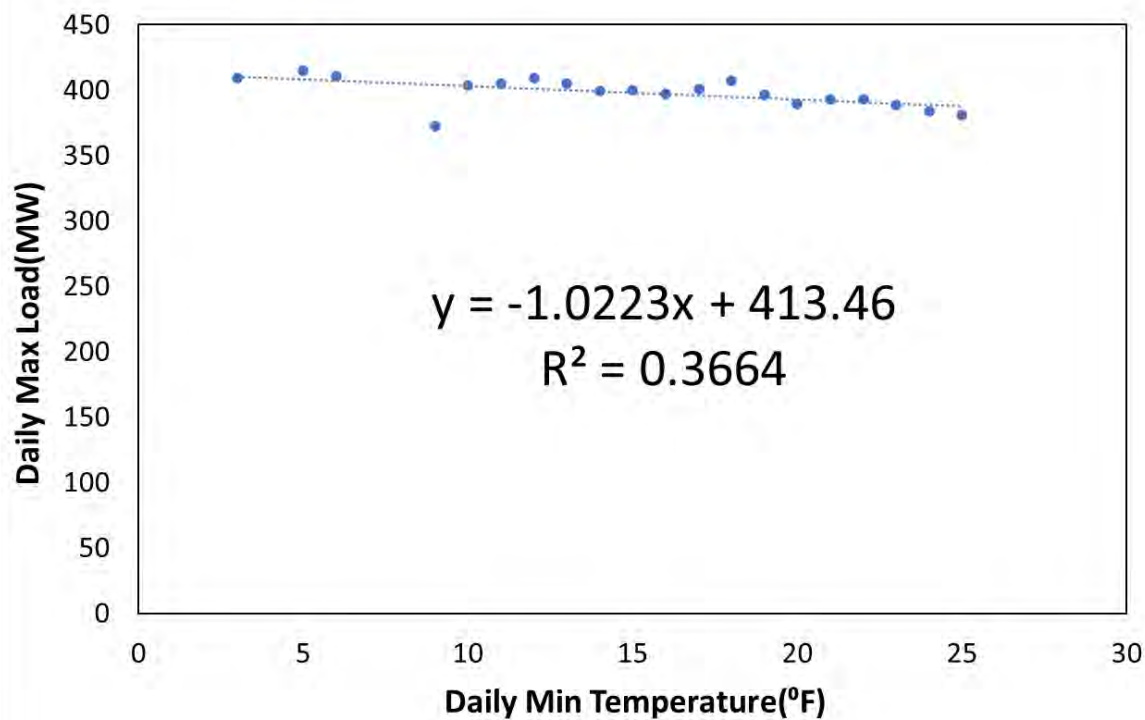


Figure 16. Tri-WCO Winter Afternoon Extreme Temperature Regression

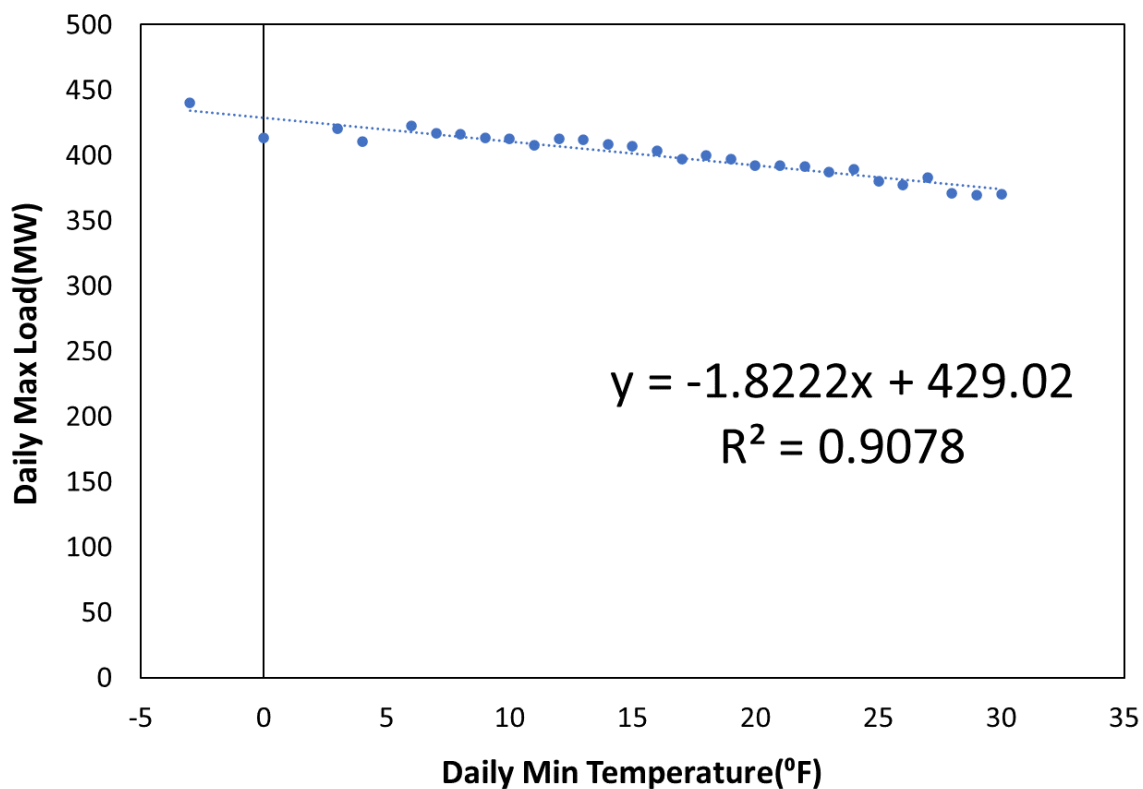


Figure 17. Tri-WCO Winter Morning Extreme Temperature Regression

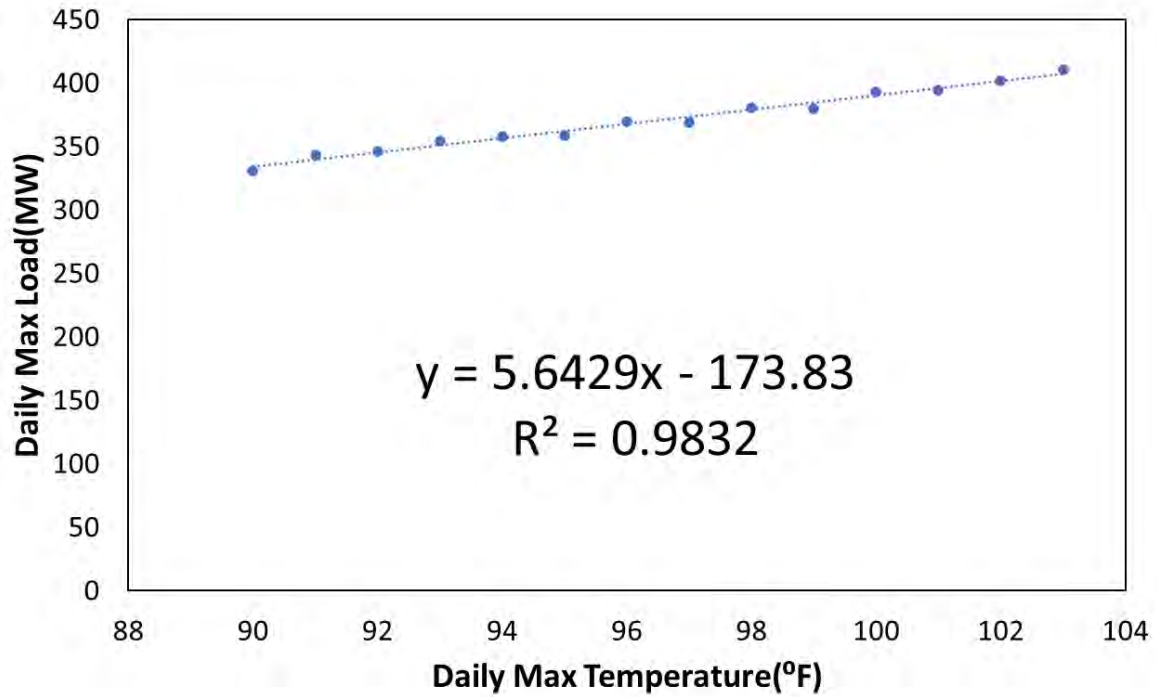


Figure 18. Tri-NM Summer Afternoon Extreme Temperature Regression

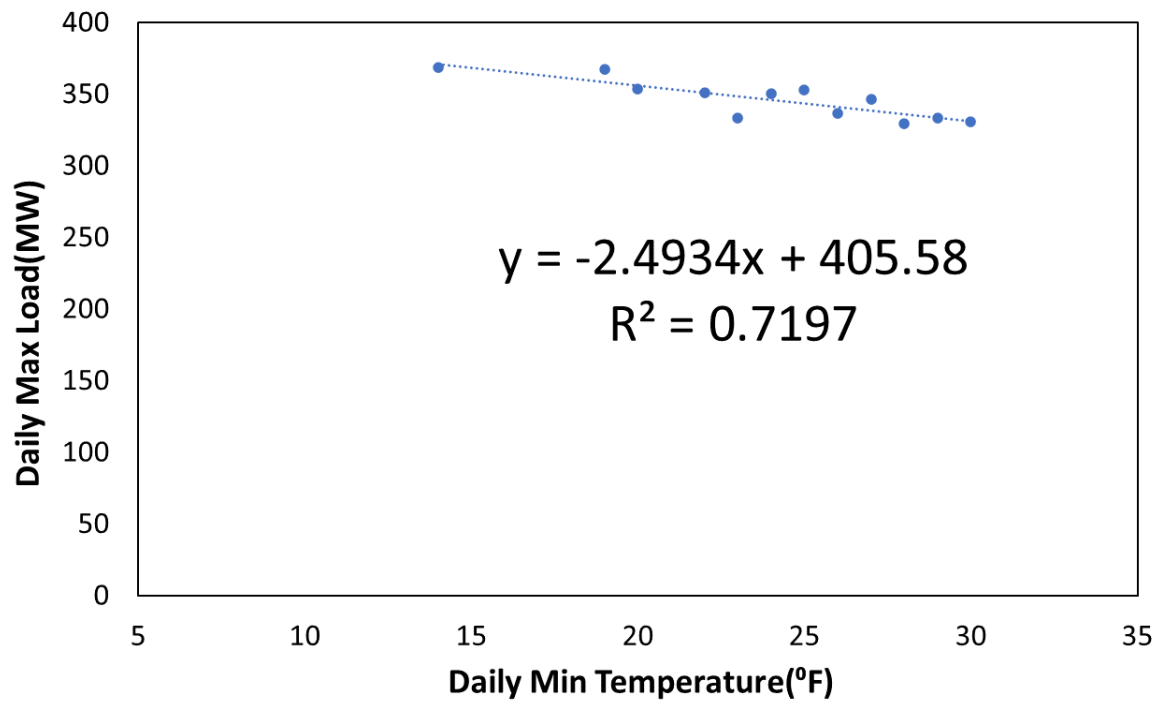


Figure 19. Tri-NM Winter Afternoon Extreme Temperature Regression

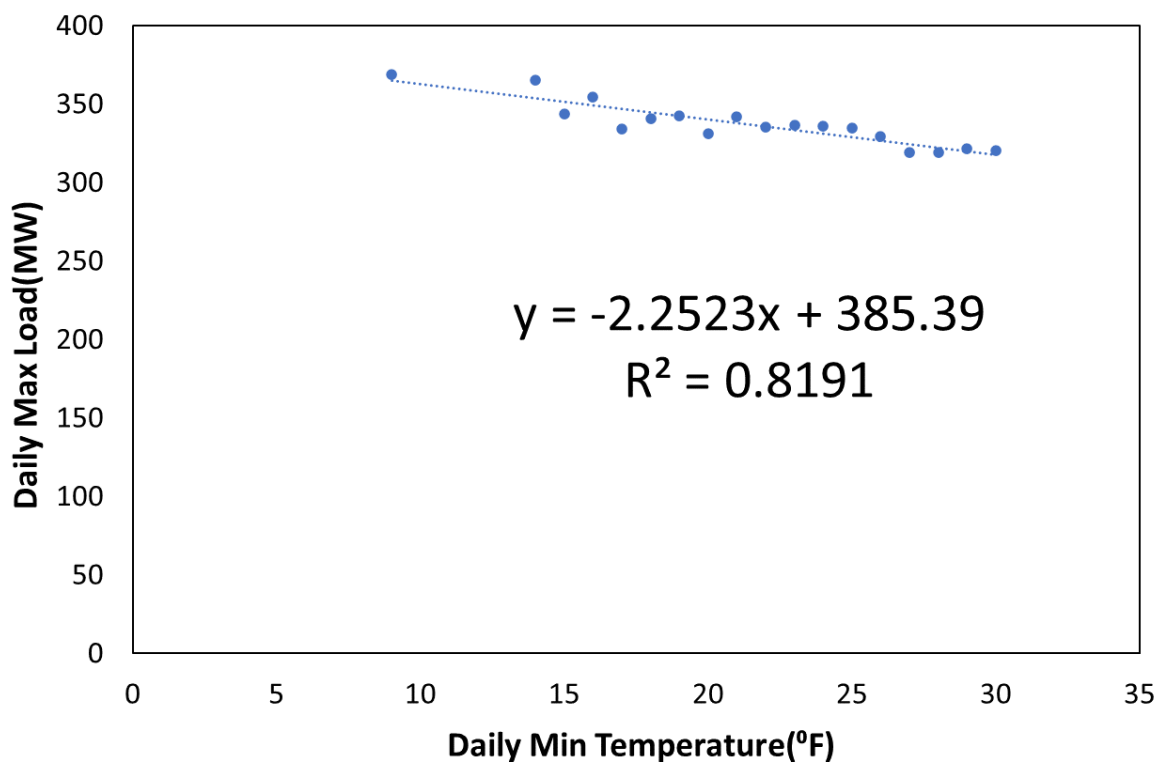


Figure 20. Tri-NM Winter Morning Extreme Temperature Regression

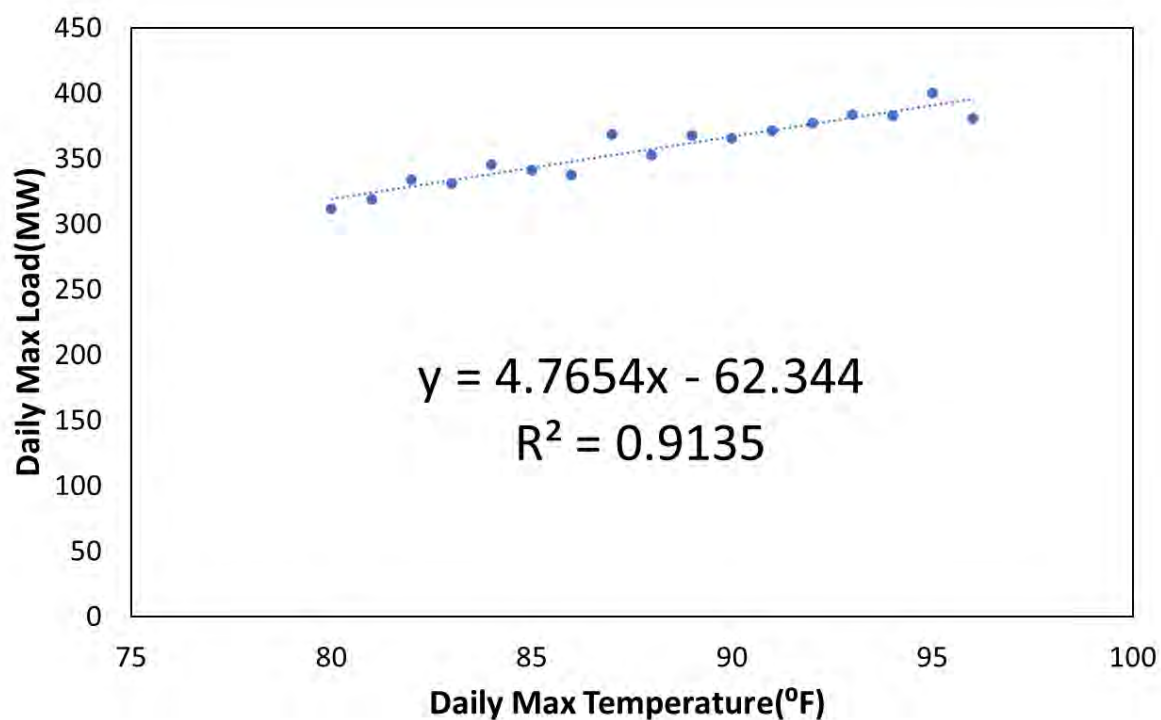


Figure 21. Tri-WYWNE Summer Afternoon Extreme Temperature Regression

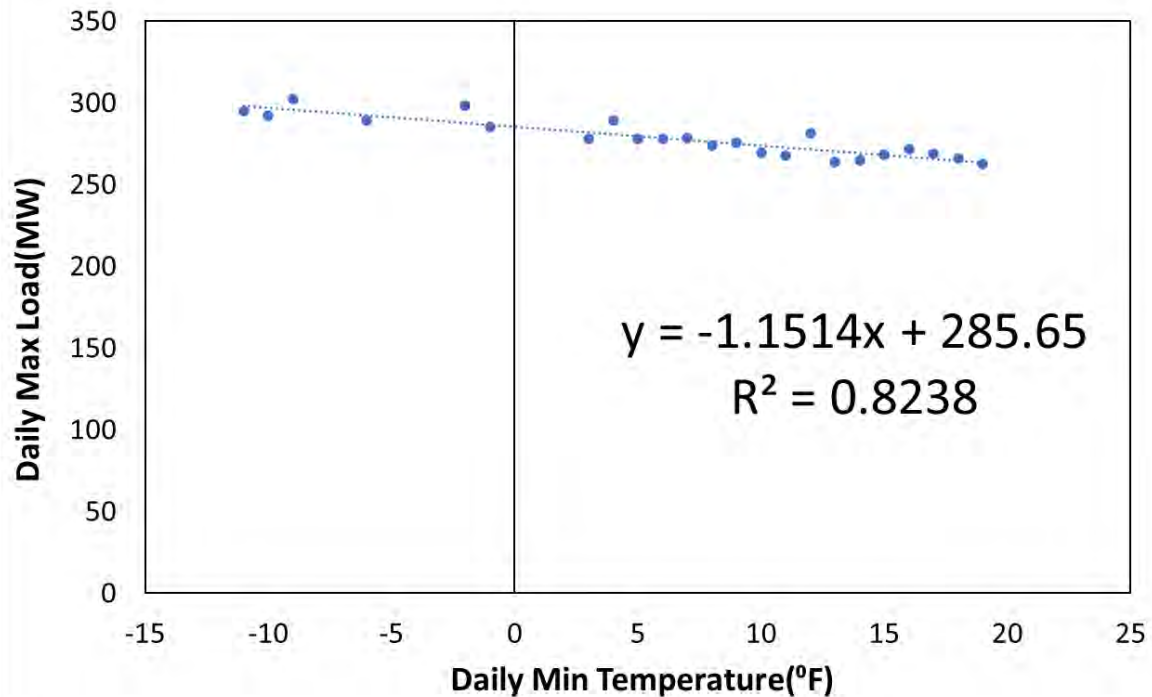


Figure 22. Tri-WYWNE Winter Afternoon Extreme Temperature Regression

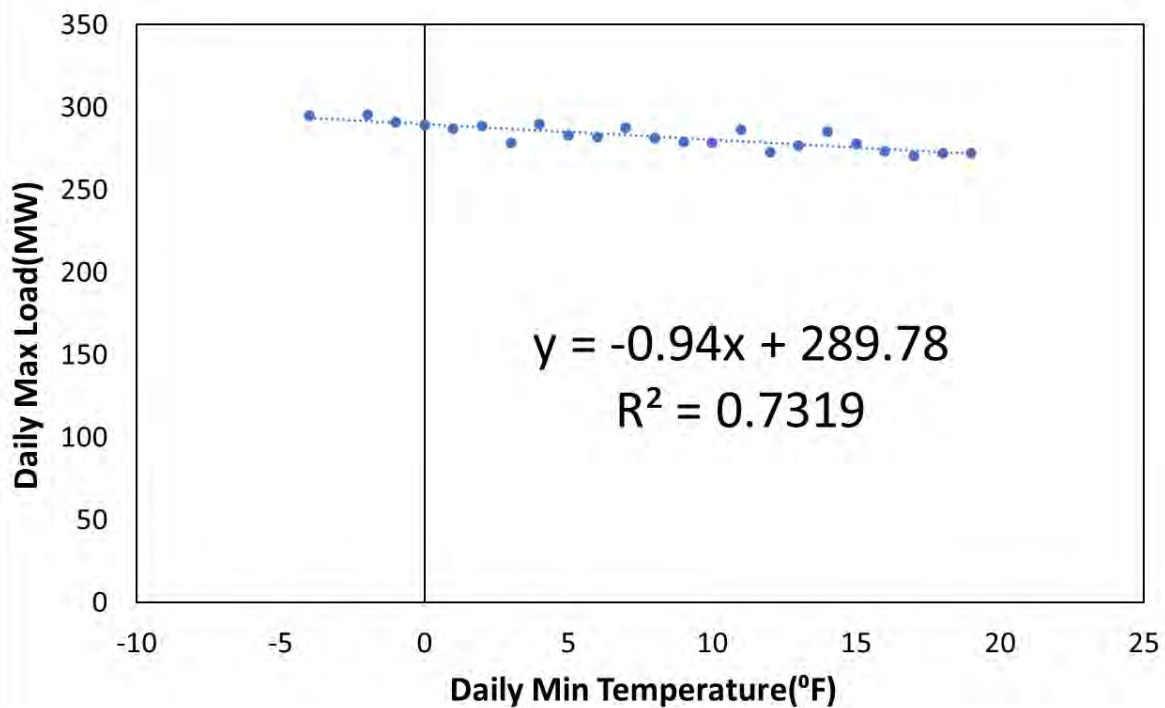


Figure 23. Tri-WYWNE Winter Morning Extreme Temperature Regression

The synthetic load shapes were then quality checked against the actual historical shapes to ensure their validity.

The figures below show a plot of the daily peak loads for each TSGT load region as a function of either the daily max or daily min temperature as appropriate. The figure compares the five years of historical data with the 42 years of synthetic data.

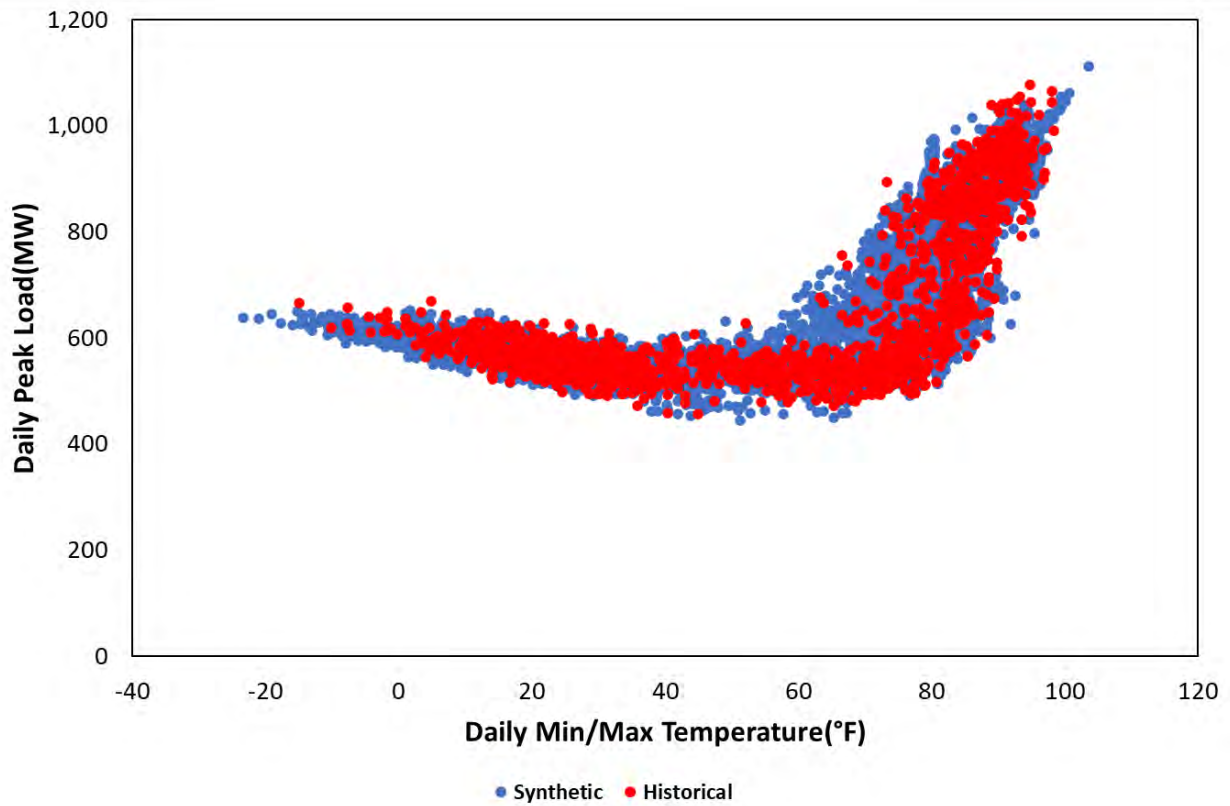


Figure 24. Tri-ECO Synthetic vs. Historical Daily Peak Loads

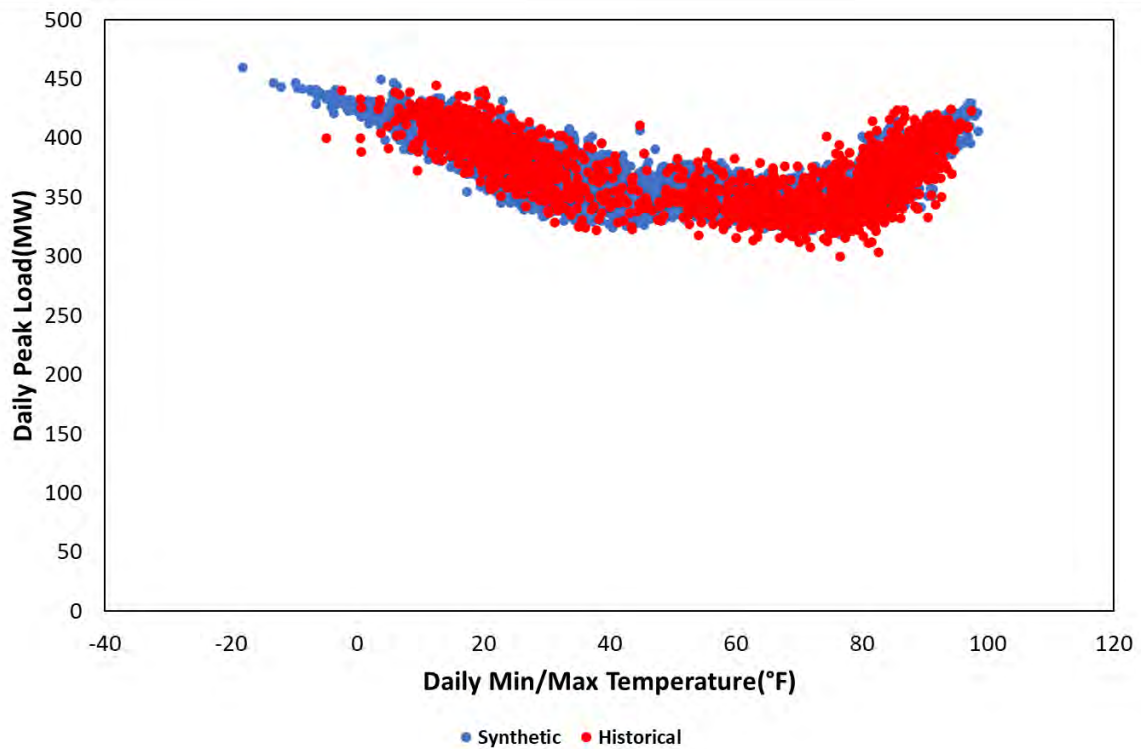


Figure 25. Tri-WCO Synthetic vs. Historical Daily Peak Loads

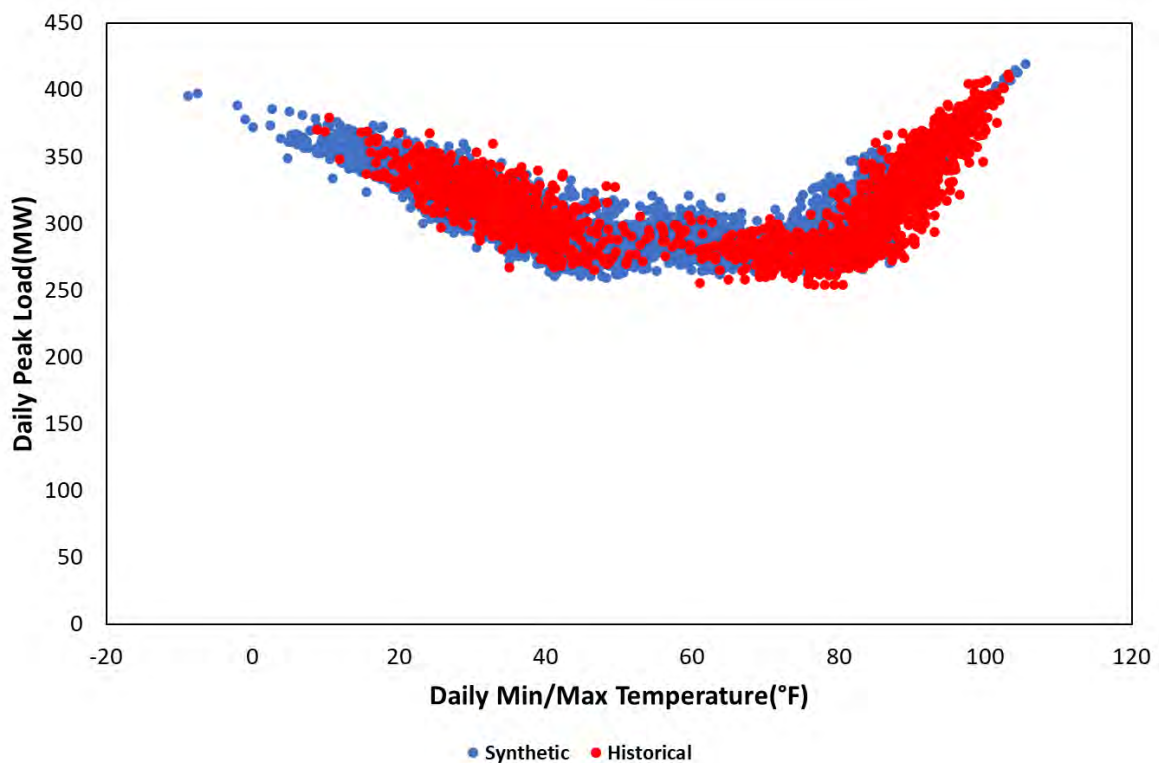


Figure 26. Tri-NM Synthetic vs. Historical Daily Peak Loads

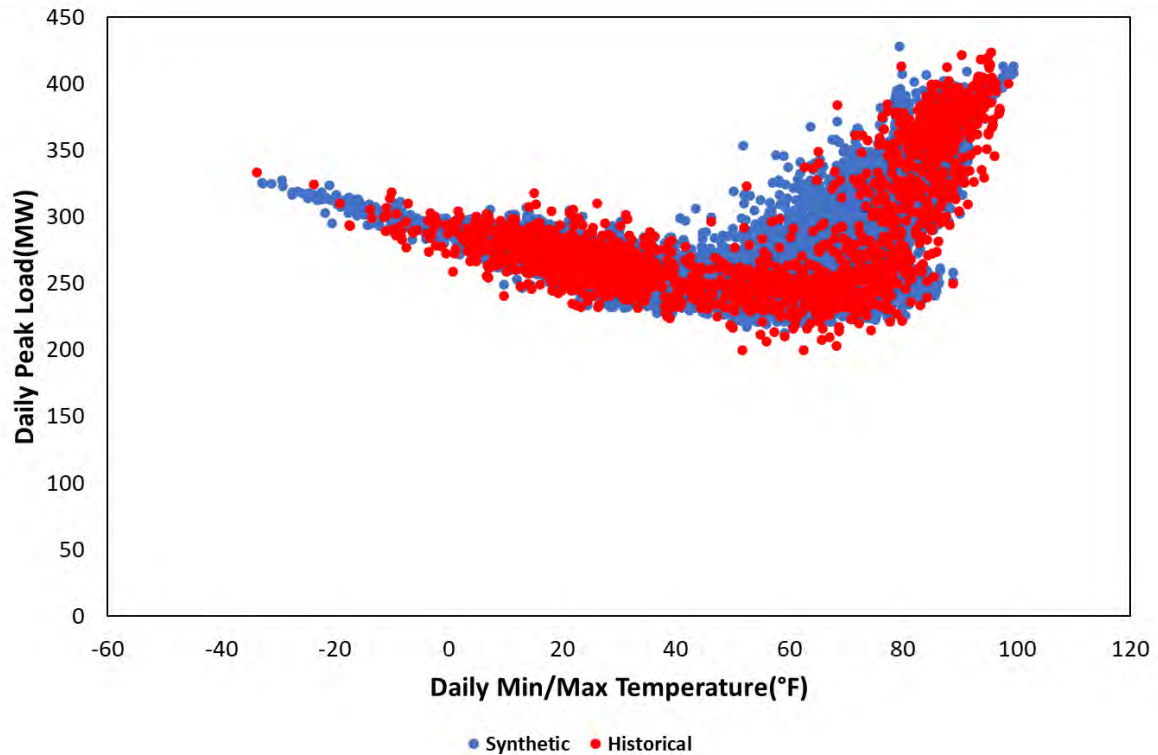


Figure 27. Tri-WYWNE Synthetic vs. Historical Daily Peak Loads

Focusing on the most extreme hours, the figures below show this same comparison for just those days in which temperatures were most extreme. The figure demonstrates a close correlation between the synthetic loads and the historical loads.

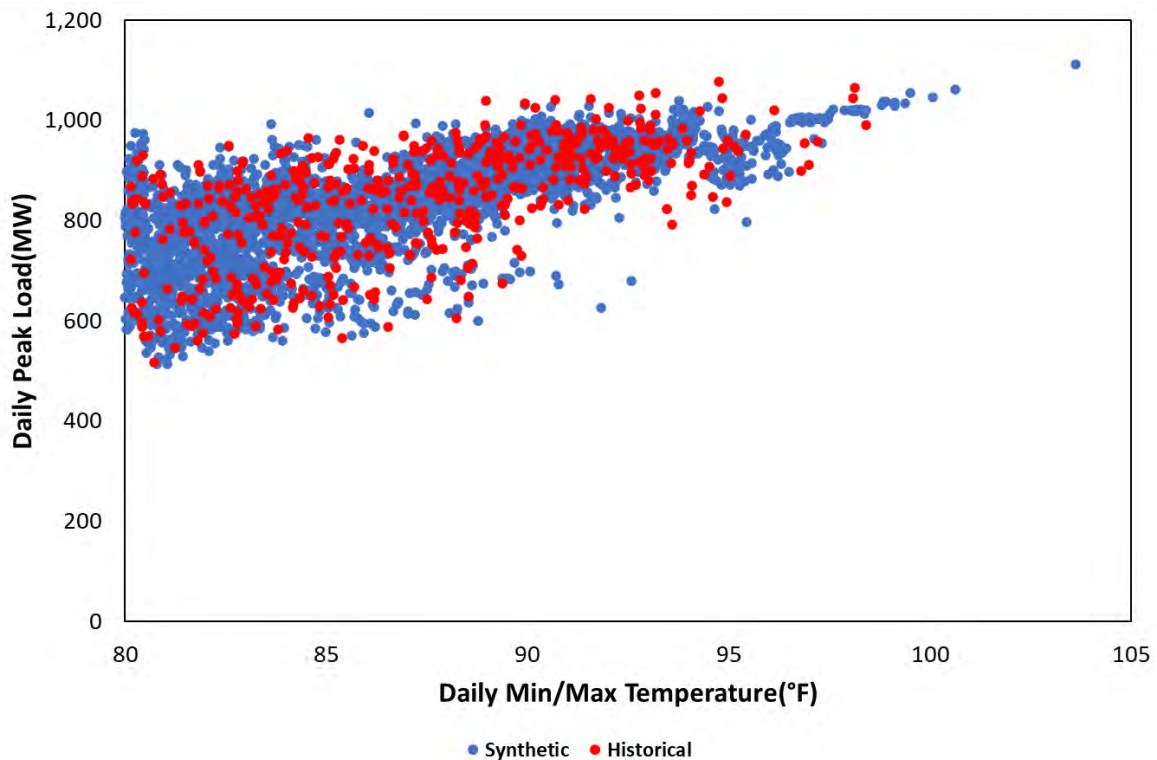


Figure 28. Tri-ECO Synthetic vs. Historical Loads for Extreme Temperatures

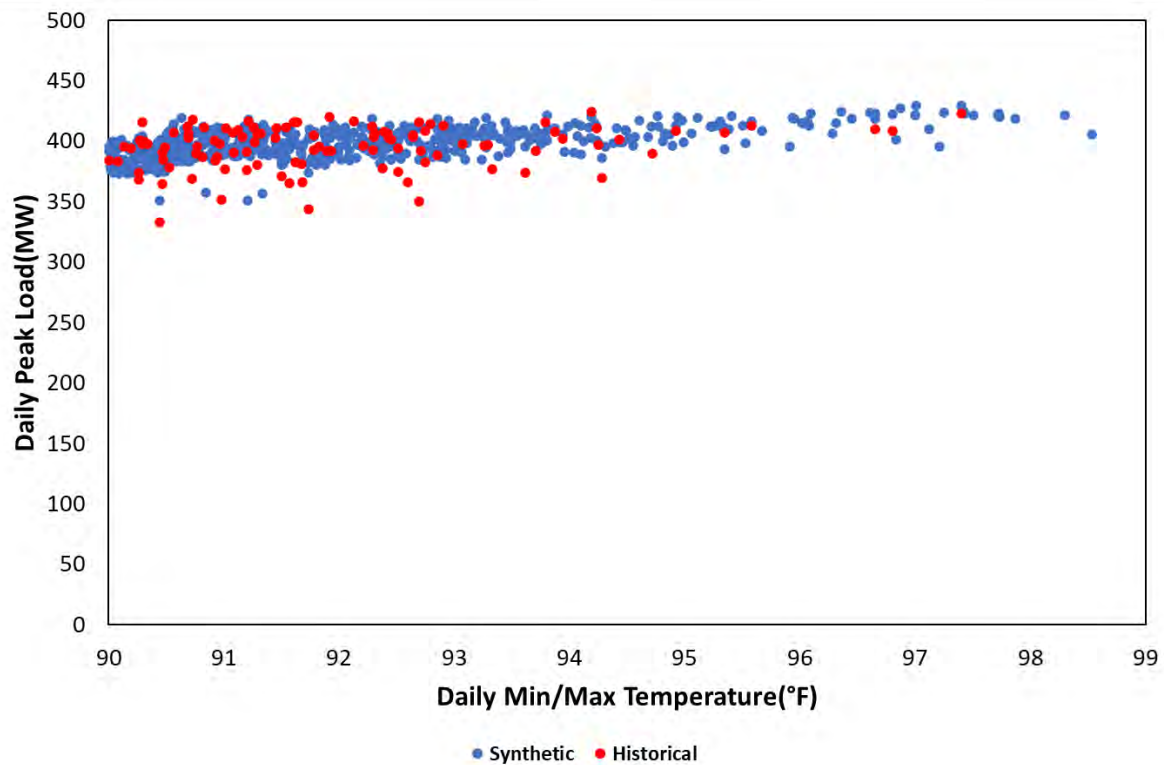


Figure 29. Tri-WCO Synthetic vs. Historical Loads for Extreme Temperatures

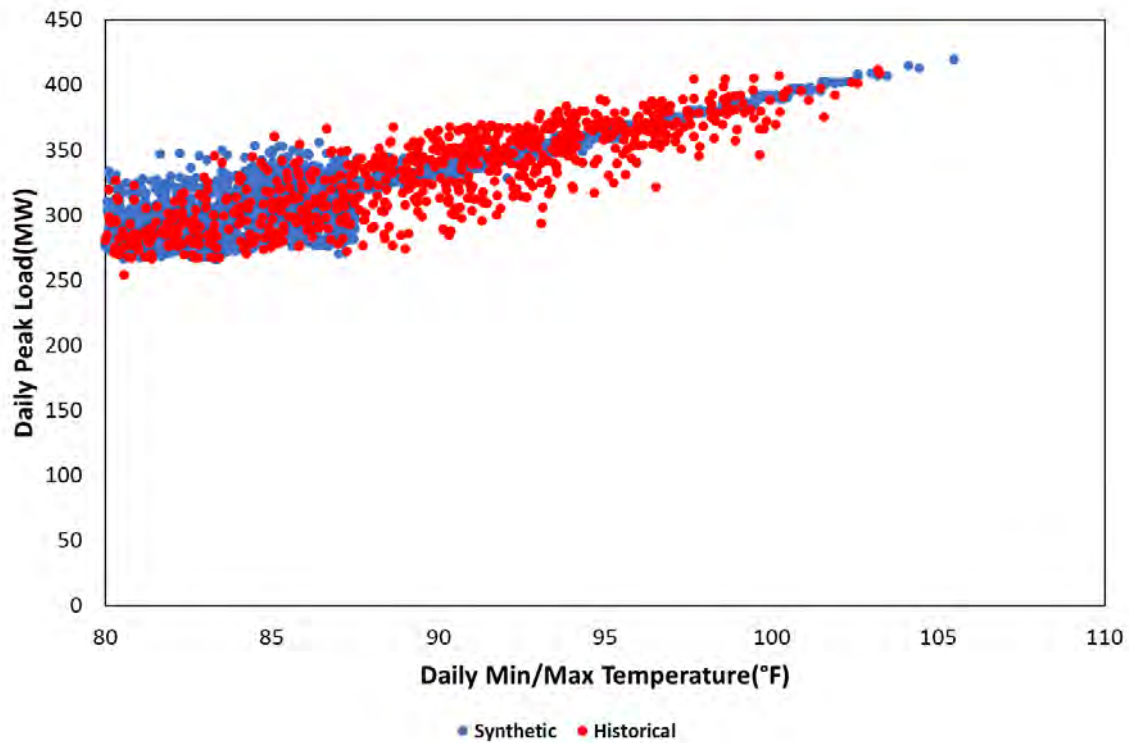


Figure 30. Tri-NM Synthetic vs. Historical Loads for Extreme Temperatures

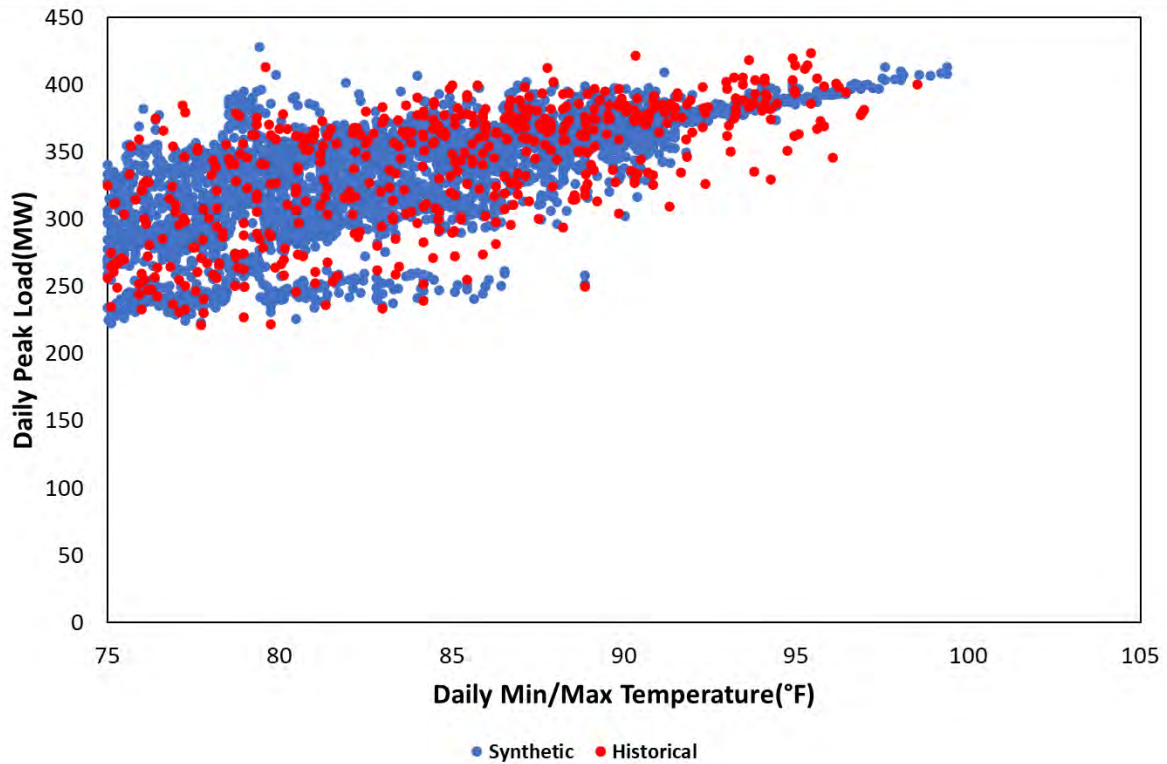


Figure 31. Tri-WYWNE Synthetic vs. Historical Loads for Extreme Temperatures

The development of the 42 synthetic load shapes results in a diverse set of annual peak loads. Within SERVIM, these shapes were scaled such that the median of the last 10 years of annual peak loads will equal the TSGT weather normal forecasted peak load. The figures below show the summer and winter peak load variance resulting from the 42 synthetic load shapes for each of the TSGT load zones. The variance is shown on a percentage basis in terms of its divergence from the 10-year median (a.k.a., weather normal load), sorted from lowest to highest.

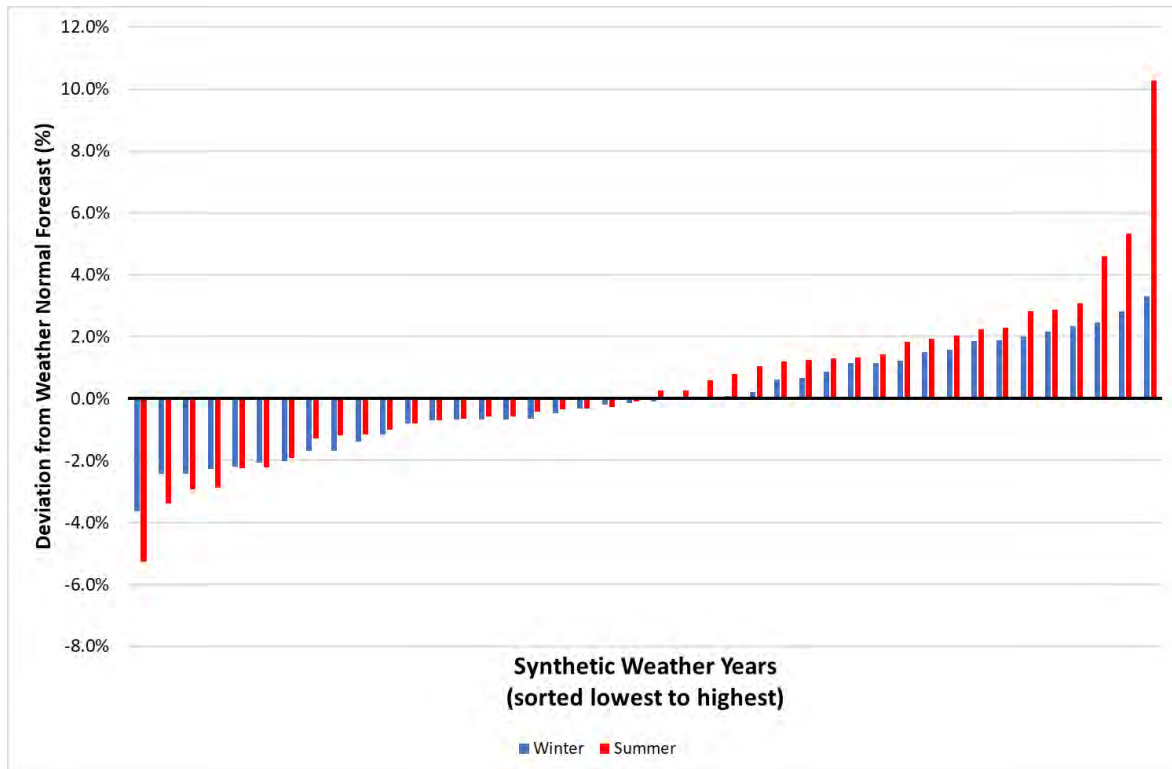


Figure 32. Tri-ECO Peak Load Variance

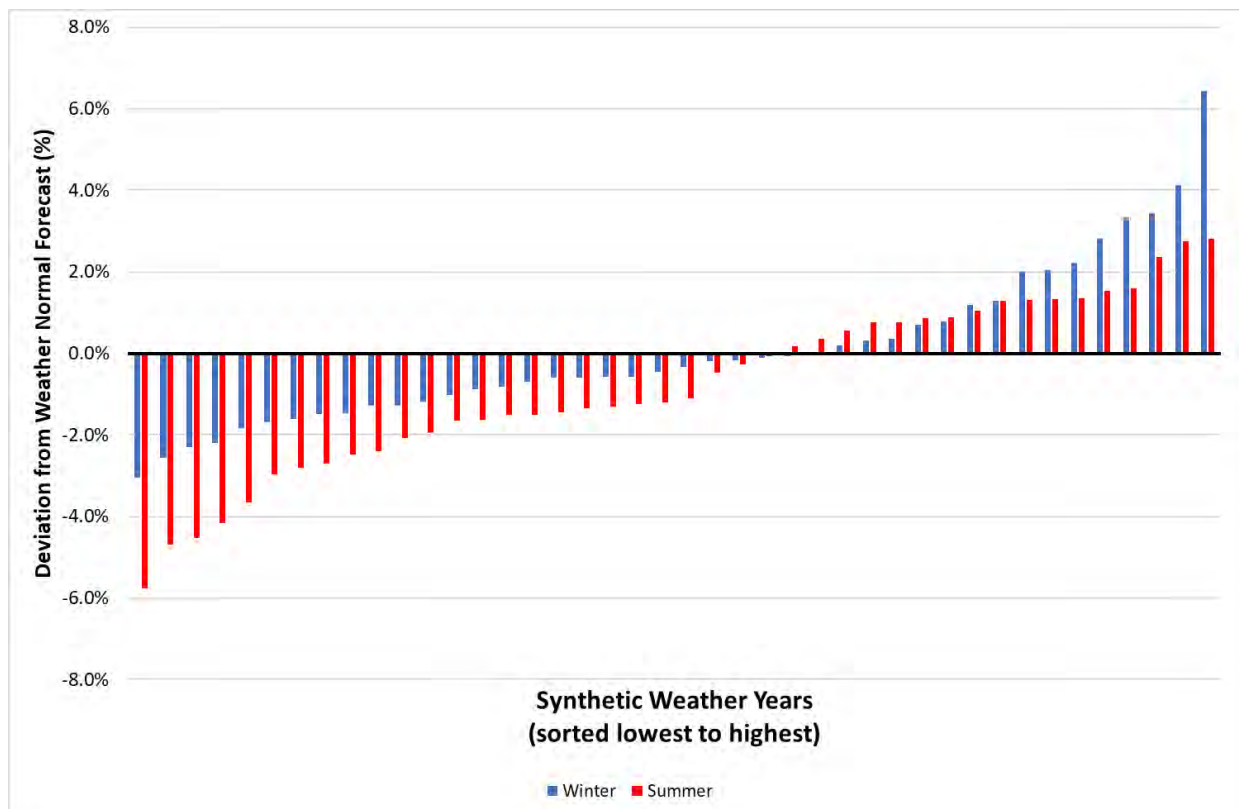


Figure 33. Tri-WCO Peak Load Variance

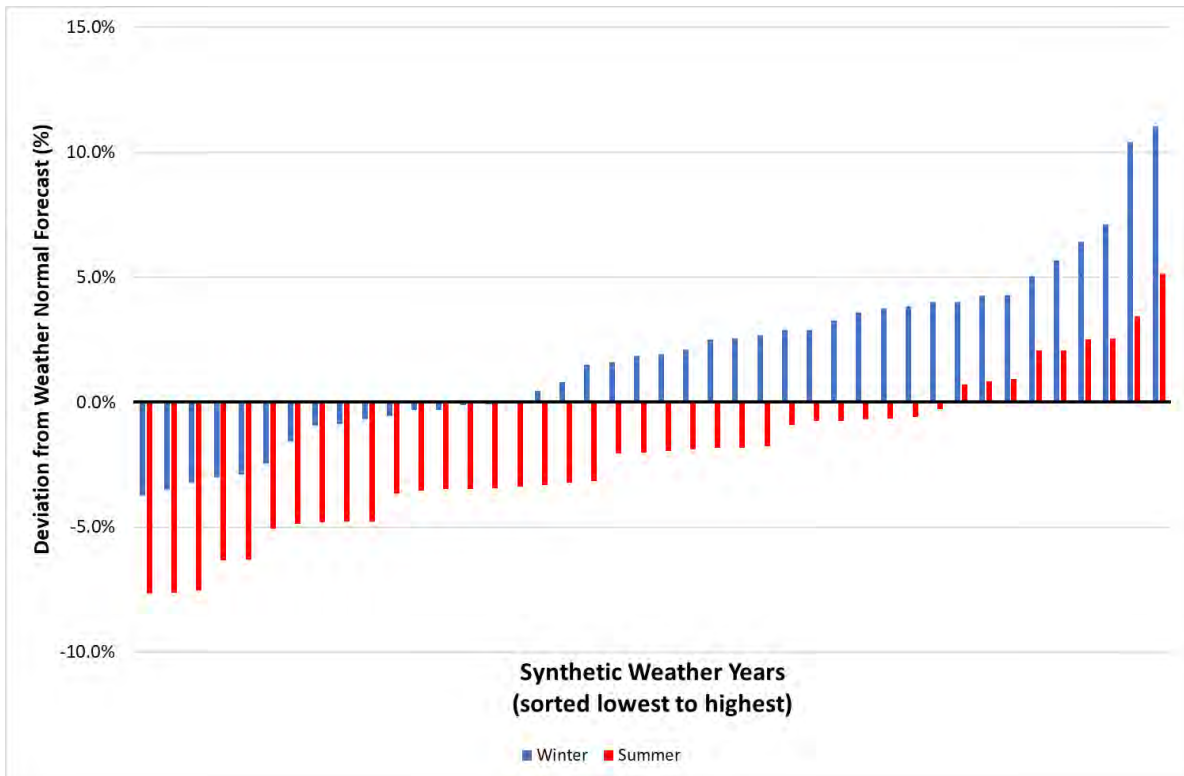


Figure 34. Tri-NM Peak Load Variance

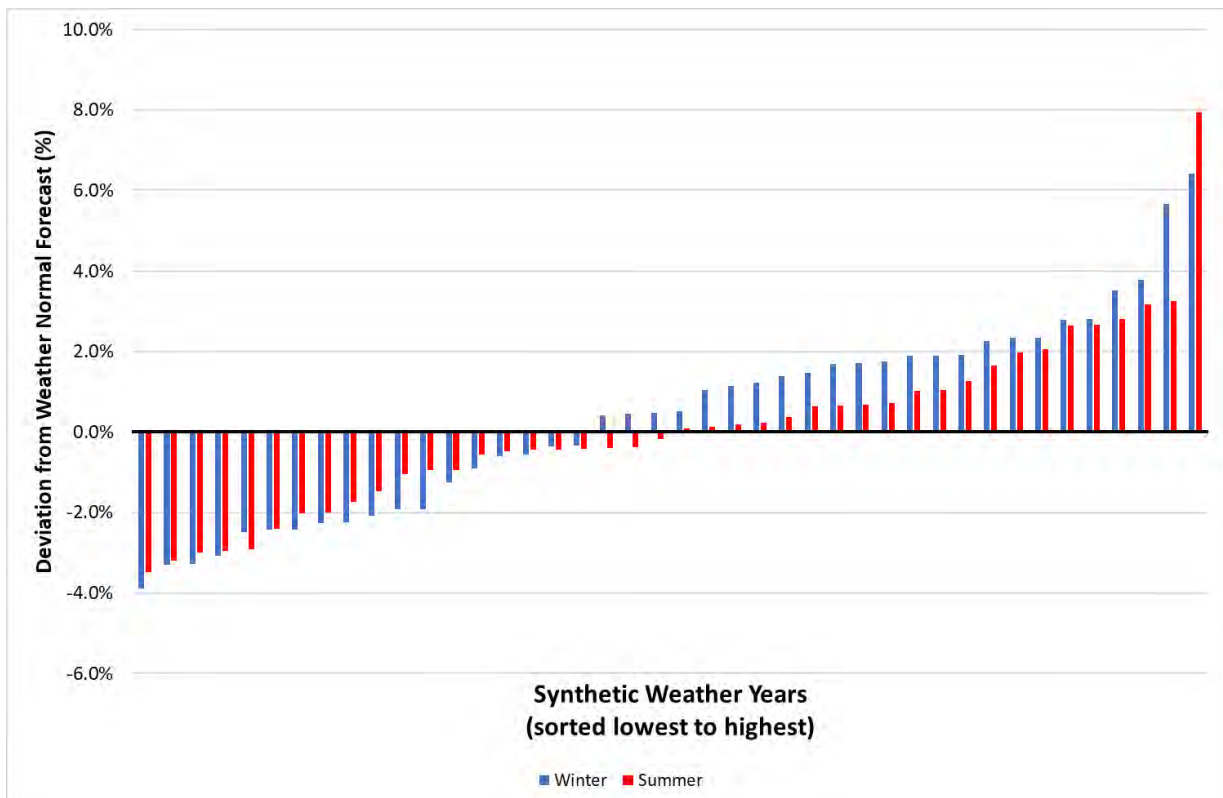


Figure 35. Tri-WYWNE Peak Load Variance

In addition to the raw loads, load modifiers were used to model incremental EE. The table below shows the 12x24 EE profile modeled for the EE programs in the Tri-ECO and Tri-WCO load zones. Values are shown in the percentage of maximum annual EE impact.

Table 3. TSGT EE Shape

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	53.8	48.3	45.7	30.8	39.9	40.1	38.7	41.2	40.0	35.3	28.0	31.3
2	52.3	44.9	43.7	29.6	38.8	39.2	37.8	39.2	38.0	33.5	25.2	29.0
3	51.3	44.2	42.3	30.2	39.6	39.5	38.2	38.9	38.7	32.9	24.4	27.9
4	52.1	44.1	43.3	32.7	41.6	40.4	40.8	39.7	41.5	33.6	25.9	29.9
5	53.8	47.2	47.3	36.2	44.8	42.8	43.6	42.3	45.0	38.2	29.2	33.0
6	57.2	51.0	51.9	40.2	49.9	47.5	48.1	45.5	47.6	42.8	33.4	37.3
7	61.6	55.1	55.3	43.9	53.6	52.1	53.3	49.0	51.3	47.3	37.8	42.2
8	64.8	58.3	59.5	46.5	57.9	58.2	59.8	52.6	53.8	51.3	42.5	46.4
9	67.7	62.5	63.4	49.0	59.2	63.2	66.5	55.3	58.1	54.0	45.7	50.2
10	69.4	66.3	65.1	50.5	62.3	67.4	70.7	60.0	64.4	56.1	47.5	51.9
11	70.3	67.1	68.1	50.8	63.9	72.4	74.2	61.0	68.2	58.8	48.1	53.0
12	70.4	67.4	68.5	52.3	64.8	75.9	75.0	60.9	71.6	60.8	49.0	53.6
13	70.2	67.4	69.2	53.1	68.6	78.1	75.7	61.1	76.0	61.3	49.4	54.0
14	70.9	67.3	69.9	54.0	70.1	79.0	77.6	63.8	77.5	63.3	50.2	53.5
15	70.9	67.0	70.6	54.8	72.2	80.5	80.4	66.7	78.4	64.5	50.7	54.2
16	71.9	68.1	71.1	55.3	73.4	80.5	81.3	70.5	80.5	65.7	51.7	55.6
17	73.3	69.6	72.6	57.4	73.9	81.5	81.5	72.4	79.3	66.4	52.8	56.6
18	76.8	71.1	74.1	58.2	72.4	80.0	81.4	72.7	76.2	65.4	54.5	58.0
19	78.0	72.4	75.7	57.0	68.5	77.0	77.6	69.2	72.6	64.1	55.1	58.7
20	77.8	72.9	74.6	54.7	63.6	69.7	72.7	65.8	67.1	61.5	53.6	57.4
21	74.7	70.8	71.1	49.9	58.5	63.1	65.6	60.1	60.2	56.1	50.1	53.9
22	69.6	66.7	65.6	44.5	51.4	55.3	57.3	53.4	52.5	49.9	44.9	48.3
23	64.1	59.8	58.6	38.1	45.9	48.0	48.3	47.5	46.1	43.7	38.5	41.8
24	58.2	52.4	50.6	33.2	39.6	41.8	42.4	41.7	40.9	38.8	32.8	35.7

The maximum annual EE impact for Tri-ECO in 2030 is 10.1 MW. The maximum annual EE impact for Tri-WCO in 2030 is 3.3 MW.

ECONOMIC FORECAST ERROR

As described in the Study Framework subsection of the Introduction section of this document, five LFE multipliers with their associated probabilities were applied to each of the 42 historical load shapes. The LFE multipliers simulate the expected probability that the peak demand forecast would be missed because of errors in the forecast of economic growth. The multipliers were developed by looking at the historical error in the 4-year out forecast GDP assuming a peak demand sensitivity to changes in GDP of 0.4% per 1% change in GDP. The set of LFE multipliers along with their probability of occurrence used in this study are shown in the table below with a graphic representation in the figure that follows.

Table 4. LFE Model

LFE	Probability
-4%	7.9%
-2%	24.0%
0%	36.2%
2%	24.0%
4%	7.9%

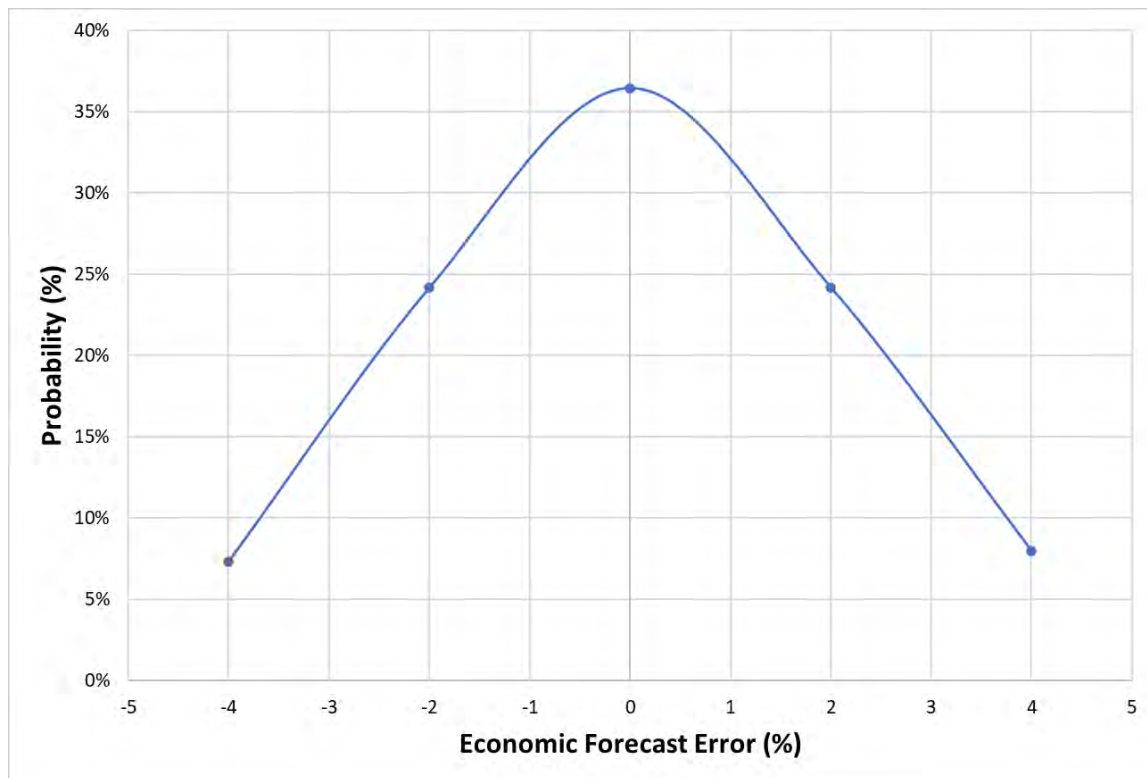


Figure 36. LFE Model

CONVENTIONAL RESOURCE MODELING

Resources for neighboring entities were developed using publicly available information. Resources for TSGT were developed using data provided by TSGT as outlined in the subsections below.

CONVENTIONAL GENERATING CAPACITY

The following table shows a summary of all the Conventional resources assumed to be available to TSGT in 2030, along with their corresponding summer capabilities. This list includes contract purchases and sales. Laramie River and Springerville are jointly owned coal units and the values shown represent the TSGT ownership share.

Table 5. TSGT Conventional Resource Capacities

Unit Name	Unit Category	Load Region	Capacity MW
Basin Ault	Contract Purchase	TRI_ECO	149.0
Basin Losses	Contract Purchase	TRI_WYWNE	8.0
Basin Stegal	Contract Purchase	TRI_WYWNE	119.0
Burlington 1	CT	TRI_ECO	48.0
Burlington 2	CT	TRI_ECO	48.0
Central Valley	Contract Purchase	TRI_NM	0.9

Knutson 1	CT	TRI_ECO	67.0
Knutson 2	CT	TRI_ECO	67.0
Laramie River 2	Coal	TRI_WYWNE	241.0
Laramie River 3	Coal	TRI_WYWNE	243.0
Limon 1	CT	TRI_ECO	67.0
Limon 2	CT	TRI_ECO	67.0
Native ECO	Contract Purchase	TRI_ECO	0.7
Native NM	Contract Purchase	TRI_NM	1.5
Native WCO	Contract Purchase	TRI_WCO	0.5
NWPP Purchase	Contract Purchase	TRI_WCO	0.9
NWPP Sale	Contract Sale	TRI_WCO	-0.4
Pyramid_1	CT	TRI_NM	40.0
Pyramid_2	CT	TRI_NM	40.0
Pyramid_3	CT	TRI_NM	40.0
Pyramid_4	CT	TRI_NM	40.0
Shafer	CC	TRI_ECO	272.0
Small Power Producer	Contract Purchase	TRI_WCO	0.2
Springerville3	Coal	TRI_NM	319.0
SMSG Purchase	Contract Purchase	TRI_NM	0.1
SMSG Sale	Contract Sale	TRI_NM	0.0

With the exception of the three Basin contract purchases, which were modeled based on hourly profiles provided by TSGT, the contract purchases and sales were modeled as fixed injections that varied monthly.

OUTAGE MODELING

Outage modeling consisted of two primary types of outages, planned maintenance outages (PO), and forced outages.

Planned Maintenance – SERVUM can model Pos as either discrete schedules or an annual rate calculated as the percentage of hours in the year. If modeled as a PO rate, SERVUM schedules planned maintenance in seasons where there would not typically be an expectation of reliability concerns. This determination is made by looking at all available weather year load shapes and developing a schedule that is least likely to cause reliability concerns. Maintenance rates were calculated using planned maintenance data provided by TSGT for the conventional resources.

Forced Outages – SERVUM models forced outages using multiple sets of time to fail (TTF) and time to repair (TTR) inputs for both full and partial outages. Each resource has its own set of TTF and TTR inputs that are used to establish that resource's EFOR. Using Monte-Carlo techniques, a TTF value is chosen randomly for each generating resource. That resource is then allowed to operate until it reaches the TTF threshold, at which point it is forced offline. Once it is forced offline, a TTR value is chosen randomly to determine how long the resource will be unavailable. That resource remains

offline until it reaches the TTR threshold, at which point it is once again made available and a new TTF variable is chosen for the resource. With sufficient Monte-Carlo iterations, the EFOR of the resource converges to its expected value.

TSGT provided historical Generating Availability Data System (GADS) data that was used to create an initial set of TTR and TTF values for each of the conventional resources. These TTR and TTF values were then tuned to targeted EFOR values provided by TSGT. The table below shows both the EFOR and the planned maintenance rates used for each conventional resource. All values are shown in percentages.

Table 6. Resource Outage Rates

Unit Name	EFOR	PO Rate
Burlington 1	30.0	0.8
Burlington 2	30.0	0.8
Knutson 1	7.3	5.3
Knutson 2	7.3	5.3
Laramie River 2	9.3	8.4
Laramie River 3	9.3	8.4
Limon 1	6.4	1.5
Limon 2	6.4	1.5
Pyramid_1	8.1	7.5
Pyramid_2	8.1	7.5
Pyramid_3	8.1	7.5
Pyramid_4	8.1	7.5
Shafer	7.6	3.6
Springerville 3	9.2	6.6

HEAT RATES

While heat rates do not have a direct impact on the reliability of the system, it is important to accurately represent the relative dispatch of resources on the system so that outages (which are affected by hours of operation and thus do affect reliability) can be accurately modeled. Heat input requirements are modeled within SERVVM using binomial (a.k.a., A-B-C) heat rate coefficients. Total heat input, average heat rates, and incremental heat rates, therefore, would be determined using the following formulas:

$$\text{Total Heat Input} = A + B \cdot X + C \cdot X^2$$

$$\text{Average Heat Rate} = A/X + B + C \cdot X \text{ and}$$

$$\text{Incremental Heat Rate} = B + 2 \cdot C \cdot X$$

Where X = the output of the resource in MW.

Heat rate coefficients for the conventional resources were provided by TSGT. The resulting average heat rate at maximum capacity is shown in the table below.

Table 7. TSGT Unit Heat Rates

Unit Name	Unit Category	Heat Rate (MMBtu/kWh)
Burlington 1	CT	14.0
Burlington 2	CT	14.0
Knutson 1	CT	11.6
Knutson 2	CT	11.6
Limon 1	CT	11.9
Limon 2	CT	11.9
Pyramid_1	CT	9.7
Pyramid_2	CT	9.7
Pyramid_3	CT	9.7
Pyramid_4	CT	9.7
Shafer	CC	9.3
Laramie River 2	Coal	10.0
Laramie River 3	Coal	10.4
Springerville 3	Coal	10.0

FUEL COSTS

As with heat rates, precise accuracy in fuel costs does not directly impact reliability. However, as with heat rates, the relative cost of one fuel source to another can affect unit operations, which in turn can affect unit outage modeling. Monthly fuel costs were provided by TSGT as shown in the figure below for the 2030 study year in 2030 dollars. Fuel prices for other regions and technologies were determined from publicly available sources.

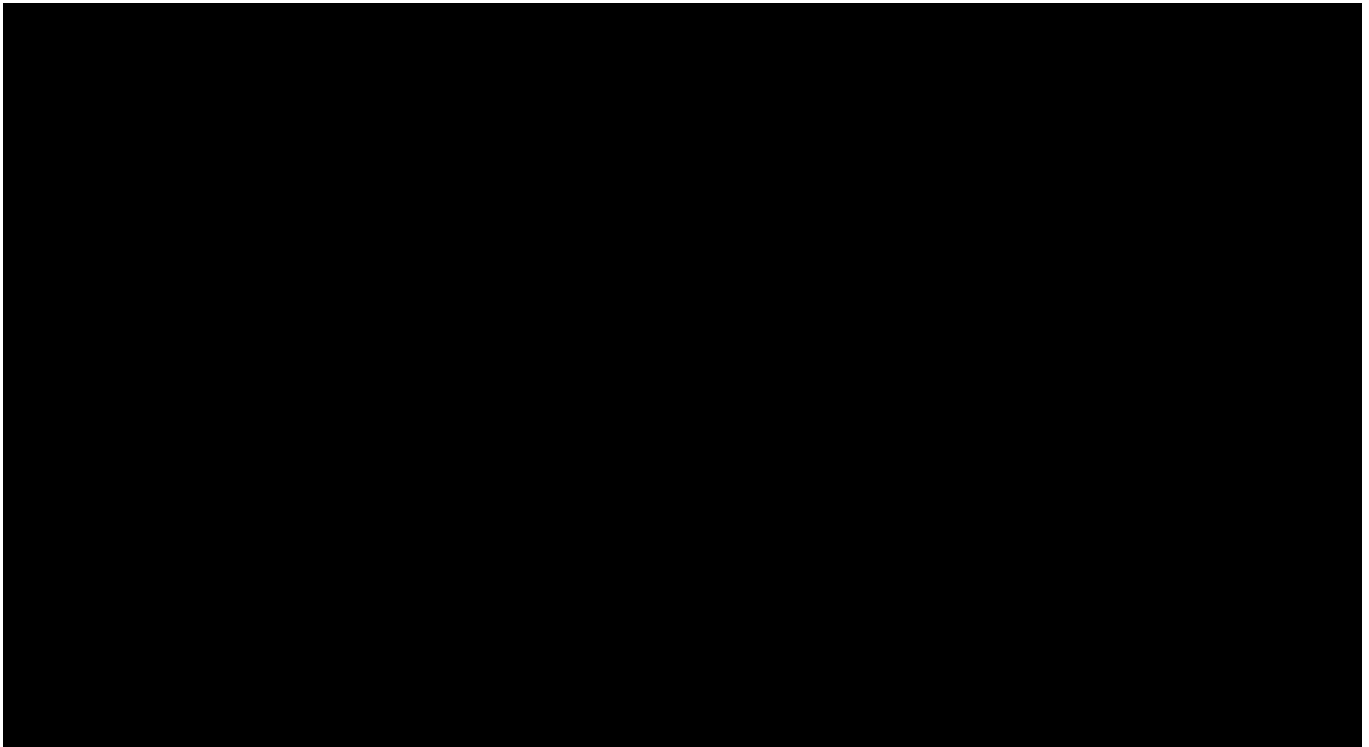


Figure 37. TSGT Monthly Fuel Costs

OTHER CONVENTIONAL DATA

Other conventional resources data provided by TSGT included startup profiles, variable operation and maintenance, minimum capacities, minimum uptime, minimum downtime, and ramp rates. These were modeled as part of the analysis but had no direct bearing on the determination of the reserve margin except to the extent they may have affected hours of operation and thus (ultimately) outage profiles.

CUSTOMER RESOURCE MODELING

The following table shows the distributed generation and partial requirements resources provided by the TSGT retail service provider customers. Except for the solar and wind resources, these were all modeled as fixed injections. The BTMPV represents customer rooftop solar, and values were estimated and assumed based on information provided by TSGT.

Table 8. Customer Provided Resources

Unit Name	Unit Category	Region	Capacity MW
BTMPV_ECO	BTMPV	TRI_ECO	89.4
BTMPV_NM	BTMPV	TRI_NM	36.9
BTMPV_WCO	BTMPV	TRI_WCO	40.9
BTMPV_WYWNE	BTMPV	TRI_WYWNE	35.8
DG_ECO	Distributed Gen	TRI_ECO	9.6
DG_Solar_ECO	Distributed Solar	TRI_ECO	185.6
DG_Solar_NM	Distributed Solar	TRI_NM	21.3

DG_Solar_WCO	Distributed Solar	TRI_WCO	24.7
DG_Solar_WYWNE	Distributed Solar	TRI_WYWNE	0.5
DG_WCO	Distributed Gen	TRI_WCO	10.3
DG_Wind_ECO	Distributed Wind	TRI_ECO	8.0
PR_NM	Distributed Gen	TRI_NM	30.0
PR_WCO	Distributed Gen	TRI_WCO	86.0
PR_WYWNE	Distributed Gen	TRI_WYWNE	47.0

See renewables sections below for details on how the solar and wind profiles were calculated.

SOLAR RESOURCE MODELING

In addition to the BTMPV and distributed solar brought by its retail service providers, TSGT has nine existing and/or planned solar facilities. The following table shows the list of modeled solar resources, with their locations mapped in the figure that follows the table.

Table 9. TSGT Solar Facilities

Unit Name	Capacity
Alta Luna	25
Axial	145
Cimarron	30
Coyote Gulch	140
Dolores Canyon	110
Escalante	200
San Isabel	30
Spanish Peaks 1	100
Spanish Peaks 2	40

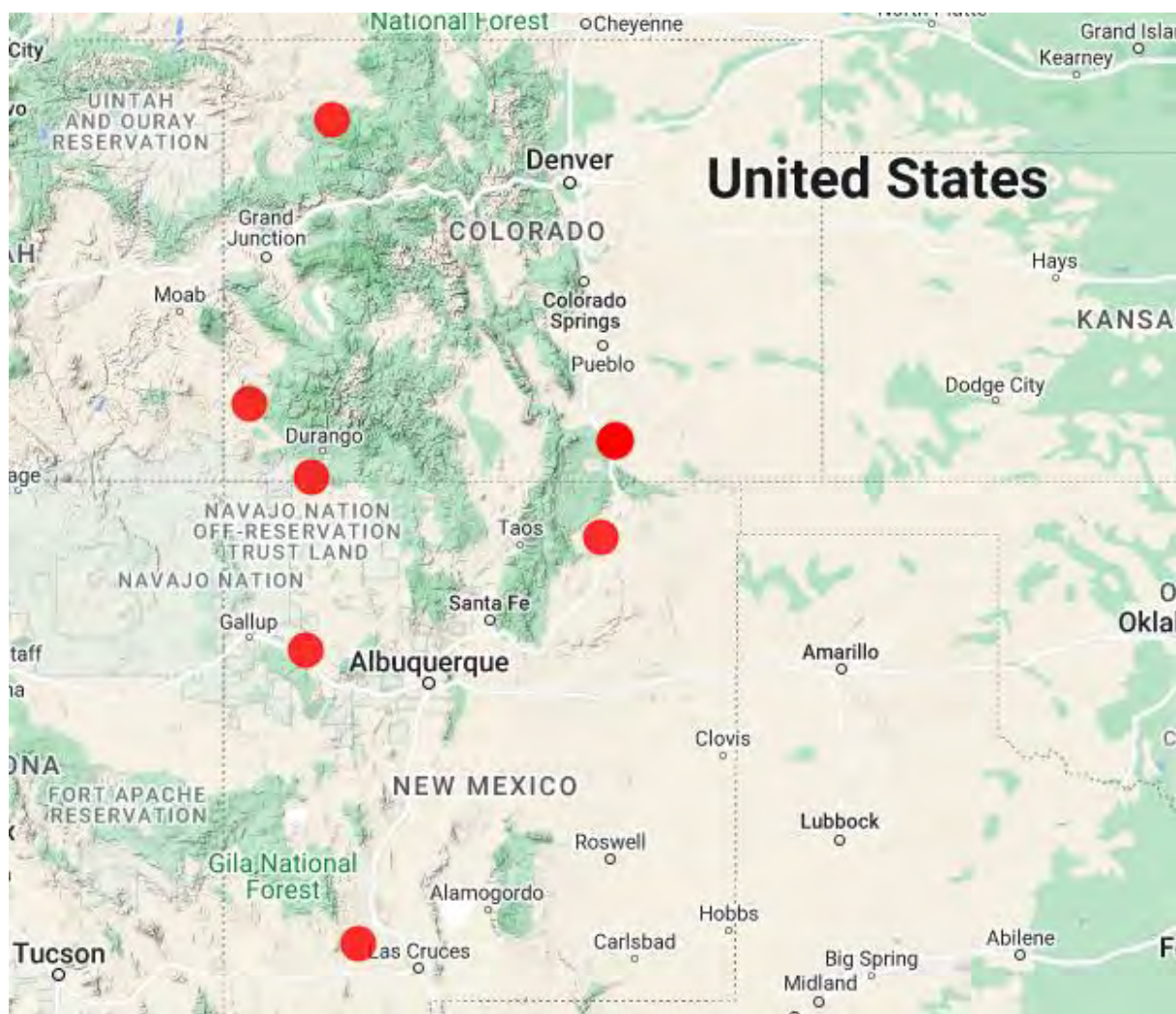


Figure 38. Location of TSGT Solar Resources

GPS coordinates for these locations can be found in the Appendix. Three of the resources, Spanish Peak 1 and 2 and San Isabel, are essentially co-located and were modeled as a single location.

SERVIM models renewable resources as an hourly profile for each weather year.

To create the weather year profiles, irradiance data for these seven locations were downloaded from the NREL National Solar Radiation Database (NSRDB) Data Viewer for the years 1998 to 2020.³ The data obtained from the NSRDB Data Viewer was input into NREL's System Advisor Model (SAM) for each year and location to generate the hourly solar profiles based on the solar weather data for fixed and tracking solar plants.⁴ Solar profiles for 1980 to 1997 and 2021 were selected by using the daily solar profiles from the day that most closely matched the peak load for the APS load out of all the days +/- 2 days of the source day for the 1998 to 2020 interval. The profiles for the remaining years 1998 to 2020 came directly from the solar shape output data from SAM.

³ <https://maps.nrel.gov/nsrdb-viewer/>

⁴ <https://sam.nrel.gov/>

For the BTMPV and Distributed solar facilities brought by the retail service providers, an aggregate profile was created by combining the profiles of all seven locations.

To ensure appropriate capacity and energy contributions, the resulting profiles were then adjusted using the inverter loading ratio (ILR) to achieve the desired capacity factor. The table below shows the list of solar sites with their historical capacity factor and the modeled ILR that achieves that capacity factor. For units with no historical data, the ILR and final capacity factor are assumed as shown to achieve an assumed 30% capacity factor.

Table 10. Solar Facility ILR and Historical Capacity Factors

Unit Name	Historical CF	ILR
Alta Luna	31.7%	1.075
Axial		1.24
Cimarron	23.5%	1.06
Coyote Gulch		1.07
Dolores Canyon		1.11
Escalante		1.03
San Isabel	28.6%	1.04
Spanish Peaks 1		1.1
Spanish Peaks 2		1.1

The figures below show respectively the resulting summer daily output profiles (average of June through September) for tracking, and fixed technologies for each of the seven sites modeled. The profiles assume an ILR of 1.0.⁵

⁵ i.e., the average of all July days including all weather years.

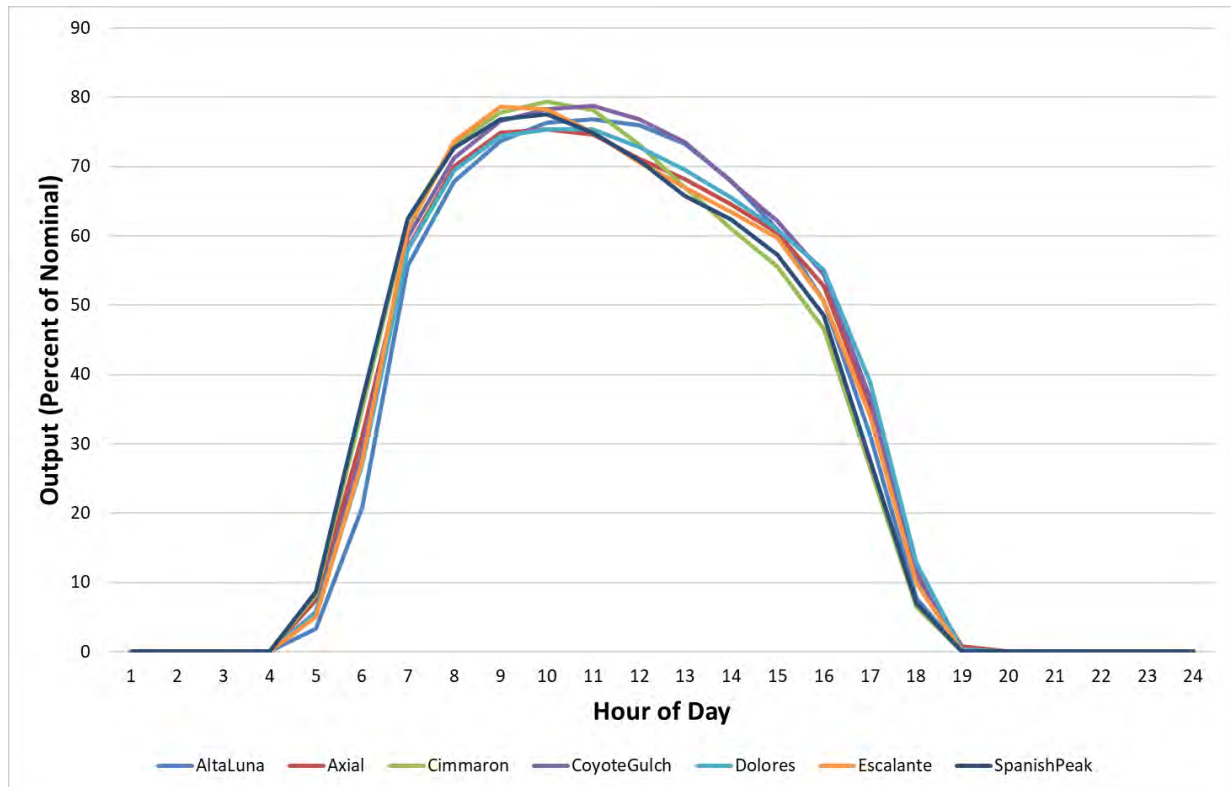


Figure 39. Average Summer Tracking Solar Profiles

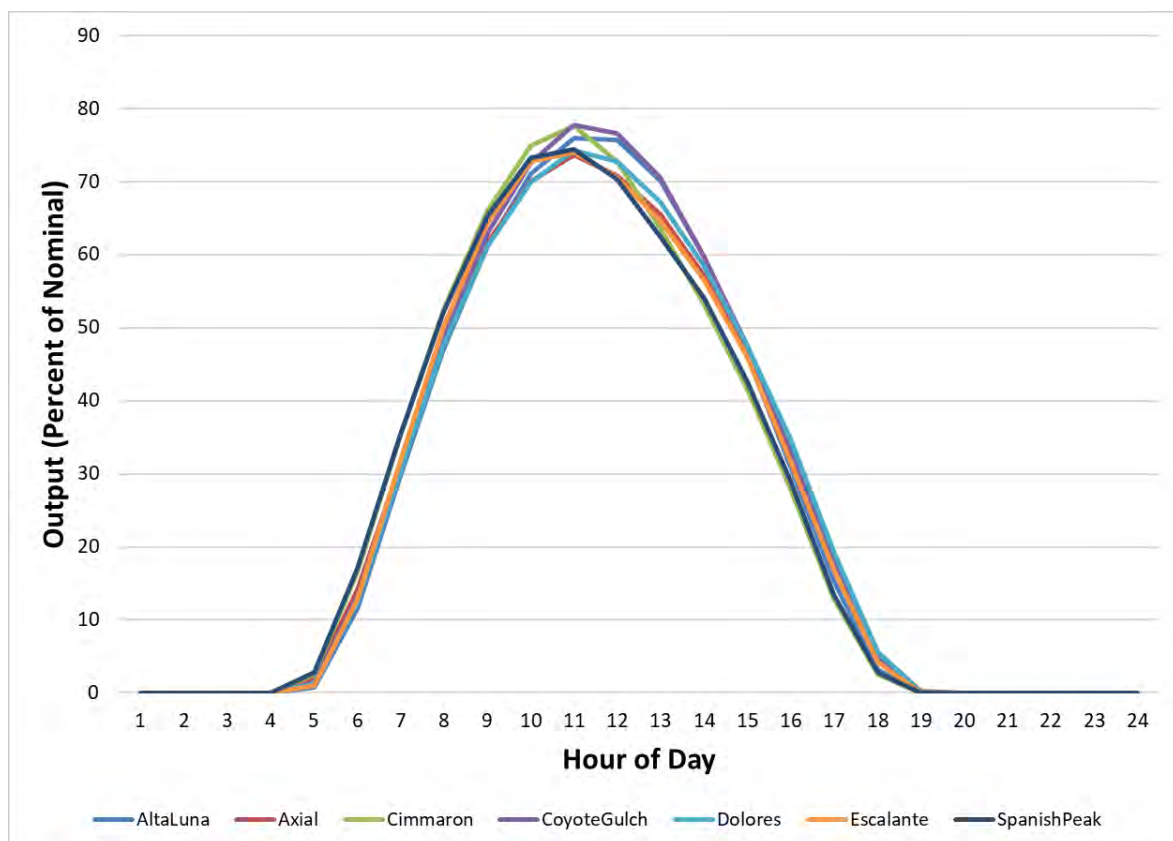


Figure 40. Average Summer Fixed Axis Solar Profiles

WIND RESOURCE MODELING

TSGT has six existing/planned wind resources as well as 200 MW of unspecified future wind capacity as indicated in the table below.

Table 11. TSGT Wind Resources

Unit Name	Capacity
Carousel	150
Colorado Highlands	94
Crossing Trails	104
Kit Carson	51
Niyol	200
Twin Buttes	75
Unspecified Wind	200

All of the existing wind is located in Colorado, while the new wind is anticipated to be in the Tri-WYWNE load zone (assumed for modeling purposes to be in Wyoming).

These projects were modeled assuming a single aggregate wind profile for Colorado and a single aggregate wind profile for Wyoming.

Synthetic wind profiles were developed using NREL's SAM tool for the years 2007-2014. Multiple coordinates were used per profile in each state and were combined to create an aggregate profile per state. NREL data, however, does not always accurately represent historical production data, especially during times of peak load output. Therefore, the NREL profiles were benchmarked using wind production data that was obtained from the EIA.gov website. For Colorado, wind data was downloaded and aggregated for the PSCO BAA. For Wyoming, wind data was downloaded and aggregated for the WACM BAA. The benchmarking process included two primary adjustments to the profiles. The first adjustment was to the overall shape of the profiles so that the aggregate load duration curves matched those of the downloaded production data. The second adjustment was to ensure that the output during peak load times was consistent with the historical data.

The following figures show the monthly output profiles in percent of nominal capacity for Colorado and Wyoming wind projects, respectively.

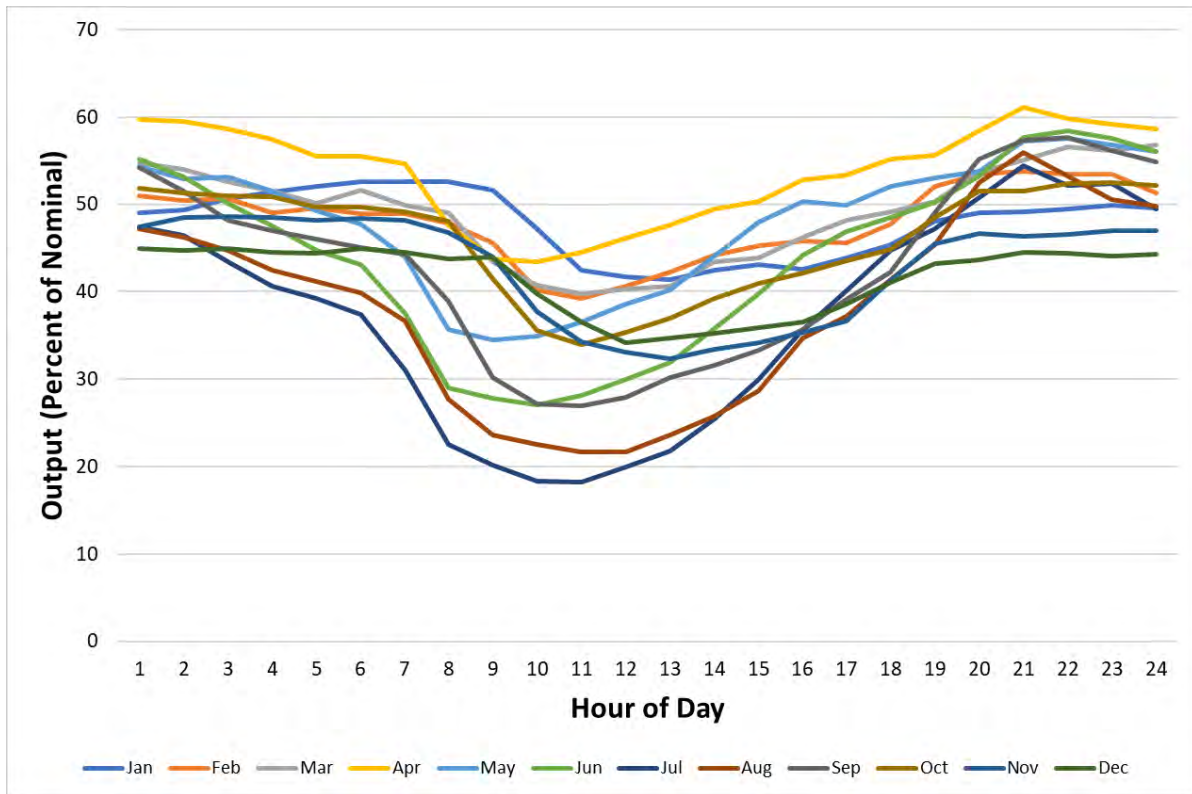


Figure 41. Colorado Wind Profiles

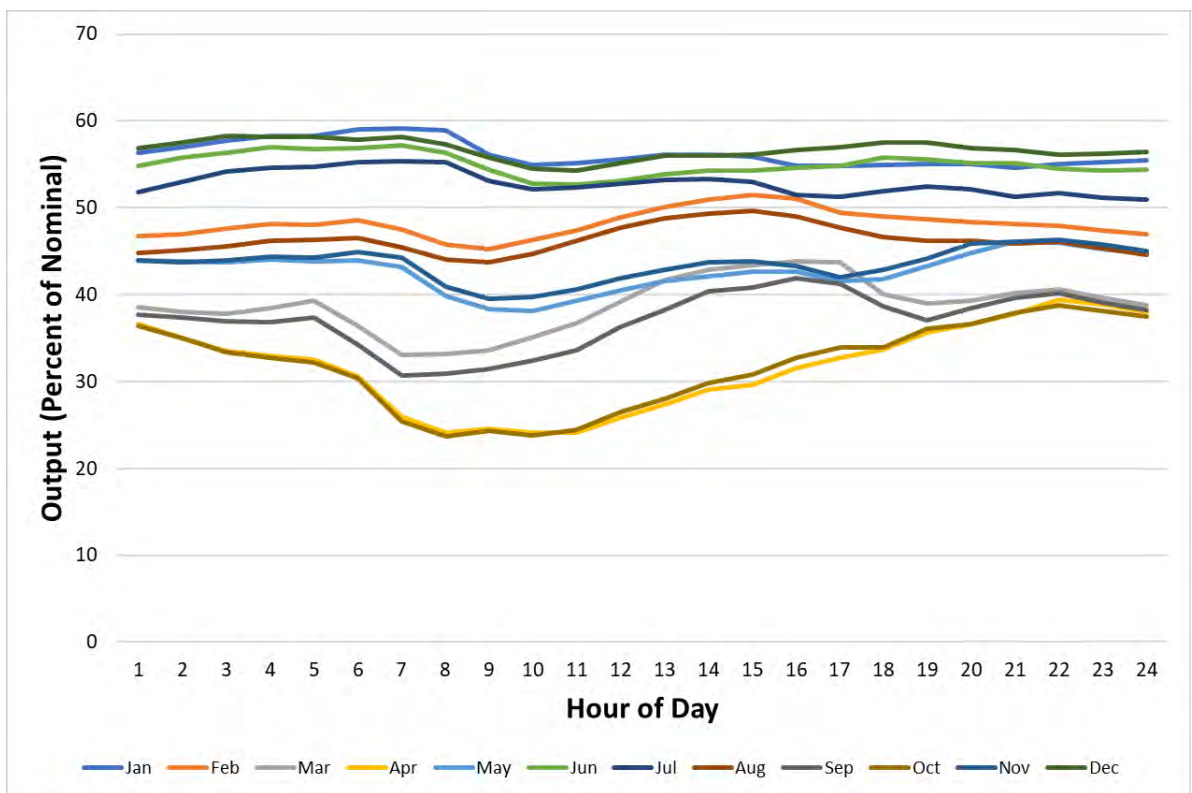


Figure 42. Wyoming Wind Profiles

As with the solar units, individual projects were further adjusted to match the project's historical capacity factor using the ILR. Future capacity was assumed to have a capacity factor of 45% and its ILR was set accordingly. The table below shows the capacity factors and associated ILRs for modeling purposes for each of the TSGT wind projects.

Table 12. TSGT Wind Historical Capacity Factors and ILRs

Unit Name	Historical CF	ILR
Carousel	47.8%	1.090
Colorado Highlands	44.2%	1.008
Crossing Trails	46.3%	1.055
Kit Carson	39.3%	0.895
Niyol	44.3%	1.010
Twin Buttes	47.4%	1.080
Unspecified Wind		1.000

STORAGE RESOURCE MODELING

TSGT does not have any battery storage facilities procured prior to 2030. Thus, no batteries are being modeled for them as part of the Base Case. However, battery storage will be a resource option in the 2023 ERP for the resource planning period and procurements will potentially occur in the resource acquisition period, 2026 to 2031. Thus, for ELCC modeling purposes, batteries were modeled with the following characteristics.

Table 13. Battery Storage Characteristics

Characteristic	Value
Storage Capacity (hours)	4
Charging Capacity (MW)	Same as Nameplate
Able to Provide Ancillary Services	Yes
Cycle Efficiency (%)	85

These battery storage resources were modeled as being available for economic arbitrage. However, during times of reliability risk, the economic arbitrage schedule was allowed to deviate so that the batteries would be discharged to avoid loss of load if storage capacity was available.

Based on recent industry experiences,⁶ grid-scale battery storage resources are expected to have outage rates of up to 15%, with improvements expected as operational experience improves. The long-term anticipated EFOR during hours of dispatch is expected to be in the 5% range. However, outages can occur in either charging or discharging periods, suggesting a 5% outage during both periods. For modeling purposes, therefore, to achieve a 5% overall EFOR in discharge hours, these (and all other) battery storage resources were modeled with a 10% forced outage rate applicable to both charging and discharging hours.

HYDRO RESOURCES

TSGT has one pumped storage hydro (PSH) facility and five hydro purchase contracts from WAPA. The hydro purchase contracts are scheduled on a two-day ahead basis with a contracted minimum and maximum hourly schedule amounts varying by month and monthly available energy amounts that change by month. The Mount Elbert PSH facility and the LAP_ECO WAPA contract share the same transmission export, which is limited to the WAPA contract value. Thus, it is not possible for both facilities to produce at their maximum value simultaneously. Therefore, the PSH facility can only produce energy to the extent the LAP_ECO WAPA contract is not fully scheduled. For this reason, no capacity accreditation is given to the Mount Elbert PSH facility in the PRM calculation. All modeled hydro facilities are shown in the table below.

Table 14. TSGT Hydro Facilities

Unit Name	Unit Category
CRSP_ECO	WAPA Purchase
CRSP_NM	WAPA Purchase
CRSP_WCO	WAPA Purchase
LAP_ECO	WAPA Purchase
LAP_WYWNE	WAPA Purchase
Mount Elbert	PSH

OTHER MODELING ISSUES

Due to time constraints and other factors, there were several items not specifically modeled for this evaluation that could have a minor impact on the resulting ICAP or UCAP PRM. Those items include demand response resources, incremental Beneficial Electrification (BE) load, and the Springerville

⁶ See <https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/APS-RPAC-Meeting-Presentation-102622.ashx?la=en&hash=9AE20E699D178AFCF8AB30BF9C64FFED>, slides 41-46, with emphasis on slide 46, "Specific lessons for battery storage".

hazard agreement that provides a 100 MW back up to Springerville 3 for up to 168 hours. It is anticipated that these and any other potential modeling enhancements will be incorporated in the next iteration of the reserve marginal analysis.

FINAL CAPACITY MIX

The figure below shows the final mix of capacity modeled for TSGT. It should be noted that BTMPV is not a resource available to TSGT and is excluded from their official load forecast. However, it is being modeled here as a resource with the forecast grossed up for the BTMPV.

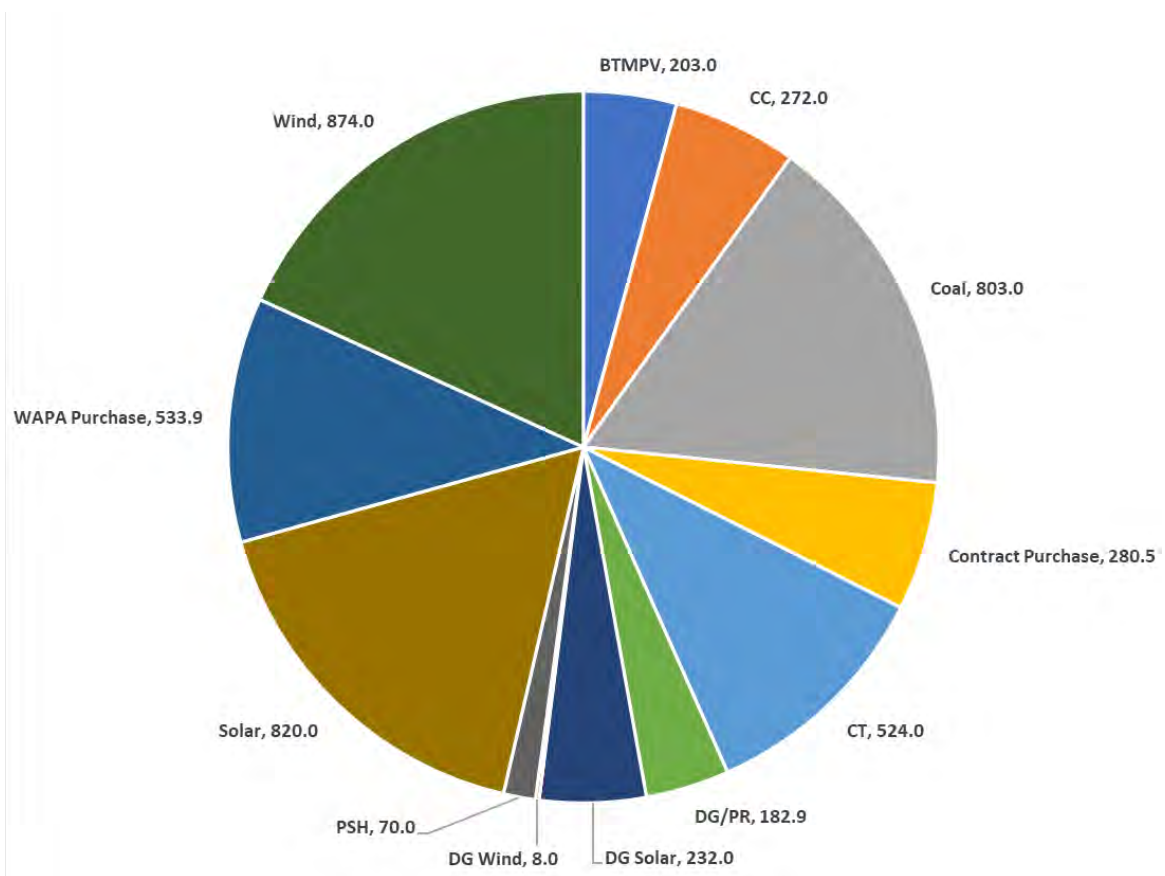


Figure 43. TSGT Capacity Mix (MW)

ANCILLARY SERVICES MODEL

Per information provided by TSGT, the ancillary services model included only 64 MW of Contingency Reserve-Non Spin in Colorado (split between Tri-WCO and TRI-ECO) and 67 MW of Contingency Reserve-Non Spin in Tri-WYWNE. In addition, 3% of load was included as a load following up target. Neither had a direct impact on the PRM because no reserves were maintained during load shed events.

STUDY APPROACH AND RESULTS

The two objectives of this study were to (a) establish the PRM for the TSGT system and (b) determine the ELCC for various penetrations of solar, wind, and BESS resources.

DEPENDABLE CAPACITY REQUIREMENTS

The PRM for the TSGT was determined for the 2030 study year. To determine the PRM, Combustion Turbine (CT) expansion capacity was added to TSGT until the system reached 0.1 days/year LOLE. This required making multiple runs with differing amounts of expansion CTs and then trending the resulting LOLE values so that the 0.1 LOLE point could be interpolated from the results. This established the total amount of dependable capacity required to maintain a reliable system. For TSGT, 59.2 MW of capacity was needed above their existing resource portfolio, to achieve 0.1 days/year LOLE.

PRM is an accounting exercise based on the amount of dependable capacity. To perform this accounting exercise requires the determination of the ELCC of the existing portfolio of renewable resources as described in the subsection below.

EXISTING PORTFOLIO ELCC AND RESULTING PRM

Determining the portfolio ELCC required the following steps:

1. Remove the full portfolio of solar and wind (including distributed solar and wind)
2. Iteratively add back perfect capacity until system returns to 0.1 days/year LOLE, and
3. Calculate portfolio ELCC by dividing the perfect added capacity by the nameplate capacity removed.

For the TSGT system, the total amount of renewable resources removed was 1,934 MW.⁷ The analysis described above resulted in a portfolio ELCC value of 350 MW or 18.0%.

Using the nameplate of the conventional resources plus the ELCC resources plus the expansion capacity, determination of the PRM (in %) is determined as follows:

$$\text{PRM} = [(\text{Conventional Capacity} + \text{ELCC Capacity} + \text{Adjustment Capacity}) / \text{Peak Load} - 1] * 100.$$

Those calculations are shown in the table below:

⁷ Because the resources are behind the meters for the load seen by TSGT or included in its load forecast, BTMPV was not included as part of the portfolio ELCC calculation.

Table 15. PRM Calculation

Component	Capacity	ELCC	Equivalent Capacity
Conventional Resources	2596.3		2596.3
ELCC Resources	1934.0	18%	348.1
Adjustment Capacity			59.2
Total Capacity at Target Reliability			3003.6
Coincident Peak Load			2210.9
Reserves			792.8
ICAP PRM			35.9%

This PRM was developed using a coincident peak load that was developed as follows:

$$\text{CPL} = \text{Load}^8 - \text{EE}.$$

This PRM represents a significant increase in PRM over TSGT's current PRM requirement of 15%. One reason for the difference is in accounting. In the past, TSGT has variously treated the capacity brought by their member systems and their customers, sometimes giving them full or partial credit and at other times giving them no credit. However, to the extent the modeling has depended upon that capacity being available, Astrapé believes such capacity should be counted in the PRM calculation. Removing that capacity from the accounting process above may lower the apparent reserve margin, but the required capacity would stay the same. Thus, the true PRM should include all capacity relied upon to achieve the target LOLE. Beyond the accounting, however, the key drivers in this PRM include the high EFOR of the conventional coal and CC resources as well as significant shaft risk due to the size of these units relative to the TSGT peak load. To demonstrate this impact, two additional analyses were performed. First, the ELCC of the CC and coal units were calculated. Then, a calculation was performed to demonstrate the impact on PRM if these units were smaller (aka no shaft risk) and had a considerably lower EFOR.

The table below shows the ELCC of the coal and CC units.

Table 16. Coal and CC ELCC

Resource	EFOR	ELCC
Shafer CC	7.8%	64.4%
Springerville Coal	9.2%	63.8%
Laramie River Coal	9.3%	58.8%

⁸ For purposes of PRM calculation, load was reduced for customer BTMPV consistent with TSGT's forecasting process.

These are significantly lower than expected, indicating a large impact due to shaft risk in addition to the EFOR impact. Assuming these units were small enough that shaft risk was not an issue and their EFOR were in the 5% range, the ELCC for these units would be expected to be in the 90% range. Making this assumption, it is possible to calculate what the PRM would be if these two drivers were somehow mitigated. The table below shows this calculation.

Table 17. Impact of High EFOR and Shaft Risk

Component	ELCC	MW	Impact
CC	64.4%	272	175.168
SPV	63.8%	319	203.522
LRS	58.8%	484	284.592
Weighted	61.7%	1075	663.282
Target ELCC	90.0%	1075	967.5
Impact MW			304.2
Base Case Reliable MW			3003.6
Adj for EFOR/Shaft Impact			2699.4
Coincident Peak Load			2210.9
PRM			22.1%

By capacity-weighting the existing ELCCs, it is shown that the total capacity value of these facilities is ~663 MW. If, however, their ELCC were 90%, their total capacity value would be ~968 MW. Thus, there is an ~304 MW impact associated with these two drivers. Mitigating against these drivers would thus lower the total reliable MW requirement by 304 MW, resulting in a PRM of 22.1%. This lower PRM is more consistent with other reserve margins in the region.

To demonstrate the relationship between reserve margin and LOLE visually, the figure below shows the LOLE as a function of the ICAP reserve margin. Assuming the 1 day in 10 criteria, the figure shows 0.1 LOLE falling at a reserve margin of ~35.9%.

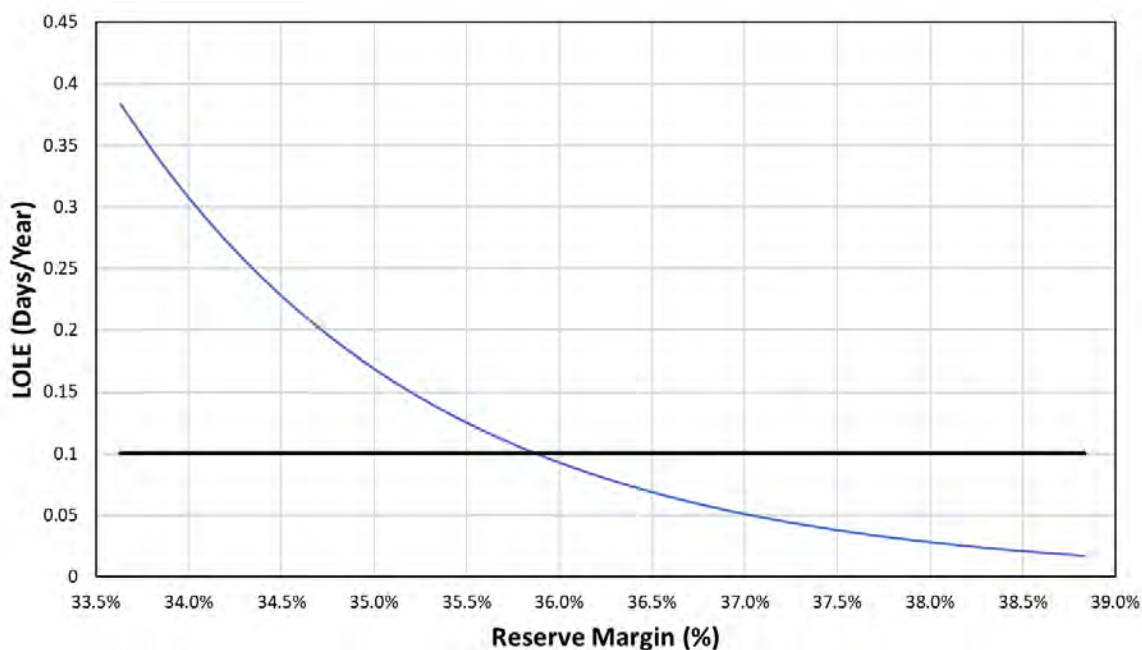


Figure 44. LOLE Analysis

As demonstrated in this graph, LOLE decreases with increased reserve margin. As more capacity is added to the system, reliability improves. The point at which the graph crosses 0.1 days/year LOLE marks the target PRM.

With ICAP accounting, the effects of forced outages on conventional resources are embedded in the PRM. The ELCC resources, however, are being represented by their perfect capacity equivalent. Thus, potential changes in system EFOR resulting from a change in system mix as well as changes in the penetration of renewable resources can cause changes in the PRM. Given the current environment of increasing penetrations of renewable resources, that means PRM is expected to change over time.

An alternative accounting approach that attempts to stabilize the PRM by removing the effects of average forced outages is called UCAP accounting. UCAP accounting discounts the capacity of conventional resources by 1-EFORd for the conventional resources. The table below shows the UCAP Capacity for the TSGT conventional resources.

Table 18. TSGT UCAP Capacity

Unit Category	Nameplate MW	1-EFORd	UCAP MW
CT	524.0	96.9%	507.5
CC	272.0	93.7%	254.8
Coal	803.0	89.4%	717.8
UCAP Resources	1599.0	92.6%	1480.1

The table below shows the base case PRM assuming UCAP accounting using the UCAP capacity from above.

Table 19. Base Case UCAP PRM Accounting

Component	Capacity	UCAP/ ELCC	Equivalent Capacity
Firm Resources			997.3
UCAP Resources	1599.0	92.6%	1480.1
ELCC Resources	1934.0	18.0%	348.1
Adjustment Capacity			59.2
Total Capacity at Target Reliability			2884.6
Coincident Peak Load			2210.9
Reserves			673.8
ICAP PRM			30.5%

However, EFOR (and EFORD) is based upon the average outage rate of the resource fleet. There are times when actual outages are higher than average and other times when they are lower than average. This creates an asymmetry in the outage profile, resulting in a true contribution to reliability that is less than the UCAP capacity. As such, UCAP accounting still results in a PRM that can change with significant changes to the system mix and penetration of renewable resources.

Both accounting methods are targeting identical 0.1 LOLE reliability conditions and represent the same portfolio. The only difference is in the PRM accounting.

Because of this significant shaft risk, LOLE is being driven by outages as much as weather or load. As such, LOLE is expected across all weather years as demonstrated in the figure below.

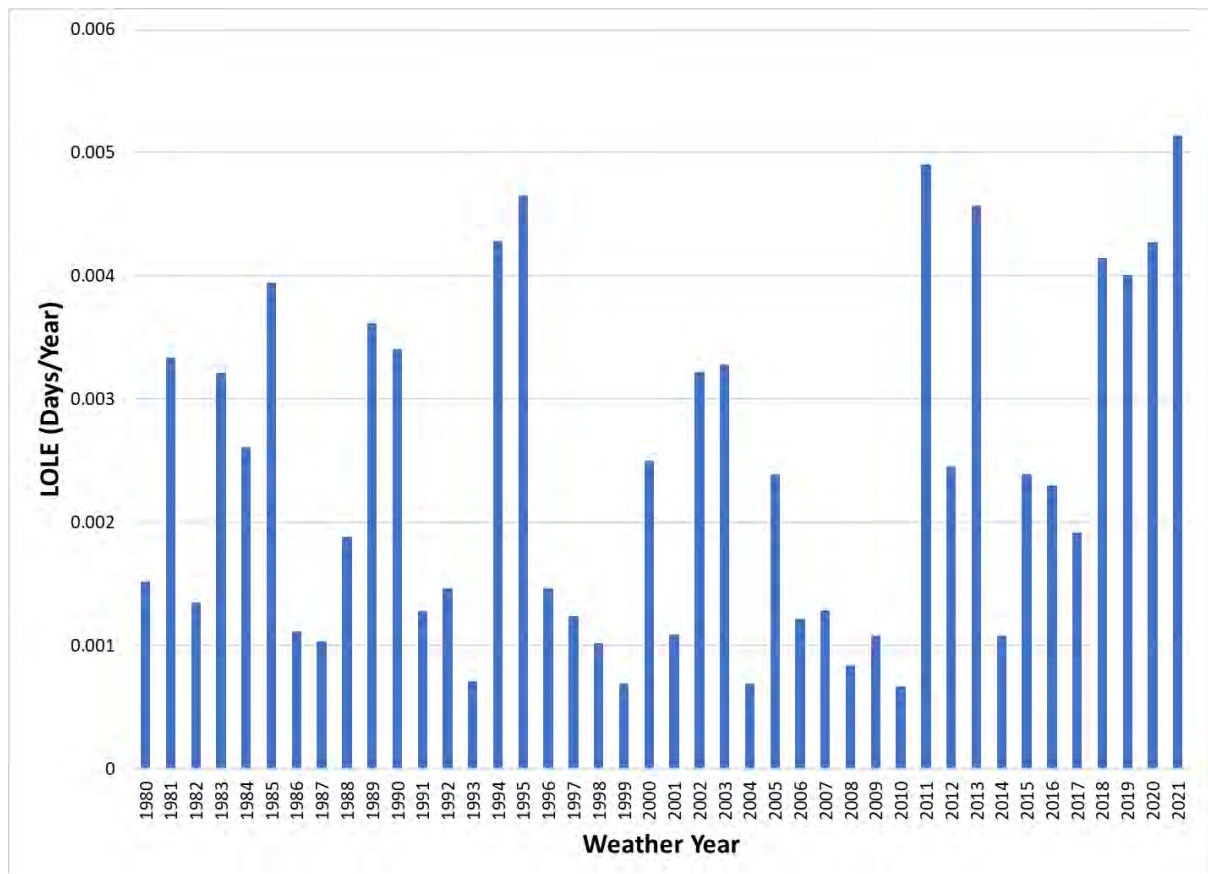


Figure 45. LOLE by Weather Year at PRM

To demonstrate the risk of loss of load by season, the figure below shows the breakdown of loss of load expectation by month. As the figure shows, the majority of the reliability risk for TSGT occurs in the summer months, although there is some risk in all months due to the shaft risk exposure associated with forced outages.

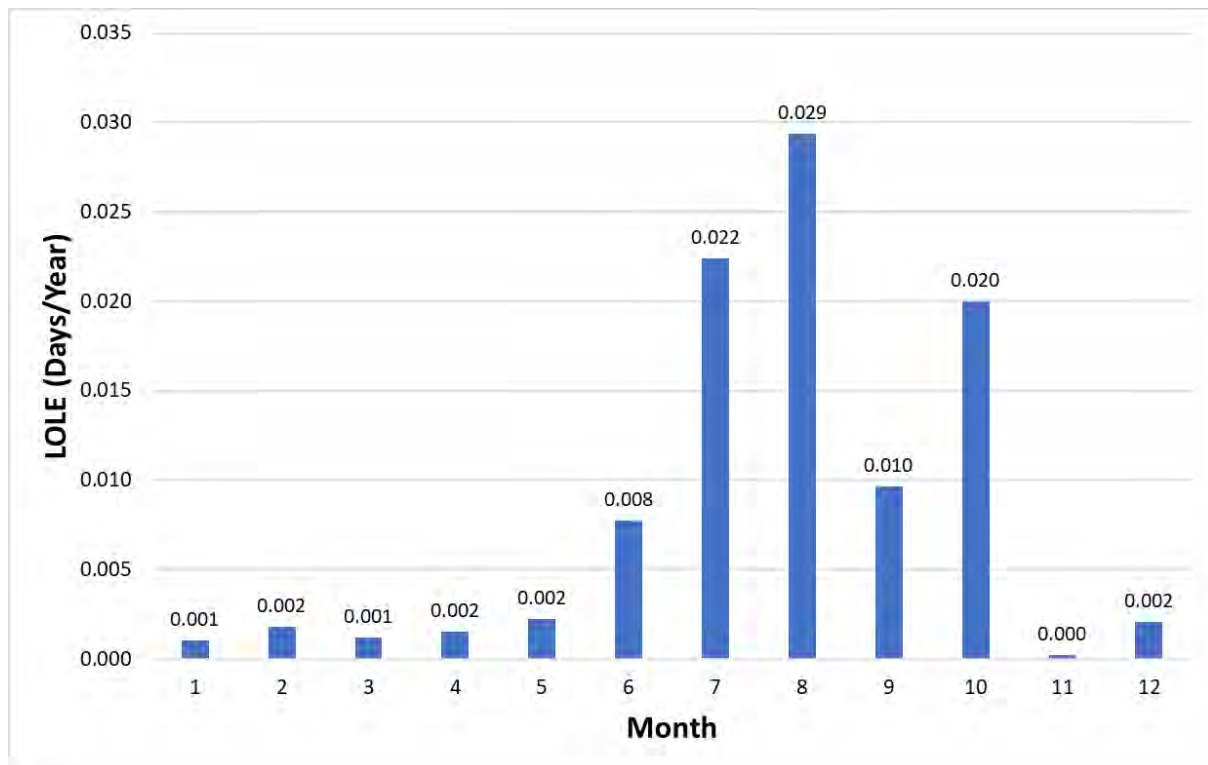


Figure 46. LOLE by Month at PRM

PRM RECOMMENDATION

Based on this analysis and based on TSGT's decision to use UCAP accounting for PRM purposes, a UCAP PRM of 30.5% is recommended. However, given the transitional period prior to 2030 in which departing member load has not yet left the system and coal units have not yet retired, a transitional PRM consistent with the shaft-risk and EFOR adjusted ICAP PRM of 22% can be supported.

TECHNOLOGY SPECIFIC ELCC

In addition to the base case portfolio ELCCs needed for the PRM calculation, analyses were performed to calculate average and marginal ELCCs by technology for solar, storage, and wind up to the following penetrations:

- Solar – 2,000 MW
- 4-hour Battery – 1,000 MW
- Wind – 2,000 MW

These ELCCs were first calculated within SERVIM for a subset of penetrations according to the following matrix. SERVIM runs were made for solar and battery combinations represented by the X marks for wind penetrations of 0 MW, 500 MW, 1,000 MW, 1,500 MW and 2,000 MW. The blue X mark was not run for the 0 MW wind penetration. The green X marks were only run for the 0 MW wind penetration.

Table 20. Matrix of SERVVM ELCC Runs

		Battery Storage (MW)					
		0	100	250	500	750	1000
Solar (MW)	0	X	X	X	X	X	X
	250	X					
	500	X					
	750	X					
	1000	X			X		X
	1250	X					
	1500	X					
	1750	X					
	2000	X			X		X

For purpose of developing this matrix, the BTMPV, customer distributed solar, and customer distributed wind were all considered pre-existing (i.e., underlying the test system), such that these penetrations would be considered incremental to those underlying penetrations of solar and wind.

Using pyramid smoothing techniques, this series of matrices were then expanded into a large three-dimensional dense matrix containing total portfolio values for any combination of solar, wind, and battery penetrations up to the specified maximum penetrations.

In addition to these solar, battery, and wind scenarios, additional scenarios were evaluated to determine the ELCCs for each of the following:

1. Customer Distributed DG,
2. Energy Efficiency, and
3. 10-hour Batteries.

ELCC METHODOLOGY

To determine the average ELCC for each of these scenarios, each scenario was evaluated in accordance with the following steps.

1. Develop a reference case for the scenario set (e.g., all the matrix solar/battery/wind scenarios used the same reference case)

- a. Remove the technology class(es) being evaluated (e.g., remove all existing solar, battery, and wind resources).
 - b. Iteratively add back perfect capacity until system returns to 0.1 days/year LOLE.
2. For each scenario, add back the penetration of the technology class(es) being evaluated (e.g., for the 500 MW solar scenario, add back 500 MW of solar).
3. Iteratively remove perfect capacity until the system returns to 0.1 days/year LOLE.
4. Divide the total amount of capacity added by the amount of perfect capacity removed to get the average ELCC for the scenario.

ELCC RESULTS

The result of this pyramid smoothing associated with the sparse matrix of SERVIM ELCC values was a dense three-dimensional matrix of portfolio capacity values from which average and marginal ELCCs can be determined for any desired penetration of solar, wind, and battery within the range of penetrations evaluated. The resulting dense matrices of capacity values and ELCCs are too large to be included in this report. However, TSGT has been provided a tool that allows the average and marginal ELCC to be determined for any desired penetration of solar, wind, and battery.

To illustrate the representative results of the analysis, the figure below shows a surface plot of the portfolio capacity value as a function of both solar and battery penetration. The surface plot assumes zero penetration of wind.

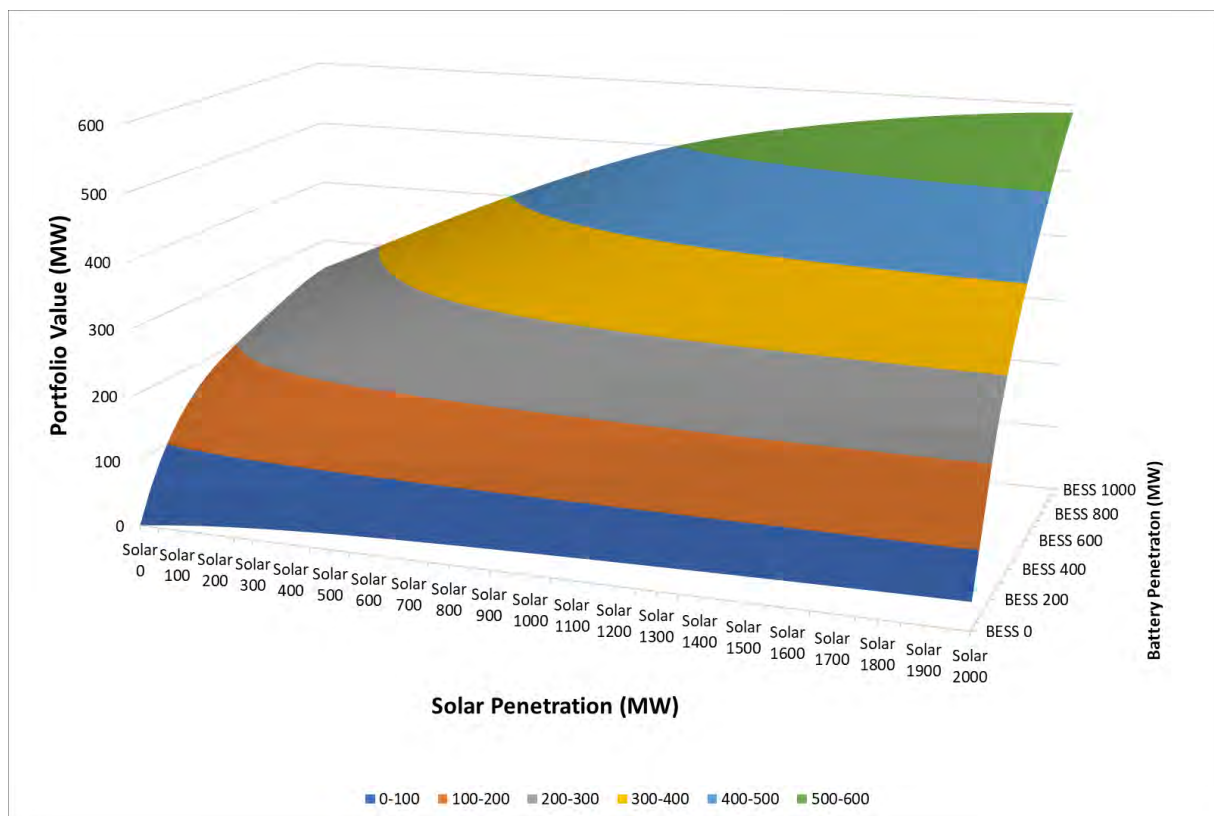


Figure 47. Portfolio Capacity Value at Zero Wind Penetration, Illustrative

To interpret this surface plot, find a desired solar penetration along the solar-axis and a desired battery penetration along the battery-axis. Then go up the vertical axis to find the total portfolio value. For example, at 2,000 MW of solar, the portfolio value is approximately 50 MW (roughly midway through the blue band). As battery penetration increases, capacity value increases to approximately 600 MW (the top of the green band). As penetrations of solar and battery increase, the total portfolio value increases. However, due to the declining improvement in capacity value, there is a flattening out of the surface along both the solar and wind axes. This will result in a declining technology specific ELCC as will be shown below.

Plots for various penetrations of wind would be similar. For example, the figure below shows the same surface plot at 2,000 MW of wind.

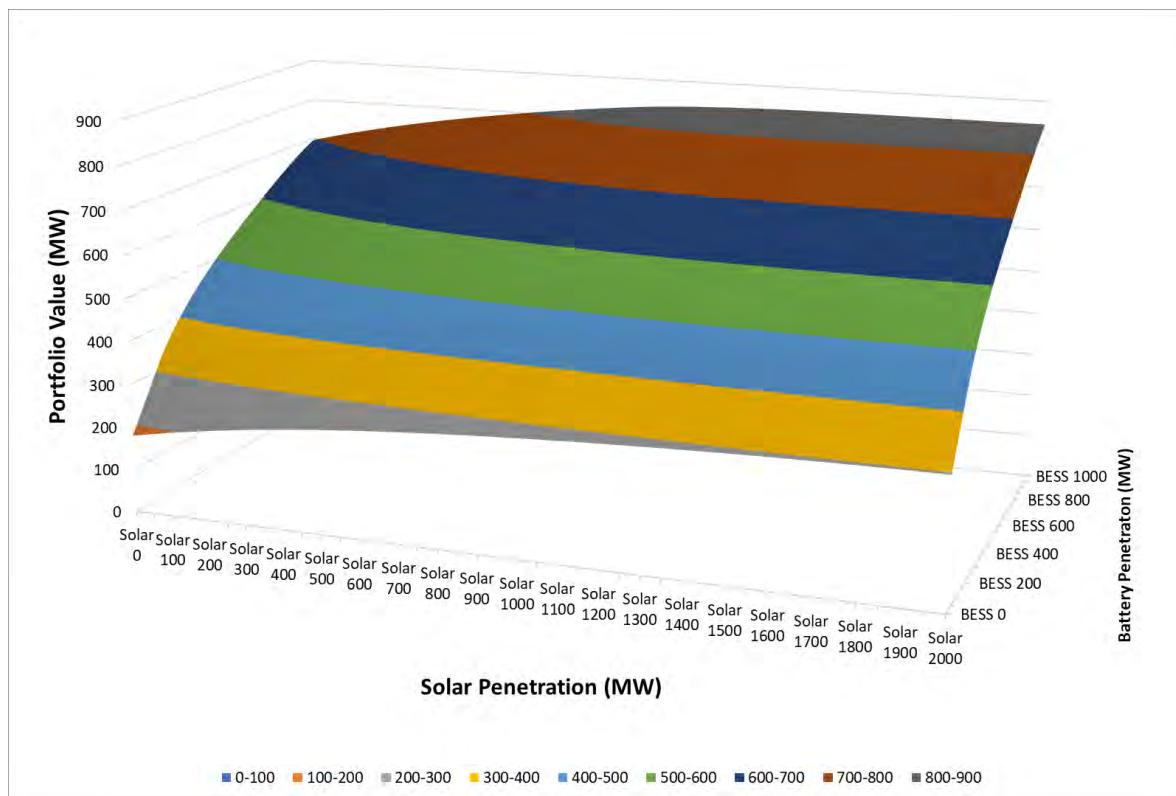


Figure 48. Portfolio Capacity Value at 2000 MW of Wind, Illustrative

From the dense matrix of portfolio capacity values, average and marginal ELCCs can be developed for any combination of solar, battery, and wind up to the maximum studied penetrations of 2,000 MW solar, 1,000 MW battery, and 2,000 MW wind. This is accomplished by finding the capacity value from the three-dimensional matrix corresponding to the desired mix of solar, wind, and battery. This is then compared to the sum of the single-technology capacity values of the desired solar, wind, and battery penetrations to establish the synergistic benefit or antagonistic harm as appropriate. That benefit/harm is then allocated among the individual technologies to get the average capacity value for

the combined technologies. Marginal capacity values are calculated using the above method applied to small, incremental steps, which are then divided by the step-size to get the marginal ELCC. These marginal capacity values are then integrated to obtain the average capacity value and associated ELCC. This proprietary method is included in the ELCC tool provided to TSGT.

As an example, the following charts show the average and marginal ELCCs for solar, wind, and batteries, respectively. For illustrative purposes, the assumed penetration of the non-subject technology in each case was 1,000 MW for solar and wind and 500 MW for batteries. For example, in the solar chart, wind is at 1,000 MW and batteries are at 500 MW.

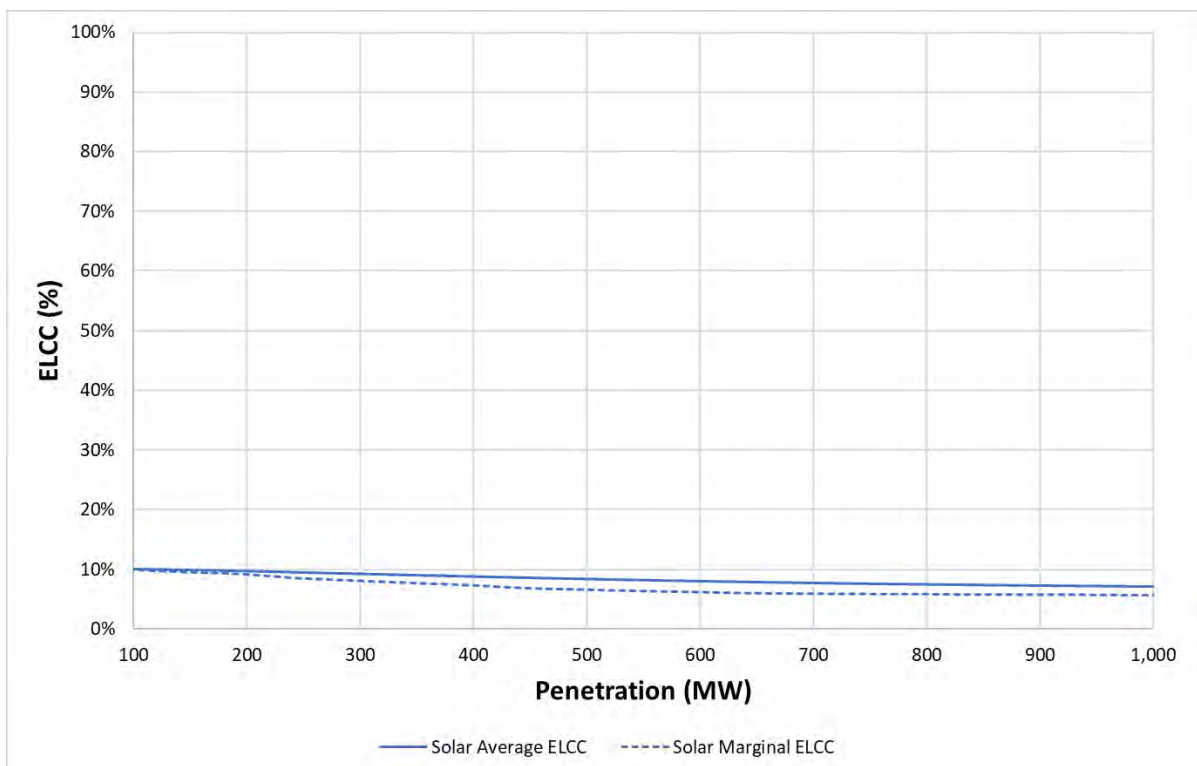


Figure 49. Solar ELCCs at 1,000 MW of Wind and 500 MW of Battery

As mentioned previously, the flattening of the surface with increased solar penetration results in a declining average and marginal ELCC. Solar ELCCs for TSGT are very low due to the significant underlying BTMPV and customer distributed solar penetrations. Although ELCC will never strictly go to zero, it will asymptotically approach zero, resulting in a flattening of the marginal ELCC curve at higher penetrations.

The wind chart is shown below.

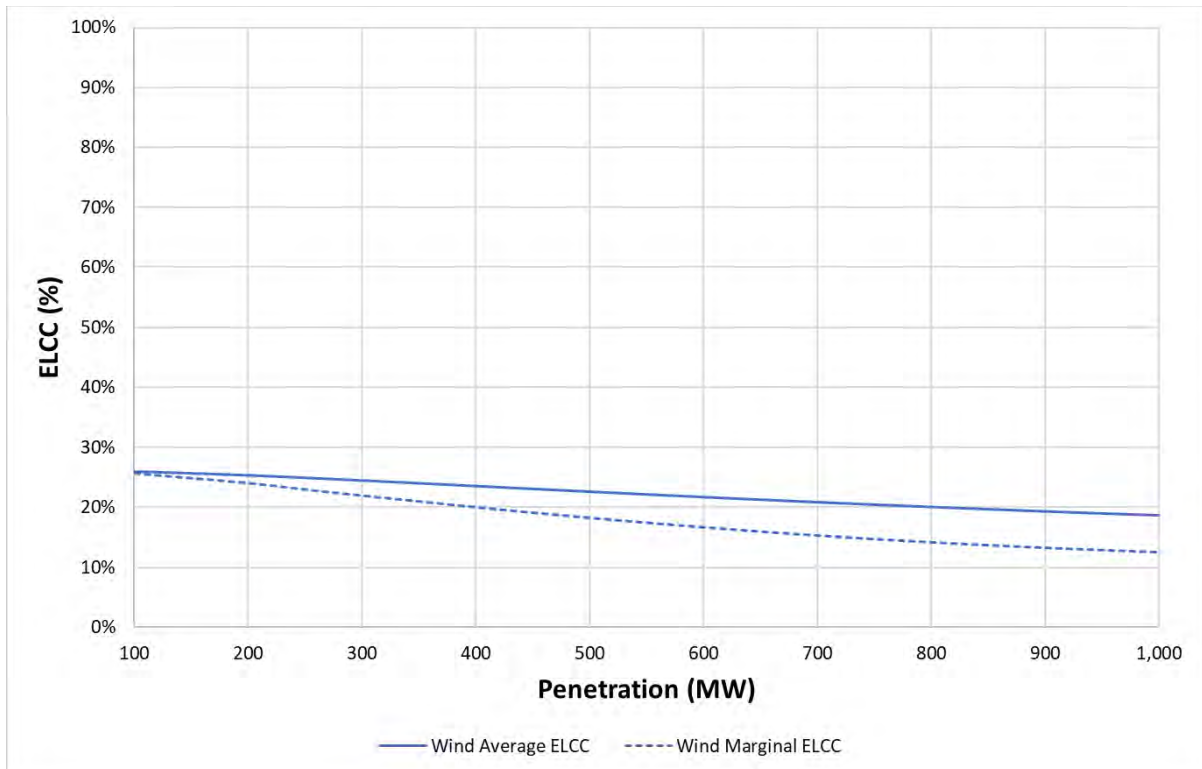


Figure 50. Wind ELCC at 1,000 MW of Solar and 500 MW of Battery

Finally, the battery chart is shown below.

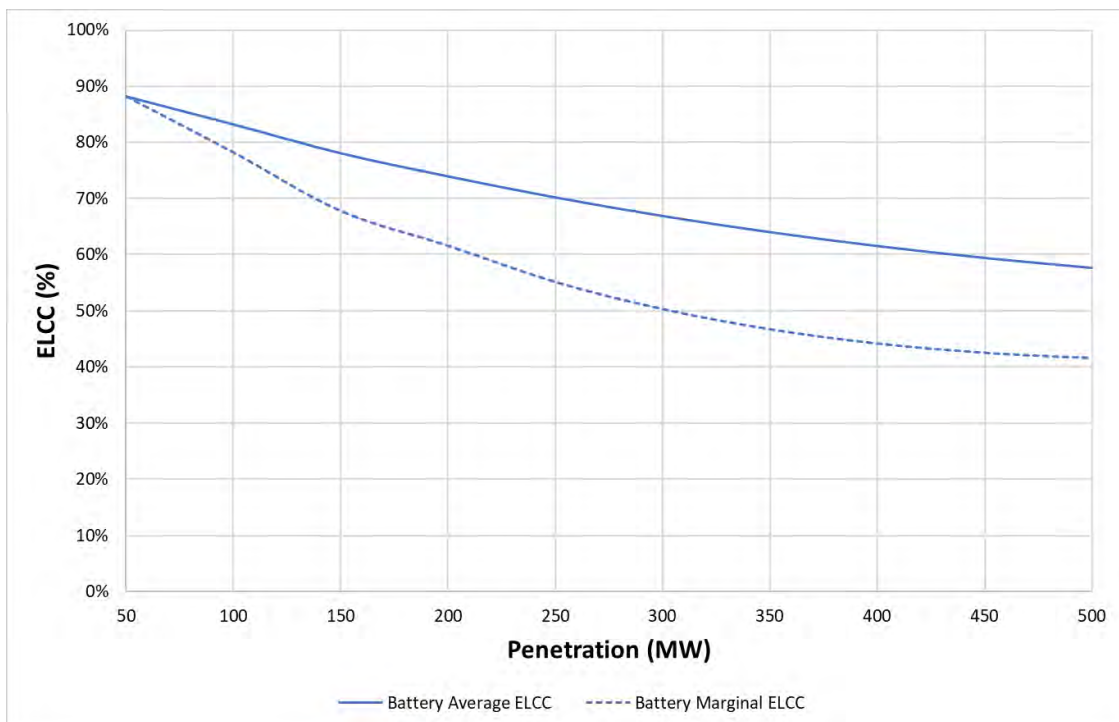


Figure 51. Battery ELCC at 1,000 MW of Solar and Wind

In addition to these scenarios, ELCC scenarios were evaluated for several other components, including customer DG solar, EE, and 10-hour batteries.

To determine the ELCC of the customer DG solar, the reference case with all TSGT renewables was used as a starting point. Using that reference case, DG solar resources were removed and replaced with perfect capacity until the system returned to 0.1 days/year LOLE. This resulted in an average ELCC for the customer DG solar of 35.15%. This is considerably higher than the TSGT solar because it is presumed to be “first in the queue” relative to the TSGT solar.

To determine the ELCC of the incremental EE, the existing EE was removed from the ELCC reference case to establish a reference case for the EE ELCC evaluation. Because the existing EE portfolio of approximately 13 MW is too small to accurately run an ELCC, a 100 MW block of EE was evaluated. This block of EE was added to the system and perfect capacity removed until the system returned to 0.1 days/year LOLE. This resulted in an average ELCC of 97.5% for the EE block.

Finally, three penetrations of 10-hour battery were evaluated. The three penetrations evaluated were 200 MW, 400 MW, and 600 MW. However, these ELCC values were calculated assuming an underlying penetration of 400MW of 4-hour batteries and base case solar and wind penetration assumptions of 820 MW for solar and 790 MW for wind. The figure below shows the average ELCC for 10-hour batteries for each of the three penetrations evaluated.

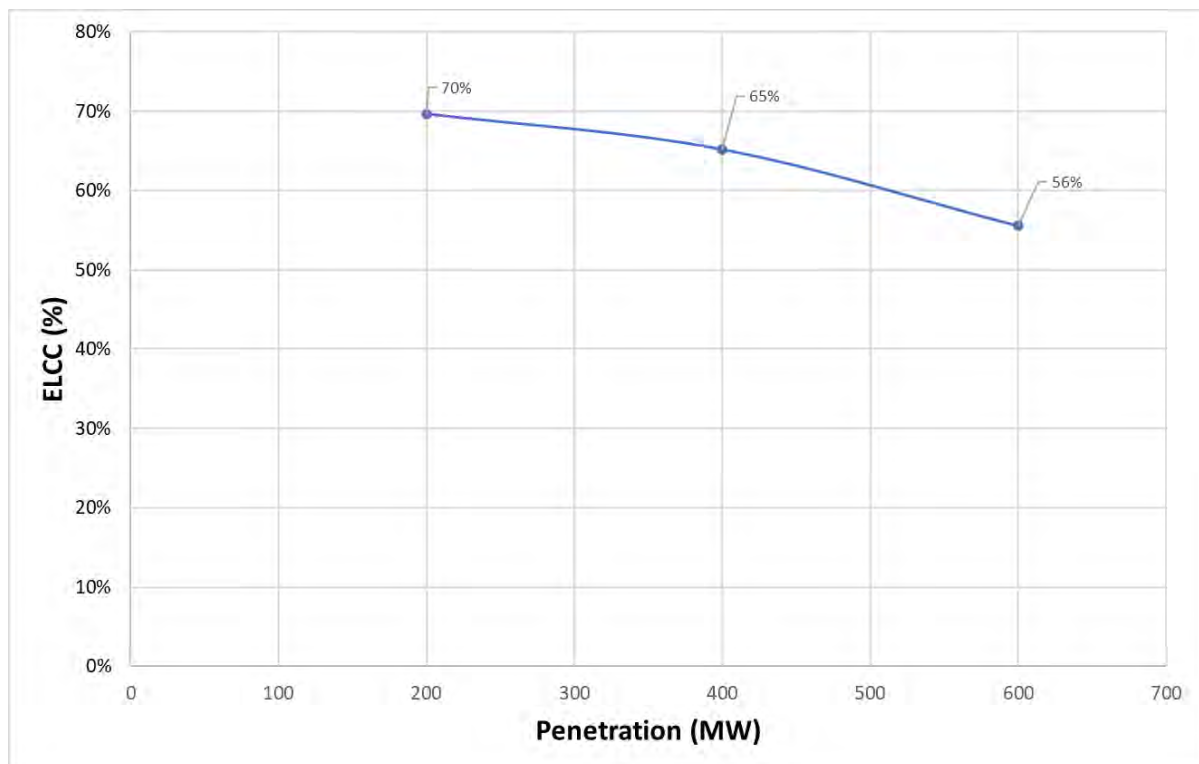


Figure 52. 10-Hour Battery Average ELCC

CONCLUSIONS

Upon examination of the study analysis, a UCAP PRM of 30.5% is warranted based on the most common industry reliability standard of 0.1 LOLE. Although this is considerably higher than the existing PRM, the differences can be attributed to accounting differences, modeling differences, and the increase in shaft risk associated with the loss of significant load responsibility. Based on an analysis of the impact of the high EFOR and shaft risk, a transitional PRM of ~22% for use prior to the retirement of certain coal facilities and the departure of certain member loads can be supported.

Regarding ELCCs, the results are as expected given the size and characteristics of the TSGT system. The very low solar ELCCs are a result of the assumed underlying rooftop and member system distributed solar receiving credit as the first tranche of solar along with the relatively small size of Tri-State's peaking load compared to online and under contract solar generation. As stated above, the order of analysis for ELCC purposes is not an issue for TSGT since the ultimate concern is the total portfolio capacity value counted towards the PRM. The lower storage ELCCs are a result of the fact that LOLE risk is driven in part by outages, resulting in longer duration EUE events.

APPENDIX

PCAP PRM Accounting

Neither ICAP nor UCAP truly reflect the reliability contributions of conventional resources (i.e., is not a perfect capacity equivalent) as evidenced by the ELCC calculations of the coal and CC resources in the results section above. Variability in outages results in some peak days having higher than average outages, resulting in a larger disparity between the true reliability contribution of the conventional fleet and the implied reliability contribution of EFORD. For TSGT in particular, shaft risk also contributes, because of the size of its coal and CC units relative to the peak load. Furthermore, UCAP does not stabilize the PRM against changes in renewable penetration. The most stable PRM accounting, therefore, utilizes PCAP accounting, in which all resources are discounted by their perfect capacity equivalent, or their ELCC. The table below shows the base case PRM assuming PCAP accounting. Only load is considered since EE would be treated as an ELCC modifier similar to resources.

Table 21. 2026 Base Case PCAP Accounting

Unit Category	MW
Total PCAP Capacity	2350.9
Coincident Peak Load	2221.3
Reserves	129.5
PRM	5.8%

Solar Modeling

The table below shows the GPS coordinates for each of the nine existing sites.

Table 22. Solar GPS Coordinates

Unit Name	GPS Coordinates
Alta Luna	32.57, -107.46
Axial	40.3, -107.77
Cimarron	36.47, -104.63
Coyote Gulch	37.04, -108.02
Dolores Canyon	37.71, -108.75
Escalante	35.42, -108.09
San Isabel	37.37, -104.48
Spanish Peaks 1	37.38, -104.46
Spanish Peaks 2	37.38, -104.45

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Craig Unit 1

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Order No. 202-25-14

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit P: Department, Order 202-25-4 (May 30, 2025)

Order No. 202-25-4

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the electricity grid operated by PJM Interconnection (PJM) due to a shortage of facilities for the generation of electric energy, resource adequacy concerns, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

PJM has recently stated its system faces “growing resource adequacy concern” due to load growth, the retirement of dispatchable resources, and other factors.¹ Upcoming retirements, including the planned retirement of Unit 3 and Unit 4 of the Eddystone Generating Station in Eddystone, Pennsylvania, will exacerbate these resource adequacy issues.

PJM indicates that resource constraints could exist within the service territory under peak load conditions, stating that “available generation capacity may fall short of required reserves in an extreme planning scenario.”² In its February 2023 assessment “*Energy Transition in PJM: Resource Retirements, Replacements & Risks*,” PJM highlights the increasing risk of reliability risk in the coming years due to the “potential timing mismatch between resource retirements, load growth and the pace of new generation entry” under “low new entry” scenarios for renewable generation.³

In December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found “the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry.”⁴ In March 2025 congressional testimony, PJM found “a growing resource adequacy concern” due to a combination of load growth, the retirement of dispatchable resources, and other factors.⁵ Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM’s interconnection queue.⁶

¹ <https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf>

² <https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/>

³ <https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx>

⁴ https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250211-3120

⁵ <https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf>

⁶ Ibid.

Constellation Energy owns the Eddystone Generating Station, which includes Unit 3 and Unit 4, each of which has a nameplate capacity of 380 MW. Units 3 and 4 have a planned retirement date of May 31, 2025. The retirement of these units would further decrease available dispatchable generation within PJM's service territory.

Pursuant to Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid* (EO 14262), DOE is developing a methodology to identify current and anticipated reserve margins for all regions of the bulk-power system regulated by the Federal Energy Regulatory Commission. EO 14262 requires this methodology to be published by July 7, 2025, and be used to establish a protocol to identify which generation resources within a region are critical to system reliability and prevent identified generation resources from leaving the bulk-power system. DOE plans to use this methodology to further evaluate Eddystone Units 3 and 4.

ORDER

Given the emergency nature of resource adequacy concerns, the declared state of national energy emergency, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, operational availability and economic dispatch of the aforementioned Eddystone Units 3 and 4 (Eddystone Units) is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the potential load stress due to aforementioned resource adequacy concerns, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The potential shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the region support the need for the Eddystone Units to contribute to system reliability.
- PJM's responsibility to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Eddystone Units, necessary to meet the load demands.

This Order is limited in duration to align with the anticipated emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse

environmental impacts. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

- A. From the time this Order is issued on May 30, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that Eddystone Units are available to operate. For the duration of this order, PJM is directed to take every step to employ economic dispatch of the units to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.
- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units have operated in compliance with the allowances contained in this Order.
- C. All operation of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- D. By June 15, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with the public interest. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. In addition, PJM and Constellation Energy are directed to file with the Federal Energy Regulatory Commission any tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- G. This Order shall be effective upon its issuance, and shall expire at 5:03 PM EDT on August 28, 2025, with the exception of the reporting requirements in paragraph D.

H. Issued in Simi Valley, California, at 5:03 PM Eastern Daylight Time on this 30th day of May 2025.



Chris Wright
Secretary of Energy

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Craig Unit 1

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Order No. 202-25-14

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit PP: Department, Order No. 202-25-10 (Nov. 25, 2025)



Department of Energy
Washington, DC 20585

Order No. 202-25-10

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists in the PJM Interconnection, L.L.C. (PJM) region due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order Nos. 202-25-4 and 202-25-8

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, PA. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that can run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order No. 202-25-4, issued pursuant to FPA section 202(c), required that the Eddystone Units remain in operation for 90 days, until August 28, 2025. Subsequently, Order No. 202-25-8, issued pursuant to FPA section 202(c), required the Eddystone Units remain in operation for 90 days, until November 26, 2025. Those orders were based on my determination that emergency conditions existed in the PJM region. I explained that there was a potential shortage of electric energy and a shortage of facilities for generation of electric energy. I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety. I determined that the operational availability and economic dispatch of the Eddystone Units was necessary to best meet the emergency and serve the public interest. My determination was based on a number of different facts.

First, in congressional testimony, PJM's president and CEO recently stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.³ Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ *Keeping the Lights On: Examining the State of Regional Reliability*, Before the H. Comm. on Energy and Com., S. Comm. on Energy, 119th Cong. (Mar. 25, 2025) (testimony of Mr. Manu Asthana, President and CEO of PJM) (Asthana Test.) at 4-5, available at <https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf>.

of resources in PJM's interconnection queue.⁴ Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."⁵ In its February 2023 assessment "*Energy Transition in PJM: Resource Retirements, Replacements & Risks* (Four Rs Report)," PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.⁶

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."⁷

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-4 and Order No. 202-25-8 continue, both in the near and long term.⁸ The production of electricity from the Eddystone Units will continue to be critical to maintaining reliability in PJM over the coming winter months. According to U.S. Environmental Protection Agency data, the Eddystone Units

⁴ *Id.*; see also *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) (*PJM Interconnection*) (PJM states that, in 2023, "it found that generator retirements, load growth, the pace of new entry, and the operating characteristics of the intermittent and limited duration resources that make up a large part of PJM's interconnection queue pose increasing reliability risks through 2030.").

⁵ *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing Risk*, PJM. (May 9, 2025), <https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/>.

⁶ *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM (Four Rs Report) at 1, (Feb. 24, 2023), <https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjmresource-retirements-replacements-and-risks.ashx>.

⁷ *PJM Interconnection*, 190 FERC ¶ 61,084 at P 14.

⁸ Further, it likely would be difficult for the oil-fired units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Further, if Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the Secretary determines that an emergency exists.

generated 26,434 MWh between June 2025 and September 2025,⁹ providing vital generation capacity to the region. Over the course of the summer, PJM issued Hot Weather Alerts and/or Maximum Generation Alerts (EEA 1) to manage grid reliability covering a total of 20 days, including days in June, July, and August.¹⁰

PJM's resource adequacy concerns are well documented. In January 2025, PJM reached a new record peak for winter demand, exceeding the previous winter peak set in 2015.¹¹ and in PJM's 2025 Long-Term Load Forecast, PJM noted that "20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%."¹² Further, PJM's risk profile continues to shift from the summer season to the winter season. For example, in a March 2025 presentation, PJM estimated that 87.8% of the expected unserved energy for the 2025/2026 delivery year falls in the winter season.¹³

The evidence also indicates that there is a potential longer term resource adequacy emergency in the PJM region.

In a news release expressing support for Order No. 202-25-4, PJM explained that it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."¹⁴

⁹ See *Custom Data Download*, EPA CAMPD (Clean Air Markets Program Data), <https://campd.epa.gov/data/custom-data-download> (search criteria Emissions >> Monthly >> Unit (default) >> Apply >> "2025" and "June, July, August, September." The data can then be filtered to only include the Eddystone Generating Station.

¹⁰ See PJM Emergency Procedures Postings for the period between June 1 and August 31, *Emergency Procedures*, <https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf> (search range set to: effective from 06/01/2025 until 08/31/2025).

¹¹ *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Electricity Demand*, PJM (Jan. 22, 2025), <https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/>.

¹² *2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand*, PJM Interconnection, L.L.C. (Jan. 30, 2025), <https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/>.

¹³ *2026/27 BRA IRM, FPR, and ELCC Class Ratings: Shift Towards More Winter Risk*, PJM Resource Adequacy Planning Special Planning Committee, at 8 (Mar. 13, 2025), <https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf>.

¹⁴ *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30*, PJM Interconnection, L.L.C. (May 31, 2025), <https://insidelines.pjm.com/pjm-statement-on-the-u-s-department-of-energy-202c-order-of-may-30/>. Further, PJM concluded, "In light of these concerns, PJM supports the U.S. Department of Energy's Order, issued May 30, pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM's footprint" *Id.*

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.¹⁵ PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately five percent.¹⁶ PJM determined that the pace of new capacity additions “would be insufficient to keep up with expected retirements and demand growth by 2030.”¹⁷ PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.

More recently, in its December 2024 RRI filing with FERC, PJM stated that “[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report”¹⁸ PJM warned that its “resource adequacy concerns are increasing at an extraordinary pace.”¹⁹ PJM went on to explain, its “resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers” and that its preliminary analysis shows “substantial increases [in load additions] since the 2024 forecast” for both the summer and winter seasons.²⁰ According to PJM, “load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence.”²¹ Although the RRI process will help expedite the construction of needed new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.²²

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM’s Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as “extraordinary” and “unprecedented,” stating that it “could not have been foreseen as recently as a year ago.”²³ Mr. Bielak expressed the opinion that the “rapid” retirement of thermal generation resources, “extreme” forecasted load growth, and “delays in new generation resources achieving commercial operation,” would adversely affect resource adequacy throughout PJM’s electricity grid.²⁴

¹⁵ Four Rs Report at 2.

¹⁶ *Id.*

¹⁷ *Id.* at 16, Table 1.

¹⁸ *PJM Interconnection, L.L.C.*, FERC Docket No. ER25-712, Tariff Revisions for Reliability Resource Initiative at 10 (Dec. 13, 2024).

¹⁹ *Id.*

²⁰ *Id.* at 10-11. *See also id.* at 13 (“the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements . . .”).

²¹ *Id.* at 14.

²² *See id.*, Attachment C (Affidavit of Mr. Donald Bielak), at PP 18-19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, “could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner.”).

²³ *Id.* at P 10.

²⁴ *Id.* at P 12.

On February 11, 2025, FERC accepted PJM's RRI filing.²⁵ In its order on rehearing, FERC concluded, "PJM identified increasing reliability risks arising in the next few years and significant resource adequacy issues anticipated by the 2030/31 delivery year. The record supports that these resource adequacy concerns are likely to manifest."²⁶

NERC has raised similar concerns. According to NERC's 2024 Long Term Reliability Assessment, "PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load."²⁷ NERC assessed the PJM region at an elevated risk starting in 2026,²⁸ explaining that "[r]esource additions are not keeping up with generator retirements and demand growth."²⁹ NERC stated that the loss of-load hour (LOLH) and expected unserved energy (EUE) risks are concentrated in the winter months (especially January), in both 2026 and 2028.³⁰

Order Nos. 202-25-4 and 202-25-8 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."³¹ President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."³² The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."³³

²⁵ *PJM Interconnection*, 190 FERC ¶ 61,084 at P 263.

²⁶ *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).

²⁷ *Long-Term Reliability Assessment*, North American Electric Reliability Corporation, at 92 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf at 92.

²⁸ *Id.* at 4.

²⁹ *Id.* at 7.

³⁰ *Id.* at 91-92.

³¹ Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (Strengthening the Reliability and Security of the United States Electric Grid), <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>.

³² Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (Declaring a National Energy Emergency), <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

³³ *Id.*

The Department of Energy's (Department) July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. It concludes, "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."³⁴ The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.³⁵ As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.³⁶ Regarding the PJM region, the Department's analysis performed this year in collaboration with the national labs modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.³⁷ Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a max unserved load of approximately 21.335 GW.³⁸

Grid operators, including PJM, have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the United States House of Representatives Committee on Energy and Commerce, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."³⁹ Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from

³⁴ See also Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, U.S. Department of Energy (July 2025), at 1, <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

³⁵ See PPL Corporation Q2 2025 Investor Update, PPLC Corporation, at 7 (July 31, 2025), https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINAL.pdf

³⁶ See Dominion Energy Virginia, Q4 2024 Earnings Call, at 18 (Feb. 12, 2025), https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slidesvTCII.pdf.

³⁷ Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, U.S. Department of Energy, at 28 (July 2025), <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

³⁸ *Id.* at 27.

³⁹ Asthana Test. at 4.

industrial growth.”⁴⁰ Mr. Asthana noted that, though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.⁴¹ Therefore, Mr. Asthana stated that PJM “encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability.”⁴²

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.”⁴³ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-4 and 202-25-8 will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes and serve the public interest under FPA section 202(c).

To ensure the Eddystone Units will be available if needed to address emergency conditions, the Eddystone Units shall remain in operation until February 24, 2026.⁴⁴

⁴⁰ *Id.*

⁴¹ *Id.* at 9-10.

⁴² *Id.* at 10.

⁴³ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. See 42 U.S.C. § 7151(b).

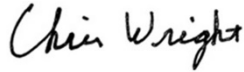
⁴⁴ 16 U.S.C. § 824a(c)(4).

Based on my determination of an emergency set forth above, I hereby order:

- A. From November 26, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.
- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by PJM pursuant to paragraph A. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units has operated in compliance with the allowances contained in this Order.
- C. All operation of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- D. By December 11, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. Constellation Energy is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resources.

H. This Order shall be effective from 00:00 PM Eastern Standard Time (EST) on November 26, 2025, and shall expire at 00:00 EST on February 24, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 2:30PM EST on this 25th day of November 2025.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Pennsylvania Public Utility Commissioners

Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-25-14
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit Q: Department, Order No. 202-25-11 (Dec. 16, 2025)



Department of Energy
Washington, DC 20585

Order No. 202-25-11

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists within the Western Electricity Coordinating Council (WECC) Northwest assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

EMERGENCY SITUATION

In its 2025–2026 Winter Reliability Assessment, NERC finds that the WECC Northwest region, which includes Montana, Oregon, Washington, and parts of northern California and northern Idaho, is at elevated risk during periods of extreme weather.³ The assessment notes that “there is sufficient capacity in the area for expected peak conditions; however, [balancing authorities] are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year.”⁴

In a September 2025 report evaluating Resource Adequacy in the Pacific Northwest, Energy + Environmental Economics (E3) determined that “[a]ccelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to 9 GW by 2030”⁵ and that “[l]oad growth and retirements mean the region faces a power supply shortfall in 2026.”⁶ E3 reported that nearly 9000 MW of new capacity will be needed in the region by 2030, but currently only 3000 MW of projects for new capacity are in active development.⁷ Overall, E3 found that “[p]referred resources such as wind, solar and batteries make only small contributions to meeting resource adequacy needs” and “[t]imely development of all resources is extremely challenging due to permitting and interconnection delays, federal policy headwinds, and cost pressures.”⁸

TransAlta Centralia Generation (“Centralia”) is an electric generating facility in Centralia,

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ NERC 2025-2026 Winter Reliability Assessment, at 6 (November 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

⁴ *Id.*

⁵ E3, *Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results*, at 2 (Sept. 22, 2025), <https://www.utc.wa.gov/sites/default/files/2025-10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20WA%20RA%20Meeting.pdf>. See also *id.* for the list of E3’s study sponsors, which include certain “regional utilities and generation owners.”

⁶ *Id.* at 10.

⁷ *Id.*

⁸ *Id.* at 2.

Washington. Centralia is owned and operated by the TransAlta Centralia Generation LLC (“TransAlta”). Centralia consists of one remaining coal-fired generation unit, Unit 2, with a nameplate capacity of 729.9 MW.⁹ Unit 2 began operations in 1973 and is slated to cease operations in December 2025. Unit 1 was retired in 2020. Unit 2 is slated to cease operation in December 2025, based on a 2011 Washington law¹⁰ and a subsequent agreement between TransAlta and the State of Washington.¹¹ TransAlta has announced plans to convert the unit to natural gas by 2028.¹²

More broadly, Executive Orders issued by President Donald J. Trump on January 20, 2025, and April 8, 2025, underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, “Declaring a National Energy Emergency,” in which he determined that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation’s economy, national security, and foreign policy.”¹³ The Executive Order adds: “Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets.”¹⁴ In a subsequent Executive Order 14262, “Strengthening the Reliability and Security of the United States Electric Grid,” President Trump emphasized that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”¹⁵

Further, the Department detailed the myriad challenges affecting the Nation’s energy systems in its July 2025 “Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid,” issued pursuant to the President’s directive in Executive Order

⁹ U.S. Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024) (2024 Form EIA-860), <https://www.eia.gov/electricity/data/eia860/>.

¹⁰ Act of Apr. 29, 2011, Ch. 180, 2011 Wash. Laws, <https://lawfilesexternal.wa.gov/biennium/2011-12/Pdf/Bills/Session%20Laws/Senate/5769-S2.SL.pdf#page=1>.

¹¹ See MOA (Dec. 23, 2011), <https://ecology.wa.gov/getattachment/858591f6-dd25-47be-ba1d-0f58264ca147/20111223TransAltaMOA.pdf> (“D. In exchange for the benefits of entering into an MOA with the State pursuant to RCW 80.80.100, the Company will . . . (5) permanently cease power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives”); see also First Amendment to MOA (July 13, 2017), <https://fortress.wa.gov/ecy/ezshare/AQ/PDFs/TransAltaMOAAmend1-20170713.pdf>. As a coal-fired facility, it would be difficult for the Centralia Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if TransAlta were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

¹² *TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion* (Dec. 9, 2025), <https://transalta.com/newsroom/transalta-signs-long-term-agreement-for-700-mw-at-centralia-facility-enabling-coal-to-natural-gas-conversion/>.

¹³ Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (Declaring a National Energy Emergency), <https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency>.

¹⁴ *Id.*

¹⁵ Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (Strengthening the Reliability and Security of the United States Electric Grid), <https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid>.

14262. The Department concluded that “[a]bsent decisive intervention, the Nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”¹⁶

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.”¹⁷ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Centralia Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes, businesses, and facilities critical to the national defense in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Centralia Unit 2 shall be made available for operation until March 16, 2026.

Based on my determination of an emergency set forth above, I hereby order:

- A. From December 16, 2025, TransAlta shall take all measures necessary to ensure that Centralia Unit 2 is available to operate at the direction of either Bonneville Power Administration (BPA) (in its role as Balancing Authority) or the California Independent System Operator Corporation Reliability Coordinator West¹⁸ (in its role as the Reliability Coordinator). Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices.
- B. To minimize adverse environmental impacts, this Order limits operation of Centralia Unit

¹⁶ U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

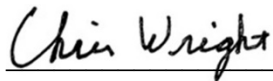
¹⁷ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. See 42 U.S.C. § 7151(b).

¹⁸ See NERC list of acronyms for Reliability Coordinators at <https://www.nerc.com/programs/bulk-power-system-awareness/reliability-coordinators>. On the official NERC Compliance Registry, CAISO is listed as the Reliability Coordinator. See NERC Compliance Registry at https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.nerc.com%2Fglobalassets%2Fprogram-s%2Fregistration%2Fcompliance-registry-files%2Fnerc_compliance_registry_matrix_excel.xlsx&wdOrigin=BROWSELINK.

2 to the times and within the parameters established in paragraph A. TransAlta shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Centralia Unit 2 has operated in compliance with this Order.

- C. All operations of Centralia Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- D. By December 30, 2025, TransAlta is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Centralia Unit 2 consistent with this Order. TransAlta shall also provide such additional information regarding the environmental and operational impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. TransAlta is directed to file with the Federal Energy Regulatory Commission tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. BPA is directed to facilitate transmission service, as needed, to effectuate this Order.
- G. This Order shall not preclude the need for Centralia Unit 2 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- H. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Centralia Unit 2 shall not be considered a capacity resource.
- I. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 16, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 16, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 5:20PM EST on this 16th day of December 2025.



Chris Wright
Secretary of Energy

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-25-14
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit QQ: Tri-State, *U.S. DOE Orders Tri-State to Keep Craig Generating Station Unit
Operating for Next 90 Days (Dec. 31, 2025)*

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12/31/25

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<https://www.addtoany.com/share#url=https%3a%2f%2ftristate.coop%2fus-doe-orders-tri-state-keep-craig-generating-station-unit-operating-next-90-days&title=u.s.%20doe%20orders%20tri-state%20to%20keep%20craig%20generating%20station%20unit%20operating%20for%20next%2090%20days>

U.S. DOE orders Tri-State to keep Craig Generating Station unit operating for next 90 days

(December 31, 2025 – Westminster, Colorado) Tri-State Generation and Transmission Association and the other utilities that co-own Craig Generating Station Unit 1 received an emergency order from the U.S. Department of Energy (DOE) under Section 202(c) of the Federal Power Act identifying an energy emergency in the Western Electricity Coordinating Council Northwest area and directing Tri-State to keep Unit 1 available to operate at the direction of either the Western Area Power Administration (WAPA)—Rocky Mountain Region Western Area Colorado Missouri (WACM) in its role as Balancing Authority or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator, for the next 90 days.

Since 2016, Unit 1 has been scheduled for retirement by Dec. 31, 2025, for economic reasons, and to comply with numerous state and federal requirements. This retirement decision has informed operational and maintenance decisions, and Tri-State has planned for adequate resources to maintain reliability on its system following the unit’s retirement.

Separately, Unit 1 went into an outage on Dec. 19, 2025, due to a mechanical failure of a valve, and Tri-State and the other co-owners will need to take the necessary steps to repair the valve in a timely manner.

“Tri-State has a policy of 100% compliance, and we will work with Unit 1 co-owners, and federal and state governments to determine the most cost-effective path to that end,” said Duane Highley, Tri-State CEO. “We are continuing to review the order to determine what this means for Craig Station employees and operations, and the financial impacts. As a not-for-profit cooperative, our membership will bear the costs of compliance with this order unless we can identify a method to share costs with those in the region. There is not a clear path for doing so, but we will continue to evaluate our options.”

As a result of the order, retaining Unit 1 will likely require additional investments in operations, repairs, maintenance and, potentially, fuel supply, all factors increasing costs. Tri-State is continuing to review the order to determine how best to comply while limiting the costs to its members, and the impacts to its employees and operations.

The retirement of Craig Unit 1 was specified in Colorado Air Quality Control Commission Regulation No. 23 on Regional Haze Limits, and the Regional Haze State Implementation Plan put in place in 2016. Tri-State’s 2020 and 2023 Electric Resource Plan (ERP) modeling reflected the previously announced retirement date for Unit 1. The model results of the 2023 ERP showed adequate resources to maintain reliability on Tri-State’s system following the retirement of Craig Station.

Craig Units 1 and 2 are part of the Yampa Project, jointly owned with multiple utility services providers including Tri-State, Platte River Power Authority, PacifiCorp, Xcel Energy and Salt River Project, with Tri-State as the operating entity. Tri-State owns 100% of Unit 3. Craig Unit 1's capacity is 427 megawatts. Unit 2, with a capacity of 410 megawatts, and Unit 3, with a capacity of 448 megawatts, are scheduled to retire in 2028.

Tri-State will share more information as appropriate when available.

About Tri-State

Tri-State is a power supply cooperative, operating on a not-for-profit basis, serving electric distribution cooperatives and public power district member-owners in four states. Together with our members, we deliver reliable, affordable and responsible power to more than a million electricity consumers across nearly 200,000 square miles of the rural West. Visit www.tristate.coop.

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Certain information contained in this press statement are forward-looking statements including statements concerning Tri-State's plans, future events, and other information that is not historical information. These forward-looking statements are subject to a number of risks, uncertainties and assumptions, including those described from time to time in Tri-State's filings with the Securities and Exchange Commission. Tri-State's expectations and beliefs are expressed in good faith, and Tri-State believes there is a reasonable basis for them. However, Tri-State cannot assure you that management's expectations and beliefs will be achieved. There are a number of risks, uncertainties and other important factors that could cause actual results to differ materially from the forward-looking statements contained herein.

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Inc. Power supplier to the rural west.

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-25-14
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit R: Department, Order No. 202-25-13 (Dec. 23, 2025)



Department of Energy
Washington, DC 20585

Order No. 202-25-13

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The F.B. Culley Generating Station (Culley) is an electric generating facility in Warrick County, Indiana. Culley is owned and operated by CenterPoint Energy and consists of two coal-fired generation units, Unit 2 (103.7 MW) and Unit 3 (265.2 MW), with a combined name plate capacity of 368.9 MW. Unit 2 and Unit 3 began operations in 1966 and 1973, respectively. Unit 2 is slated to cease operations in December 2025.³

EMERGENCY SITUATION

Midcontinent Independent System Operator, Inc.'s (MISO) year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.⁴ MISO justified this revision by explaining that "Reliability risks associated with Resource Adequacy have shifted from 'Summer only' to a year-round concern."⁵ MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.⁶

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ As a coal-fired facility, it would be difficult for Culley Unit 2 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Culley were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

⁴ *Midcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. See *Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

⁵ MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).

⁶ *Id.* at 3-4.

transforming energy landscape.”⁷ Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.⁸

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, “*MISO’s Response to the Reliability Imperative*.”⁹ In a section of that report entitled “Risks in Non-Summer Seasons,” MISO again stressed that it has resource reliability concerns outside of the summer season:

Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region’s highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.¹⁰

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season. The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO.

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area is at an elevated risk “because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years.”¹¹

When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources” in the northern and central zones, which include Indiana.¹²

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to

⁷ MISO, *Attributes Roadmap*, at 3 (Dec. 2023), <https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf>.

⁸ *Id.* at 11.

⁹ MISO, *MISO’s Response to the Reliability Imperative* (Updated Feb. 2024), <https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf>.

¹⁰ *Id.* at 12.

¹¹ NERC 2024 Long-Term Reliability Assessment, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

¹² MISO, *Planning Resource Auction: Results for Planning Year 2025-26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

which expected capacity resources satisfy planning reserve margin requirements.¹³ The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.¹⁴ The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.¹⁵ Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.¹⁶

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large quantities of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.¹⁷ Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.¹⁸

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.¹⁹ The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.²⁰ In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.²¹ Consequently, it is not at all clear that the new ERAS process will result in the addition of new capacity in the next few years.

¹³ OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025), <https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf>.

¹⁴ *Id.* at 2.

¹⁵ *Id.* at 7.

¹⁶ *Id.* at 9.

¹⁷ *Id.* at 7, 9.

¹⁸ *Id.*

¹⁹ *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

²⁰ *Id.* P 84.

²¹ See generally, S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, (May 2025), ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), <https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply>.

More broadly, executive orders issued by President Donald J. Trump on January 20, 2025, and April 8, 2025, underscore the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump likewise declared a national energy emergency in Executive Order 14156, “Declaring a National Energy Emergency,” that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation’s economy, national security, and foreign policy.”²² The Executive Order adds: “Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets.”²³ In a subsequent Executive Order 14262, “Strengthening the Reliability and Security of the United States Electric Grid,” President Trump emphasized that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”²⁴

Further, the Department detailed the myriad challenges affecting the Nation’s energy systems in its July 2025 “Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid,” issued pursuant to the President’s directive in Executive Order 14262. The Department concluded that “[a]bsent decisive intervention, the Nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”²⁵

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.”²⁶ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Culley Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

²² Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency>.

²³ *Id.*

²⁴ Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid>.

²⁵ U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

²⁶ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of Energy. See 42 U.S.C. § 7151(b).

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of Culley Unit 2 is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c).

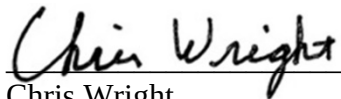
To ensure Culley Unit 2 will be available if needed to address emergency conditions, Culley Unit 2 shall remain in operation until March 23, 2026.

Based on my determination of an emergency set forth above, I hereby order:

- A. From December 23, 2025, MISO and CenterPoint Energy shall take all measures necessary to ensure that Culley Unit 2 is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Culley Unit 2 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. CenterPoint Energy is directed to comply with all orders from MISO related to the availability and dispatch of Culley Unit 2.
- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Culley Unit 2 has operated in compliance with the allowances contained in this Order.
- C. All operations of Culley Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- D. By January 13, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Culley Unit 2 consistent with this Order. MISO and CenterPoint Energy shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

- E. CenterPoint Energy is directed to file with the Federal Energy Regulatory Commission tariff revisions or waivers to effectuate this Order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for Culley Unit 2 to comply with applicable state, local, or Federal laws or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Culley Unit 2 shall not be considered a capacity resource.
- H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 23, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 23, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Denver, Colorado at 6:39 PM EST on this 23rd day of December 2025.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Indiana Utility Regulatory Commission
Chairman Jim Huston
Commissioner David Veleta
Commissioner David Ziegner

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Craig Unit 1

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Order No. 202-25-14

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit RR: Powell, R., *1 coal plant open amid order* (Jan. 6, 2026)

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1 coal plant open amid order



Rebecca Powell

Fort Collins Coloradoan

Jan. 6, 2026, 5:02 a.m. MT

Platte River Power Authority's general manager says he disagrees with a federal order requiring one of the coal plants it owns a stake in to remain open past its scheduled retirement and is waiting to learn what it might cost Fort Collins' wholesale electricity provider.

The U.S. Department of Energy on Dec. 30 issued an emergency order requiring Craig Unit 1 in Moffat County to remain available to operate for at least the next 90 days at the direction of the Western Area Power Administration or Southwest Power Pool West.

The plant was set to be retired on Dec. 31 after 45 years of operation, until that order was issued only a day prior.

PRPA is a joint owner of the plant with PacifiCorp, Xcel Energy, Salt River Project and Tri-State Generation and Transmission, which operates the facility.

PRPA owns 18% of the Craig 1 and 2 coal units.

The nonprofit provides wholesale electricity to Fort Collins Utilities. It is owned by four Northern Colorado cities: Fort Collins, Loveland, Longmont and Estes Park.

The Department of Energy's emergency order contends there is a shortage of electric energy and facilities in the Western Electricity Coordinating Council Northwest assessment area, which includes Colorado, Idaho, Montana, Oregon, Utah, Washington and Wyoming.

Coloradoan.

Wright cites supply chain issues with building battery storage systems to help replace the energy from those retirements.

The emergency order also cited two executive orders from President Donald Trump. One declared a national energy emergency due to "insufficient energy production, transportation, refining, and generation." The other declares the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, like the expansion of AI data centers and domestic manufacturing.

But PRPA General Manager and CEO Jason Frisbie says PRPA does not need the Craig 1 unit because it has already replaced the energy that came from it.

"We have planned for the retirement of Craig Unit 1 for nearly a decade and have proactively replaced the capacity and energy from new sources," Frisbie said in a statement provided to the Coloradoan.

The joint owners have been planning for the plant's closure since 2016 "for economic reasons and to comply with numerous state and federal requirements," a Dec. 31 news release from Tri-State states. "This retirement decision has informed operational and maintenance decisions, and Tri-State has planned for adequate resources to maintain reliability on its system following the unit's retirement."

The state of Colorado is requiring utility providers to cut their 2005 carbon emissions by 80% by 2030.

The Craig 1 plant hadn't been operating since a mechanical failure occurred on Dec. 19, according to Tri-State. The problem will have to be fixed for it to become available for operations.

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Duane Highley, Tri-State CEO, said the not-for-profit cooperative's membership will bear the costs of compliance "unless we can identify a method to share costs with those in the region."

"There is not a clear path for doing so, but we will continue to evaluate our options," Highley said.

Frisbie said PRPA is working to understand the impacts.

"While we disagree with the need to keep the plant open, we are working with the unit's operating agent, Tri-State Generation and Transmission, and the other owners to understand the compliance requirements and cost obligations of the emergency order," he stated.

PRPA is set to retire its last coal plant, Rawhide 1, located north of Fort Collins, at the end of 2029.

At that point, PRPA expects 88% of its energy will be from noncarbon sources. Today that figure is around 36%.

To help fill the void, PRPA is expected to invest \$600 million in construction of five aeroderivative gas turbines to provide electricity when wind and solar resources aren't available due to the weather.

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